MISO

Transmission Expansion Plan

2013

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Executive Summary

The annual Midcontinent Independent System Operator (MISO) Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. As part of MTEP13, MISO staff recommends $1.48 billion of new transmission expansion through 2023, as described in Appendix A, to the MISO Board of Directors for review, approval and subsequent construction.

MTEP13, the 10th edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders. A key purpose of this, and other MTEP reports, is to identify transmission projects that:

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

Additionally, MTEP provides an overview of key system issues and impacts facing the Midcontinent region.

Notable MTEP13 themes include:

- Heightened concern and ongoing study regarding EPA compliance, natural gas coordination, and Resource Adequacy
- Parallel effort to integrate new MISO South Region members into the MISO planning process. The South Region will fully participate in MTEP14
- Increased interregional planning through Order 1000 and cross-border studies
- As with MTEP12, economic planning studies continue to find modest economic benefit potential from transmission expansion—due largely to the congestion-relieving effects of Multi-Value Projects, lower natural gas prices and lower economic growth

Key findings and activities from the MTEP13 planning cycle include:

- The recommendation of 317 new projects for inclusion in Appendix A provides an incremental $1.48 billion in transmission infrastructure investment
- Only one new cost-shared project in this cycle: a Generation Interconnection Project
- Project monitoring and reporting on the status of previously approved projects was enhanced during this cycle with additional milestone status codes
- A changing Resource Adequacy environment with the potential impact of current and proposed air regulations. Recent assessments show the potential for a 3 to 7 GW capacity shortfall as early as 2016
- Completion of the Northern Area Study and Manitoba Hydro Wind Synergy Study, both exploratory efforts to identify the potential for economically justified transmission
- Completion of the first full Market Efficiency Planning Study using new methodology. Results from this study are helping inform its companion study — the MISO PJM Joint Planning Study
- Completion of MISO's Independent Coordinator of Transmission (ICT) role for Entergy upon full integration of Entergy on December 19, 2013
- FERC Order 1000 regional and interregional filings

Book 1: **Transmission Studies**

MTEP Overview – Chapter 2

MTEP13 recommends 317 new projects for inclusion in Appendix A. These projects represent an incremental $1.48 billion[1] in transmission infrastructure investment within the MISO footprint and fall into the following three categories (Figure 1.1-1):

- **79 Baseline Reliability Projects (BRP) totaling $372 million –** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **3 Generator Interconnection Projects (GIP) totaling $15 million –** GIPs are required to reliably connect new generation to the transmission grid.
- **235 Other Projects totaling $1.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.

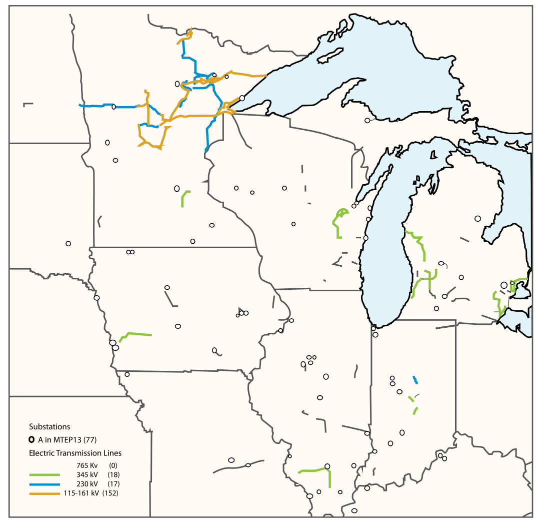

Figure 1.1-1: Map of new MTEP13 Appendix A projects

MTEP History – Chapter 3

Since the first MTEP report in 2003, more than $6.2 billion in projects have been constructed in the MISO region. Currently there are $17.9 billion of approved projects in various stages of design, construction, or in-service (Figure 1.1-2). MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project.

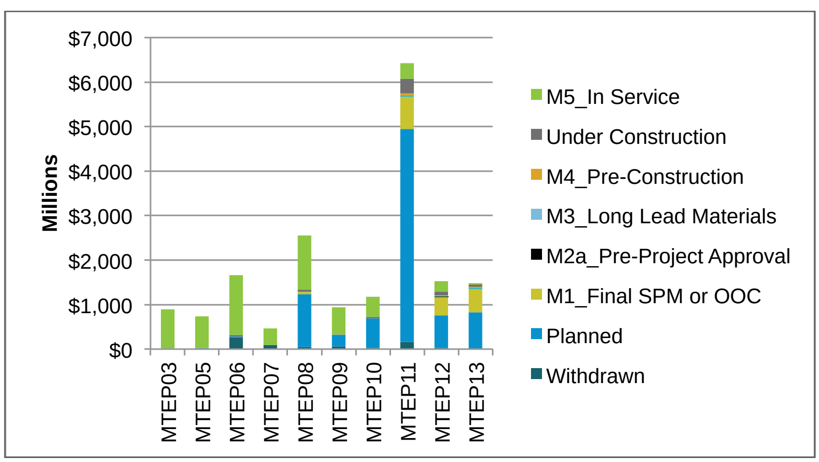

Figure 1.1-2: Approved MTEP investment by year and facility status

[1] The MTEP13 report and project totals reflect all project approvals across the year, including projects approved on an out-of-cycle basis prior to December.

Reliability Analysis – Chapter 4

Maintaining system reliability is the primary purpose of most MTEP projects. In support of this goal, MISO conducts baseline reliability studies to ensure the transmission system is in compliance with two entities: applicable national Electric Reliability Organization (ERO) reliability standards and the reliability standards adopted by Regional Reliability Organizations applicable within the Transmission Provider region. These mandatory standards define acceptable power flows, voltage levels and system stability limits. MISO is required to identify a solution for each identified violation that could otherwise lead to overloads, equipment failures or blackouts.

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MISO's studies include simulations to assess transmission reliability in the near and long term, using analytical models representing various system conditions two, five and 10 years out. MISO planners study reliability from a thermal perspective—making sure the transmission facilities do not overheat, and from voltage and dynamic perspectives—making sure the frequency remains stable. Detailed results of these analyses are included in Appendix D of the MTEP13 report.

Economic Analysis – Chapter 5

In addition to maintaining reliability, MISO explores the potential for economically justified projects. MISO uses economic benefit analysis to identify solutions to relieve the most congested flowgates. This year's Market Efficiency Planning Study (MEPS) analyzed congested flowgates to determine whether the proposed solution qualified for inclusion in MTEP Appendix A or B as a Market Efficiency Project (MEP), a Cross-Border Market Efficiency project, or a self-funded project. As in MTEP12, this year's MEPS showed lower potential benefits than those reported in previous studies. This is largely due to congestion relief benefits gained from the inclusion of MTEP11 Multi-Value Projects, lower gas prices and decreased load growth rates.

Developing future "what-if" scenarios and conducting capacity expansion analyses are necessary pre-requisites for this economic analysis. MISO develops models to identify least-cost generation portfolios needed to meet Resource Adequacy Planning Reserve Margin requirements of the system for various future scenarios. Results of this year's assessment for the Business as Usual future predicts the need for 24,900 MW of additional capacity for the MISO system between 2013 and 2028, while 12,200 MW of capacity is forecasted to retire (Figure 1.1-3).

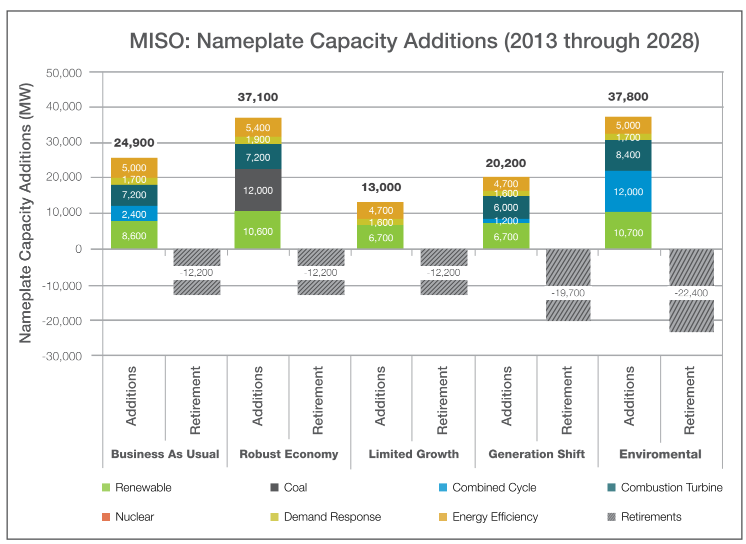

Figure 1.1-3: Projected nameplate capacity additions through 2028 by future

Book 2: **Resource Adequacy**

In conjunction with transmission studies, MISO assesses the adequacy of generation for the current planning year and future planning horizons.

The MISO region has historically operated with healthy reserve margins. But MISO believes that long-term Resource Adequacy picture will change dramatically in response to new and proposed emission regulations. The uncertainty increases with the potential for carbon emission limitations. This year's assessment on the potential impact of current and proposed air regulations, show the potential for a 3 to 7 GW capacity shortfall below the Planning Reserve Margin as early as 2016. Avoiding these negative outcomes requires increased collaboration among MISO and its members, the Organization of MISO States (OMS), and other key players in the industry.

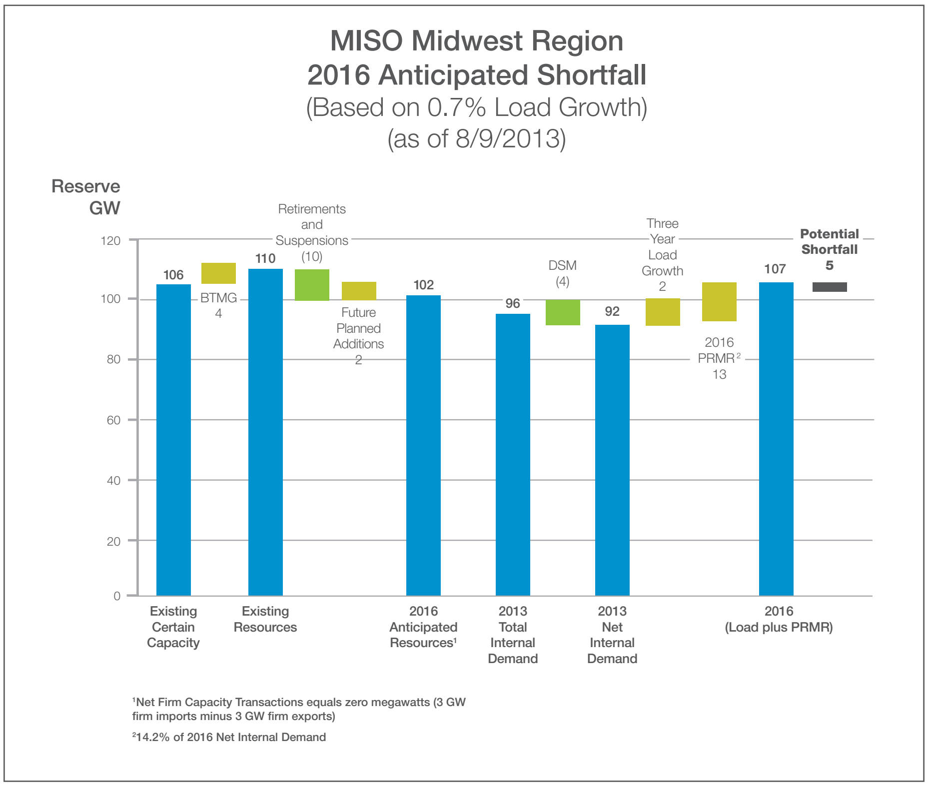

Figure 1.1-4: Planning Reserve Margin Requirement (PRMR) to Total Resources Comparison, MW

For the near term, MISO determined the Planning Reserve Margin (PRM) for the 2013-2014 planning year to be 14.2 percent, decreasing 2.5 percent from the 16.7 percent PRM set for the 2012-2013 planning year (Figure 1.1-4).

Related policy discussions around environmental compliance and natural gas coordination continued to drive active studies. MISO refined the quarterly survey of generator retirement plans, and supplemented that data with Attachment Y retirement and suspension data. Collaboration with the natural gas industry continued through ongoing stakeholder forums and a new phase of investigation. This 2013 phase complements the modified backcast analysis used in Phase I and II with a forward balancing analysis, providing a robust picture of gas pipeline capacity in the next three to five years.

Book 3: – Policy Landscape Studies

MISO Midwest **Regional Studies** – Chapter 7

In a world of constantly evolving state and federal policies, fuel prices, load patterns and transmission configurations, MISO strives to provide meaningful analyses to help inform policy discussions and decisions. These independent analyses are critical to achieve MISO's goal to meet transmission needs efficiently and deliver the lowest-cost energy to consumers.

Northern Area Study

The Northern Area Study is a regional evaluation of production cost savings potential and related reliability issues in MISO's northern footprint. The study found that large-scale regional transmission expansion in North Dakota, Minnesota, Northern Wisconsin and Michigan is not cost-effective based solely on production cost savings, under current business-as-usual conditions. The study discovered that MISO could see economic benefits with minimal incremental transmission investment from new Manitoba Hydro to MISO tie-lines (Figure 1.1-5).

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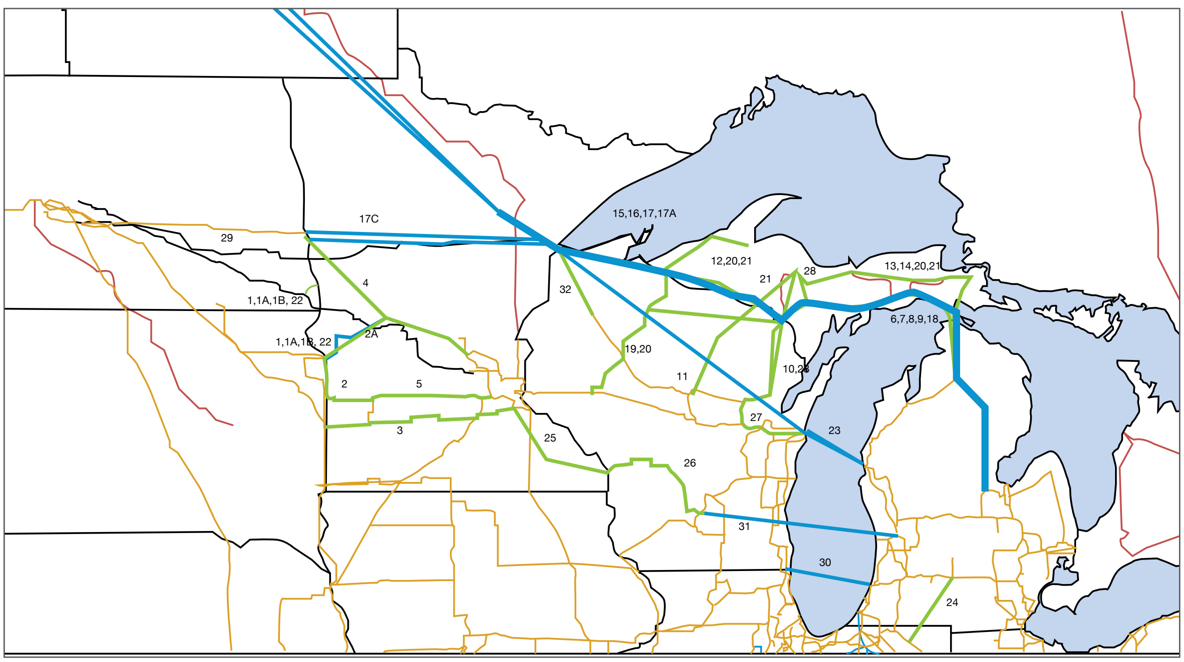
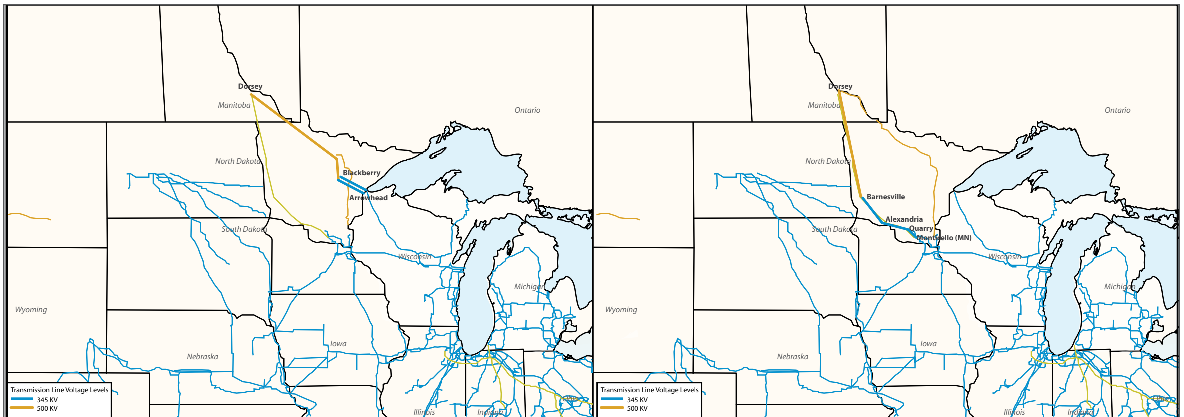


Figure 1.1-5: Northern Area Study transmission options

Manitoba Hydro Wind Synergy Study

This study also dealt with Manitoba Hydro tie-lines — but from a different perspective. The purpose of the study, called the Manitoba Hydro Wind Synergy Study, was to assess how Canadian hydro power can work with MISO wind to provide benefits to MISO.

The study found significant benefits from the addition of either an eastern 500 kV line between Dorsey, Manitoba, and Duluth, Minn., or a western 500 kV line between Dorsey, Manitoba, and Fargo, N.D./ Moorhead, Minn. (Figure 1.1-6). Additional near-term benefits can be obtained by expanding the External Asynchronous Resource (EAR) structure from unidirectional to bidirectional.



East Option: Dorsey to Blackberry	West Option: Dorsey to Fargo/Moorhead Area
- 500kV line from Winnipeg to Grand Rapids - 345kV double circuit line from Grand Rapids to Duluth	- 500kV line from Winnipeg to Fargo/Moorhead Area - 345kV line from Fargo/Moorhead to Monticello

Figure 1.1-6: Manitoba Hydro Wind Synergy Study east and west options

MISO South **Region Studies** – Chapter 8

The Midwest Independent System Operator became the Midcontinent Independent System Operator with the expansion of MISO's boundary to the Gulf of Mexico. Integrating these new entities into MISO required intense efforts during the MTEP13 cycle (Figure 1.1-7).

The South Region will fully participate in MTEP14.

On December 1, 2012, MISO assumed the role of Independent Coordinator of Transmission (ICT) for Entergy's transmission network. As the ICT assessment completes, MISO will incorporate the final 2014-2018 construction plan into the MTEP14 planning cycle.

During the MTEP13 cycle MISO worked with South Region stakeholders on:

- Generator Deliverability Analysis
- Loss of Load Expectation Study
- Market Efficiency Planning Study
- Environmental Compliance Study

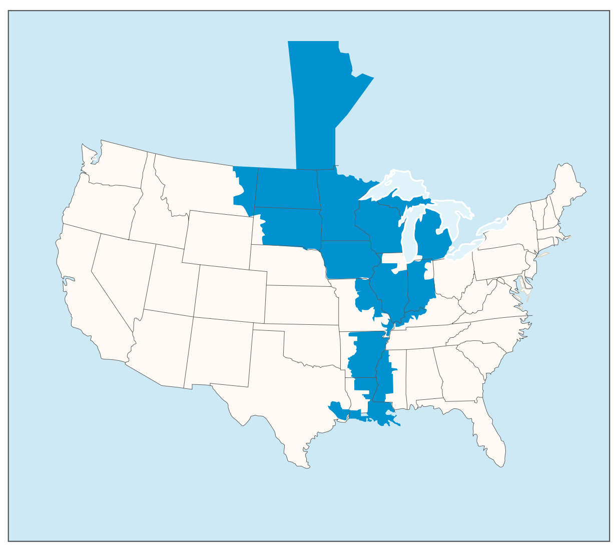


Figure 1.1-7: MISO's expanded footprint

Interregional Studies – Chapter 9

FERC Order 1000

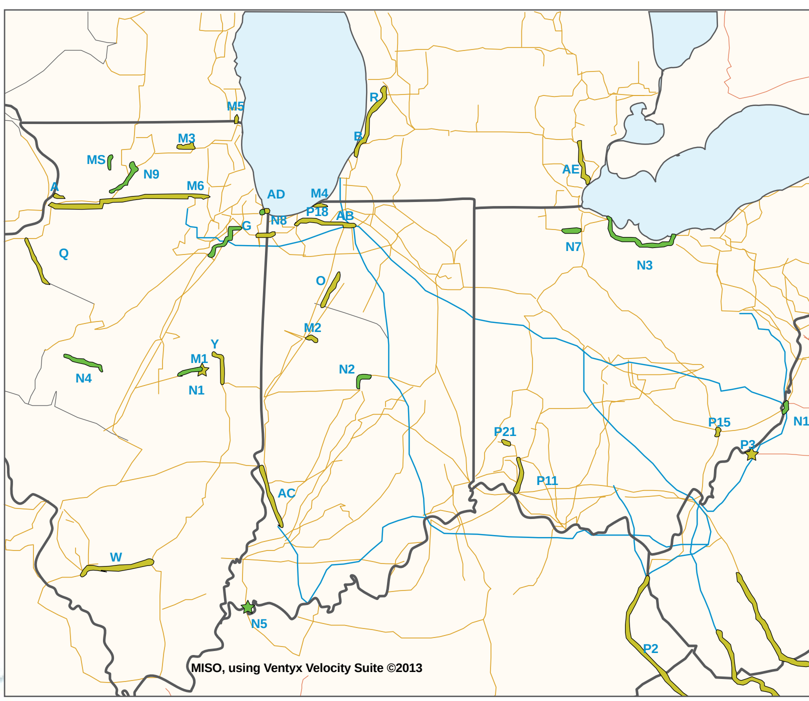
MISO filed documentation with FERC on October 25, 2012 stating how MISO complies or will comply with the regional planning components of the order. A second filing covering interregional components was filed on July 10, 2013. While MISO was already largely compliant with the regional transmission planning provisions of Order 1000, the elimination of the federal right of first refusal (ROFR) was a new requirement that required significant stakeholder engagement.

FERC Order 1000 seeks to ensure more efficient and cost-effective regional planning and interregional coordination

MISO's interregional compliance required development of planning coordination and cost allocation processes with each of MISO's four neighboring planning regions: Midcontinent Area Power Pool (MAPP), PJM Interconnection, Southeastern Regional Transmission Planning group (SERTP) and Southwest Power Pool (SPP). To accomplish this, MISO worked with each of the four neighboring planning regions, along with stakeholders, through interregional workshops from April 2012 through July of 2013.

Cross Border Studies

MISO and PJM launched a Joint Planning Study in October 2012 to evaluate cross-border seams issues and identify transmission solutions that promote market efficiency. When completed in 2014, this study may identify cross-border transmission projects (Figure 1.1-8).



A	Beaver Channel - Albany 161kV
B	Benton Harbor - Palisades 345kV
E	Cordova - Nelson 345kV
G	Crete - St Johns 345kV
M	Marengo - Woodstock 138kV
O	Monticello - East Winimac 138kV
Q	Oak Grove - Galesburg 161kV
R	Palisades - Roosevelt 345kV
W	Prairie State - Mt Vernon 345kV
Y	Rantoul - Rantoul Junction 345kV
AB	Stillwell - Dumont 345kV
AC	Breed - Wheatland 345kV
AD	Sheffield - Marktown 138kV
AE	Monroe - Wayne 345kV
M1	Rising 345/138kV XFMR (Fg z)
M2	Cumberland - Bush 138kV (Fg h)
M3	Marengo - Pleasant Valley 138kV (Fg L)
M4	Michigan City - Laporte 138kV (Fg N)
M5	Kenosha - Lakeview 138kV (Fg J)
M6	Nelson - Electronic Junction 345kV (Fg P)
P2	AEP - DOM interface
P3	Belmont500/765 XMFR
P11	Pierce - Foster 345kV
P15	Waterford - Muskingum 345kV
P18	Babcock - Stillwell 345kV
P20	Rantoul Jct - Sidney 138kV
P21	Toddhunter - Trentton 138kV
N2	Whitestown - Guion 345kV
N3	Ottawa - Lakeview 138kV
N4	Havana - Elkhart 138kV
N5	AB Brown 138/345kV Xfmr
N6	Marylan - Bailey 138kV
N7	Lemoyn - Bowling Tap 138kV
N8	Hegewisch - Burnham 138kV
N9	Dixon - Still 138kV
N10	Braidwood - E Frankfort 345kV
N11	Kammer - Natrium 138kV

Figure 1.1-8: Top congested M2M and non-M2M flowgates

Book 4: Regional Energy Information

Understanding the complexities of regional electric energy systems requires looking at the data from as many perspectives as possible. The first three books of the MTEP13 Report focus on regional information largely related to the MTEP13 planning cycle. However, MISO collects, produces and calculates additional information that can provide insights on the state of the regional energy system. Book 4 presents additional regional energy information, placing special emphasis on historical trends, to provide MISO observers with a more complete picture of the regional energy system (Figure 1.1-9).

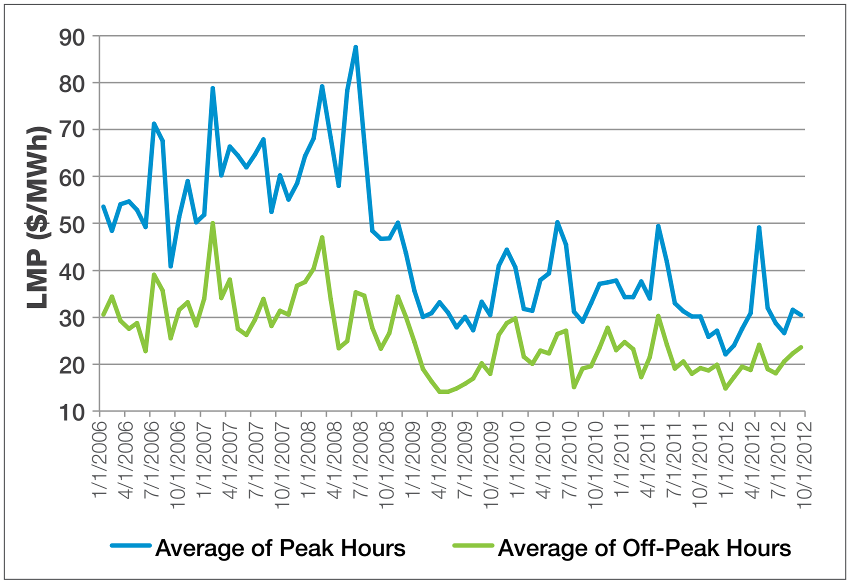


Figure 1.1-9: MISO average monthly locational marginal price (LMP): 2006–2012

The MISO Planning Approach

A defined set of principles, established by MISO's Board of Directors, guides the organization's planning efforts. These principles were created to improve and guide transmission investment in the region and to furnish strategic direction to the MISO transmission planning process. These principles, last reconfirmed March 2013 ,[2] are as follows:

Guiding Principles for Expansion Plans

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

[2] 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 and March 2013.

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost.
- **Guiding Principle 2:** Provide a transmission infrastructure 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.
- **Guiding Principle 3:** Support state and federal energy policy requirements by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- **Guiding Principle 5:** 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.
- **Guiding Principle 6:** Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.

To support these principles, a transmission planning process has been implemented to reflect a view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons studied. A number of conditions must be met through this process to build long-term transmission that can support future generation growth and accommodate documented energy policy mandates or laws. These conditions are intertwined with the MISO Board of Directors' planning principles and include:

- A robust business case for the plan
- Increased consensus around regional energy policies
- A regional tariff matching: who benefits with who pays over time
- Cost recovery mechanisms to reduce financial risk

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. We are grateful for the input and support from our stakeholder community, which allows us to create well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. We welcome feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission power system. For detailed information about MISO, MTEP13, renewable energy integration, cost allocation and other planning efforts, visit www.misoenergy.org.

BOOK 1
TRANSMISSION STUDIES

Book 1 of the MTEP13 report summarizes this cycle's projects and the analyses behind them, as well as the history and status of previously approved transmission projects.

Book 1 – **Chapter 2**
MTEP13 Overview

MTEP13 Overview

The ultimate deliverable of MTEP is a list of transmission projects for recommendation to the MISO Board of Directors. This chapter provides highlights of MTEP projects, both new and already-approved. A complete list of all MTEP projects is included in [Appendices A, B and C](). A further explanation of Appendix A, B, and C definitions can be found in Chapter 2.4.

2.1 Investment Summary

The 317 MTEP13 new projects represent an incremental $1.48 billion[3] in transmission infrastructure investment and fall into the following three categories (Figure 2.1-1):

- **79 Baseline Reliability Projects (BRP) totaling $372 million –** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **3 Generator Interconnection Projects (GIP) totaling $15 million –** GIPs are required to reliably connect new generation to the transmission grid.
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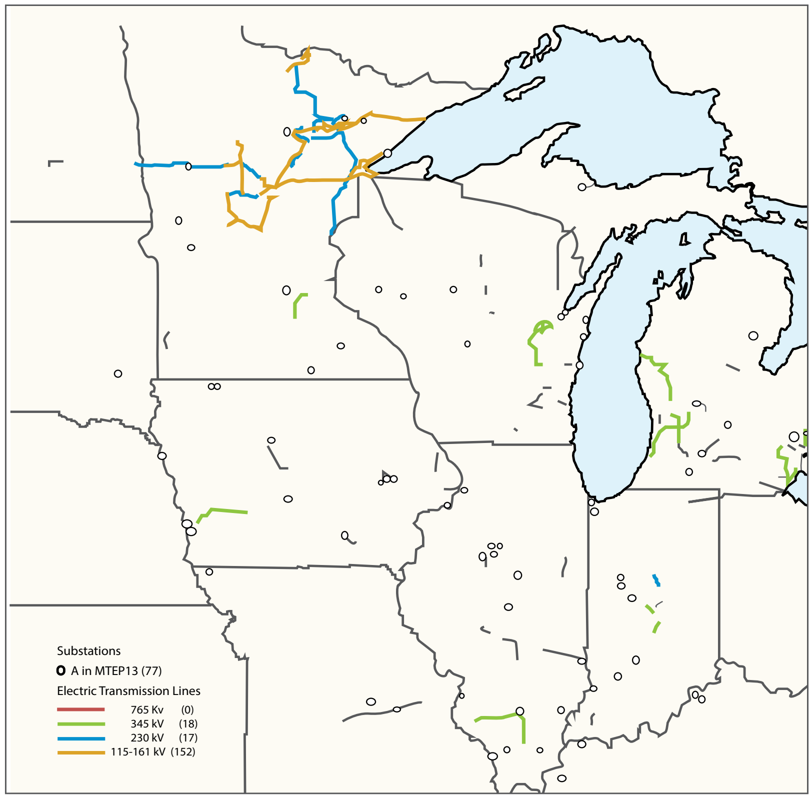


Figure 2.1-1: Map of new MTEP13 Appendix A projects

New Appendix A projects proposed for MTEP13 are distributed across all MISO states (Figure 2.1-1). This map is for illustrative purposes and does not include all projects. Some of the projects shown are upgrades to existing transmission facilities.

[3] The MTEP13 report and project totals reflect all project approvals during the MTEP13 cycle, including those approved on an out of cycle basis prior to December.

Aggregate Appendix A Investment

The aggregate project spending for Appendices A, with the addition of MTEP13 new projects, increases to approximately $11 billion by 2022 (Figure 2.1-2). MTEP13 Appendix A contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Investment totals by year assume that 100 percent of a project's investment is fulfilled when the facility goes into service. Large project investment is shown in a single year but often occurs over multiple years.

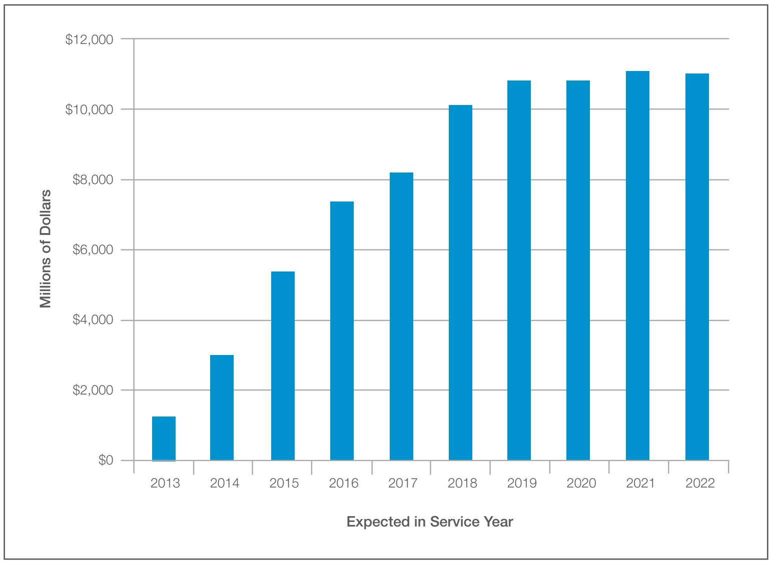


Figure 2.1-2: MTEP13 Appendix A projected cumulative investment by year

MISO Transmission Owners have committed to significant investments in the transmission system (Table 2.1-1). Cumulative MTEP transmission investment for Appendix A is approximately $11 billion with another $1.7 billion in Appendix B for the 2013-2022 time period. New MTEP13 Appendix A projects represents $1.48 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $5 billion of the approximately $11 billion in cumulative Appendix A is from the Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the three MISO geographic planning regions: East, Central and West (Figure 2.1-3).

MISO Region	Appendix A	Appendix B
Central	$2,433,176,000	$386,762,000
East	$1,825,625,000	$544,798,000
West	$6,703,553,000	$765,634,000
Total	$10,962,354,000	$1,697,194,000

Table 2.1-1: Projected transmission investment by planning region through 2022

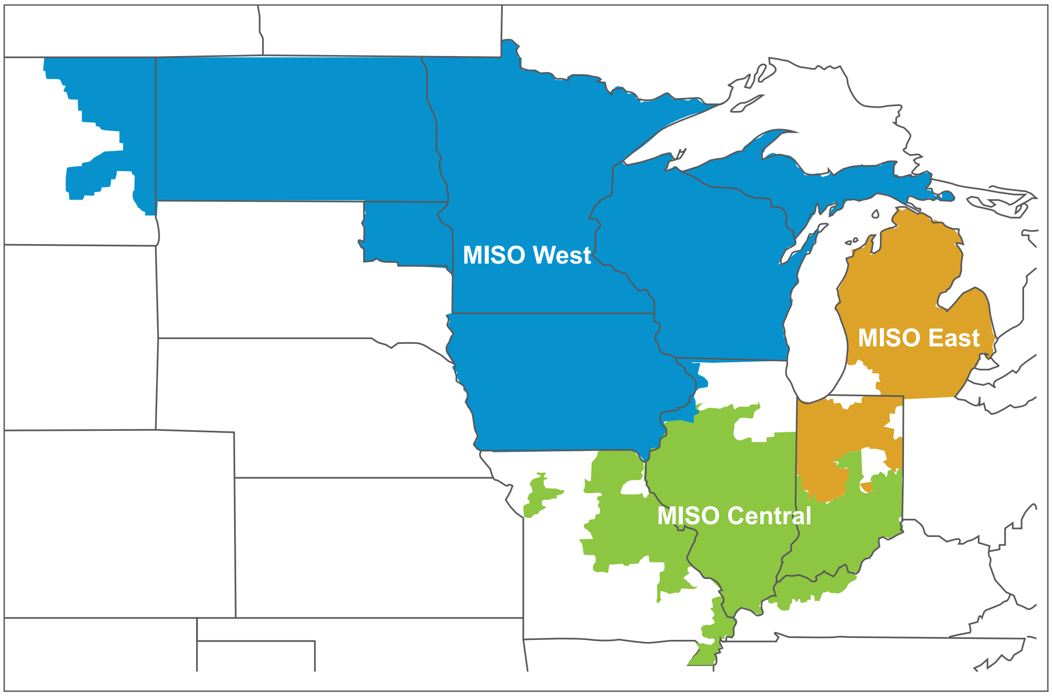


Figure 2.1-3: MISO footprint and planning regions

The new portion (new projects approved in the 2013 planning cycle) of MTEP13 Appendix A values are broken down by region and project type (Table 2.1-2). New projects in MTEP13 Appendix A contain only one cost shared project — a Generator Interconnection Project. Cost sharing information is provided in Chapter 2.2.

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Other	Total
Central	$82,055,000	$5,200,000	$136,552,000	$223,807,000
East	$101,247,000	$8,019,000	$225,025,000	$334,291,000
West	$188,922,000	$2,045,000	$735,544,000	$926,511,000
Grand Total	$372,224,000	$15,264,000	$1,097,121,000	$1,484,609,000

Table 2.1-2: MTEP13 new Appendix A investment by project category and planning region

New Appendix A projects are spread over many states, with five states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state. The investment was split between the states approximately representing the investment in each 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 there.

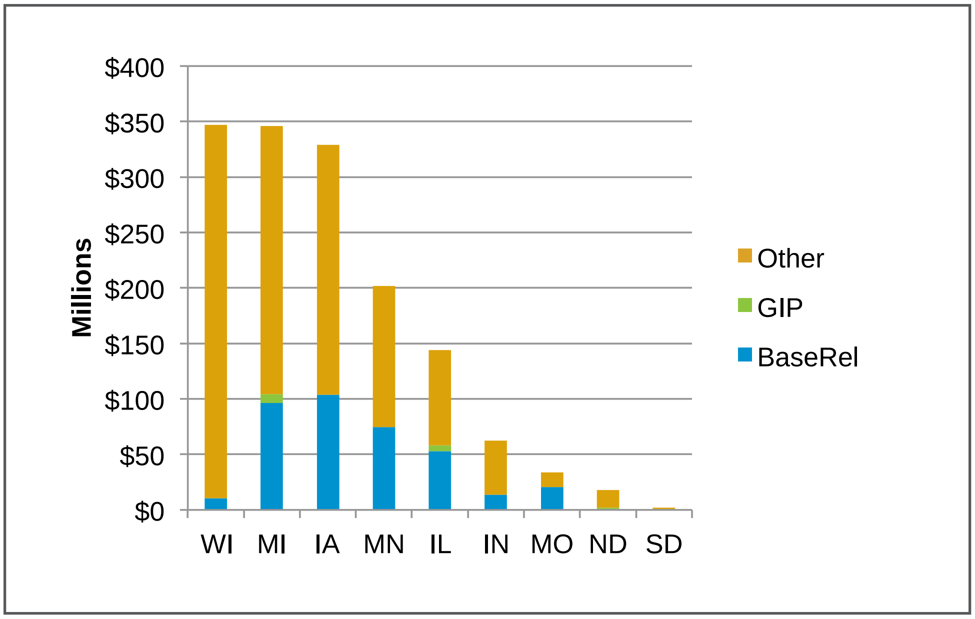


Figure 2.1-4: New MTEP13 Appendix A investment categorized by state

Appendix A and B Line Miles Summary

MISO has approximately 49,500 miles of existing transmission lines. There are approximately 10,442 miles of new or upgraded transmission lines projected in the 10-year planning horizon in MTEP13 Appendices A and B (Figure 2.1-5).

- 6,548 miles of upgraded transmission line on existing corridors are planned[4]
- 3,894 miles of new transmission line on new corridors are planned

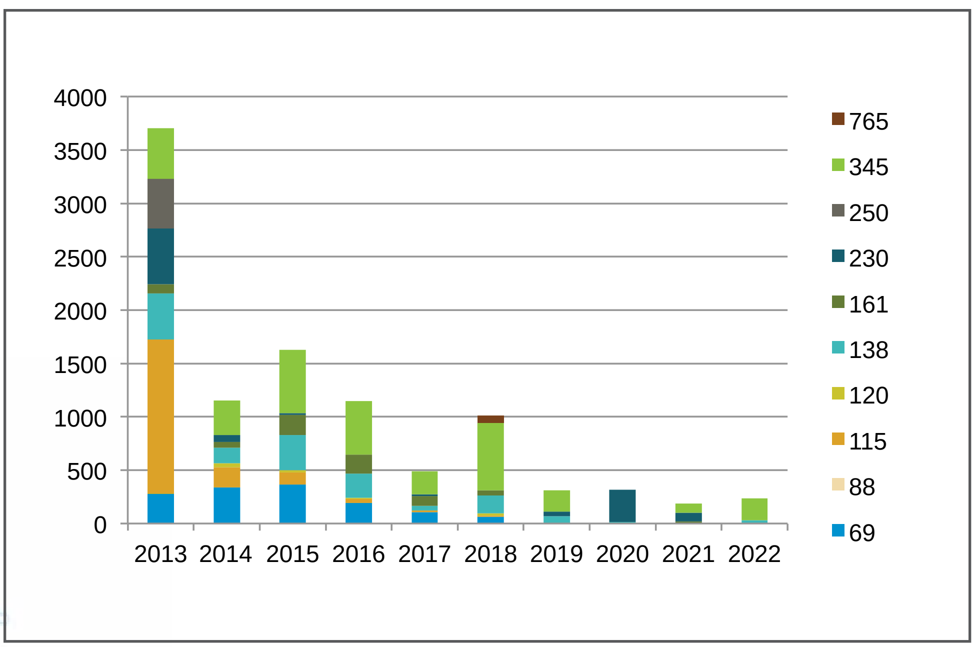


Figure 2.1-5: New or upgraded line miles by voltage class (kV) in Appendix A and B through 2022

[4] More than 2,300 miles of the upgraded line miles are associated with transmission line rating review in 2013. Therefore, actual miles being upgraded will likely be less than 2,300 miles.

2.2 Cost Sharing Summary

New MTEP13 Appendix A Cost-Shared Projects

In MTEP13 there is one Generation Interconnection Project (GIP) designated as a cost-shared project with all of the costs for that project allocated to the pricing zone where the project is located.

- One GIP with a total project cost of $7.9 million, with $3.95 million allocated to load and the remaining $3.95 million allocated directly to the generator [5]

Having only one new project categorized as a cost-shared project is much lower than in previous MTEP cycles. One driver for the reduction in the number of cost-shared projects is the ruling issued by FERC on March 22, 2013, that modified starting with MTEP13 the cost allocation for Baseline Reliability Projects to the local pricing zone where the project is located.

Cumulative Summary of All Cost-Shared Projects Since MTEP06

A total of 154 projects have been eligible for cost sharing since cost sharing methodologies were first incorporated into the MTEP process in 2006 for Baseline Reliability Projects [6] (BRP) and GIPs, and later augmented with Market Efficiency Projects (MEP) in 2007 and Multi-Value Projects (MVP) in 2010. Starting with MTEP13 and going forward the costs for BRPs will be allocated to the pricing zone where the project is located. This represents $8.87 billion in transmission investment, excluding projects that have subsequently been withdrawn or had a portion of project costs allocated directly to generators for GIPs (Figure 2.2-1 and Table 2.2-1). The distribution of projects includes:

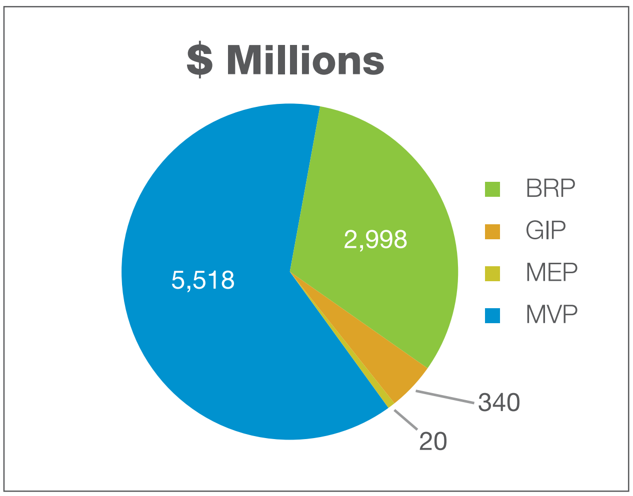


Figure 2.2-1: MTEP Cumulative Cost Sharing by Project Type ($ Millions)

- Baseline Reliability Projects (BRP) – 78 projects, $3.00 billion
- Generation Interconnection Projects (GIP) – 57 projects, $340 million (excluding the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) – two projects, $20.1 million
- Multi-Value Projects (MVP) – 17 projects, $5.52 billion

[5] The $3.95 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

[6] 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	GIP	MEP	MVP	Total
A in MTEP06	681.6	28.8	-	-	710.4
A in MTEP07	92.2	16.6	-	-	108.8
A in MTEP08	1,238.3	12.9	-	-	1,251.2
A in MTEP09	170.8	64.6	5.6	-	241.0
A in MTEP10	43.3	2.1	-	510.0	555.4
A in MTEP11	385.3	103.9	-	5,008.4	5,497.6
A in MTEP12	386.1	106.7	14.5	-	507.3
A in MTEP13	-	4.0	-	-	4.0
Total	2,997.6	339.6	20.1	5,518.4	8,875.7

Table 2.2-1: MTEP06 to MTEP13 Cost Shared Project Costs by MTEP Cycle and Project Type (shown in $ millions)

Different project types use different cost allocation methods depending on the driver of the project and distribution of benefits. For BRPs, GIPs and MEPs the majority of the costs are allocated to the pricing zone where the project is located (see Chapter 5.1 for more information on project cost allocation). Of the total $3.35 billion in approved costs for these three project types (not including MVPs), approximately 68.4 percent ($2.29 billion) is allocated to the pricing zone where the project is located. The remaining 31.6 percent ($1.06 billion) is allocated to neighboring pricing zones or system-wide to all pricing zones.

68.4 percent ($2.29 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located with the remaining 31.6 percent ($1.06 billion) allocated to neighboring pricing zones or system-wide to all pricing zones.

The total project costs allocated to each pricing zone for Baseline Reliability Projects, Generation Interconnect Projects and Market Efficiency Projects were broken down into two components: the portion of costs for projects located outside the pricing zone (Table 2.2-2, Column 3), and the portion of costs for projects located within the pricing zone (Column 4). Column 2 in provides the total project cost of approved BRPs, GIPs and MEPs that are located in the pricing zone. The values shown in Figure 2.2-2 exclude the portion of GIPs assigned directly to the generator.

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	164.3	40.5	135.8	176.3
AMMO	88.8	30.1	82.7	112.8
ATC	941.1	77.8	775.1	852.9
BREC	-	2.3	-	2.3
CWLD	-	1.0	-	1.0
CWLP	7.0	1.7	7.0	8.7
DUK*	22.1	3.7	10.4	14.1
DPC	47.7	98.5	43.6	142.1
FE*	16.5	36.1	14.7	50.8
GRE	197.7	26.9	9.6	36.5
HE	-	12.2	-	12.2
IPL	27.9	17.9	5.4	23.4
ITC	168.2	37.3	147.0	184.3
ITCM	146.8	48.6	131.5	180.1
MDU	8.2	9.2	8.0	17.3
MEC	0.7	4.2	0.1	4.3
METC	429.2	89.0	415.5	504.5
MI13AG	-	2.3	-	2.3
MI13ANG	-	2.9	-	2.9
MP	128.8	105.5	35.7	141.2
MPW	-	0.1	-	0.1
NIPS	21.5	18.7	20.4	39.1
NSP	601.7	256.5	336.9	593.4
OTP	179.7	109.3	54.1	163.4
SIPC	-	1.8	-	1.8
SMMPA	-	18.3	-	18.3
VECT	155.9	6.0	61.9	67.9
Total	3,353.9	1,058.2	2,295.7	3,353.9

Figure 2-2.2: Allocated project cost from MTEP06 to MTEP13 for approved Baseline Reliability, Generation Interconnection and Market Efficiency projects[7]

[7] Costs allocated for projects located in the now non-existent First Energy pricing zone are included in the values shown. The Duke Pricing Zone includes the project cost allocated to the withdrawn Duke Ohio and Kentucky transmission owners.

For the approved portfolio of MVPs, the costs will be allocated 100 percent region-wide and recovered from customers through a monthly energy charge calculated using the applicable monthly MVP Usage Rate. This charge will apply to all MISO load, excluding load under grandfathered agreements and export and wheel-through transactions sinking in PJM.

For the average residential household that uses 1,000 kWh each month the estimated monthly cost for MVPs averages to $1.27 per month over the next 20 years.

Indicative annual MVP Usage Rates[8] (dollar per MWh), based on the approved MVP portfolio using current estimated project costs and in-service dates, have been calculated for the period 2014 to 2053 and are shown by the blue line (Figure 2-2.3).[9] The orange and green lines in Figure 2-2.3 represent an average of the estimated MVP Usage Rates over 20 and 40 year periods, respectively.

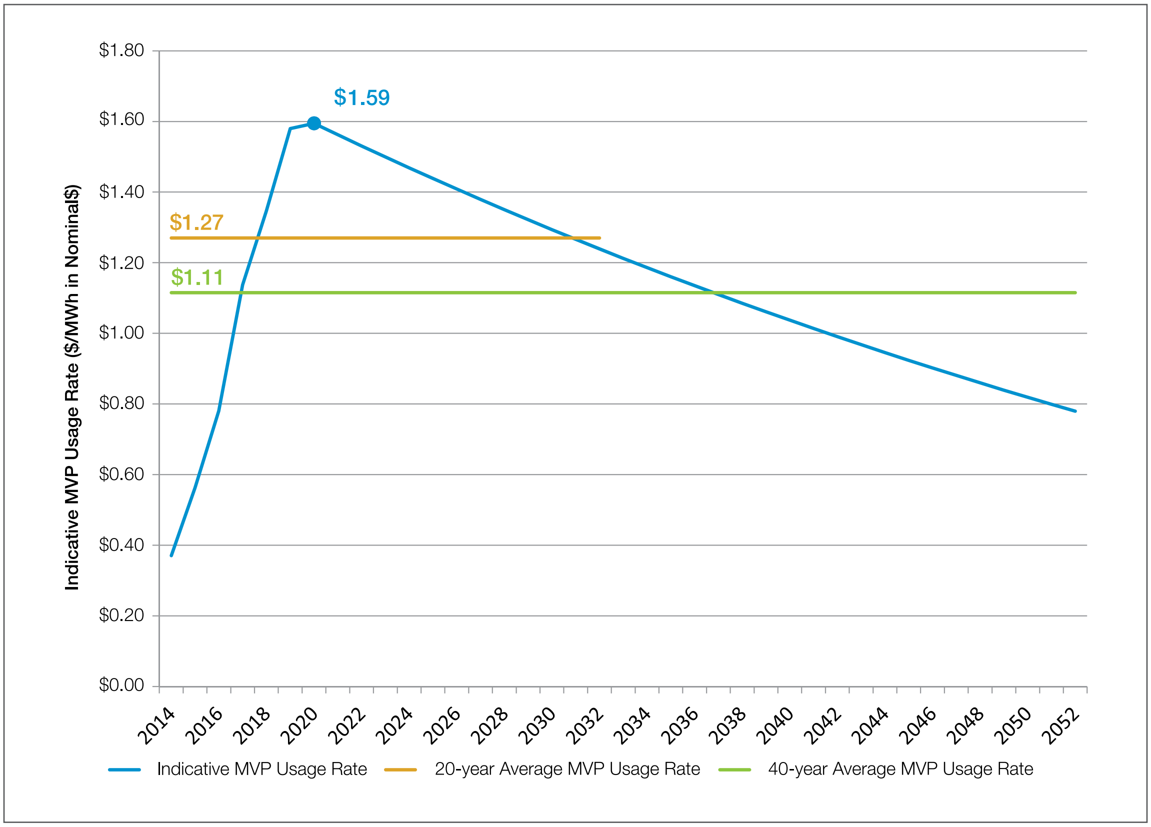


Figure 2-2.3: Indicative MVP usage rate for approved MVP portfolio from 2014 to 2053

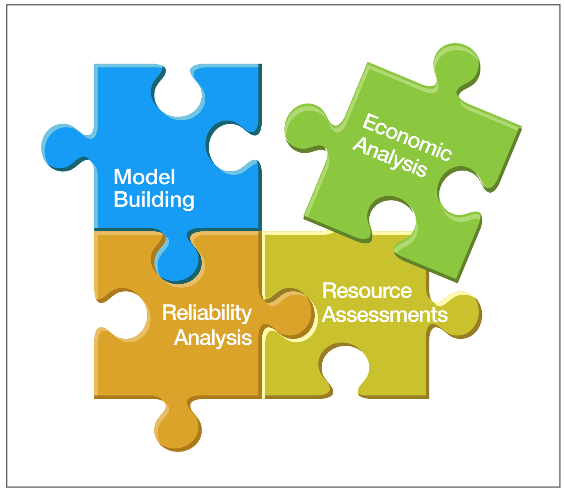
[8] The MVP Usage Rate is charged via Schedule 26-A to: 1) Export and Through-Schedules excluding deliveries sinking in PJM; and 2) Monthly Net Actual Energy Withdrawals, excluding those Monthly Net Actual Energy Withdrawals provided under GFAs. For Withdrawing Transmission Owners with obligations for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

[9] The annual estimated MVP Usage Rates for 2014 to 2053 shown in Figure 2-2.3 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 MTEP13 Process and Schedule

MTEP13 Process Overview

MTEP is a myriad of moving pieces. Each piece needs to fit together to create the complete plan. 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 2013 Board of Directors meeting.



The process to produce the list of Appendix A projects typically 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. Along the way, the process produces many sub-deliverables, such as Planning Reserve Margins, resource forecasts, and regional policy studies. Input to the MTEP report comes from stakeholders and other base models (Figure 2.3-1).

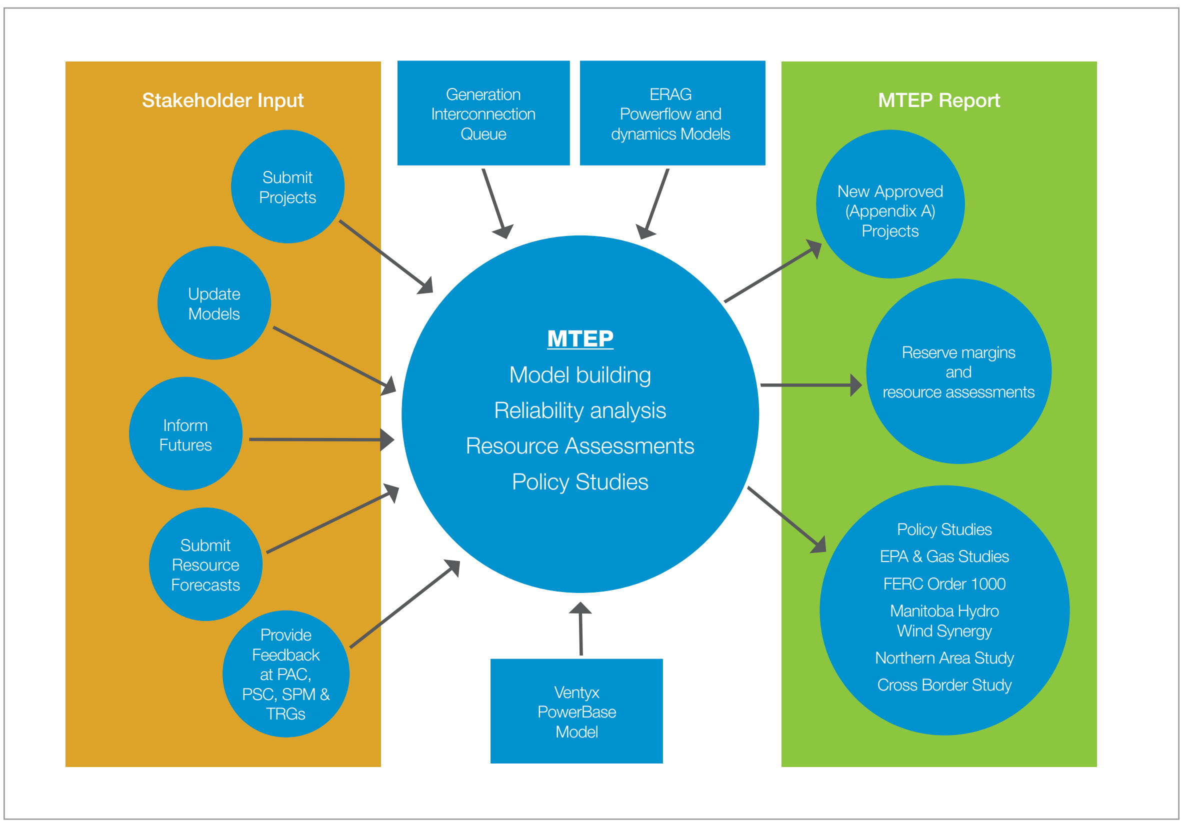


Figure 2.3-1: MTEP Inputs and Outputs

MTEP Planning Approaches

MISO evaluates transmission expansion from several angles. To incorporate all perspectives MISO conducts reliability analysis and economic analysis. It evaluates 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).

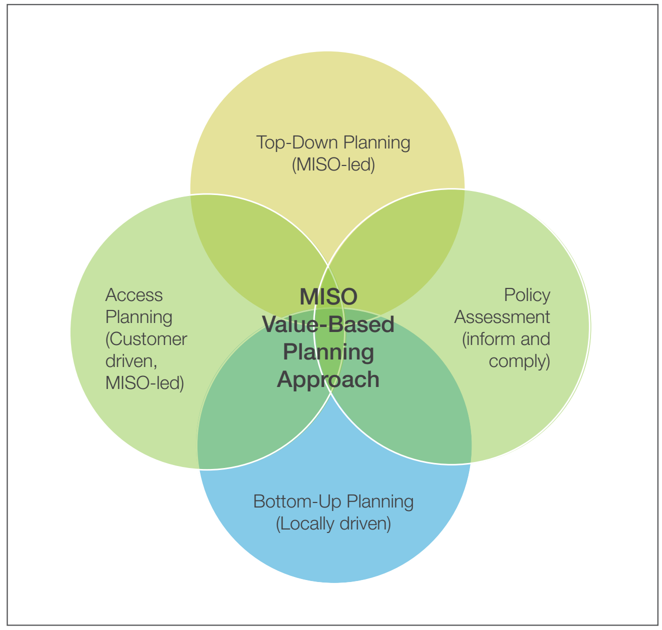


Figure 2.3-2: MTEP13 timelines

MTEP13 Workstreams

Completion of MTEP13 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.

The varied elements of MTEP must work together to produce the final report and recommendations. At the core is model building (Chapter 2.5). The models are updated by stakeholders and serve as the basis for the various types of analyses. The MTEP futures (what-if scenarios) feed both the capacity expansion analysis (Chapter 5.2), Resource Adequacy studies (Chapter 6.1 and 6.2) and policy studies (Book 3). The 18-month MTEP process culminates in recommendations for various type of transmission expansion.

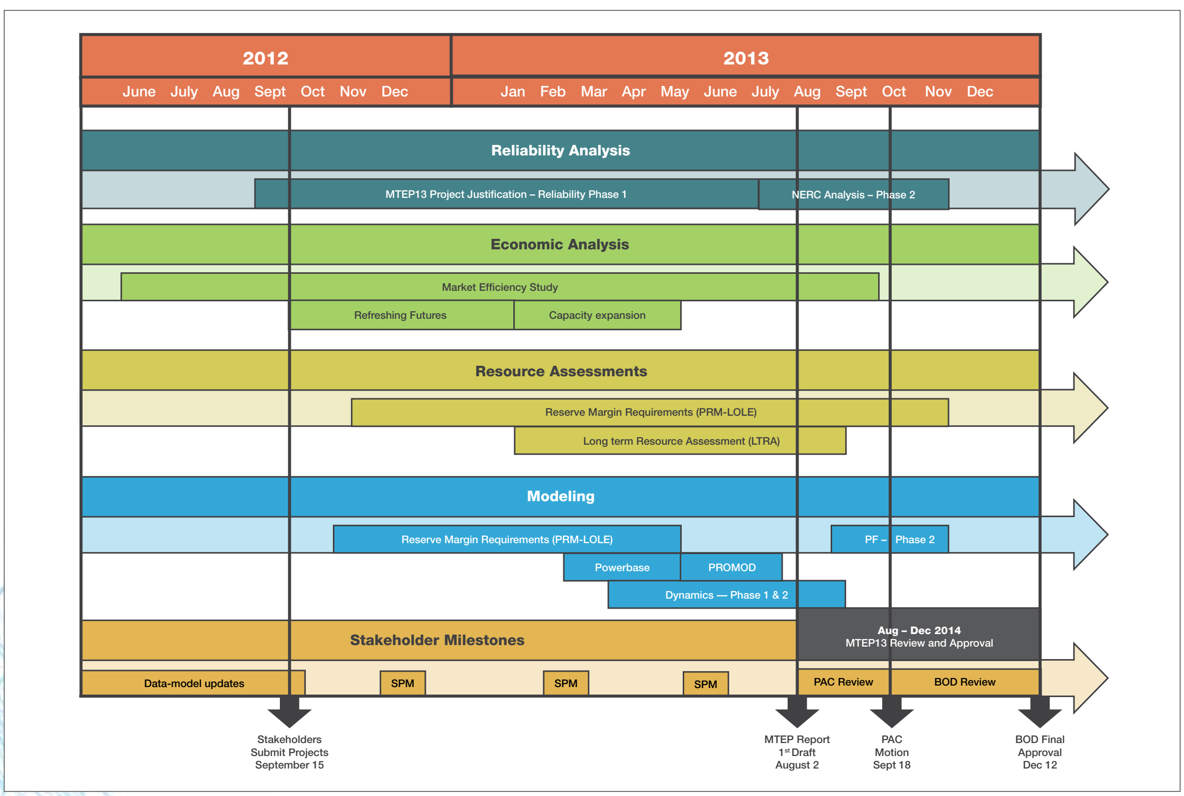


Figure 2.3-3: MTEP13 timelines

Stakeholder Involvement in MTEP13

Stakeholders provide model updates, project submissions, and review the results and report. This feedback occurs through a series of stakeholder forums. Each subregion holds Subregional Planning Meetings (SPM) at least three times a year (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

MTEP13 Schedule

MTEP13 began June 1, 2012 and for most projects ends with Board approval consideration in December 2013 (Figure 2.3-5).

MTEP13 begins with information exchanges	June 1, 2012
Stakeholders submit proposed MTEP13 projects	September 15, 2012
First round of Subregional Planning Meetings (SPM)	December 2012
Stakeholders submit GADS data	January 31, 2013
Models for MTEP13 Project justification complete (RMD)	February 2013
Second round of SPM	Late March 2013
NERC Reliability Study – Phase 1 Powerflow Models complete	April 30, 2013
Capacity expansion and generation siting complete	April 24, 2013
PowerBase Modeling complete	Early May 2013
Third round of SPM	June 2013
PROMOD Models complete	June 24, 2013
MTEP13 Report first draft posted	August 2, 2013
NERC Reliability Study – Phase 2 Powerflow Models complete	August 2013
NERC Reliability Study – Dynamics Models complete	August 2013
Planning Advisory Committee final review and motion	Late September, 2013
MISO Board - System Planning Committee review	Mid October 2013
MISO Board of Directors meeting to consider MTEP13 approval	Mid December 2013

Figure 2.3-5: MTEP13 schedule, major milestones

A Guide to MTEP Report Outputs

The primary output of MTEP13 is the recommendation of new transmission expansion projects for Board approval and inclusion into MTEP Appendix A. In addition, the process produces many sub-deliverables such as updated models, Planning Reserve Margins, resource forecasts, and policy studies.

This year's MTEP is organized as follows:

- Book 1 of the MTEP13 report 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, Long Term Resource Assessments, Regional Generation Portfolios Analysis, and EPA-Gas related studies
- Book 3 of this report presents policy landscape studies. It summarizes regional studies like the Northern Area Study and Manitoba Hydro Wind Synergy Study, and interregional work on FERC Order 1000 and Cross-Border Planning studies
- Book 4 presents additional regional energy information, with special emphasis on historical trends, to paint a more complete picture of the regional energy system
- More detailed results and analysis behind the report findings are in Appendices A through F

2.4 MTEP Project Types and Appendix Overview

MTEP Appendices A, B and C indicate the status of a given project in the MTEP planning process. Projects start in Appendix C when submitted into the MTEP process, transfer to Appendix B when MISO has documented the project need and effectiveness, and then move to Appendix A after approval by the MISO Board of Directors. While moving from Appendix C to Appendix B to Appendix A is the most common progression through the appendices, projects may also remain in Appendix C or Appendix B for a number of planning cycles, or may go from C to B to A in a single cycle.

Appendix A includes projects from prior MTEPs that have not been completed, as well as new projects and associated facilities recommended to the MISO Board of Directors for approval in this cycle. The newest projects are indicated as “A in MTEP13” in the “Target Appendix” field of Appendix A. The Appendix ABC field defines the 2013 progression of projects: “B>A” or “C>B>A” for new projects; “A” for previously approved projects. Projects in Appendix A are classified on the basis of their respective designation in Attachment FF to the MISO Tariff.

- **Baseline Reliability Projects (BRP)** are required to meet North American Electric Reliability Corp. (NERC) standards. Costs for Baseline Reliability Projects approved in MTEP cycles prior to 2013 may be shared if the voltage level and project cost meet the thresholds designated in the Tariff. Starting in MTEP13 Baseline Reliability Projects will no longer be cost shared.
- **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 Service Delivery (TSR**) projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.
- **Market Efficiency Projects (MEP**), formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion. MEPs are shared based on benefit-to-cost ratio, cost and voltage thresholds.
- **Multi-Value Projects (MVP)** meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.
- **Other** projects do not meet any of these classifications. The “Other” category incorporates a wide range of projects, including those intended to provide local reliability, economic or similar benefits, but not meeting requirements as MEPs or MVPs. Many other projects less than 100 kV are required on the transmission system. However, these are generally not part of the bulk electric system under MISO functional control.

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.

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards. Other projects 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 be needed to reduce resource adequacy requirements through reduced losses during system peak or reduced planning reserve. 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 via Subregional Planning Meetings
- Validate that the project addresses one or more transmission need
- Consider and review alternatives
- Consider and review costs
- Endorse the project
- Verify that the project is qualified for cost sharing as a Generation Interconnection Project, Market Efficiency Project or Multi-Value Project per provisions of Attachment FF
- 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 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 are generally moved to Appendix A in conjunction with the annual approval of the MTEP report. A June mid-cycle approval option is available for projects that have been under study in an open process for an appropriate period of time and need to be approved prior to the normal December cycle. In addition to the regular annual approval process, under specific circumstances, recommended projects need not wait for completion of the next MTEP for Board of Directors approval and inclusion in Appendix A, but can go through an expedited Out-of-Cycle approval process.

MTEP Appendix B

Projects in Appendix B have been analyzed to ensure they effectively address one or more documented transmission issues. In general, MTEP Appendix B contains projects still in the Transmission Owners' planning processes or still in the MISO review and recommendation process. Appendix B may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. Any designation of project type (Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects) for projects in Appendix B are preliminary. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

MTEP Appendix C

Appendix C contains transmission reliability projects that have just entered the MTEP study process and have not been reviewed by MISO staff for need and effectiveness.

2.5 MTEP13 Model Development

Transmission system models are the foundation of MTEP. The accuracy and viability of the study results hinges significantly on the accuracy of the models used. MISO employs collaborative processes to develop the various models. Stakeholders provide actual modeling data, help develop assumptions for modeling future transmission system scenarios, and review the models. MTEP models are also coordinated with neighboring (MISO first-tier) entities and their system representation is updated based on their feedback.

Transmission system models are the foundation of MTEP

For MTEP studies, reliability (powerflow and dynamics) and economic models are built to represent a planning horizon spanning the next 10 years. Models representing seasonal variations in load and generation dispatch are included. The primary sources of information used to develop the models are:

- Transmission Owners and MISO Load Serving Entities
- Model on Demand (MOD) base case
- Latest available Eastern Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) series models
- PowerBase database

MTEP13 models are interdependent (Figure 2.5-1).

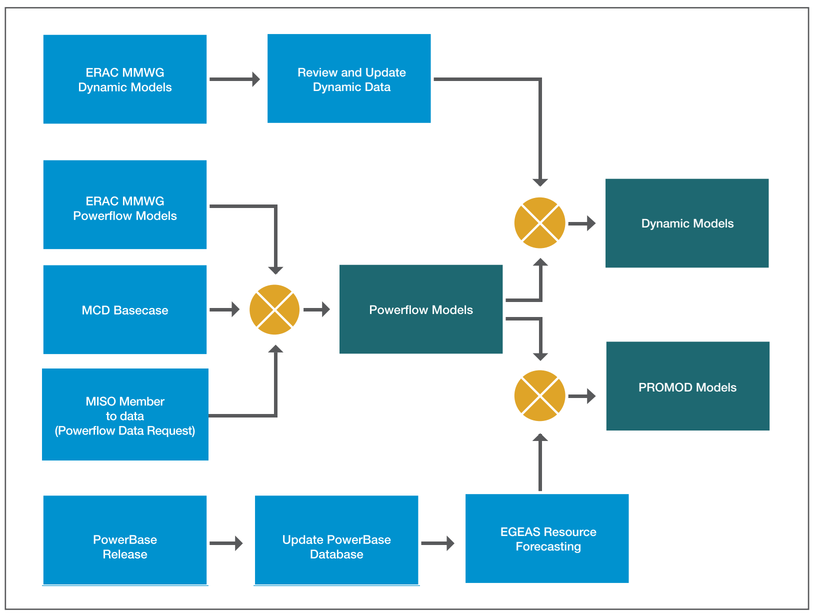


Figure 2.5-1: MTEP13 model relationships

Reliability Study Models

Powerflow Models:

For MTEP13, MISO conducted regional studies using the following base models:

- 2015 Summer Peak
- 2018 Summer Peak
- 2018 Shoulder Peak
- 2018 Light Load
- 2018/2019 Winter Peak
- 2023 Summer Peak
- 2023 Shoulder Peak

A data request for modeling information was sent to the MISO members in October 2012. Modeling data was requested to be submitted to MOD. The MISO system is represented in MTEP models using data available in MOD. The ERAG MMWG cases are the base starting point for non-MISO system representation in MTEP models. Requests for updated information to the ERAG MMWG models from bordering neighbors were sent after these models were released in late November. Preliminary models were built from MOD and posted for stakeholder review in early December 2012. After incorporating the feedback received, final models needed for MISO's independent evaluation of Transmission Owner projects were built and posted in early 2013. The powerflow models needed for NERC Transmission Planning Standards (TPL) Compliance assessment were developed in the April/May timeframe, closer to the commencement of those studies (see Chapter 4.1). The process followed a defined timeline with key milestones (Figure 2.5-2).

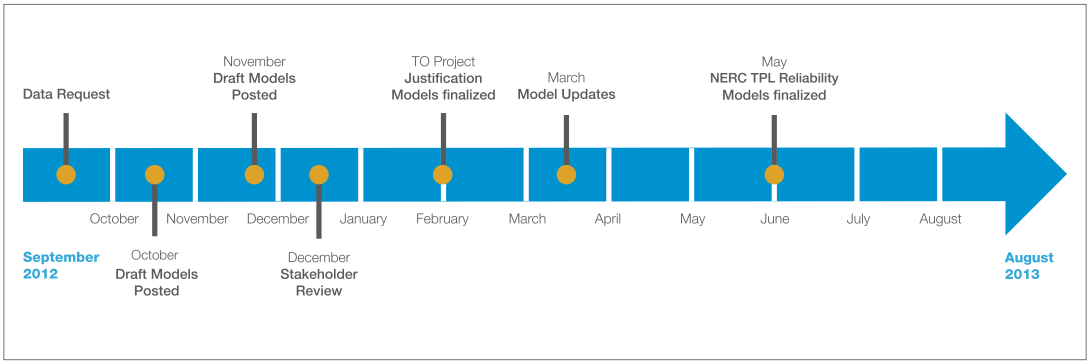


Figure 2.5-2: MTEP13 powerflow model development timeline

Assumptions regarding inclusion of future transmission, generation and load facilities are summarized as:

- Load
  - Load is modeled based on seasonal load projections provided by member companies in MOD
- Generation
  - Existing and planned generators with signed Generation Interconnection Agreements, with expected in-service dates through the corresponding season being modeled are included.
  - Broadly, powerflow cases needed for member Transmission Owner project justification have a tiered Regional Merit-Order Dispatch (RMD) and cases developed for NERC TPL reliability studies use a Security Constrained Economic Dispatch (SCED).
  - Renewable generation is dispatched at levels agreed upon through the stakeholder processes.
  - Generation is dispatched to allow for the cumulative MISO net area interchange level to be consistent with equivalent ERAG MMWG cases.
- Transmission topology
  - In-service and future transmission facilities approved through prior MTEP studies with expected in-service dates through the corresponding season being modeled are included.
  - Transmission projects submitted for approval in MTEP13 planning cycle are also included.

Dynamic Stability Models

For MTEP13, MISO conducted dynamic stability analysis using the following base models:

- 2018 Light Load
- 2018 Summer Shoulder load

The MTEP12 dynamics model was used as a starting point for the MTEP13 models. MISO leveraged many improvements made during MTEP12 for MTEP13 models. Additionally, the ERAG MMWG 2012 dynamic stability models were reviewed and any improved modeling data was incorporated in the MTEP13 models. Dynamics model are used for transient stability assessment performed as part of NERC TPL compliance and generation interconnection studies (see Chapters 4.1 and 4.2).

MTEP13 dynamic models were posted for stakeholder review towards the end of July 2013. During the review period stakeholders were asked to provide:

- Updates to existing dynamics data
- Additional dynamic models for new equipment
- Updates to existing disturbance files
- Additional disturbances to be studied in MTEP13
- Output quantities to be measured

The MTEP13 dynamics model development timeline had six key milestones during the study year (Figure 2.5-3). The MTEP13 dynamics cases were finalized and posted in August 2013.

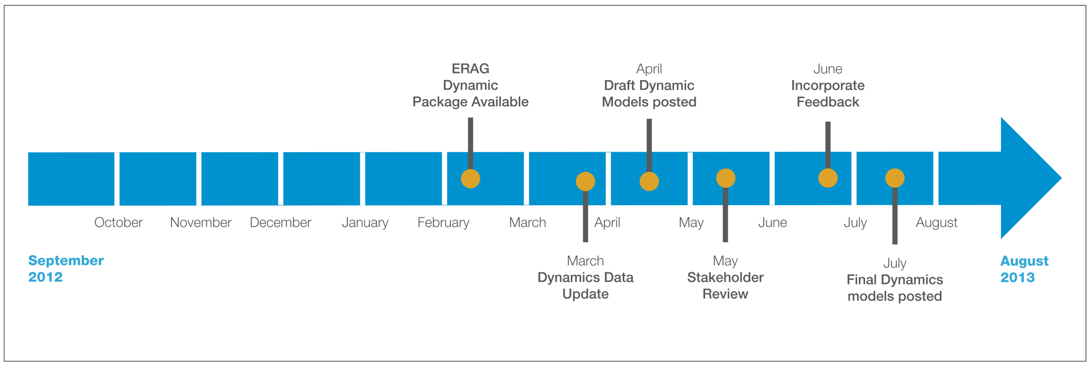


Figure 2.5-3: MTEP13 dynamics model development timeline

Economic Study Models

The economic study models used in the MTEP process are forward-looking, time-dependent models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP13, the Planning Advisory Committee (PAC) approved five different future scenarios that include:

- Business as Usual (BAU)
- Robust Economy (RE)
- Limited Growth (LG)
- Generation Shift (GS)
- Environmental (ENV)

The details on these scenarios are available in Chapter 5.2.

The base data used in all future scenarios is maintained through the PROMOD PowerBase database. This centralized database uses data provided annually by ABB Ventyx as a starting point. MISO then goes through an extensive model development process that updates the original data provided by Ventyx with more accurate data specific to MISO.

Updates include data obtained from the following sources:

- Commercial Model
- Generator Interconnection Queue
- Module E data
- Powerflow model (developed through the MTEP process)
- Publicly announced generation retirements
- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff — see Chapter 5.2)

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

Updates to generator data

- Maximum and minimum capacity
- Retirement dates
- Emission rates

Updates to powerflow mapping

- Generator bus mapping
- Demand mapping
- Updates to contingencies and flowgates/ interfaces monitored

In addition to the stakeholder review process, MISO continued to collaborate with neighboring entities to develop a coordinated model which more accurately reflects the neighbor's systems. Highlights of this collaboration include extensive updates from PJM Interconnection and SPP. The economic model development timeline is an 11-month process (Figure 2.5-4).

The PowerBase model was finalized in June 2013.

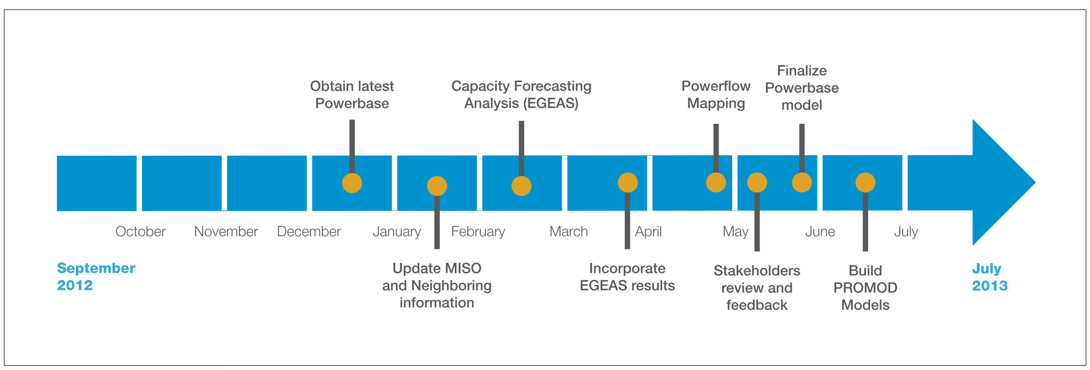


Figure 2.5-4: MTEP13 economic model development timeline

Book 1 – **Chapter 3**
Historical MTEP Plan Status

Historical MTEP Plan Status

Since the first MTEP report in 2003, more than $6.2 billion in projects have been constructed in the MISO region. Currently there are $17.9 billion of approved projects in various stages of design, construction, or already in service.

Chapter 3.1 provides an historical perspective of past MTEP approved plans and Chapter 3.2 presents status update on the implementation of active projects approved in previous MTEP reports.

3.1 MTEP Implementation History

This chapter encompasses the implementation history for all approved MTEP plans, including the current MTEP13 plan. The number of projects and investment can vary dramatically from year to year depending on system need, or "project drivers." Such things as changes in the generation mix, driven by economics and environmental emissions control, can drive large transmission projects. Congestion on the transmission system that limits delivery of power to load, as well as new large industrial loads, can drive the need for new transmission projects.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP13 cycle, is more than $17.9 billion (Figure 3.1-1). MTEP13 data depicted in this figure, subject to Board approval, is from the current MTEP study and 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, more than $6.2 billion of cumulative approved projects have been constructed and are in service as of July 2013

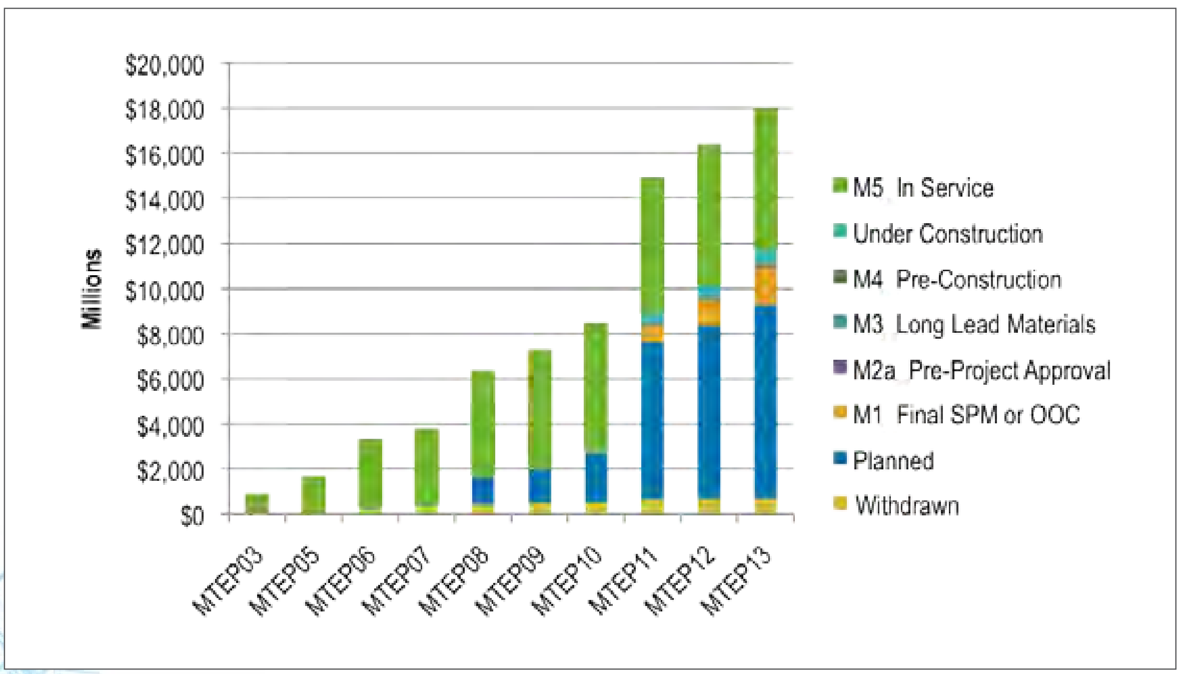


Figure 3.1-1: Cumulative approved investment by facility status[10]

[10] Project milestones described in Chapter 3.2

[11] New Appendix A projects in the MTEP13 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 condition 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 other's schedules.

• $1.6 billion of MTEP projects are expected to go into service in 2013

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 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 number 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 in past MTEPs as projects are built
- MTEP10 contains significant adjustments for reduced load forecasts
- MTEP11 contains most of the MVP Portfolio, which is approximately $5.1 billion of transmission investment
- MTEP12 reflects a return to a more typical MTEP, primarily driven by reliability projects
- MTEP13 reflects a continuation of a typical MTEP, primarily driven by reliability projects

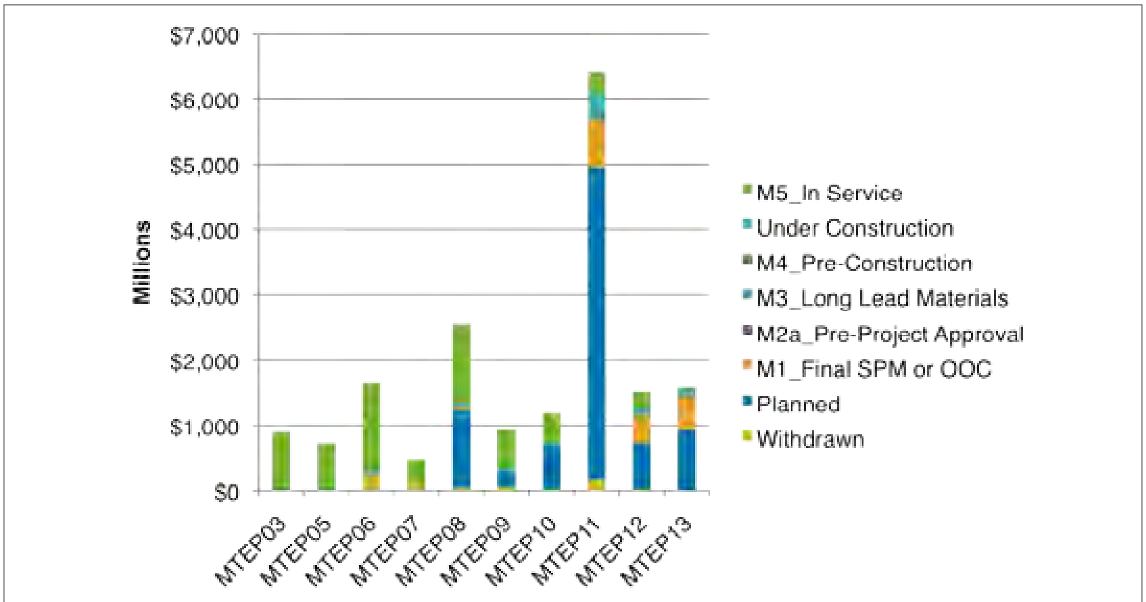


Figure 3.1-2: Approved investment by MTEP cycle[11]

Since MTEP03, 89 MTEP-approved projects totaling $710 million in investment have been withdrawn. MISO documents all withdrawn projects to ensure the planning process addresses required system needs. Common reasons for 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

Of the withdrawn facilities, $150 million of the total is from a single project in the Detroit area, withdrawn because of a significant load reduction. An additional $331 million of the withdrawn totals were attributed to service requests or generation interconnection being cancelled. A single generator retirement in 2013 resulted in the withdrawal of $133 million in generator interconnection related projects.

3.2 MTEP12 Status Report

MISO transmission planning responsibilities include monitoring progress and the implementation of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners on a quarterly basis to determine the progress of each project. These status updates are reported to the MISO Board of Directors and posted to the MISO MTEP Studies web page. This chapter provides a summary of this quarterly status report, and elaborates on the status of the MTEP11 Multi-Value Projects (MVP).

Since 2006, the MISO Board of Directors has received quarterly status updates on active plans. The information in this report reflects project status as of the second quarter 2013 report to the Board of Directors, which includes the status of MTEP12 Appendix A projects as of June 2013. The statistics include in-service and cost variance for several milestones of the planning and construction time periods.

More than 98 percent of the approved facilities included in MTEP12 are in service, on track or have encountered reasonable delays. That translates to $10.644 billion of the $10.83 billion on track in MTEP12 Appendix A.

Tracking the progress of projects ensures a good-faith effort to move projects forward, as prescribed in the Transmission Owners' Agreement. Most approved projects move forward despite possible complications, such as equipment procurement delays, construction difficulties and longer-than-anticipated regulatory processes. A project is only considered "off-track" if MISO cannot determine a reasonable cause for delay or withdrawal. MTEP12 Appendix A contains 598 projects comprised of 1,262 facilities. These figures have been updated to reflect the progress of members' projects. MTEP12 Appendix A includes expansion facilities through 2020. More than 98 percent of the approved facilities included in MTEP12 are in service, on track or have encountered reasonable delays. That translates to $10.644 billion of the $10.83 billion on track in MTEP12 Appendix A.

This year marks the beginning of a phase-in for a milestone-driven project update process recently approved by the Planning Subcommittee and Planning Advisory Committee. This process focuses on the progress of projects through their construction, and requests updates when projects pass key milestones in their implementation milestones. These milestones are:

- Milestone 1: Final Subregional Planning Meeting/Out of Cycle Request Submittal
- Milestone 2a: Pre-project approval
- Milestone 2b: Developer selection
  - Only applicable for Market Efficiency Projects (MEP) and MVPs that will proceed through the MISO inclusive evaluation process to select the transmission developer
- Milestone 3: Prior to ordering long lead materials
- Milestone 4: Pre-construction
- Milestone 5: Facility completion

Due to the volume of projects currently in MTEP12 Appendix A, which must be assigned to a milestone and transitioned to the milestone process, the phase-in for this process will occur in three parts. At the end of June 2013, MISO requested that transmission owners provide updates under the new milestone process for proposed MTEP13 Appendix A projects. In the second phase in September 2013, MISO requested that transmission owners continue to update proposed MTEP13 Appendix A projects as well as provide updates under the new milestone project Business Practice Manual for the previously approved MVP portfolio. Finally, in December 2013, all projects in Appendix A are expected to conform to the new milestone process. At this point in time, the milestone project update process will be used for all current MTEP12, MTEP13 and future Appendix A projects.

The milestone-driven updates will contain, at a minimum, the following data:

- Most recent milestone achieved
- In service date
- Planning status (Proposed, Planned, Under Construction, In Service)
- Total project cost estimate

Additionally, under the milestone-driven updates facilities over $50 million and those projects that are regionally or inter-regionally cost-shared will supply additional details. Details will include line cost estimates, substation cost estimates, regulatory costs and explanations on current variances. Although the details provided will remain confidential, a key outcome of the reporting process will be improved summary variance explanations for the applicable projects.

In conjunction with the milestone-driven project status updates, MISO continues to work to improve the manner in which project costs and schedules are tracked and reported. In addition to the "on-track" metric, MTEP13 contains cost and schedule variance analysis. The cost and schedule variance summarizes the differences between what was originally approved in the MTEP and most up-to-date projections as of June 2013. This first year's analysis uses the current data available, which is largely collected through quarterly status updates. As the milestone-driven status update process matures and provides additional details on project costs and in-service dates, the MTEP project variance analysis will increase in terms of both granularity and substance.

The MTEP13 cost and variance analysis considers all MTEP12 Appendix A projects that are not in-service or withdrawn as of June 2013. Additionally, because the amount of investment of the MVP portfolio relative to other projects included in Appendix A, the MVP portfolio is excluded from the subset used in the variation analysis (Figures 3.2-1 through 3.2-6) and instead a detailed status report is provided in Figure 3.2-7. The MTEP12 Appendix A projects in the variance analysis represents 368 projects totaling $2.95 billion in approved investment. Of the projects in MTEP12 Appendix A, 38 percent were approved in MTEP12 and the remaining 62 percent were approved in MTEP03 through MTEP11. All costs contained within this section are in nominal, as-spent dollars.

Project Cost Variation

The current cost estimates have deviated by less than 25 percent of the approval estimates for 84 percent of the MTEP12 Appendix A projects. 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

Additionally, a project cost's perceived variance from approval to the current estimate may be attributable to different types of dollars, such as real versus nominal/as-spent, or a different basis year, i.e. $-current vs. $-in-service year, being used for an estimate. As the new status reporting procedures are implemented, the consistent dollar type and basis year issues should decline.

The current estimates have no reported change from the approval estimates for 71 percent of the MTEP12 Appendix A project subset (Figure 3.2-1). The total costs for the 368 MTEP12 Appendix A projects have increased from the MTEP approved $2.95 billion to $3.21 billion, thus the average cost variance is 8.8 percent. Overall, projects with larger percent cost increases were a minority. The projects with a largest percentage deviation were generally projects with a small total cost. Project costs have increased by less than 25 percent for $2.4 billion (80 percent) of the MTEP12 Appendix A subset and 96 percent of projects have less than a 50 percent projected cost increase (Figure 3.2-2).

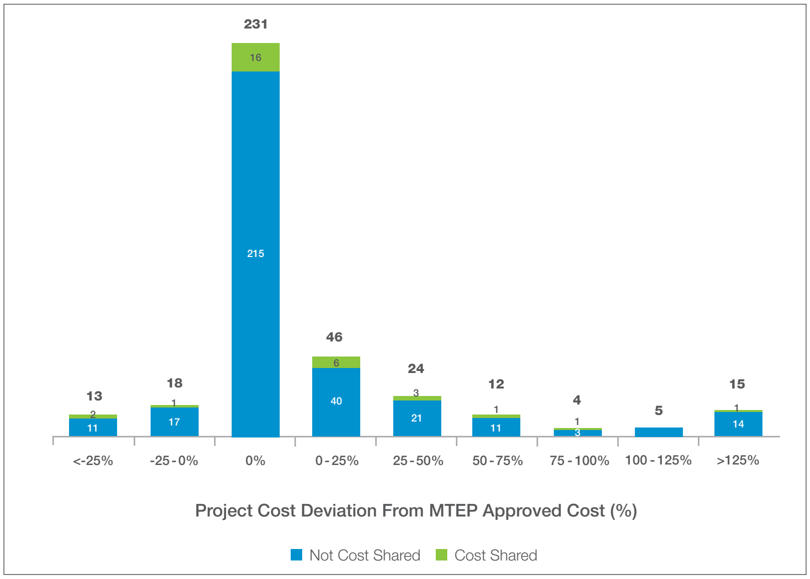


Figure 3.2-1: Frequency of cost variation from approval to current for MTEP12 Appendix A projects

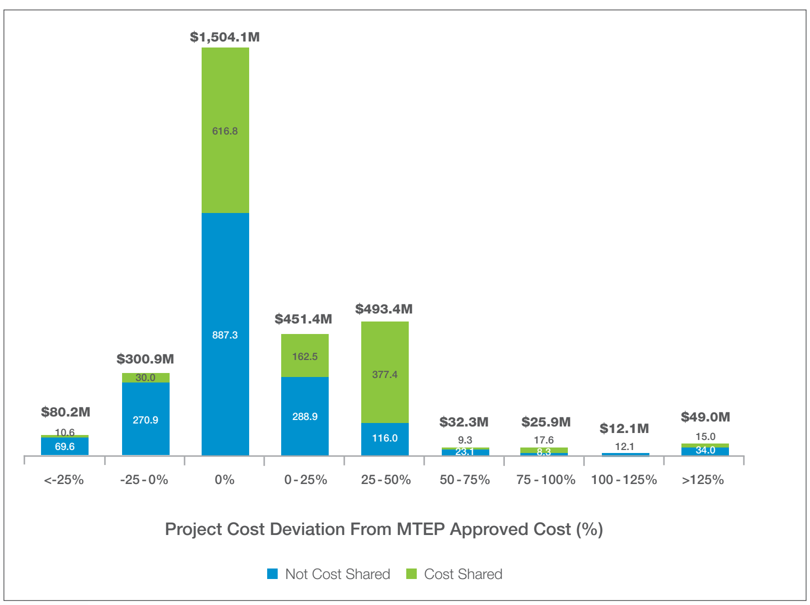


Figure 3.2-2: Total project cost sum of cost variation from approval to current for MTEP12 Appendix A projects

Cost-Shared Project Cost Variation

The cost-shared projects of the MTEP12 Appendix A subset represent $1.24 billion in approved MTEP investment (Figure 3.2-3). Of the 31 cost-shared projects' cost estimates, 61 percent have not increased since approval. Six projects' (19 percent) costs are projected to deviate by more than 25 percent all of these projects are Baseline Reliability Projects not justified based on economics. The largest deviations on a percentage basis are primarily small projects. Each of these projects had small changes in scope (substation work, right of way, routing) that was a large percentage of the total project cost. For example, as shown in Figure 3.2-2, there were 24 projects totaling $493 million with a 25 to 50 percent cost variance. Those variances were largely driven by longer line routing, structural changes, and modifications to the project scope. Only one cost-shared project's cost has deviated by more than 25 percent. A $300 million Baseline Reliability Project currently has a projected cost variance of 31 percent attributed to a state commission requiring a longer line routing and the ability for future expansion.

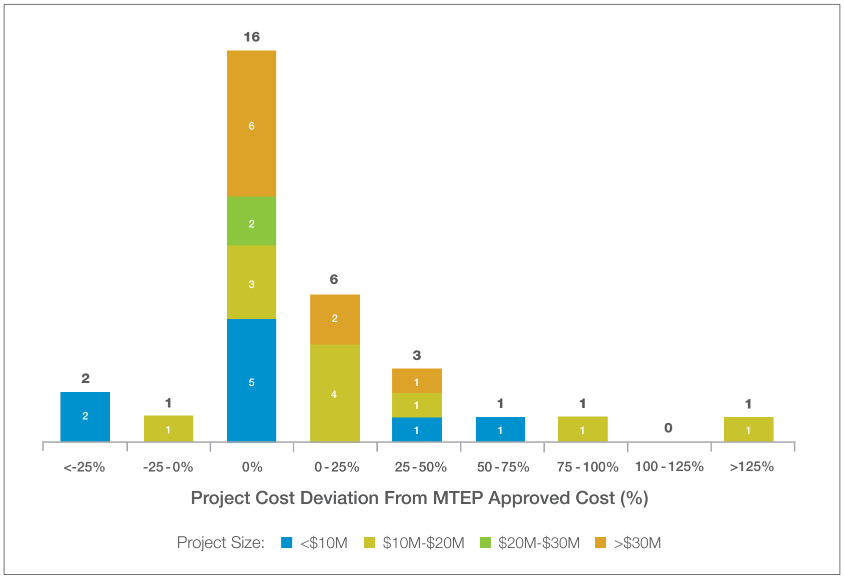


Figure 3.2-3: Frequency of cost variation from approval to current for cost-shared MTEP12 Appendix A projects

Project Schedule Variation

There are 228 in-service date adjustments to MTEP12 Appendix A projects not in service, withdrawn or included in the MVP portfolio (Figure 3.2-4). Little or no impact on reliability is expected because the in-service date adjustments are primarily driven by the economic slowdown. 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 57 percent of MTEP12 Appendix A investments have extended beyond the MTEP approved estimate. However, less than 10 percent of projects have projected in-service dates extended beyond 24 months (Figure 3.2-5). Because common drivers for schedule variances primarily result in project delays as opposed to a project moving ahead of schedule, Figures 3.2-4 and 3.2-5 have negatively or left-skewed distributions. The average (non-cost weighted) schedule delay in Figure 3.2-4 is 16 months.

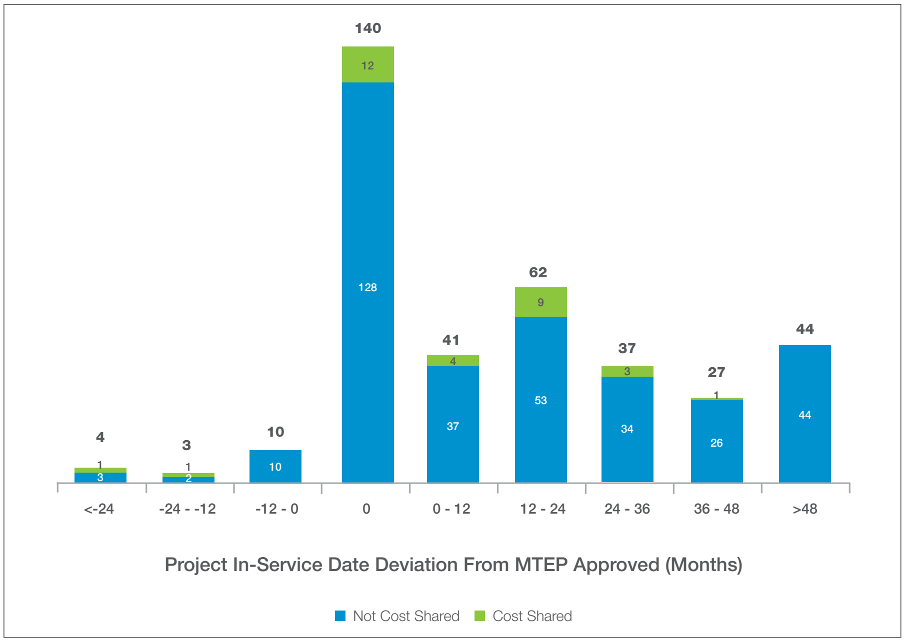


Figure 3.2-4: Frequency of schedule variation from approval to current for MTEP12 Appendix A projects

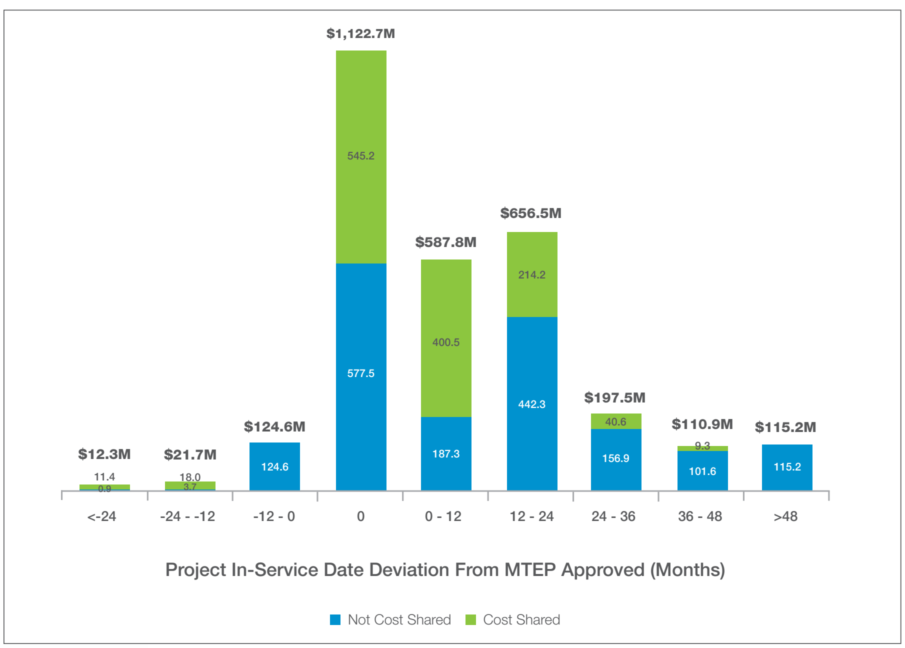


Figure 3.2-5: Total project cost sum of schedule variation from approval to current for MTEP12 Appendix A projects

Cost-Shared Project Schedule Variation

The current expected in-service date has not changed for 39 percent of the 31 cost-shared MTEP12 Appendix A project subset (Figure 3.2-6). In-service dates for 13 projects (42 percent) have extended beyond a year and four projects beyond two years. Two of the four projects with in-service date extensions beyond two years attributed the delays to budgetary constraints; the remaining two were delayed because of regulatory delay and forecast changes.

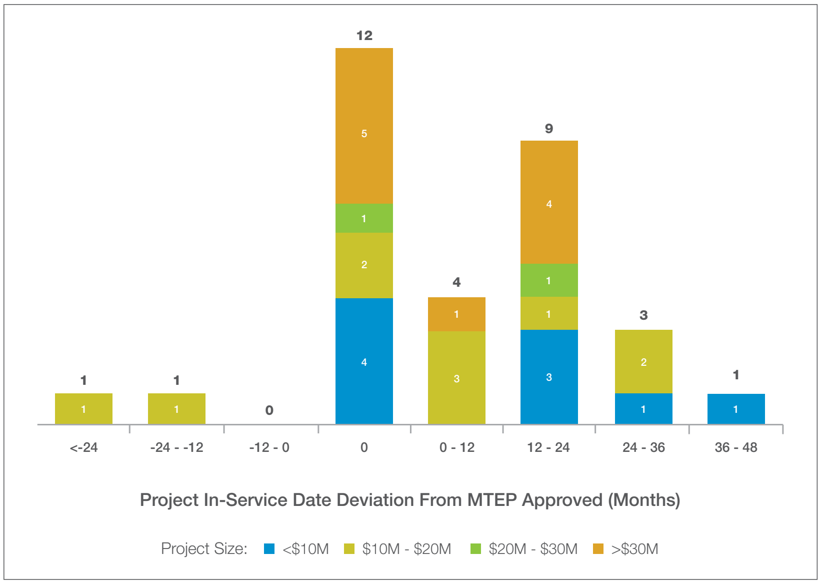


Figure 3.2-6: Frequency of schedule variation from approval to current for cost-shared MTEP12 Appendix A projects

Multi-Value Project Portfolio Status

MISO's 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 a regional transmission solution to provide value across the region while meeting local energy and reliability needs. The MVP portfolio is expected to:

- 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 August 2013, five projects have progressed beyond the regulatory process, or have no regulatory process requirements, and eight are in the regulatory process (Figure 3.2-7).

Since the MTEP11 approval, the total projected budget for the MVP portfolio has increased by 5 to 6 percent, the result of longer-than-planned line routing, substation design changes, and use of more developed construction estimates. Additionally, several MVPs' cost estimates have decreased since approval through a combination of design and schedule optimization, implementation of contracting/risk sharing strategies, and favorable commodity prices.

Going forward, the MVP dashboard (Figure 3.2-7) will be updated semi-annually to reflect changes, if any, provided through the standard milestone process.

			Estimated in Service Date[1]		Status		Cost[1]		
MVP NO.	**Project Name**	**State**	**MTEP Approved**	**Current Estimate**	**State Regulatory Status**	**Const-ruction**	**MTEP Approved**	**Current Estimate**	**Reason for Cost Variance**
1	Big Stone-Brookings	SD	2017	2017	◐	Pending	226.7	226.7	—
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Underway	738.4	639.9	Implementation of contracting/risk sharing strategies, design and schedule optimization, favorable commodity pricing
3	Lakefield Jct.- Winco-Burt area & Sheldon- Burt Area-Webster	MN/IA	2015-2016	2016-2017	◐	Pending	550.4	541.7	—
4	Winco- Lime Creek- Emery- Black Hawk-Hazelton	IA	2015	2014-2018	◐	Pending	468.6	463.8	—
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project) & Dubuque Co.-Spring Green-Cardinal	WI/IA	2018-2020	2018-2020	○	Pending	797.5	937.4 - 980[2]	Current estimate in nominal dollars for N. La Crosse-N. Madison-Cardinal reflects more-final design work in the development of two alternative routes; one route which is longer and one which has challenging terrain for construction. Both include increased escalation costs and will be proposed in the PSCW application. The current estimate for Dubuque-Cardinal reflects more-refined project design
6	Big Stone South - Ellendale	ND/SD	2019	2019	◐	Pending	330.7	371.4	Increased line length identified during state routing process
7	Adair - Ottumwa	IA/MO	2017-2020	2017-2018	○	Pending	152.3	172.9	Use of steel poles rather than wood
8	Adair- Palmyra Tap	MO	2016-2018	2016-2018	○	Pending	112.8	143.4	Use of steel poles rather than wood
9	Palmyra Tap- Quincy - Merdosia-Ipava & Meredosia-Pawnee	MO/IL	2016-2017	2016-2017	◐	Pending	432.2	549.0	Increased route length, additional costs associated with river crossing
10	Pawnee-Pana	IL	2018	2018	◐	Pending	99.4	96.7	—
11	Pana-Mt. Zion-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2019	◐	Pending	318.4	307.6	—
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Pending	271.0	271.0	—
13	Michigan Thumb Loop Expansion	MI	2013-2015	2013-2015	●	Underway	510.0	510.0	—
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	330.4	Longer line routing, contingency inclusion
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Underway	28.8	34.0	More detailed project design and updated construction estimates including railroad induction mitigation, easement acquistion, and substation costs
16	Fargo-Galesburg-Oak Grove	IL	2014-2019	2016-2018	○	Pending	199.0	198.0	—
17	Sidney-Rising	IL	2016	2016	◐	Pending	83.2	62.7	—
						Totals:	5,564	5,856 - 5,899	

State Regualtory Status Indicator Scale

○ Pending
◐ In regulatory process
● Beyond regulatory process or no regulatory process requirements

1. Estimates provided by constructing Transmission Owners. Costs stated in millions of nominal dollars
2. Estimate for the Dubuque-Cardinal portion presented as a range because project is subject to resolution of joint ownership issues between affected transmission owners

Figure 3.2-7: Multi-Value Project Statuses as of August 2013

Book 1 – **Chapter 4**
Reliability Analysis

Reliability Analysis

Maintaining system reliability is the primary purpose of most MTEP projects. In support of this goal, MISO performs an annual Reliability Assessment through its MTEP process. MISO planners study reliability from a thermal perspective – making sure the transmission facilities do not overheat, and from voltage and dynamic perspectives – making sure the frequency remains stable. Detailed results of these analyses are included in Appendix D of the MTEP13 report.

In support of its MTEP assessment, MISO conducts Baseline Reliability studies to ensure the transmission system is in compliance with two entities: applicable national Electric Reliability Organization reliability standards and reliability standards adopted by Regional Reliability Organizations, applicable within the transmission provider region. These analyses evaluate local Transmission Owner (TO) planning criteria after it is filed and approved by Federal Energy Regulatory Commission (FERC). The TO's criteria may drive additional upgrades, to the extent it is more strict than North American Electric Reliability Corp. (NERC) requirements. MISO's studies typically include simulations to assess transmission reliability in the near and long term by using powerflow models representing various system conditions two-, five- and 10-years out.

Projects are included in MTEP Appendix A when they have been determined to be the preferred solution to a transmission need and when their implementation timeline requires near-term progress through their implementation timelines. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles.

The results of these reliability analyses were presented and peer-reviewed at sub-regional planning meetings (SPM) in December 2012, March 2013 and June 2013. The final results of this reliability analyses are summarized in this chapter and Appendix D of this MTEP13 report.

4.1 MTEP13 Reliability Assessment Overview

MISO performs rigorous studies to ensure the continued reliability of the transmission system, as measured by compliance against NERC and local TO planning criteria. These standards define minimum requirements for long-term system planning and require explicit solutions for violations that occur in a 10-year timeframe. MISO is required to identify a solution for each identified violation that could otherwise lead to overloads, equipment failures or blackouts.

MISO's MTEP reliability assessment focuses out two, five and 10 years into the future. The combination of these analyses allows MISO to assess and recommend reliability upgrades to meet near-term system load growth and reliability concerns. They also allow MISO to look into longer-term system trends and assess potential transmission and non-transmission alternatives to be evaluated in successive years.

The MISO reliability assessment is broken into two parts: 1) project justification reviews and 2) NERC reliability assessment. The two portions of the analysis feed and provide information for the other, as new constraints determined during the NERC reliability assessment may lead to new projects in the next project justification cycle.

Project Justification Analysis and Subregional Planning Meetings

MISO evaluates project submissions from the Transmission Owners through an annual series of internal analysis and discussions of these projects through Subregional Planning Meetings (Figure 4.1-1). These subregional public stakeholder forums are held at least three times during the year to allow for transparency around project submittals; identified need drivers; and transmission or non-transmission alternatives.

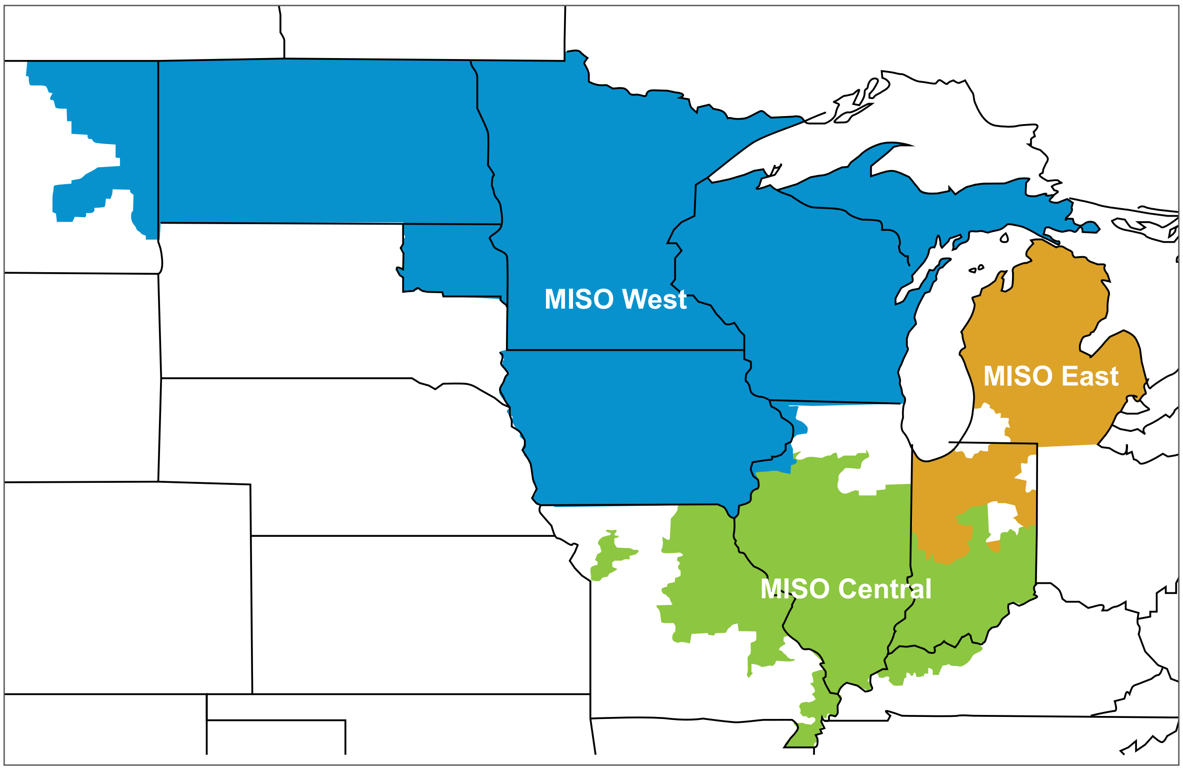


Figure 4.1-1: MISO Subregions

Additionally, Technical Study Task Force meetings are convened for each subregion on an as-needed basis to discuss confidential system information (Figure 4.1-2). These meetings are open to any stakeholders who are able to sign Critical Energy Infrastructure Information and non-disclosure agreements. At this end of this analysis and discussion, MISO staff recommends a set of projects to the MISO Board of Directors for review and approval. These projects are summarized in Chapter 2 of the MTEP13 report.

Date	Meeting	Location
4-Dec-12	East Sub Regional Planning Meeting	Detroit, MI
6-Dec-12	Central Sub Regional Planning Meeting	Carmel, IN
10-Dec-12	West Sub Regional Planning Meeting	St. Paul, MN
15-Jan-13	Michigan Technical Study Task Force Meeting	Detriot, MI
31-Jan-13	West Technical Study Task Force Meeting	Conference Call
25-Feb-13	Michigan Technical Study Task Force Meeting	Novi, MI
18-Mar-13	East Sub Regional Planning Meeting	Novi, MI
25-Mar-13	Central Sub Regional Planning Meeting	Carmel, IN
5-Apr-13	West Sub Regional Planning Meeting	St. Paul, MN
3-May-13	Michigan Technical Study Task Force Meeting	Jackson, MI
23-May-13	West Technical Study Task Force Meeting	Conference Call
5-June-13	Central Technical Study Task Force Meeting	Conference Call
12-June-13	West Sub Regional Planning Meeting	St. Paul, MN
13-June-13	Michigan Technical Study Task Force Meeting	Conference Call
20-June-13	East Sub Regional Planning Meeting	Cadillac, MI
27-June-13	Central Sub Regional Planning Meeting	Carmel, IN
25-July-13	Central Technical Study Task Force Meeting	Conference Call

Figure 4.1-2: MTEP13 Technical Study Task Force and Subregional Planning Meeting schedule

NERC Reliability Assessment

MISO performs an annual assessment of the transmission system against all reliability standards and requirements, including local planning criteria. The results of this analysis feed into the subsequent cycle of "bottom-up" transmission planning and project justification analysis, as MISO and its Transmission Owners are required to develop and implement solutions for each identified violation. The results of these analyses, as detailed in Appendix D, create a comprehensive assessment of long-term system reliability, as well as evidence for NERC compliance.

Based on MISO's NERC reliability assessment, potential thermal and voltage reliability issues are identified. The majority of these identified violations may be mitigated via system re-configurations, including generation re-dispatch. For all other issues, mitigations, in form of future proposed transmission upgrades, will be identified for the projected thermal and voltage issues. These network upgrade mitigations will be investigated further in future MTEPs.

NERC Reliability Analysis Results

The results of MTEP13 Reliability Analyses will be included in Appendix D2 - D8 and are posted at the MISO FTP site.

MISO Planning Regions are separated into West, Central and East. Generation, load, losses and interchange are modeled in each of the six planning models used in MTEP13 Reliability Analysis, and more information may be found in Appendix D2 to this report.

Models

In MTEP2013, MISO conducted regional studies using the following base models:

- 2015 Summer Peak
- 2018 Summer Peak
- 2018 Shoulder Peak
- 2018 Light Load
- 2023 Summer Peak
- 2023 Shoulder Peak

MISO member companies and external Regional Transmission Organizations (RTO) companies use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2013 series Multi-Area Modeling Working Group interchange. MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from Transmission Owners.

Generation dispatch within the model building process has become complex. Growing inputs from various planning processes and expected shifts in generation portfolio within the MISO footprint are big reasons.

Inputs in the dispatching process include:

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

Loads come directly from MISO members. Generation dispatched in each region is based on a number of assumptions, such as for the modeling of wind. For example, wind generation is dispatched at 20 percent of nameplate in the summer peak case and 90 percent of nameplate in the shoulder and light-load cases. These wind dispatch levels were selected through MISO planning stakeholder process. More information on the models may be found in Appendix D2 of this report.

Steady State Analysis Results

MTEP13 Appendix E1.1.4 will list contingencies tested in steady state analysis. These contingencies were used in the MTEP13 2015 summer peak model; the 2018 summer peak; shoulder peak and light-load models; and the 2023 summer peak and shoulder peak models. All steady state analysis-identified constraints and associated mitigations are listed in the results tables in MTEP13 Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis Results

MTEP13 Appendix E1.1.1 lists types of transfers tested in voltage stability analysis. A summary report with associated P-V plots is documented in MTEP13 Appendix D4.

Dynamic Stability Analysis Results

MTEP13 Appendix E1.1.4 lists types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP13 2018 light load and shoulder peak load models. Results tables listing all simulated disturbances along with damping ratios are tabulated in MTEP13 Appendix D5, demonstrating compliance with applicable NERC transmission standards.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, equal and non-discriminatory access to the electric transmission system customers requesting interconnection to the transmission system. Generation Interconnection Projects (GIP) are upgrades to the transmission system necessary to ensure the reliability of the system when new power generators interconnect. MTEP13 contains three Target Appendix A GIPs totaling about $15 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests G788, G889 and J034 (Figure 4.2-1 and Table 4.2-2).

MTEP13 only contains one cost shared GIP project (project 4155).

MTEP Project ID	Project Name	Submitting Company	Share Status	Region	Estimated Cost ($)
4155	G889-Harvest Wind Phase 2	ITC	Shared	East	7,901,675
4271	G788 Spiritwood Generator	OTP	To be determined	West	2,044,760
4327	J034 Fogarty Breaker Station	Ameren	Not Shared	Central	5,200,000

Table 4.2-1 Generation Interconnection Projects in MTEP13 target Appendix A

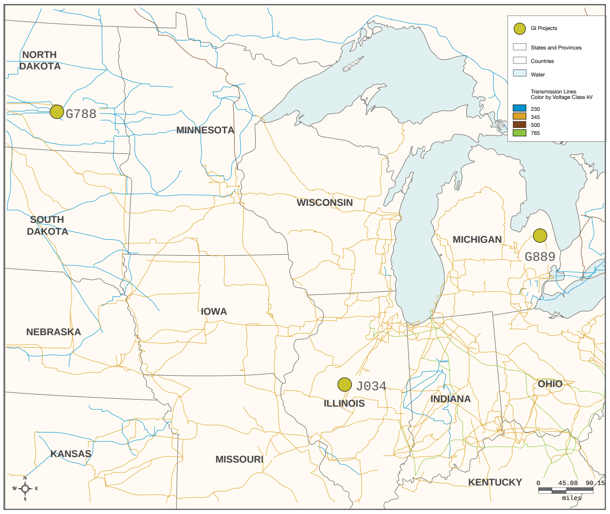


Figure 4.2-1 Generation Interconnection requests associated with MTEP13 Target Appendix A

GI Project No.	TO	County	State	Study Cycle	Point of Interconnection	Max Summer Output	Fuel Type	GIA
G788	OTP	Stutsman	ND	DPP-2010-Aug	Ladish 115 kV substation	49	Coal	G788_GIA
G889	ITCT	Huron	MI	DPP-2008-NOV	ITC Cosmo Tap (Bad Axe - Arrowhead) 120 kV	59.4	Wind	G889_GIA
J034	Ameren	Logan	IL	DPP-2009-JUL	New Holland 138 kV Substation	175	Wind	J034_GIA

Table 4.2-2 Generation Interconnection requests associated with Target Appendix A

More Details on the GIPs

MTEP Project 4155

The G889-Harvest Wind Phase 2 project was triggered by Generation Interconnection request G889, an expansion of the existing G526 wind generation plant. G526 is a wind facility with 52.8 MW gross and 52 MW net output, which is located near the intersection of Maxwell Road and the Chesapeake–Ohio Rail Road in Huron County, Mich. The interconnection customer substation site is adjacent to the right-of-way containing Detroit Edison's 120 kV circuit connecting the Cosmo substation to the Bad Axe substation in Huron County, Mich., and the Arrowhead substation in Tuscola County. G889 expands the generating facility by 59.4 MW, and it consists of 33 Vestas V100 VCS 1.8 MW wind turbine generators owned by Harvest II Wind Farm LLC.

MTEP Project 4155 includes the following network upgrades and Transmission Owner Interconnection Facilities update required for G889:

- Adding a third 345/120 kV transformer at Rapson substation, adding a new row and installing two 345 kV breakers and a new 120 kV breaker, which are estimated to cost $7,882,475
- Modifying Bad Axe substation Protection by installing two 2506 SEL-2506 relays at Bad Axe substation, which is estimated to cost $13,200
- Updating Interconnection Customer and Transmission Owner drawings to reflect any new facilities at the point of interconnection, which is estimated to cost $6,000

MTEP Project 4271

This project is associated with Generation Interconnection request G788. G788 is also an expansion project of a coal generation facility, originally designated as G645 in the MISO generation queue. Together, G788 (49 MW) and G645 (50 MW), have 99 MW net output at the point of interconnection of Network Resource Interconnection Service. The generator is a single liquid-fluidized bed coal-burning steam generator driving a steam turbine generator. It is located near Ottertail Power's 115 kV Spiritwood substation, which is located south of Spiritwood, N.D., within Stutsman County.

The MTEP13 target Appendix A project will rebuild 1.6 miles of the Jamestown Peaking Plant–Jamestown Downtown Tap 115 kV; rebuild 1.9 miles of the Jamestown Downtown Tap–Jamestown North 115 kV; and replace switches and change relay settings on the Jamestown Peak. These are the network upgrades required for the Spiritwood plant.

MTEP Project 4327

The Fogarty Breaker Station project is associated with Generation Interconnection request J034. J034 is a 175 MW wind project, known as Sugar Creek Wind Farm, in Logan County, Ill. It consists of 117–GE 1.6–100 (1.62 MW) wind turbines. Ameren will construct a new Fogarty Breaker Station, establishing a three-position 138 kV ring bus in the Mason City, West-Latham 138 kV Line 1346 near the tap to Kickapoo to provide a connection for the Sugar Creek Wind Farm.

How the Queue Process Works

Requests to connect new power generation to the system are studied and approved under the interconnection queue process. Each generator must fund a study to ensure the new connection will not cause reliability issues. Each project proceeds through a formal queue process, where milestones must be met in order to proceed to the next phase of the interconnection process (Figure 4.2-2).

Since the beginning of the queue process in 1995, MISO and its Transmission Owners have received approximately 1,300 interconnection requests totaling 256,000 MW. Among them, 28,236 MW now connect 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.

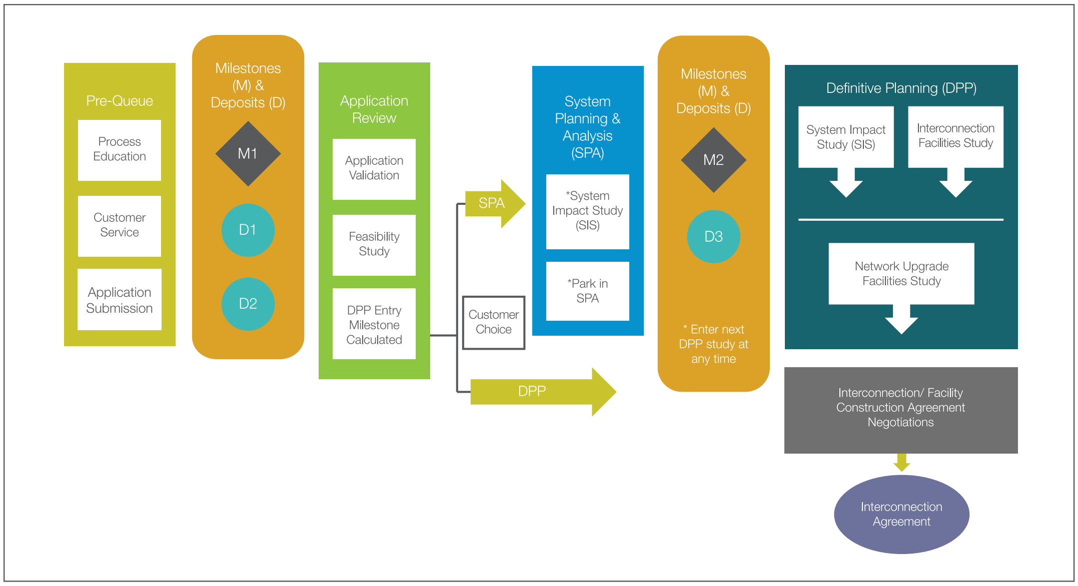


Figure 4.2-2: The queue process

Queue Trends

A look at interconnection requests over the years shows the exponential growth in wind project requests. These requests reflect the dramatic increase in registered wind capacity in MISO (Figure 4.2-3).

- In 2012, MISO received 31 interconnection requests. Nineteen – or almost two-thirds – were wind related.
- In 2011, MISO received 64 interconnection requests. Forty-four – or almost three-fourths – were wind related.
- In 2010, MISO received 39 wind-related projects out of 55 requests.
- As of July 1, 2013, there are 23,198 MW in the interconnection queue representing 138 projects. Of this total, 14,858 MW (119 projects) are wind-related, representing 64 percent of the megawatts and 86 percent of the projects. (These numbers include “Parked” projects.)

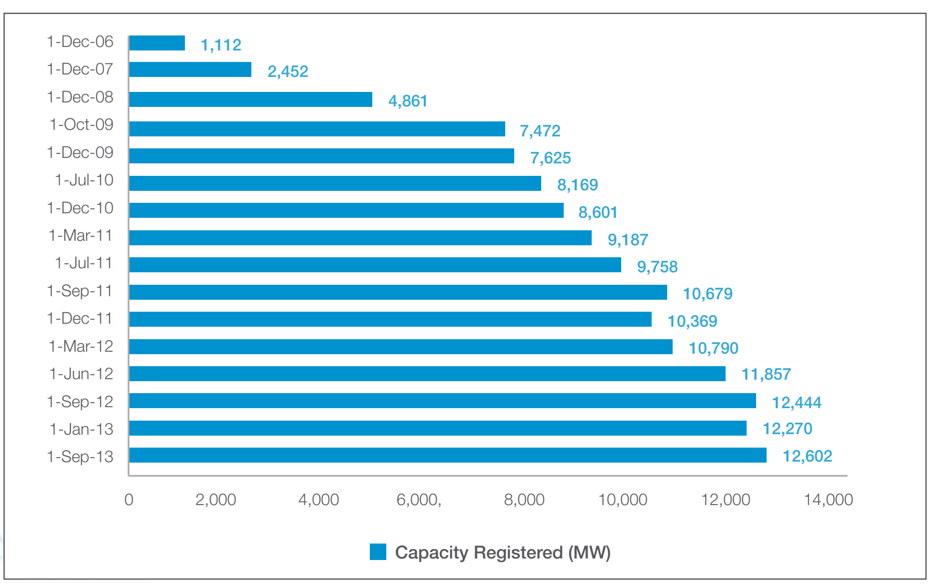


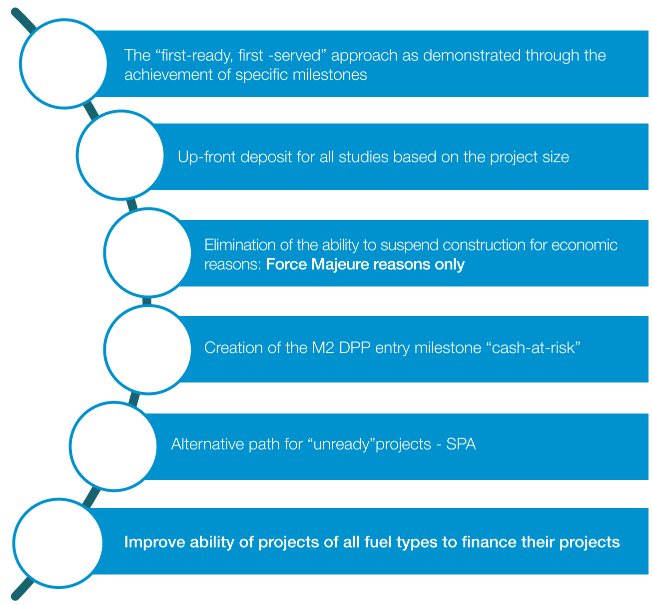
Figure 4.2-3: Nameplate Wind Capacity Registered for MISO

Queue Reforms

MISO implemented industry-leading queue reform in 2008, largely to address significant growth in wind-based generation projects. This queue reform proposal sped up the development and integration of more than 84,000 MW of requested generation. Those changes included transition to a first-ready, first-served approach; changes in deposit amounts; and the elimination of the ability to suspend projects for economic reasons.

Since then, MISO and its stakeholders have worked together to further refine the interconnection process to address backlogs in the generator interconnection queue and late-stage terminations of Generator Interconnection Agreements more efficiently.

MISO's latest queue reform, approved by FERC on March 30, 2012, provides more certainty for developers as they move to finance their projects by improving their conversations with lenders and investors. Queue reform changes include the creation of the Definitive Planning Phase (DPP) "cash-at-risk" milestone and removal of most front-end timing deadlines, which allows projects to proceed through the process.



Overall, the queue reform efforts produced substantial results. It helped clear the backlog of projects in the queue and enabled other projects to move forward (Figure 4.2-5). Sixty-six old interconnection projects see fewer uncertainties in their financial picture. This accounts for more than 5,000 MW, in Group 5, DPP Cycle 1, 2, 3 and 6 in the west region. On top of that, MISO completed DPP System Impact Studies and Facilities Studies for another 46 projects totaling 5,688 MW. Among the above, 31 projects totaling 2,293 MW completed a Generation Interconnection Agreement.

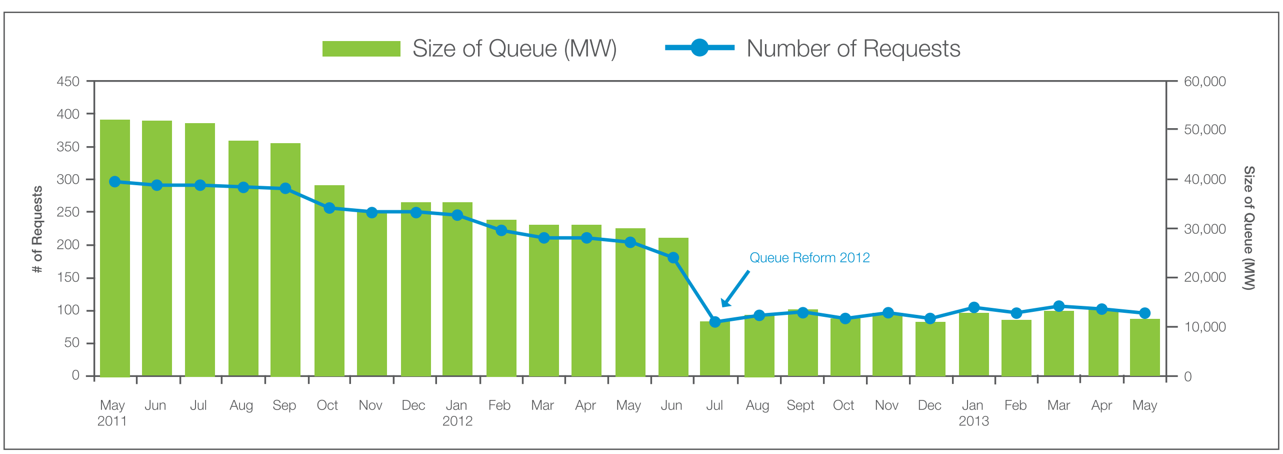


Figure 4.2-5 Generation Interconnection Queue - Overall Status (excludes "parked" projects)

4.3 Generator Deliverability Analysis Results

Generator deliverability analysis was performed as a part of MTEP13 to ensure continued deliverability of aggregate network resources. Analysis results show a total of 2,120 MW of deliverability is restricted in the near term, 2018, due to constraints identified in MTEP13. Mitigation will be identified for 120 MW of deliverability that is restricted in the near and long term due to constraints under MISO functional control. There are an additional 1,630 MW of restricted deliverability in the near term (2018). Transmission solutions exist in the long term (2023) to mitigate this 1,630 MW of restrictions. It also found an additional 370 MW of deliverability is restricted due to 69 kV constraints identified on non-transferred transmission facilities subject to MISO Agency Agreements defined under the MISO Transmission Owners' Agreement.

A total of 120 MW of deliverability is restricted due to constraints under MISO functional control identified in MTEP13.

Results of the assessment are based on an analysis of near-term and long-term summer peak scenarios. Generation observed as restricted beyond the established Network Resource amount in both scenarios must be mitigated for constraints under MISO functional control. The additional 69 kV constraints not under MISO functional control are listed in Appendix D6 as reference as part of the Agency Agreements under the MISO Transmission Owners Agreement. Furthermore, more than 1,500 MW are observed to be restricted in the 2023 planning scenario. These constraints will be monitored in future MTEP studies to determine if mitigation is required. See Appendix D6 for the detailed results with a list of impacted Network Resources.

This analysis revealed one constraint that restricts existing deliverable amounts (Table 4.3-1). Deliverability was tested only up to the granted Network Resource levels of the existing and future Network Resources units modeled in the MTEP13 2018 case. MTEP13 projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.3-1, know that:

- An "Overload Branch" is caused by bottling-up of aggregate deliverable generation
- The "Area" is the Transmission Owner of the facility
- Use the "Map ID" to find an approximate location of the overloaded element (Figure 4.3-1)
- "Contingency" is the outage causing the overload. In some cases, the system may be intact, so there is no outage.
- "Rating" the limit of the element in the analysis. The normal rating applies if the system is intact, but emergency ratings apply for post-contingent facilities.
- "Delta Increase" is the difference in loading after ramping up generation compared to before ramping up of generation in the "gen pocket."

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	Delta Increase
Black Dog – Wilson 115 kV ckt1	XEL	1	Black Dog – Wilson – Nine Mile 115 kV	239	13.39%

Table 4.3-1: The MTEP13 constraints that limit deliverability of about 120 MW of Network Resources.

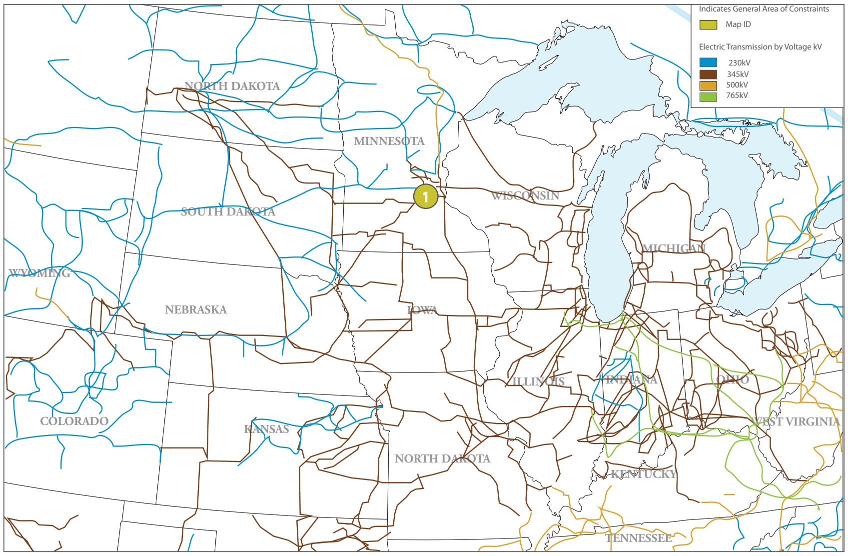


Figure 4.3-1: General location of MTEP13 2018 summer peak baseline generator deliverability constraints

Since MTEP09, MISO has performed an annual generator deliverability study to keep a closer look at the restricted megawatts and Network Resources. The 120 MW of restricted deliverability from MTEP13 compares to more than 1,000 in MTEP12, 350 MW in MTEP11, 900 MW in MTEP10 and more than 3,000 MW of restricted deliverability in MTEP09 (Figure 4.3-2)

MTEP12 identified 1,000 MW of deliverable generation restricted. Planned upgrades identified to mitigate the restricted MWs are projects 3013 and 3709 (Table 4.3-1)

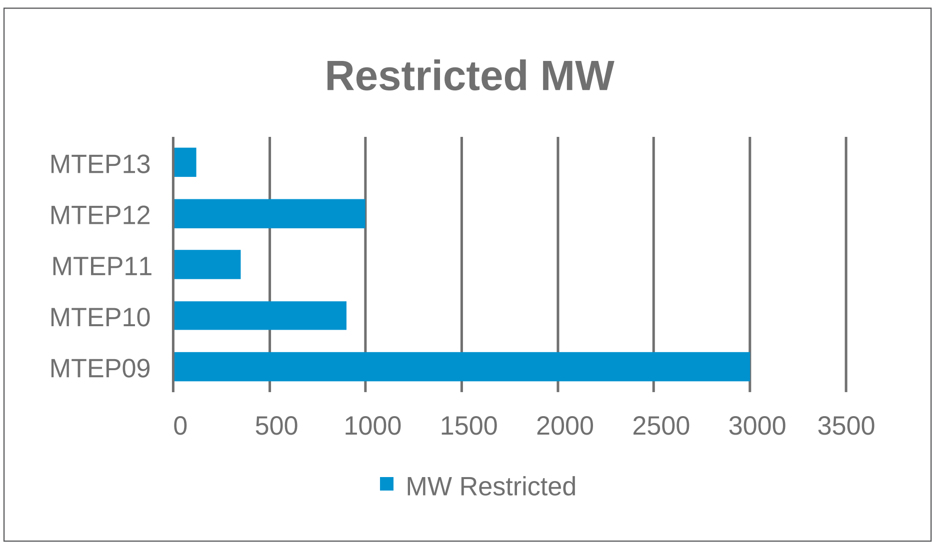


Figure 4.3-2: Restricted MW identified concluded through MTEP Cycles

MTEP12 Deliverability Constraint	Total Generation Restricted (2017)	Rating (MVA)	Percent Overload	MTEP Project ID	Target Appendix
Baldwin to Turkey Hill 345 kV	935.0	956	113%	3013	A (MTEP13)
Neal to Salix 161 kV	65.0	223	102%	3709	A (MTEP12)

Table 4.3-1: Mitigations for the outstanding constraints from MTEP12 that were proven effective

4.4 Long-Term Transmission Rights (LTTR)

MTEP involves, among other objectives, evaluating the ability of the Transmission System to fully support the simultaneous feasibility of Long Term Transmission Rights (LTTRs). To that effect, MISO performs an annual review of the drivers of the LTTR infeasibility results from the most recent annual ARR Allocation and determines the sufficiency of MTEP upgrades in resolving this infeasibility.

This chapter details the financial uplift associated with infeasible LTTRs (Table 4.4-1) and documents planned upgrades that may mitigate the drivers of LTTR infeasibility identified using the Annual Financial Transmission Rights (FTR) auction models (Table 4.4-1).

MTEP transmission expansions provide for reliable and economic use of resources, reducing the likelihood of infeasible LTTRs.

As part of the annual Auction Revenue Rights (ARR) allocation process, MISO runs a simultaneous feasibility test (SFT) 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 un-allocated LTTRs are deemed infeasible, and their cost is uplifted to the LTTR holders.

Conditions experienced in real-time systems and markets during 2012 lead to a more restrictive model for the 2013-2014 ARR Allocation than seen in the 2012-2013 planning year. The more restrictive model has impacted LTTRs by increasing the shadow prices and the number of constraints for 2013-2014. The uplift ratio (ratio of uplift cost to total LTTR payments) has risen from 3.03 percent in MTEP12 to 6.91 percent (Table 4.6-1), as noted in the 2013 Annual ARR Allocation. The 2013 value of infeasible LTTRs resulted in an uplift of $22.8 million out of total LTTR payments of $329.8 million.

Year	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible Uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
2013 Allocation	319.3	329.8	22.8	6.91 percent

Table 4.4-1: Uplift costs associated with infeasible LTTR in the 2013 Annual ARR Allocation

Infeasibility in any annual allocation of rights 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 4.4-2. 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.

Constraint	Summer 2013	Fall 2013	Winter 2013	Spring 2014	Grand Total	Potential Mitigation
ALBANY-BEAVERCHNL FLO ROCKCK-SALEM	$0	$1,058,251	$1,751,645	$196,345	$3,006,241	P4093: Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
ALBANY-BVRCH FLO STERLING STEEL-NELSON	$0	$1,685,283	$0	$0	$1,685,283	P4093: Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
WHITSTWN-GUION FLO PTRSBRG-THMPSON	$80,984	$908,702	$196,434	$228,916	$1,415,036	P2899: Guion - Whitestown 345 kV line rating upgrade ISD: 12/31/2013
ALBANY-BVR CH FLO SALEM 345/161 TR2	$1,298,873	$0	$0	$0	$1,298,873	P4093: Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
ALBANY-BVR CH FLO CORDOVA-NELSON 15503	$0	$0	$0	$1,229,695	$1,229,695	P4093: Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
EWINMAC-MNTCE-LO FLO SCHAHFER-BURR OAK	$509,704	$225,733	$118,998	$49,651	$904,086	P3203: Reynolds to Burr Oak to Hiple 345 kV ISD: 12/31/2019
RISING XF1 FLO CLINTON-BROKAW + BRKW TR2	$660,703	$0	$0	$0	$660,703	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
NERC #2439 (Crete_StJohn_flo_Wilton_Dum_SPS_Burnham_Munster)	$0	$202,203	$200,496	$253,777	$656,476	Project under evaluation in 2013 Market Efficiency Study

Constraint	Summer 2013	Fall 2013	Winter 2013	Spring 2014	Grand Total	Potential Mitigation
LOWELL-MARQUTTE FLO NBELDING-VERGENNES	$139,765	$0	$504,212	$0	$643,977	Marquette-Lowell 138kV Uprate ISD: End of 2013
GUION N TR FLO GUION 345/138 SOUTH TR	$0	$363,922	$73,061	$205,974	$642,956	Area under evaluation in 2013 Market Efficiency Study
NERC # 3645 (Cum-berland_Bush_138_FLO_Westwood_Concord_SE_138)	$0	$0	$320,859	$195,244	$516,104	
ALBANY-BVR CH FLO CORDOVA-NELSON+SPS	$467,308	$0	$0	$0	$467,308	P4093: Beaver Channel-Albany 161kV Uprate ISD: 4/1/2013
BUSHCIN-CUMBA FLO CAYUGA-EUGENE 345	$0	$378,952	$0	$47,068	$426,020	Area under evaluation in 2013 Market Efficiency Study
BUSHCIN-CUMBA FLO WESTWOOD-TIPP LABS	$0	$403,959	$0	$0	$403,959	Area under evaluation in 2013 Market Efficiency Study
RISING 345/138 XF FLO PONTIAC-BLUEMOUND	$0	$32,022	$0	$333,914	$365,936	P2239 Rising to Sidney 345kV MVP Line. ISD: 11/15/2016
REYNOLDS-MONTICELLO FLO CAYUGA-EUGENE	$0	$330,685	$0	$0	$330,685	P3203: Reynolds to Burr Oak to Hiple 345 kV ISD: 12/31/2019
MONTICE213847 A LN	$0	$288,517	$0	$0	$288,517	
RANT 1 138 kV to RNTOULJ 300 138 kV	$210,398	$18,113	$35,487	$0	$263,997	

Constraint	Summer 2013	Fall 2013	Winter 2013	Spring 2014	Grand Total	Potential Mitigation
DRESSR-ALNJCT FLO WRTHNG-BLMT+BLMT T3+4	$0	$0	$0	$259,992	$259,992	P2783 New Wheatland – Bloomington 345 kV Line. ISD: To be determined
08MARGRT-ALEJCT FLO DRSSR-TRE HAUT WATR	$17,236	$0	$236,241	$0	$253,477	P2783 New Wheatland – Bloomington 345 kV Line. ISD: To be determined
ROXANA-PRAXAIR FLO DUMNT-WILTN CNTR	$247,658	$0	$0	$0	$247,658	Area under evalua-tion in 2013 Market Efficiency Study
MITCHELL-USSCOKE FLO BURNHM-MUNSTER	$246,367	$0	$0	$0	$246,367	
STILWEL-BABCOCK FLO WLTN CNTR-DMNT SPS	$109,023	$126,601	$2,478	$0	$238,101	Area under evaluation in 2013 Market Efficiency Study
LAPORTE-MICH CTY FLO WLTN CNT-DMNT SP/S	$237,336	$0	$0	$0	$237,336	Area under evaluation in 2013 Market Efficiency Study

Table 4.4-2: Infeasible uplift to binding constraints from the 2013 annual FTR Auction

Book 1 – **Chapter 5**
Economic Analysis

Economic Analysis

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 electric system cost.

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 To date, the Multi-Value Projects being developed by transmission owners that were identified in MISO's economic analyses will save Midwest energy customers more than $1.2 billion in projected annual costs. The Value-Based Planning Process has also enabled 41 million MWh of wind energy per year to meet renewable energy goals and provided stakeholders and regulators valuable information to aid their decisions.[12]

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. Through the RGOS, it was 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 also 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 solely in regional transmission development. The "bottom-up, top-down" planning approach evaluates both locally identified transmission projects (bottom-up) and also regional transmission development opportunities (top-down) to find the dynamic balance that minimizes both transmission capital costs and production costs (Figure 5.1-1).

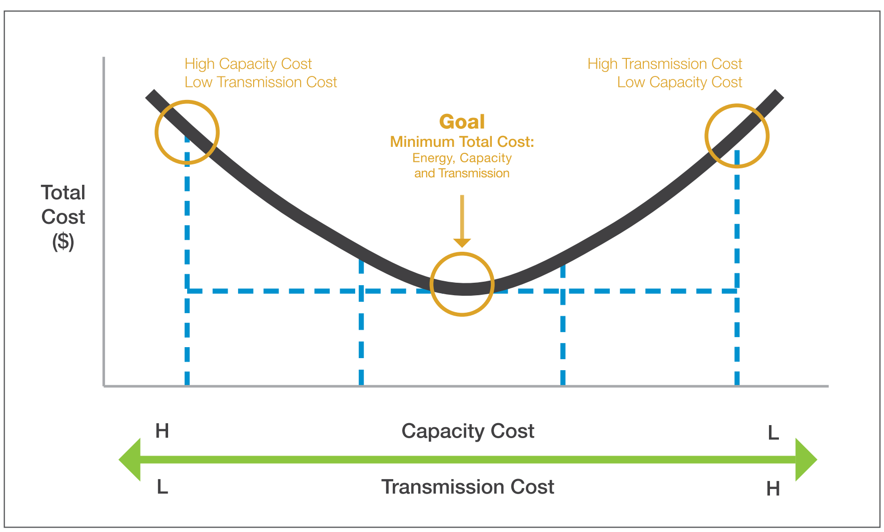


Figure 5.1-1: Producing the highest value while minimizing the total cost is the goal of the MISO Value-Based Planning Process

[12] Source: Multi-Value Project Portfolio

Since MTEP06, the MISO planning process has used multiple future scenarios to bookend 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 and 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.

MISO's Value-Based Planning Process supports state and federal policy requirements by planning for access to a changing resource mix.

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 first step of MISO's Value-Based Planning Process. MISO transmission expansion plans are developed to be robust to ensure reliability, minimize total system cost, and support energy policy requirements under all futures.

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 transmission plan that is the best fit 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 not uncommon 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:

Multiple future scenarios are analyzed to bookend out-year policy and economic uncertainty to provide context and inform choices for stakeholders and policy makers.

- Energy Planning – PROMOD and Plexos
- Reliability Planning – PSS/E, PSLF and TARA
- Decision Analysis – GE-MARS, PROMOD and EGEAS
- Strategic Planning – EGEAS
- Generation 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 must 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 of and project approvals 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.

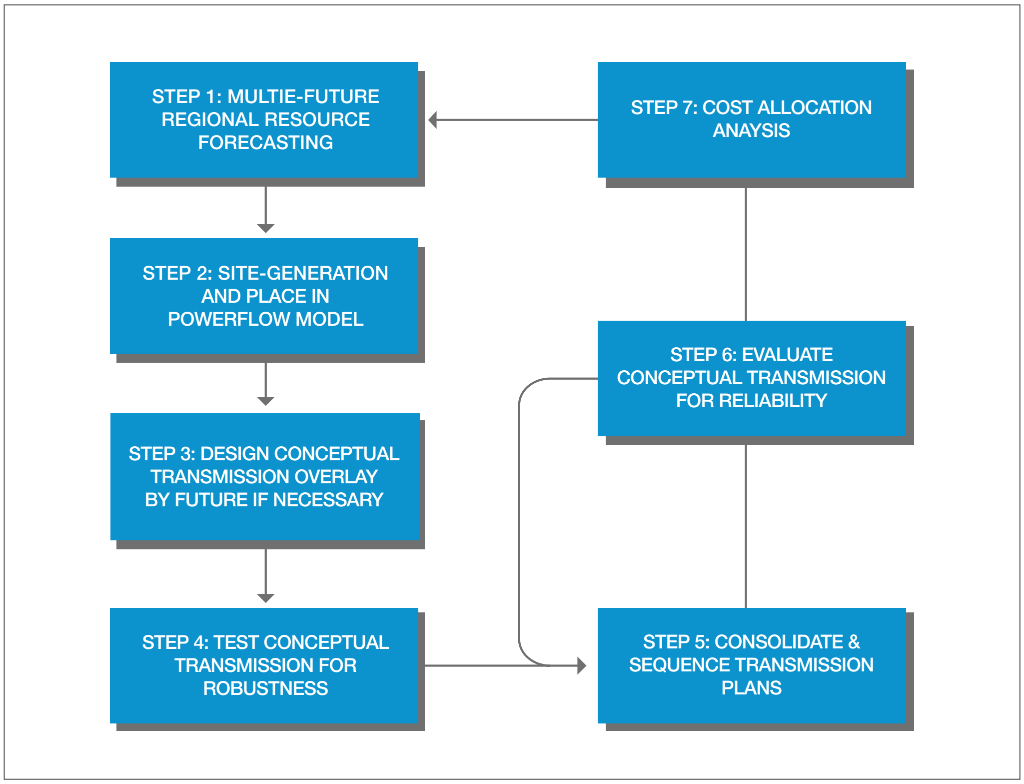


Figure 5.1-2: MISO's Value-Based Seven-Step Planning Process

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 generation portfolio. Generation 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 collaboratively with stakeholders annually 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 MTEP13 future scenarios is in Chapter 5.2.

Step 2: Siting of Regional Resource Forecast Units

Generation 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 generation 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 generation. 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 MTEP13 future is in Chapter 5.2.

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 top-down regional projects as well as bottom-up projects identified by local 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.

Step 4: Test Conceptual Transmission for Robustness

Step 3 of the process develops transmission plans for each future scenario, but may also include equivalent plans developed through other major transmission studies. Up to this point, preliminary plans are developed in isolation of other future scenarios or plans. The ultimate goal of 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 against the metrics used across each of the other 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. Identifying and incorporating appropriate value measures in the assessment is critical since value comparisons can be made only when the complete value of transmission plans are captured.

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 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 generation 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. As an additional advantage, evaluating multiple future scenarios shows which transmission configurations consistently produce value. If the same group of projects is the preferred solution for multiple scenarios, it is a good indication that a given portfolio is robust and would result in a less future regrets than a portfolio that does not.

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 for reliability, to improve market efficiency, or to interconnect new generation and/or support energy policy laws.

Cost allocation mechanisms are developed and revisited in a collaborative and open stakeholder process through the Regional Expansion Criteria and Benefits (RECB) Task Force.

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms	Paid by requestor (local zone)
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 and exports other than PJM

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 MTEP13, MISO's Value-Based Planning Process is exemplified in the Generation Portfolio Analysis (Chapter 5.2), Market Efficiency Planning Study (Chapter 5.3), Northern Area Study (Chapter 7.1), Manitoba Hydro Wind Synergy Study (Chapter 7.2), Southern Region Economic Analysis (Chapter 8.4), and Cross-Border Planning (Chapter 9.2).

5.2 Generation Portfolio Analysis

MISO completed an assessment of generation required for the MISO footprint using the Electric Generation Expansion Analysis System (EGEAS) model on May 15, 2013. Using assumed projected demand and energy for each company and common assumptions for resource forecasting, 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.

In the Business As Usual future, it is projected that between 2013 and 2028, 24,900 MW of additional capacity will need to be added to the MISO system while12,600 MW of capacity will retire

The study determined the aggregated, least-cost, capacity expansions for each defined future scenario through the 2028 study year (Figure 5.2-1). This added capacity is required to maintain planning reliability targets for each region. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

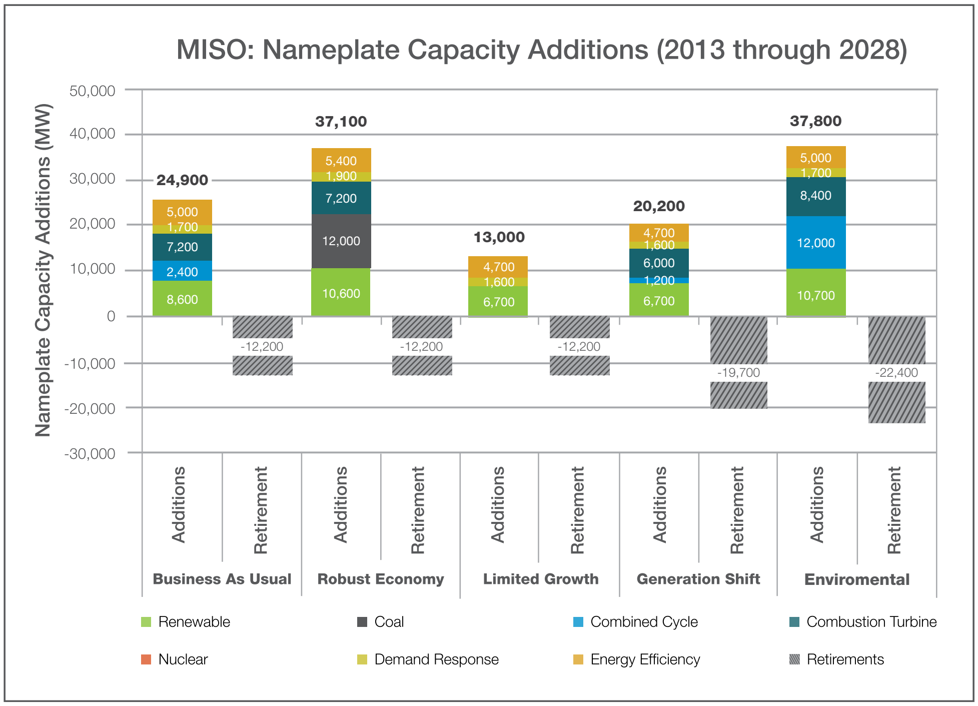


Figure 5.2-1: MISO nameplate capacity additions by future (2013-2028 EGEAS model)[13]

Results of the assessment for the Business as Usual (BAU) future shows that 24,900 MW of additional nameplate capacity are expected to be needed between 2013 and 2028, while 12.2 GW of capacity is forecasted to retire. MISO, with advice from the Planning Advisory Committee (PAC) is modeling 12.6 GW of coal retirements in all future scenarios except the Environmental scenario, which models 23 GW[14], and the Generation Shift future, which includes age-related retirements in addition to the 12.6 GW assumed in the other futures. The 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. The retired capacity is mostly coal generation, resulting from simulation of pending EPA regulations.

[13] Due to coal plant retirements that have already occurred, only the additional amount of modeled retirements are shown in the figure.
[14] 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.

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 the future 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 have been developed and refreshed annually 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. The work completed in recent studies, including MTEP09, MTEP10, MTEP11, MTEP12, the Joint Coordinated System Planning Study, and the Eastern Wind Integration and Transmission Study, demonstrate MISO's continued commitment to robust transmission planning.

The following narratives describe the 2013 future scenarios and their key drivers:

- The **Business as Usual (BAU)** future is considered the status quo future and continues current economic trends. This future models the power system as it exists today with reference values and trends. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.
- The **Environmental** (ENV) future considers a future where policy decisions have a heavy impact on the future generation mix. Mid-level demand and energy growth rates are modeled. Potential new EPA regulations are accounted for using a carbon tax and state-level renewable portfolio standard mandates and goals are assumed to be met. A total of **23 GW of coal unit retirements** are modeled.
- The **Limited Growth** (LG) future models a future with low demand and energy growth rates due to a very slow economic recovery and impacts of EPA regulations. This can be considered a low side variation of the BAU future. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.
- The **Generation Shift** (GS) future considers a future with low demand and energy growth rates due to a very slow economic recovery. This future models a changing base load power system due to many power plants nearing the end of their useful life. In addition to the **12.6 GW of coal unit retirements** modeled as a minimum in all futures, this future also models the retirement of each thermal generator (except coal or nuclear) in the year that it reaches 50 years of age or each hydroelectric facility in the year that it reaches 100 years of age during the study period. Renewable portfolio standards vary by state.
- The **Robust Economy** (RE) future is considered a future with a quick rebound in the economy. This future models the power system as it exists today with historical values and trends for demand and energy growth. Demand and energy growth is spurred by a sharp rebound in manufacturing and industrial production. Renewable portfolio standards vary by state and **12.6 GW of coal unit retirements** are modeled.

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 (Global) in 2010. This effort developed 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 MTEP13, 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 (Steps 3, 4 and 5 of the MTEP planning process), 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 0.22 percent to 1.25 percent for demand and 0.29 percent to 1.34 percent for energy (Table 5.2-1). Demand response programs are modeled within the production costing simulations as oil-fired generators with a significantly high fuel cost when compared to other generators.

Future Scenarios	Demand	Energy
Business As Usual	0.75%	0.81%
Environmental	0.76%	0.81%
Limited Growth	0.22%	0.29%
Generation Shift	0.22%	0.29%
Robust Economy	1.25%	1.34%

Table 5.2-1: 2013 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 2028 (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 compared to a Business as Usual-type scenario. Production costs include fuel, variable and fixed operation and maintenance and emissions costs (where applicable).

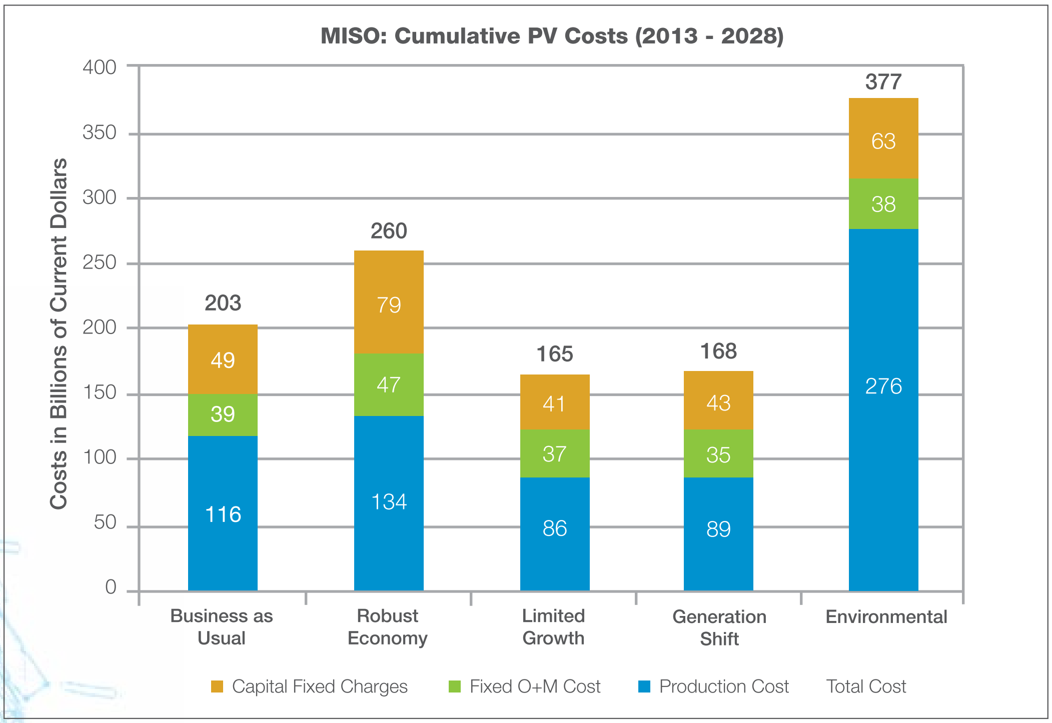


Figure 5.2-2: MISO present value of cumulative costs in 2013 U.S. dollars

Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand land energy growth rates, fuel prices, carbon costs and Renewable Portfolio Standard (RPS) requirements that drive the future capacity expansion capital investments and total production costs.

Due to the significantly higher production costs in the Environmental future, it should be noted that approximately $152 billion of the total $276 billion in production costs are due to the $50/ton carbon tax modeled in that future. Also, the retirement of 23 GW of coal units (versus 12.6 GW in the other futures) leads to higher production costs resulting from higher capacity factors of gas-fired generation which has a higher modeled fuel price than coal.

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, they have reached well over $10/MMBtu as recently as 2008. Therefore, it is important to capture a wide range of forecasts that take into account this potential volatility. For MTEP13, a baseline natural gas forecast was developed using a combination of NYMEX exchange and Energy Information Agency (EIA) forecasts. The gas price modeling approach uses a NYMEX forecast of monthly natural gas prices from January 30, 2013, through December, 2015. To populate values beyond 2015, the EIA Annual Energy Outlook Reference case was used only to provide year-over-year growth rates, which were then appended to the NYMEX forecast. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. Since NYMEX and EIA assume an inflation rate of approximately 1.75 percent in their forecasts, 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. The five resulting MTEP13 natural gas forecasts are shown below in nominal dollars per MMBtu (Figure 5.2-3).

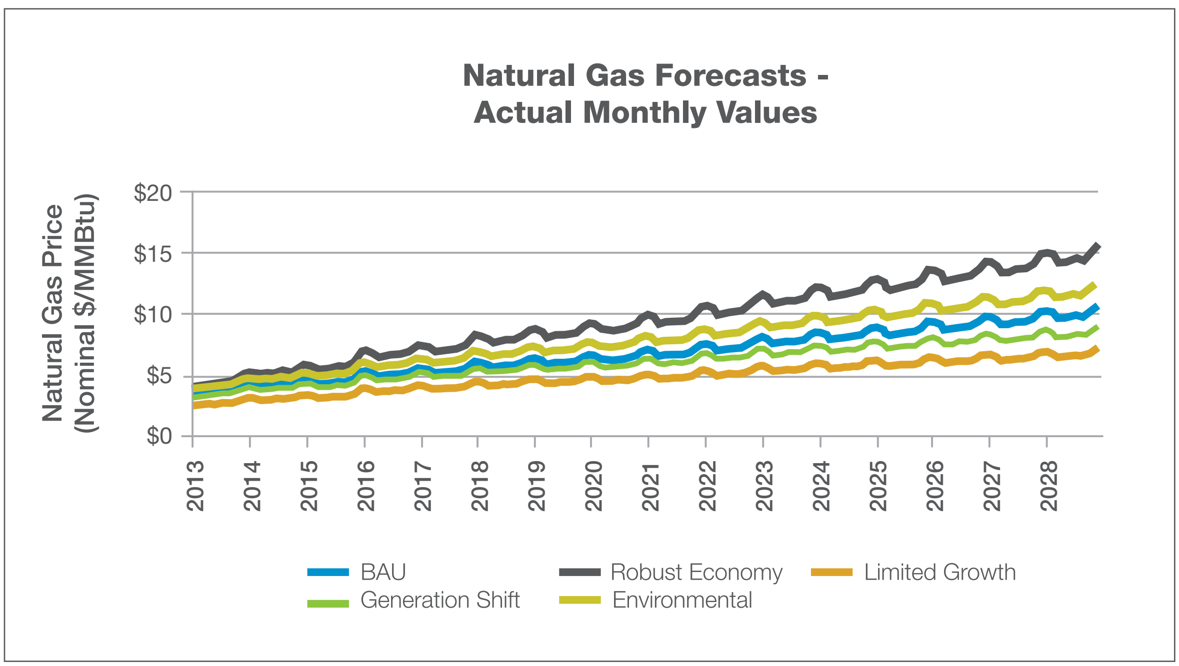


Figure 5.2-3: Natural gas forecasts by future

Renewable Portfolio Standards

Nearly every state in the MISO Midwest footprint has 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 wind and solar, in each of the MTEP futures (Table 5.2-4). All MTEP13 futures model state-mandated wind and solar only, with the exception of the Environmental future, which models both state mandates and goals.

Future Scenario	MISO Midwest Incremental Wind Penetration	MISO Midwest Incremental Solar Penetration	Percentage of Energy from All Renewable Resources in 2028
Business As Usual	6,900 MW	1,725 MW	15%
Environmental	9,000 MW	1,725 MW	16%
Limited Growth	5,100 MW	1,600 MW	15%
Generation Shift	5,100 MW	1,600 MW	14%
Robust Economy	8,700 MW	1,850 MW	14%

Table 5.2-4: MISO Midwest wind and solar penetrations including those with signed generation interconnection agreements through 2028

Carbon Emissions

Each of the future scenarios has a different impact on carbon dioxide output (Figure 5.2-5). These output values for 2028 for the different capacity expansions can be compared to the base year, 2013, CO2 output. For all futures, except the Robust Economy future, total CO2 emissions decline or remain flat between 2013 and 2028. Coal plant retirements, in combination with increased levels of renewables and demand-side management programs, are key factors in allowing carbon emissions to decline. When compared to the MTEP12 analysis, the carbon output numbers for similar futures are higher, which is a direct reflection of the reduced levels of DSM being modeled in MTEP13.

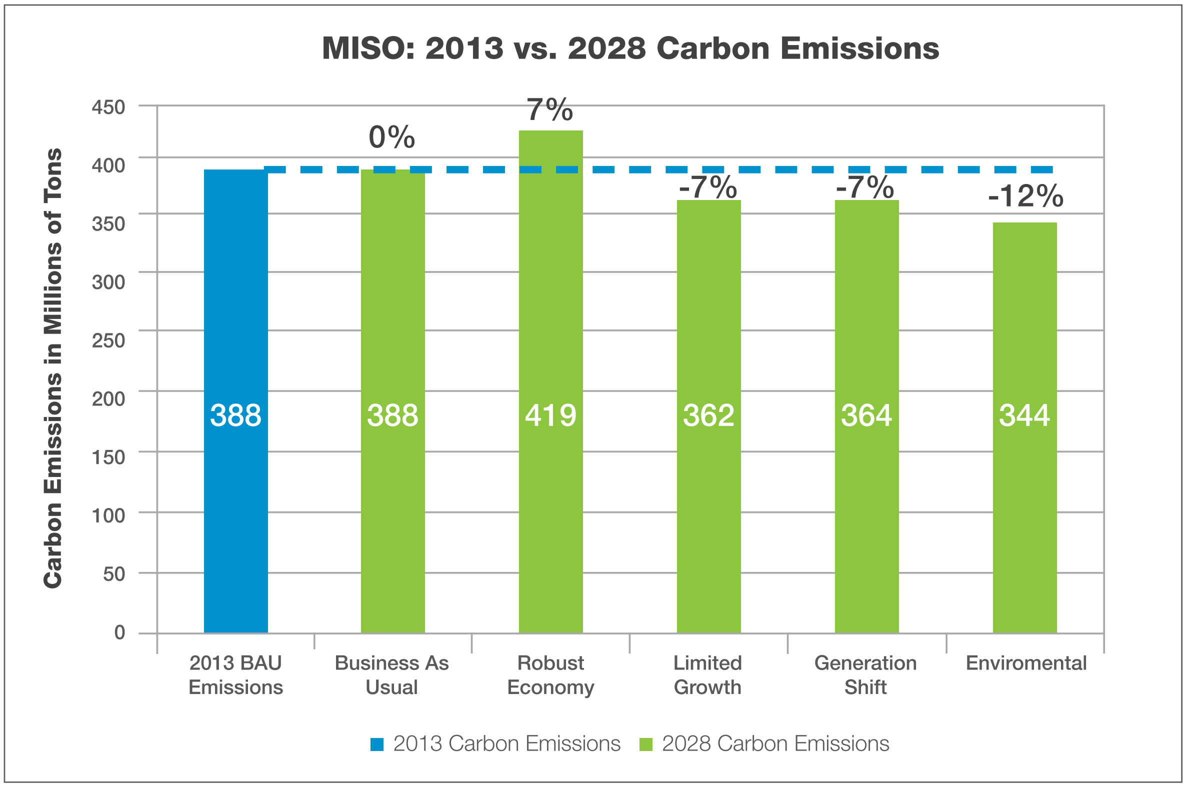


Figure 5.2-5: MISO carbon dioxide production

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 Map Info Professional Geographical Information System (GIS) software.

The sited capacity for the Robust Economy scenario is the only one to show a significant new capacity expansion (Figure 5.2-6).

Demand Response programs are sited at the top five load buses for each LSE in each state having a DR mandate or goal. The amount of DR remains constant across all futures (Figure 5.2-7). More detailed siting guidelines, methodologies and the results for the other futures are depicted in Appendix E2.

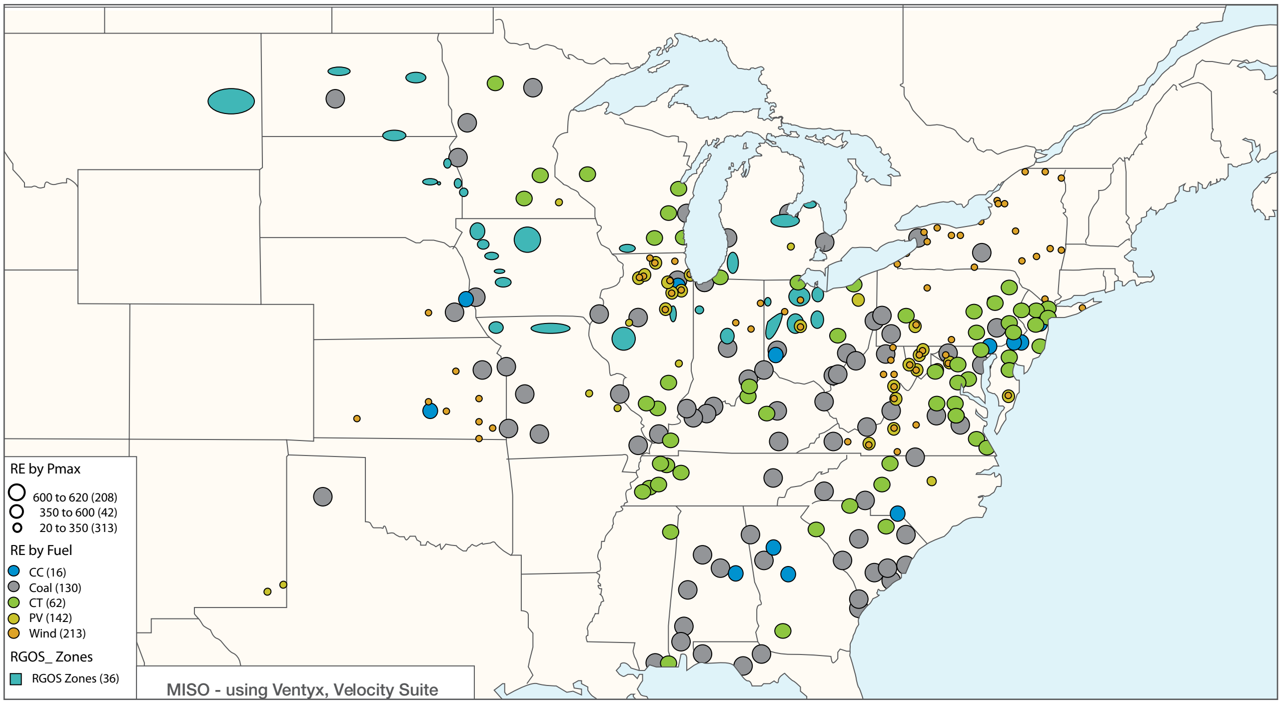


Figure 5.2-6: Future capacity sites for MISO Robust Economy scenario

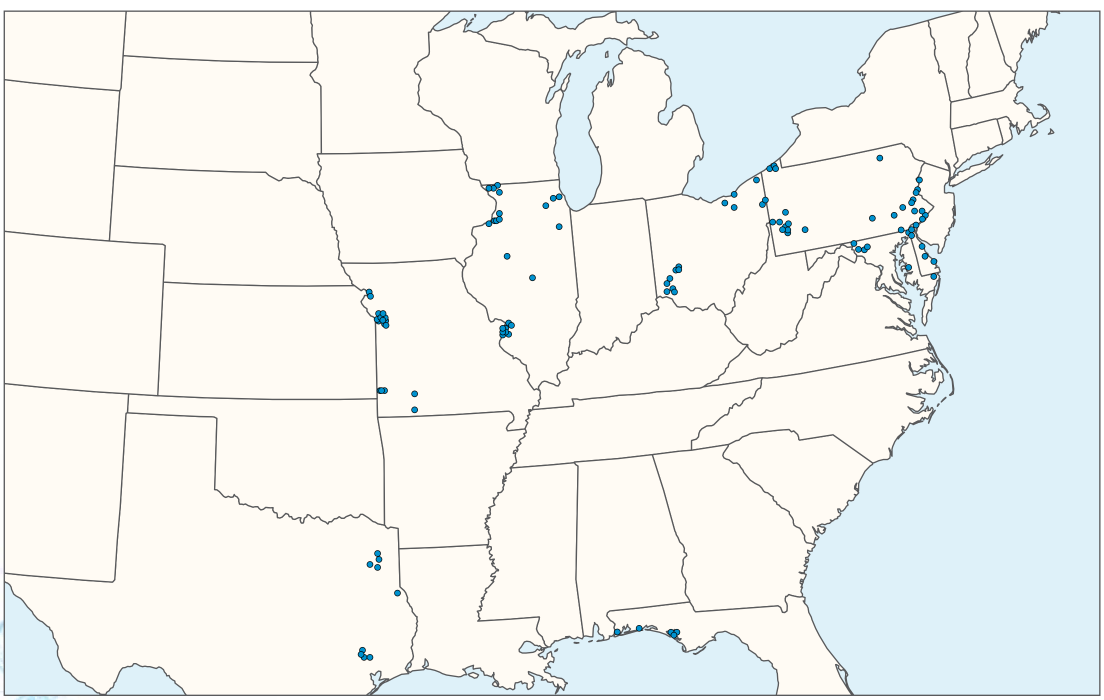


Figure 5.2-7: Future DR sites for MISO

5.3 Market Efficiency Planning Study

The purpose of the recently initiated Market Efficiency Planning Study (MEPS) is to evaluate transmission needs and identify solutions to promote market efficiency from a holistic regional view, through a comprehensive, structured process. By identifying and addressing both near-term transmission issues and long-term economic opportunities, this study seeks to find more efficient and cost-effective near-term solutions to support long-term goals.

Expanded from the former Top Congested Flowgate Study (TCFS), a narrowly defined flowgate-specific approach, MEPS identifies and evaluates transmission plans to enhance market efficiency more broadly, both within the MISO footprint and on its seams.

Throughout a 12-month study process, a total of 44 projects were proposed and studied. The large number of projects, spread throughout the MISO footprint, represents the cumulative efforts of MISO staff and a stakeholder technical review group (TRG).

Over 12 months, 44 projects within the MISO footprint were studied_three projects were considered as preferred Market Efficiency Project candidates.

With multiple iterations of project evaluation and refinement, of the 44 projects evaluated, 14 were selected as best-fit solutions for further robustness testing against a broad set of MTEP futures and reliability assessment. Of these 14, seven options met the Market Efficiency Project criteria and three of the seven options were considered the preferred Market Efficiency Project solution candidates based on stakeholder feedback and weighted benefit-to-cost ratios.

1. NIPSCOg: Wilton Center-Reynolds 345 kV line, Gwynville 765/345 kV transformer, and a St. John switch upgrade
2. DATC1-South: New Advance-Qualitech 345 kV line and a Qualitech-Royalton 138 kV line
3. FG E7: New Guion-Rockville-Thompson 345 kV line and a Guion 345/138 kV transformer

These projects will be further evaluated, along with other proposed solutions, through MISO-PJM Joint Planning study process for interregional benefits to ensure full coordination of impacts on the MISO-PJM seams. Although the analysis done to date would allow recommendation of one of the alternatives as part of the December MTEP 2013 approval, because of the need to ensure consideration of cross border benefits the three projects will be moved to Appendix B for the December cycle. MISO does expect that should one or more of these projects prove to be the recommended solution for either MISO or interregional benefits, it would be approved by June of 2014 as an MTEP13 project.

MEPS also yielded numerous projects that met Market Efficiency Project benefit-to-cost thresholds but did not meet voltage or project cost requirements. Any transmission plans that did not meet the Market Efficiency Project criteria may still move forward as a Market Participant-funded project or be studied in future MEPS.

In general, MEPS found that out-year economic potential was relatively modest, primarily due to the Multi-Value Project (MVP) portfolio, decreased demand growth rates, and low natural gas prices. Given the low projected level of economic potential, focusing on local resource zone or sub-regional level projects appeared to yield the more efficient and cost-effective solutions.

A full Market Efficiency Planning Study report is posted on the MISO website.

Study Process

The study starts with a bifurcated process to identify both near-term and long-term transmission needs, which is comprised of top congested flowgate analysis to identify near-term system congestion within MISO footprint and on the seams and congestion relief analysis explores longer-term economic opportunities. Following the need identification is a holistic evaluation of projects to identify optimal solutions and project justification in accordance with MISO tariff provisions and Joint Operating Agreement JOA protocols.

New to this year's study process is the creation of an integrated view to formulate optimal solutions by screening and linking proposed transmission options with identified transmission needs (Figure 5.3-1). By promoting the development of larger-scale projects to recognize broader benefits beyond just mitigating a specific congested flowgate, this new process ensures that the most efficient and cost-effective transmission solutions will be identified from the economic viewpoint.

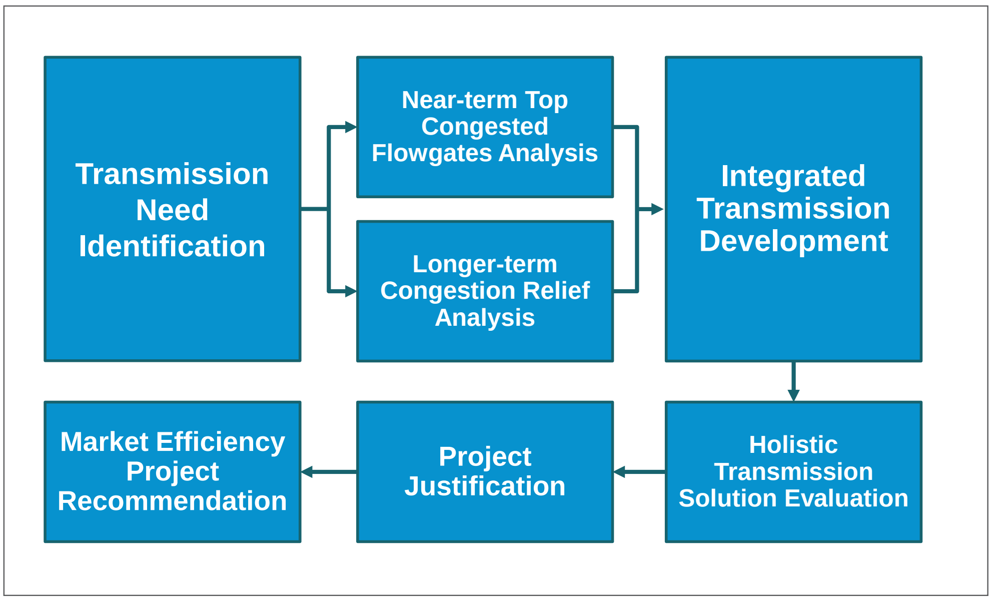


Figure 5.3-1: Market Efficiency Planning Study process

Transmission Need Identification

While the near-term approach focuses on flowgate-specific congestion, the long-term looks at transmission economic opportunities. Disjointed by nature of their scopes, these two processes run the risk of offering a myopic view of the transmission needs. In turn, these inefficiencies are propagated in the transmission development phase and lead to sub-optimal solutions. MEPS provides a link between the two methodologies, offering a broader lens through which a holistic and comprehensive, yet efficient, approach can be taken in designing and evaluating transmission.

The need-identification phase takes a bifurcated approach that seeks to identify both near-term and long-term transmission needs. It employs a Top Congested Flowgate Analysis to identify near-term system congestion and a Congestion Relief Analysis to explore longer-term economic opportunities. Although these two sub-processes functioning independently can provide useful information, they would inevitably result in an incomplete view of the transmission needs. The MEPS process builds on each study's strengths and further improves them by appropriately linking the two processes to identify both transmission issues and economic opportunities.

Top Congested Flowgate Analysis

The top congested flowgate analysis primarily identifies system congestion trends based on historical market data as well as forecasted future congestion patterns based on out-year production cost model simulations. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint, and explores cross-border seams efficiency enhancement opportunities in coordination with neighboring regions.

Candidate flowgates considered in the analysis are those that consistently demonstrate negative transmission congestion impact historically and are projected to continue to be congested into the future. Information examined to find such flowgates includes:

- Historical binding constraints identified in MISO Real-Time and Day-Ahead markets in the last two years
- Future projected congested transmission elements identified via out-year production cost model simulations

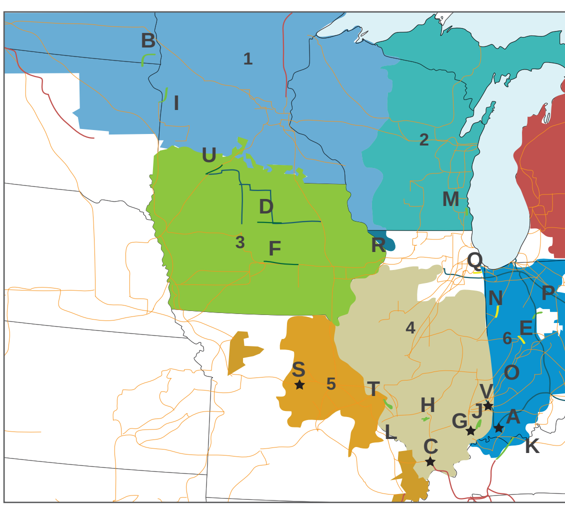
A key consideration for identifying top congested flowgates is to have a proper flowgate ranking methodology with the goal of identifying the flowgates that have the highest potential benefit from congestion relief.

New Flowgate Ranking Methodology

MISO staff, with the consensus of stakeholders, proposed and adopted a new flowgate ranking methodology called Estimated Potential Benefit (EPB). EPB provides a better approximation of the possible economic benefits by mitigating a congested flowgate. EPB is defined as the product of a flowgate's base-case shadow price and the maximum flow change when a flowgate is completely relieved.

MISO adopted a new flowgate ranking methodology, Estimated Potential Benefit, which outperforms the other traditional ranking strategies in identifying top congested flowgates to be mitigated.

The proposed new ranking strategy appears to outperform the other ranking strategies: congestion cost, shadow price and binding hours. A ranking correctness index was proposed to facilitate the quantitative comparison among different ranking strategies. Using EPB, a total of 22 flowgates were selected as the Top Congested Flowgates. The top selected flowgates were found primarily in Indiana and Illinois (Figure 5.3-2).



FG Letter	Common Name
A	Newtonville 138/161 Transformer
B	Hankinson-Wahpeton 230kV
C	Joppa 345/161 Transformer
D	Franklin - Wall Lake 161kV
E	Whitestown-Gulon 345kV
F	Montezuma-Bondurant 345kV
G	A.B. Brown 345/138 Transformer
H	Nason Point - Ina 138kV
I	Johnson Jct-Ortonvill 115kV
J	Toyota-Elliot 138kv
K	Hardinsburg-Paradise 161kV
L	Baldwin 345/138 Transformer
M	Oak Creek-St. Rita 138kV
N	Honey Creek - South Prarie Tap 69kV
O	Worthington-Owenville-Bedford 138kV
P	Grant-Greentown 138kV
Q	Crete-St. John 345kV
R	Quad City-Rock Creek 345kV
S	Overton 345/161kV Transformer
T	Coulterville-Cahokia 230kV
U	Lakefield Junction-Lakefield Gen Station 345kV
V	Petersburg 345/138/34.5kV East Transformer

Figure 5.3-2: Top Congested Flowgates ranked using Estimated Potential Benefit

Congestion Relief Economic Analysis

Coupled with near-term top-congested flowgate analysis, congestion relief economic analysis identifies longer-term transmission needs and guides development of larger-scale transmission projects that offer the maximum value. To identify economic transmission opportunities, MISO performed two production cost models simulations: a constrained case with existing transmission constraints and an unconstrained case with all transmission constraints removed for a defined area. The unconstrained case establishes a lower bound of production costs, which can serve as a reference to measure the production cost performance of all the other cases with higher production costs.

By producing a broad set of economic indicators comparing the two cases reveals the potential value of transmission congestion relief and more efficient generation utilization that help guide and screen transmission solution development. The set of information includes energy sources and sinks, forecasted Locational Marginal Pricing (LMP), incremental interface flow, incremental power transfer needs, and estimated Adjusted Production Cost Savings potential. Two of these economic indicators were particularly helpful in guiding transmission development: energy source and sinks and estimated Adjusted Production Cost Savings potential, detailed in the following

Congestion relief analyses were conducted on three separate levels, encompassing MISO's local resource zones (LRZ), MISO's market footprint, and the entire Eastern Interconnect study footprint.

Energy Source and Sinks

Energy sources and sinks on a hub and unit level were determined by observing the annual generation production differences between the unconstrained and constrained cases (Figure 5.3-3). Red represents areas of surplus energy and blue signifies the energy sink areas to which energy can be delivered economically. Energy sources and sinks provide general guidance on the location of energy export limited and import limited areas. The direction of desired powerflow is from energy sources to sinks. Linking energy sources and sinks tends to accrue the most value.

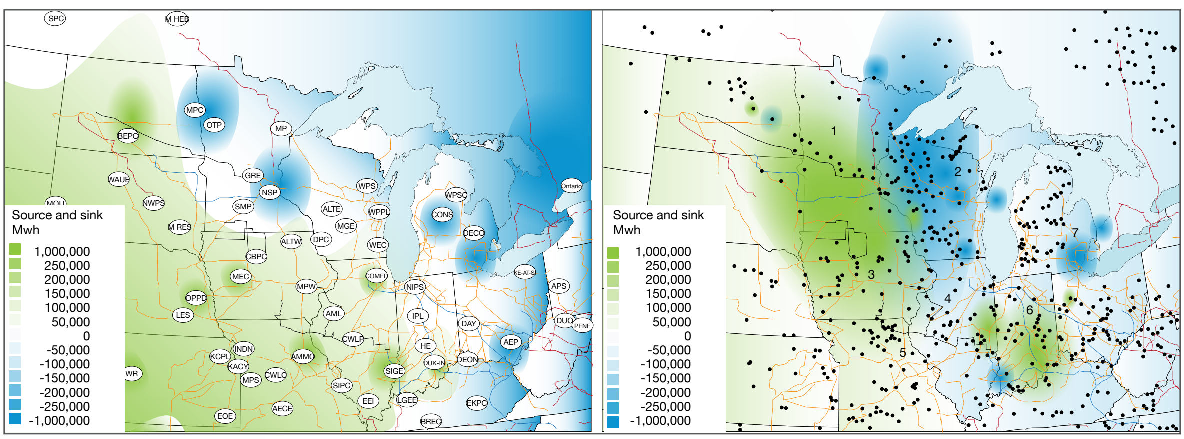


Figure 5.3-3: Hub (left) and unit (right) level energy sources and sinks from MISO Regional Analysis

Estimated Adjusted Production Cost Savings Potential

The congestion relief analysis offers a means for estimating the total budget available for transmission expansion, based on energy economic benefits — a key strength of the analysis. A rough estimate of the potential budget for building transmission can be derived from the total benefit savings by taking production cost differences between the constrained and unconstrained cases. This represents the maximum possible economic benefits to be captured from constructing a perfect transmission system, also known as the unconstrained case. The annual maximum adjusted production cost savings potential available to MISO is relatively modest, ranging from $0 to $149 million in 2027 (Figure 5.3-4). The estimated Adjusted Production Cost Savings potential, in conjunction with other economic indicators produced from the Congestion Relief Analysis, were used to screen and guide development and refinement of transmission projects, allowing more informed decisions on the economic viability of transmission plans.

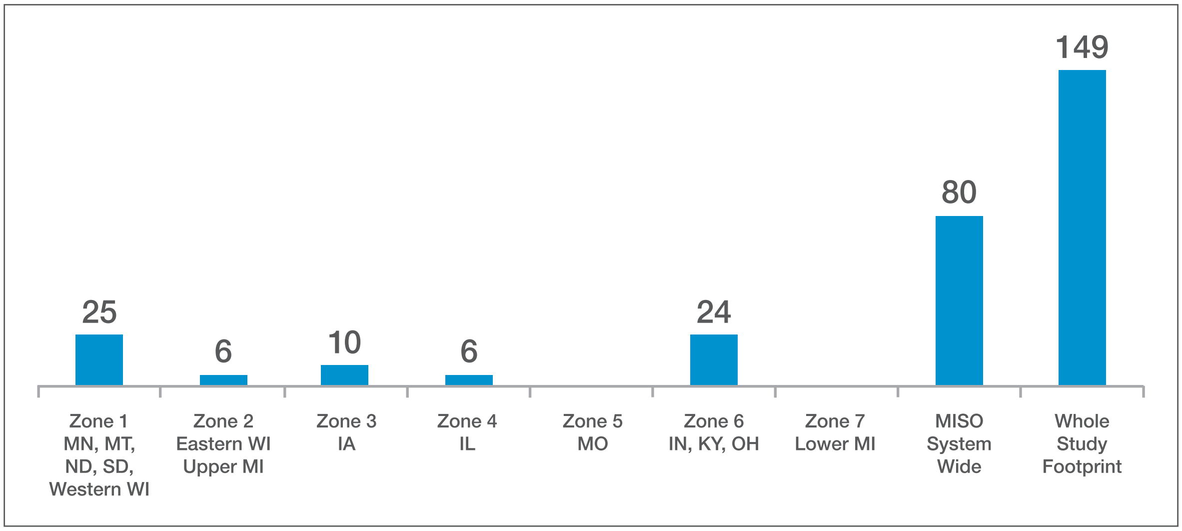


Figure 5.3-4: Maximum adjusted production cost savings potential to MISO from Zonal/Regional/Interregional Congestion Relief Analyses ($ millions in 2027)

Holistic Transmission Solution Development and Evaluation

The holistic evaluation step of MEPS entails a stakeholder-inclusive process to develop potential transmission options utilizing the list of top congested flowgates from the near-term top congested flowgate analysis and the set of economic indicators derived from the longer-term congestion relief analyses. In soliciting project solutions, consideration was given to larger-scale options that address longer-term transmission needs on a regional basis, as well as flowgate-specific mitigation plans to address near-term congestion.

The 44 solutions submitted include projects that were designed to directly address specific congested flowgates, provide energy transfer paths, or to unlock cheaper resources by connecting import-limited areas to export-limited areas (Figure 5.3-4). Consistent with the scope and purpose of the study, the MEPS sought every opportunity to coordinate with appropriately related MISO economic planning studies. Of the 44 projects studied, two were from the Top Congested Flowgate Study 2011 and four from the Northern Area study.

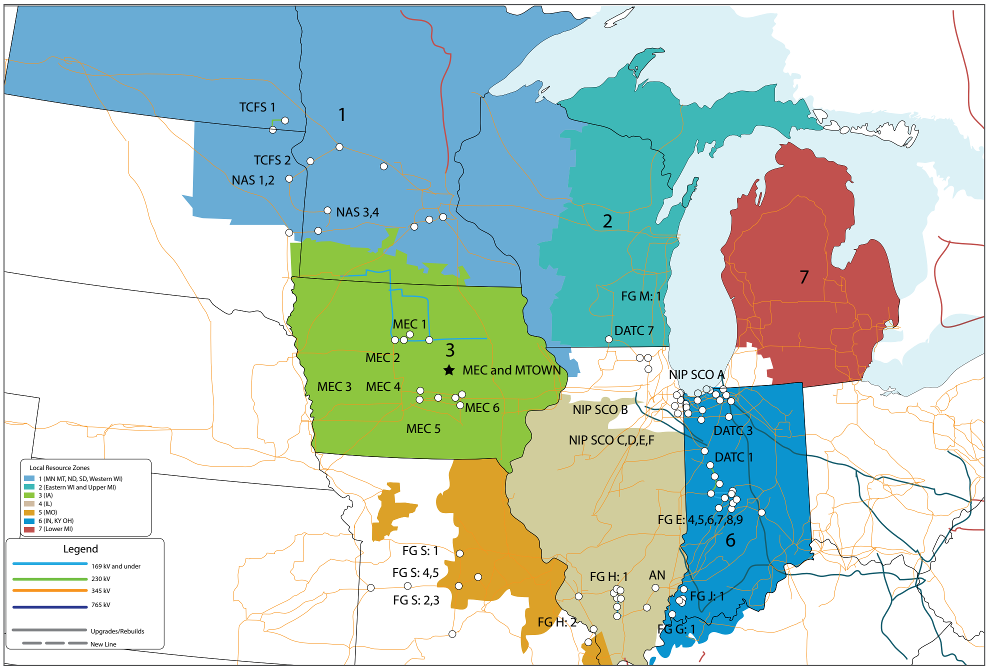


Figure 5.3-5: Transmission options analyzed to address identified market congestion issues

Project Pre-screening

Given the intensity of production cost model simulations and availability of time and resources, it is necessary to screen and narrow down the total number of transmission projects, focusing only on those that would be more likely pass the 1.25 benefit-to-cost ratio threshold for Market Efficiency Projects. To achieve this end, a project pre-screening process was developed to inform the feasibility of transmission options prior to any detailed economic evaluations.

The screening considered project costs submitted by stakeholders and the maximum Adjusted Production Cost Savings Potential information produced from the Congesting Relief Analysis. Rather than performing the resource-intensive detailed analysis of all submitted projects, the preliminary screening helped to determine, a priori, the projects most likely to meet the Market Efficiency Project benefit-to-cost ratio criterion of 1.25. The intent of project pre-screening was not to preclude any projects from further evaluation, but was instrumental in the further refinement of the proposed solutions. With the goal of developing the best fit transmission solution, MISO staff and stakeholders were guided by the preliminary screening results to better refine the 44 proposed options.

Project Evaluation and Justification

A Market Efficiency Project must meet the following criteria, as outlined in Attachment FF of the MISO Tariff:

- 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, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio
- Benefit-to-cost ratio of 1.25
- Not determined to be Baseline Reliability or New Transmission Access projects

The MISO Tariff further specifies that a project's benefit will be measured by the reduction in Adjusted Production Cost achieved by the project under each of the four Planning Advisory Committee (PAC) defined MTEP future scenarios. A total weighted reduction in Adjusted Production Cost is then calculated so that all futures are given proper proportional consideration corresponding with the future weights determined by the PAC. The broad set of policy-driven future scenarios allow for the development of one optimal transmission plan that can best manage uncertainties around future policy decisions and offer the best value in support of future resource mix. The congestion mitigation plans were evaluated using 2017, 2022 and 2027 reference case production cost models. A net present value benefit was calculated by linear interpolation and extrapolation of the three years of data and the resultant future specific benefit-to-cost ratio were weighted in accordance with the MTEP12 PAC Futures definitions.

Of the 44 projects solicited from MISO stakeholders, 14 were selected as best-fit solutions based on their specific benefit-to-cost ratios as evaluated under the Business as Usual and Historical Growth futures. As specified in the aforementioned MEP criteria, these 14 projects had a benefit-to-cost ratio greater than 1.25 in at least one of the two future scenarios. The best-fit solutions were further tested for robustness against the two other futures (Combined Policy and Limited Growth). The ultimate goal of robustness testing was to identify the transmission plans that provide the best value under most future outcomes to minimize the risk associated with the uncertainty around policy decisions. Of the 14 best-fit solutions, seven met both the MEP voltage and cost criteria (Table 5.3-1)

Option Names	Description	Project Cost (M$)	B/C ratio (BAU)	B/C ratio (HG)	B/C ratio (COMB)	B/C ratio (LG)	Weighted B/C ratio
FG E4	Guion-Rockville-Tompson 345 kV	$39	2.4	12.19	40.78	1.71	10.21
FG E5	Qualitech-Rockville 345 kV	$26.75	5.71	31.56	73.19	3.05	20.67
FG E6	Amo-Rockville 345 kV	$43	3.52	19.88	41.84	1.9	12.31
FG E7	Guion-Rockville-Thompson 345 kV plus Guion 345/138 kV xfmr	$57	3.04	18.24	45.83	1.5	12.34
FG E8	Qualitech-Rockville 345 kV plus Guion 345/138 kV xfmr	$39.75	4.32	26.19	75.28	2.2	19.24
DATC1 South	Advance – Qualitech 345 kV plus Qualitech - Royalton 138 kV	$64	2.76	12.43	22.19	1.33	7.31
NIPSCOG[15]	Wilton Center-Reynolds 345 KV, Gwynville 765/345 Xfmr, St John switch Upgrade	$175	0.68	4.27	5.5	0.5	2.08

Table 5.3-1: Cost-sharable best-fit solutions

The other seven projects (Table 5.3-2) that did not meet at least one criteria and were thus not considered as potential Market Efficiency Projects in this study. However these projects may still be considered as Market Participant Funded projects.

[15] Project involves facilities within the footprint of various Transmission Owners in both MISO and PJM and therefore requires coordination among all parties involved

Option Names	Description	Project Cost (M$)	B/C ratio (BAU)	B/C ratio (HG)	B/C ratio (COMB)	B/C ratio (LG)	Weighted B/C ratio
MEC1	Upgrade Franklin-Wall Lake 161 kV	$3.83	5.93	3.76	40.61	2.37	10.07
MEC3	Upgrade Bondurant-Montezuma 345 kV	$1.20	3.01	-1.19	26.51	1.02	5.41
MEC and MTOWN	Upgrade Franklin-Wall Lake and Webster-Wright-Wall Lake 161 kV, Bondurant Montezuma 345 kV, Marshalltown 161/115kV transformer	$14.63	3.27	1.67	67.30	0.92	12.55
NAS1	Upgrade Hankinson – Wahpeton 230 kV, Big Stone – Morris 115 kV	$22.20	7.87	17.99	75.66	0.42	18.55
MEC and MTOWN + NAS1	MEC and MTOWN Upgrades and Upgrade Hankinson – Wahpeton 230 kV, Big Stone – Morris 115 kV	$36.83	5.83	10.84	88.32	0.75	18.56
FG E9	Guion 345/138 kV xfmr	$13	12.86	77.97	196.1	6.51	52.77
FG G1	Add reactor in series with the transformer, Upgrade Francisco–Elliott 138 kV	$0.75	17.27	-3.48	83.36	3.65	20.09

Table 5.3-2: Non cost-sharable best-fit solutions

With a combination of their weighted benefit to cost ratios and further considerations by Transmission Owners on project construction feasibility, three of the seven projects that met the Market Efficiency Project criteria were identified as preferred Market Efficiency Project candidates: NIPSCOG, DATC1 South and FG E7. These projects will be further evaluated, along with other proposed solutions, through MISO-PJM Joint Planning study process for interregional benefits to ensure full coordination of impacts on the MISO-PJM seams. Although the analysis done to date would allow recommendation of one of the alternatives as part of the December MTEP 2013 approval, because of the need to ensure consideration of cross border benefits the three projects will be moved to Appendix B for the December cycle. MISO does expect that should one or more of these projects prove to be the recommended solution for either MISO or interregional benefits, it would be approved by June of 2014 as an MTEP13 project.

Going Forward

This year's MEPS grew in both scope and complexity, a trend that is expected to continue with new member integration, changing public policy, and evolving stakeholder expectations. To better meet dynamic stakeholder needs, several suggestions have been made for next year's study:

- **Enhancement of the preliminary transmission screening process:** The TRG would like the use of more objective criteria to determine the local resource zones being affected by a solution and how a solution aligns with the need identification results.
- **Definition and evaluation of larger scale projects or group of projects:** The TRG would like to further exploit synergies to maximize value by considering a group of projects from a more holistic view.
- **Better coordination between regional and interregional planning processes**

5.4 Estimating Retail Rates using MTEP13 Futures

The electricity industry faces significant policy changes from the state and federal level. These changes generate uncertainty for the industry and its customers, including uncertainty on future retail electricity rates to end-use customers. Examples of the significant policy changes include such items as: meeting future EPA regulations and meeting the state Renewable Portfolio Standard (RPS) mandates or goals that have been enacted in 10 states within the MISO region. To address these potential different futures, MISO examines multiple "what-if" scenarios through its long-term planning process to capture a wide range of potential policy outcomes, which are represented for this planning cycle by the five MTEP13 futures described in Chapter 5.2. This chapter provides analysis comparing estimated total retail rates for each of the MTEP13 futures to an average MISO-wide retail rate. It utilizes information from multiple sources including the MTEP13 futures, prior MTEP planning cycles and the Energy Information Administration (EIA).

Current MISO-wide Average Retail Electricity Rates

The current MISO-wide average retail rate weighted by load in each state for residential, commercial and industrial sectors is 9.3 cents/kWh, about 5 percent lower than the national average of 9.7 cents/kWh.[16] The EIA's Annual Energy Outlook 2013 estimates the 2013 cost components of the retail electricity rate average 61.1 percent for generation; 11.2 percent for transmission and 27.7 percent for distribution.[17] This equates to approximately 5.7 cents/kWh for generation, 1.0 cents/kWh for transmission and 2.6 cents/kWh for distribution.[18] For this rate impact analysis, it is assumed the average MISO residential customer uses approximately 1,000 kWh of electricity each month, equivalent to annual electricity charges of $1,116; based on a 9.3 cents/kWh retail rate.

Overview of Rate Impact Methodology

To measure the potential impact to rate payers under each of the MTEP13 futures, MISO projected a 2028 retail rate by estimating annual revenue requirements for the generation, transmission and distribution rate components.[19] This projection was based on the following assumptions:

- **Transmission component**
  - Includes approved Multi-Value Project (MVP) portfolio (constant across all scenarios)[20]
  - Additional required reliability transmission investment through 2028 (constant across all scenarios)
  - Non-depreciated current transmission that would still be recoverable in 2028 (constant across all scenarios)
- **Generation component**
  - Production costs for MISO generation resources associated with each scenario in 2028; including fuel, emissions, variable operations and maintenance expenses
  - Capital costs, including fixed operations and management, associated with the capacity expansion for each scenario through 2028[21]
  - Non-depreciated current generation that would still be recoverable in 2028 (constant across all scenarios)

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[16] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly from June 2013. MISO average rate was calculated by taking the load weighted average of the 11 states in the MISO footprint. See Figure 10.2-3 for the state level data.

[17] MISO average generation, transmission and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2013 for the following modeling regions: MRO-East, MRO-West, RFC-MI, RFC-West, SERC-Central, and SERC-Gateway. The modeling regions were weighted based on MISO load in each of the regions.

[18] Each category assumes some allocation of general and administrative expenses.

[19] Additional detail on the rate calculation methodology is provided in Appendix E3.

[20] Based on the approved MVP portfolio with a total project cost of $5.5 billion in in-service dollars.

[21] Refer to Chapter 5.2 for details on the capacity expansion, by fuel type, for each MTEP13 Future. Generation siting maps for each MTEP13 Future are also provided in Appendix E2.

- **Distribution component**
  - Assumes that the distribution component of the current MISO retail rate at 2.7 cents/kWh will grow at the assumed rate of inflation through 2028

To calculate MISO's 2028 retail rate, revenue requirements for the generation, transmission and distribution components described above were distributed uniformly across the forecasted 2028 energy usage levels. The 2028 rate was then deflated, using the assumed inflation rate to 2013 for comparison to the current MISO-wide average retail rate. The result of this calculation for each scenario shows the potential impact the different scenarios could have compared to the current end-use customer retail rates (Figure 5.4-1). Note that the rates calculated for the future scenarios include costs for generation, transmission and distribution; but do not include an estimate of general and administrative costs.

Rate Impact Results

All but one of the scenarios shows that retail rates can be expected to grow at a rate similar to that would be experienced if rates simply increased by inflation. However, the magnitude of this impact varies across the four scenarios, from an 11 percent decrease for the Limited Growth scenario to a 31 percent increase for the Environmental future (Table 5.4-1).

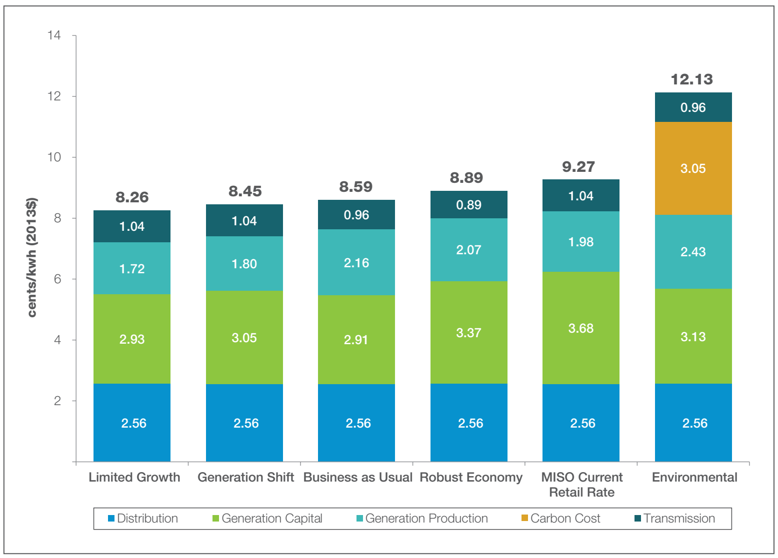


Figure 5.4-1: Comparison of estimated retail rate for each future scenario (Cents per kWh in 2013 dollars)

MTEP13 Future	Rate (cents/kWh)	Percent (Change from current retail rate)	Annual Household Electricity Costs
Limited Growth	8.26	-10.9%	-$121
Generation Shift	8.45	-8.8%	-$98
Business as Usual	8.59	-7.2%	-$80
Robust Economy	8.89	-4.0%	-$45
MISO Current Retail Rate	9.27		
Environmental	12.13	31.0%	$344

Table 5.4-1: 2028 retail rate impacts in 2013 dollars for each future scenario (Cents per kWh in 2013 dollars)

BOOK 2
RESOURCE ADEQUACY

In conjunction with transmission studies, MISO assesses the adequacy of generation for the current planning year and future planning horizons. These studies look at resources now and into the future, and in light of changing federal policy and resource retirements. This book covers the planning reserve margin, long-term resource assessment, asset owner compliance with EPA regulations and gas-electric coordination.

Book 2 – **Chapter 6**
Resource Adequacy

6.1 Planning Reserve Margin

6.2 Long-Term Resource Assessment

6.3 Asset Owner Compliance with EPA Regulations

6.4 Gas-Electric Coordination

Resource Adequacy

6.1 Planning Reserve Margin

As directed under Module E-1 of the MISO Tariff, MISO coordinates with Market Participants 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 the applicable 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 day 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 requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The MISO PRM for the 2013–2014 Planning Year was 14.2 percent, decreasing 2.5 percentage points from 16.7 percent.

The 2013-2014 planning year was the first year the Planning Resource Auction was conducted and where the deliverables mentioned above were needed for each Local Resource Zone (LRZ). The MISO PRM for the 2013-2014 planning year was 14.2 percent, decreasing 2.5 percent from the 16.7 percent PRM set in the 2012-2013 planning year (Figure 6.1-1). PRM installed capacity (PRMICAP) is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 2.5 percent PRMICAP decrease was the net effect of three decreasing factors and three increasing factors. In approximate values, decreases totaled -4.1 percent and were attributed to increased non-firm external support at -0.5 percent; treatment of Load Modifying Resources (LMRs) at -1.3 percent; and removal of the PRM adjustment at -2.3 percent. The three increasing factors included 1.1 percent due to increased load forecast uncertainty; modeling of demand response limits at 0.4 percent; and other changes such as forced outage rates; and generator rating changes at 0.1 percent.

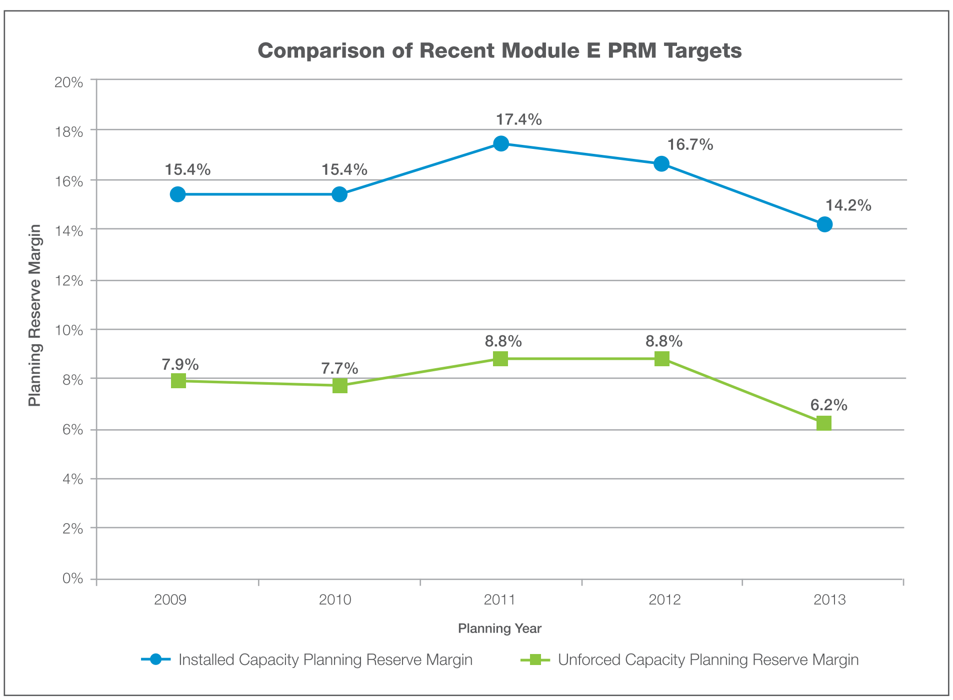


Figure 6.1-1: Comparison of recent module E PRM targets

The LOLE study and the deliverables from the Loss of Load Expectation Working Group (LOLEWG) are based on the new Resource Adequacy construct per Module E-1. MISO performs a LOLE study to determine the congestion-free PRM on an installed (ICAP) and unforced (UCAP) capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined. These results are merged with the Capacity Import Limit (CIL), Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.

The LOLE study underwent significant changes for the 2014-2015 planning year. The LOLE study incorporates MISO South beginning in the 2014-2015 study, which adds a significant amount of generation and load to the MISO footprint as well as includes two additional LRZs. The 2014-2015 planning year study also includes a few major modeling enhancements: adjustment methodology change to align with the tariff, the external regions PRM targets reduced by demand-side management; load forecast uncertainty and alignment with the zonal construct; and an improved transfer analysis methodology that is used to determine the CIL and CEL limits. These improvements have become necessary in order to mature and stabilize reliability requirements with the uncertainty of the impact of Environmental Protection Agency (EPA) retirements in future years. The Long-Term Resource Assessment (Chapter 6.2) details some of these uncertainties. Each of these improvements is described in the 2014-2015 planning year section of this chapter.

The 2011 and 2012 State of the Market Reports says that the Independent Market Monitor (IMM) believes the capacity credit for wind resources and a large share of the demand response resources are likely overstated in MISO's capacity market, which results in lower capacity prices and reduces the incentive to invest in other resources that are needed for reliability. The IMM recommends MISO evaluate improvements that would allow the credits to better reflect the resources' expected contributions during peak conditions. MISO presented these comments and evaluated other methods in open discussions with stakeholders at the LOLEWG. Stakeholders indicated that MISO's approach in determining wind capacity credits was reasonable. Going forward, MISO will evaluate the IMM's recommendations as additional data is available for wind resources as well as evaluate alternative testing procedures for demand response resources that qualify as Load Modifying Resources.

Zonal congestion was not realized in the 2013 Planning Resource Auction.

The PRMUCAP increased from 3.79 percent to 6.2 percent, which was due to the change in the Module E construct. In previous years, the PRMUCAP was applied to the non-coincident peak of each Load Serving Entity (LSE). Under the existing construct, the PRMUCAP is applied to the peak of each LSE coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated. This information was supplied to the Planning Resource Auction and the CILs and CELs could have been adjusted within the Planning Resource Auction to assure that the resources cleared in the auction could be reliably delivered. Congestion impacts are not realized until the Planning Resource Auction takes place each spring. Therefore, the ultimate PRM for a zone could be driven higher if congestion in a particular zone is realized.

However, for the 2013-2014 planning year, each zone was given a PRMUCAP of 6.2 percent, which shows no zone realized any congestion impacts. The 2013-14 planning year was the first year deliverables for the Planning Resource Auction were needed (Table 6.1-1). The CIL and CEL values,along with the limiting transmission facility and any applicable contingent facility show there were no significant limiting constraints (Table 6.1-2).

RA and LOLE Metrics	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7
Default Congestion free PRM_{UCAP}	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
LRR_{UCAP} (Per Unit of Zonal Non-Coincident Peak Load)	1.188	1.150	1.195	1.172	1.242	1.161	1.199
Capacity Import Limit (MW)	4,085	4,144	3,717	6,614	5,035	6,838	4,576
Capacity Export Limit (MW)	1,416	1,766	1,612	2,230	1,616	3,432	4,306

Table 6.1-1: Summary of CIL and CEL transfer limits and other metrics for the April 2013 Planning Resource Auction (PRA)

Type	Zone	Limit (MW)	Map ID	Limiting Element	Contingency
Import (CIL)	1	4,085	1	Werner West - North Appleton 345kV	Contingency: ATC-B1_WES_G4-4 Removed Weston Unit 4
	2	4,144	2	Lisle - Lockport 345kV	Lockport - Lombard 345kV
	3	3,717	3	St. Joe - Iatan 345kV	Iatan - Stranger Creek 345kV
	4	6,614	4	Eugene - Bunsonville 345kV	Breed - Casey 345kV
	5	5,035	5	Joachim - Rush 345kV	Rush - Tyson 345kV
	6	6,838	6	Casey - Newton 345kV	Neoga - Howland, NW 345kV
	7	4,576	7	Clifity Creek - Trimble 345kV	Jefferson - Rockport 765kV
Export (CEL)	1	1,416	8	Flowgate: FTCAL_S Substation 3451 - Substation 3459 345kV Substation 3451 - Substation 3454 345kV Substation 1251 - Substation 1297 161kV	System intact
	2	1,766	9	Zion - Zion Energy Center 345kV	Zion - Pleasant Prairie 345kV
	3	1,612		Limited by generation in zone	
	4	2,230		Limited by generation in zone	
	5	1,616		Limited by generation in zone	
	6	3,432	10	Limited by generation modeled in zone, which is short of generation in LOLE for zone 6, then encounters constraint:	Contingency: TodWood1 Todhunter - Woodsdale 345kV ckt1
	7	4,306		Todhunter - Woodsdale 345kV ckt2	Todhunter - Woodsdale 345kV ckt1

Table 6.1-2: LRZ transfer limits tracking
(Considers only facilities > 200 kV and constraint distribution factors > 3%)

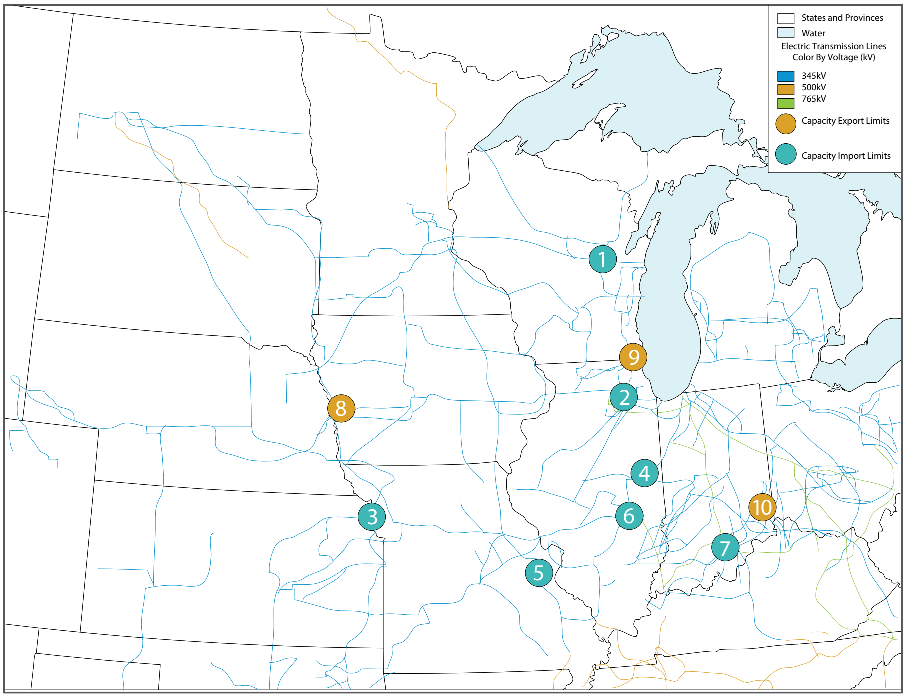
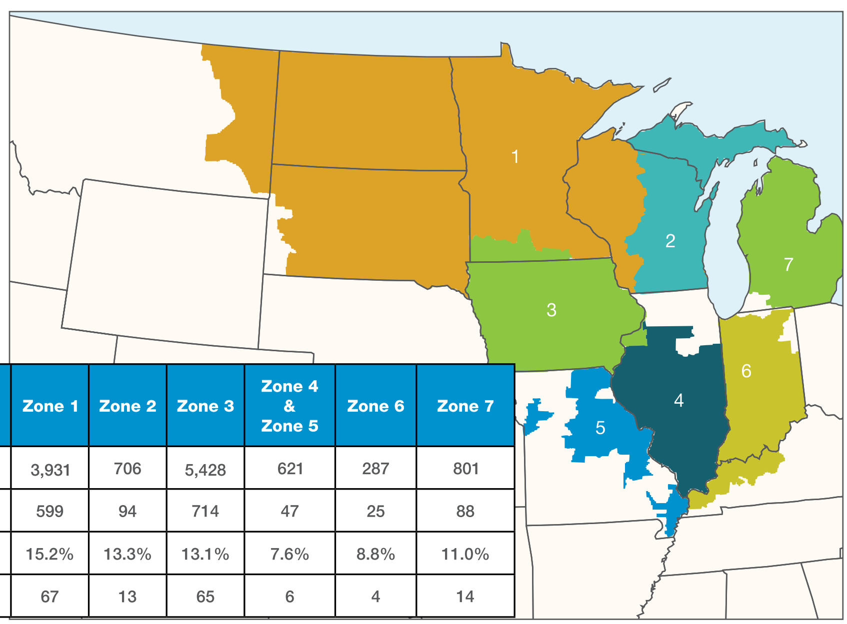


Figure 6.1-2: Capacity import and export limiting elements

A wind capacity credit of 13.3 percent was established for the 2013-2014 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit decreased 1.4 percent from the wind capacity credit of 14.7 percent established in the 2012-2013 Planning Year (Table 6.1-3). Read the complete 2013 Wind Capacity Credit Report for more information.



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 & Zone 5	Zone 6	Zone 7
Registered Max (MW)	11,774	3,931	706	5,428	621	287	801
UCAP (MW)	1,567	599	94	714	47	25	88
ELCC %	13.3%	15.2%	13.3%	13.1%	7.6%	8.8%	11.0%
Wind CPnode count	169	67	13	65	6	4	14

Table 6.1-3: MISO Local Resource Zones and distribution of wind capacity

The 2013-2014 Planning Year PRM study results are also used for the MISO South transitional PRA. Since the MISO South companies are officially integrating into MISO in the middle of the 2013-2014 Planning Year (December 2013), they will utilize the results established for that planning year. The proof-of-concept study for MISO South in which Local Resource Zones (LRZs) were developed for that region is described in Chapter 8.6. In addition, projected planning reserve margin requirements for 2014 to 2022 are used for MTEP futures described in Chapter 6.2 as a comparison to the projected reserves.

The complete 2013 report on MISO LOLE study can be found at:
https://www.misoenergy.org/Library/Repository/Study/LOLE/2013%20LOLE%20Study%20Report.pdf

2014–2015 Planning Year

Several enhancements have been made to the PRM Study for the 2014-2015 planning year. These enhancements include adjustment methodology change to align with the tariff, external system modeling, modeling of sales to PJM, load forecast uncertainty, LRZ load forecast uncertainty and the transfer analysis that establishes the CIL and CEL values. These enhancements help to mature the PRM study model.

Adjustment Methodology

For the 2014-2015 PRM study, a slight change was made in how capacity is adjusted in the LOLE model to reach an LOLE of 0.1 days/year. Previously, a perfect positive or negative generator was added in the model and adjusted appropriately to reach 0.1 days/year depending on the capacity in that particular area. For this year's study, the capacity adjustment was changed to align with the tariff. For areas or zones that need capacity to meet 0.1 days/year, 160 megawatt combustion turbines with a class average EFORd were added in the model until 0.1 days/year was reached. For areas or zones that had excess capacity and needed capacity removed to reach 0.1 days/year, units with the smallest unforced capacity were removed to reach 0.1 days/year.

External Support

In previous years, the first-tier external areas were modeled at their PRM targets. For the 2014-2015 planning year, first-tier external areas are not only modeled at their PRM targets but that target is reduced even further by reducing the demand-side management programs each of those areas has from its PRM target. This was done so that MISO was not relying on external areas to utilize its demand-side management programs to reduce its PRM. Also, the maximum Net Scheduled Interchange (NSI) from the previous year has been historically used to set the tie limits between MISO and the external areas. For the 2014-2015 planning year, the tie limits are set at the maximum NSI of the previous year's summer peak hours. This change was made to more accurately reflect the support MISO could get in a emergency type situation.

Sales to PJM

Another modeling enhancement in the 2014-2015 PRM study was derating the MISO capacity eligible to participate in PJM's market. These units' installed capacity values were derated to account for the megawatts being sold to PJM, which totalled 2,721 MW. MISO did not want to account for megawatts that were potentially unavailable to MISO in the calculation of a planning reserve margin.

Load Forecast Uncertainty

For the 2014-2015 planning year, the load forecast uncertainty (LFU) methodology did not change from the 2013-2014 planning year. However, the major data source used in calculating the LFU changed. Previously, the majority of data was pulled from EIA 861 at an annual level whereas for the 2014-2015 planning year the majority of data was pulled from Energy Velocity at an hourly level. Also, MISO South data was collected for the 2014-2015 planning year LFU calculations, which was not needed in previous years. For a more detailed description of the LFU methodology see the LOLE Reports page linked at the end of this section.

This outlines what data was used and from what periods:

Midwest

- **EV Data**
  - All Members currently in MISO: 1993-2008
  - Duke Indiana: 1993-2011
  - BREC: 1993-11/30/2010
  - DPC:1993-05/31/2010
  - MEC, MPW:1993-08/31/2009
  - MISO Settlements Data
  - All Members Currently in MISO 2009-2011

Except:

- Duke Indiana: 1993-2011
- BREC: 2009-11/30/2010
- DPC:2009-05/31/2010
- MEC, MPW:2009-08/31/2009

South

- **EV Data**
  - Zone 9 members excluding EES: 1993-2011
  - EES 2003-2011 EV New Topology
- **FERC 714**
  - Entergy EES 1993-1995
- **Directly from Entergy**
  - EAI+AECC load served by Entergy 1993-2011
  - EES 1996-2002

Local Resource Zone LFU

For the 2014-2015 planning year analysis, an enhancement was made in how the LFU is applied for the MISO system. In previous years, a MISO LFU was calculated to determine the MISO-wide PRM values and zonal LFU values were used to calculate the LRZ LRR values. This year MISO aligned the zonal construct with the MISO system PRM and modeled the nine individual LRZ LFU values as part of the MISO PRM analysis. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load, which was not previously captured by applying one MISO LFU value for each LRZ. This application of LFU more accurately reflects the uncertainty impacts of each LRZ's geographic area.

Transfer Analysis

The transfer analysis used to establish the Capacity Import and Export Limits for the PRM study for the 2014-2015 planning year was improved significantly from the prior year. The most significant improvements include considering all facilities under MISO functional control regardless of the kV level as limiting and utilizing local MISO generation for transfers. Another important goal was to more thoroughly document study assumptions and procedures through BPM language and LOLE Working Group meeting materials. To determine an LRZ's limits, a generation to generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is being determined for the sink subsystem. MISO generation resources outside the LRZ under study are increased based on electrical proximity to the LRZ under study while decreasing the generation inside the LRZ proportionately. Generation in areas with ties to the LRZ under study will be utilized by using the following approach:

- Generation in the MISO areas with ties to the LRZ under study (Tier 1) will be utilized first
- If no constraint is identified using the available capacity from Tier 1, then capacity from Tier 1 and MISO areas with ties to Tier 1 (Tier 2) will be used

This tiered approach was added to avoid limits due to remote constraints. Other improvements to the transfer analysis include the following enhancements which help more accurately represent the true capacity import and export limits of each LRZ.

- Additional unit exclusions based on machine parameters
- Transmission owner review of models and input files
- Re-dispatch options considered for mitigation
- Coordinating with operations and transmission owners regarding constraints when the constraint is unknown or re-dispatch does not exist. All of these enhancements help to more accurately represent the true capacity import and export limits of each LRZ.

An additional improvement included determining capacity import and export limits for 5- and 10-year-out models. These results are useful for planning and indicate what changes can be expected based on future changes to the transmission system.

MISO South Integration

The 2014-2015 planning year was the first year that MISO South companies were incorporated in the PRM study since they will be integrating into MISO in December 2013. In order to incorporate the MISO South companies into the PRM study, MISO asked them for data. Many of the MISO South companies submitted Generator Availability Data System (GADS) data, which is the source for much of the data used in the PRM Study. If a company did not submit this information, then vendor data and class average forced outage rates were used. A vendor database was also used to compile the load data for the MISO South companies. In addition, MISO conducted several training sessions on Resource Adequacy and Loss of Load Expectation at various locations in the south. These training sessions helped to familiarize the southern companies with MISO's PRM study process and how their data impacts the overall planning reserve margin.

The complete 2014 report on MISO LOLE study can be found at:
https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacyStudies.aspx

6.2 Long-Term Resource Assessment

Higher reserve margins historically seen in the MISO Midwest Region are eroding due to projected retirement of about 11 GWs of base load generation. This uncertainty heightens the potential for planning reserve requirement deficiencies.

Avoiding these negative outcomes requires increased collaboration amongst MISO, its members, the Organization of MISO States (OMS), and other key players in the industry. To that end, MISO is working in partnership with the key industry players to conduct a Forward Resource Assessment, which captures critical risks in the planning horizon to depict a more comprehensive projection of long-term Resource Adequacy. Going forward, MISO faces significant uncertainties that could present new reliability challenges requiring close collaboration with all stakeholders.

The potential impact of current and proposed air regulations show the potential for a 3 to 7 GW capacity shortfall as early as planning year 2016.

As an example of MISO's engagement, MISO and the OMS are conducting a joint survey of Load Serving Entities to help bridge the gap of limited visibility that exists between the annual one-year-out Tariff Module E1 Resource Adequacy construct and Forward Resource Assessment. The survey outreach to MISO Load Serving Entities will provide MISO with detailed out-year load forecasts as well as corresponding resource plans. Granular data would consist of detailed load forecasts such as forecasting errors, demand side management, future capacity plans, including behind the meter generation that LSEs are counting on to meet their out-year reserve requirement. MISO will conduct its Forward Resource Assessment using this data and report out to its stakeholders on differences between current projected reserves.

From MISO's vantage point, the long-term resource adequacy picture changes dramatically as the landscape changes in response to new and proposed emission regulations. An assessment on the potential impact of current and proposed air regulations show the potential for a 3 to 7 GW capacity shortfall in meeting the Planning Reserve Margin Requirement as early as 2016.

New challenges require new approaches. The MISO Forward Resource Assessment and other on-going initiatives seek to meet these challenges by:

- Bridging the gap of limited visibility that exists between the annual Module E process and Forward Resource Assessment[22] through closer collaboration on out year assessments with its stakeholders including the OMS
- Continuing to increase visibility of future resource retrofits and retirements due to environment regulations
- Continuing to pursue the development of processes to assure the most reliable coordination of both generation and transmission retrofit outages[23]
- Enhancing Loss of Load Expectation (LOLE) study to incorporate fuel limitations among other risk factors in the development of planning requirements[24]

More information on this assessment and other Forward Resource Assessment initiatives are found along with the full 2013 Long-Term Resource Assessment report.

[22] Long-Term Resource Adequacy Survey
[23] EPA Survey
[24] Fuel Availability LOLE Study Details

Methodology Evolution

MISO has been studying the potential impacts of regulations on resource adequacy since 2011. A report entitled "EPA Impact Analysis" was published in October 2011 and the results were summarized in the MTEP11 report.[25] The study indicated the potential for 12.6 GW of coal generation within MISO's footprint to retire as a direct result of the EPA regulations.

Since the EPA regulations had not yet been finalized in 2011, the 12.6 GW of retirements was assessed in the MTEP11 Long-Term Resource Assessment as a future sensitivity rather than as part of the reference case. The 2011 reference case (without EPA retirements) indicated a 2016 reserve margin of 22.5 percent and with EPA retirements a 2016 reserve margin of 10.1 percent, or a 3,750 MW shortfall based on a 14.2 percent planning reserve margin requirement. In the MTEP11 assessment, MISO did not have information regarding firm sales out of MISO into PJM. Assuming 3,365 MW of sales from MISO into PJM had been reported in 2011 for planning year 2016, as is currently being reported, the 2016 reserve margin with EPA retirements would have been 6.5 percent, or a 7,115 MW shortfall based on a 14.2 percent planning reserve margin requirement.

Again, in the MTEP12 Long-Term Resource Assessment, MISO did not report EPA retirements as part of the reference case. The potential shortfall in 2016 was again identified as a sensitivity. In that sensitivity MISO projected a 9.7 percent Anticipated Reserve Margin, or a 4,103 MW shortfall based on a 14.2 percent planning reserve margin requirement.[26] Again, keeping consistent with current forecasted firm sales into PJM for planning year 2016, the 2016 reserve margin would have been 6.0 percent, or a 7,468 MW shortfall based on a 14.2 percent planning reserve margin requirement.

Now, in the 2013 Long-Term Resource Assessment, projected EPA retirements and forecasted firm sales into PJM are a part of the reference case.

Demand

In 2016 MISO anticipates that the MISO Midwest Region's coincident net internal demand will be 93,703 MW, which is a 50/50 weather normalized load forecast less expected Demand Side Management MWs.

Load-Serving Entities submit an annual peak demand forecast coincident to MISO's time of peak for the upcoming planning year. The summation of all 2013 Load Serving Entity peak demand forecasts totals 96,192 MW.[27]

Load-Serving Entities also submit monthly peak demand forecasts for two years and an additional eight years seasonal peak demand forecasts non-coincident to MISO's peak. MISO utilizes these forecasts to calculate a MISO business as usual load growth. Based on these forecasts, MISO anticipates a system-wide growth rate of approximately 0.70 percent.

Interruptible Load (IL), Direct Control Load Management (DCLM), and Energy Efficiency Resources (ERR) are eligible to participate in the Planning Resource Auction as a registered Load Modifying Resource (LMR). LMR Demand Side Management (DSM) is an emergency resource callable by MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. MISO assumes the 4,548 MW of LMR DSM that cleared in the 2013 Planning Resource Auction to be available throughout the assessment period.

[25] MTEP11 Report Chapter 4.2
[26] MISO 2011 LTRA Table 1-1 and Table 1-3
[27] 2013 MISO Coincident Load Forecasts; Slide 5 (PRMR Obligation divided by 1.062)

Generation

In 2016 MISO expects a total of 102,258 MW of Anticipated Capacity Resources to be available on-peak.

MISO's Existing-Certain Capacity Resources of 106,091 MW, which is the total summer-rated capacity of its existing generation fleet that is eligible to participate in the annual Planning Resource Auction, is the baseline from where MISO projects future resources expected on-peak in the out-years. MISO's current registered capacity (Nameplate) of 127,963 MW steps down to Existing-Certain Capacity Resources of 106,091 MW by accounting for summer on-peak generator performance, transmission limitations and energy-only capacity (Existing-Other Capacity Resources), and current units on suspended operations (Existing-Inoperable Capacity Resources) (Figure 6.2-1). MISO only relies on 106,091 MW towards its Planning Reserve Margin Requirement to meet a Loss of Load Expectation (LOLE) of one day in 10 years (Figure 6.2-1).

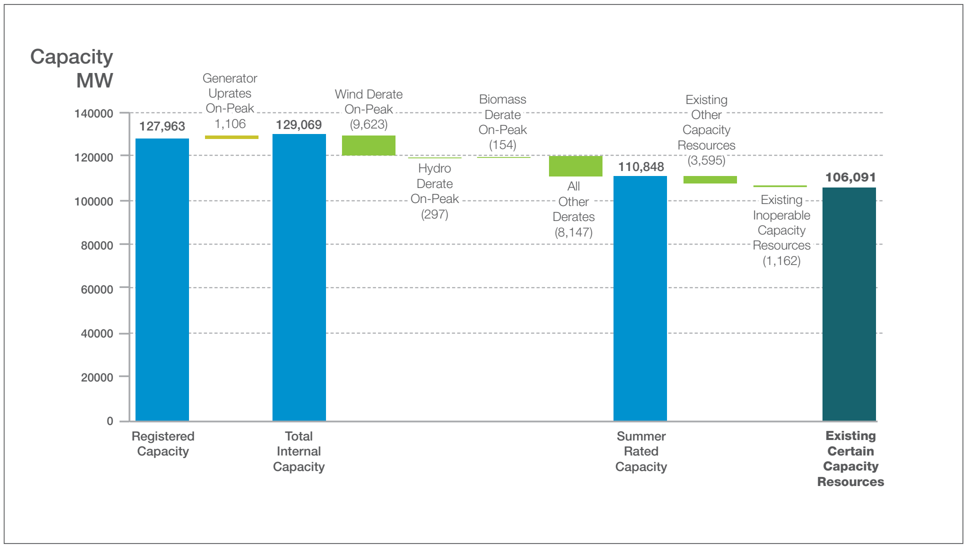


Figure 6.2-1: MISO Midwest Region incremental MW breakdown from registered capacity to existing-certain capacity resources (as of August 9, 2013)

Behind-the-meter generation (BTMG) is eligible to participate in the Planning Resource Auction as a registered "Load Modifying Resource" (LMR). LMR BTMG is an emergency resource callable by MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. Since MISO's visibility of future expansion and/or reduction of BTMG is low, MISO assumes the 3,394 MW that cleared in the 2013 Planning Resource Auction to be available throughout the assessment period, along with 152 MW of Demand Response Resources, totaling 3,546 MW.

MISO anticipates the potential retirement and suspended operation of its older base load generation fleet largely driven by new U.S. Environmental Protection Agency (EPA) rules. Over the last two years, approximately 1 GW of summer rated capacity has retired, and MISO is projecting 10,383 MW of Existing-Certain Capacity Resource retirement and suspended operation by 2016. This is based on information coming from the following sources: Attachment-Y, Attachment-Y2, and the quarterly EPA Survey as of August 9, 2013.

Also, through the Generator Interconnection Queue (GIQ) process, MISO anticipates up to 3,004 MW of future capacity additions to be in-service and expected on-peak during the 2016 summer. This is based on a snapshot of the GIQ as of July 1, 2013 and is the aggregation of active projects with either a signed Interconnection Agreement, in Facilities Studies, or in Definitive Planning Phase (DPP) Studies.

Planning Reserve Margin Requirement

Based on MISO's current visibility of projected retirements and the resource plans of its membership, MISO forecasts reserve margins will erode over the course of the next three years causing a shortfall by 2016 of 3 to 7 GW. This is the amount that MISO would be short of meeting the one day in 10-years LOLE reserve requirement set forth per Module E of MISO's tariff, referred to as the Planning Reserve Margin Requirement (PRMR).

A no load-growth scenario equates to a 3 GW shortfall; a mid-load growth scenario equates to a 5 GW shortfall; and a high-load growth scenario equates to a 7 GW shortfall for 2016 (Figures 6.2-2, 6.2-3 and 6.2-4).

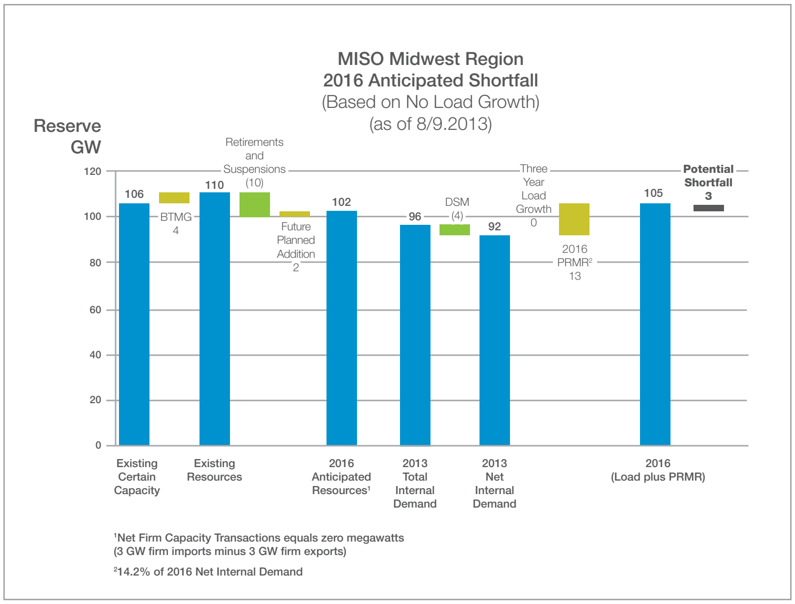


Figure 6.2-2: MISO's potential reserve shortfall by 2016 – no load growth

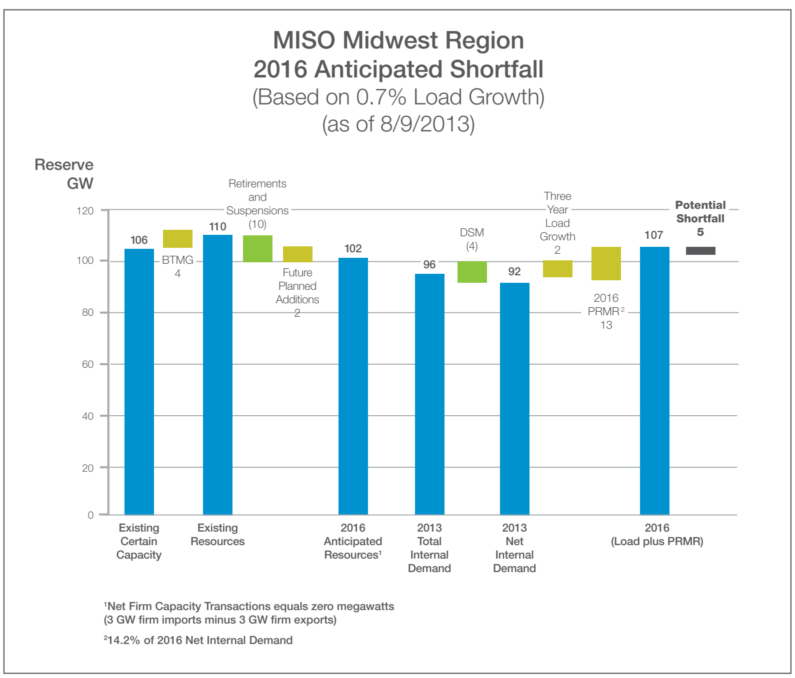


Figure 6.2-3: MISO's potential reserve shortfall by 2016 – mid load growth

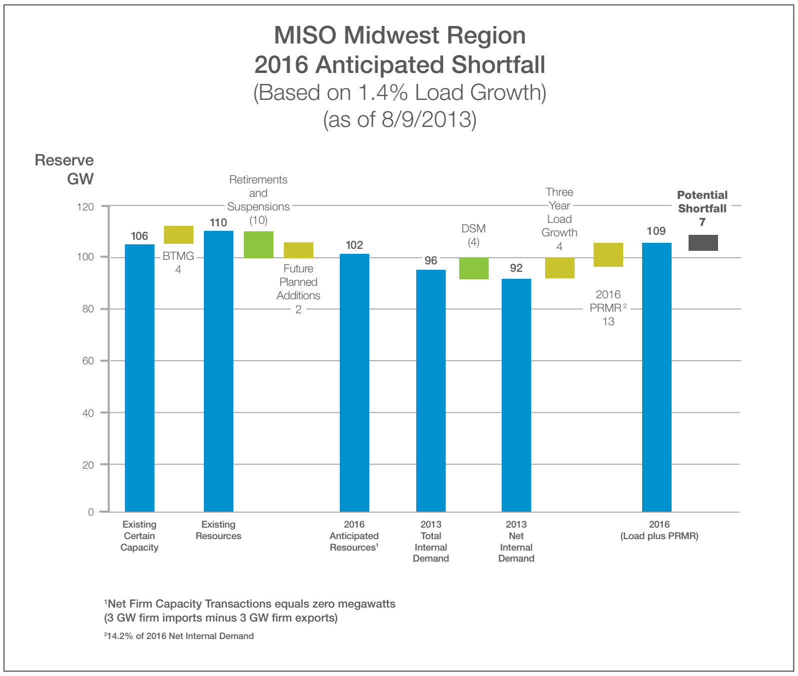


Figure 6.2-4: MISO's potential reserve shortfall by 2016 – high load growth

Uncertainty exists in critical components of the projected reserve margin including, but not limited to, out-year load forecasts, resource additions, capacity credit for intermittent resources and retirements (including both economic and environmental regulation impacts). Further enhancements are being studied to project uncertainties in external emergency support, fuel supply and monthly variations in Load Forecast Uncertainty, among others, to improve future reserve margin calculations. These studies are ongoing and expected to be informed by the Forward Resource Assessment.

Potential Mitigations

MISO and the OMS are conducting a joint 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 needs more granular data with respect to DSM growth and resource procurement to conduct Forward Resource Assessments that more accurately predict reserve margins in out years. MISO will not disseminate individual Load Serving Entity data and will use the data for MISO system level assessments and to support individual state jurisdictional Integrated Resource Planning requirements where applicable.[28]

The potential exists to mitigate some or all of the entire projected 2016 shortfall by assessing key components of the projected Anticipated Reserve Margin, including, but not limited to the:

- potential for growth in DSM
- additional support anticipated from the MISO Southern Region
- potential for transmission upgrades to mitigate current generation deliverability constraints
- potential for transmission upgrades to convert current energy only resources to network resources

[28] Joint MISO-OMS Long-Term Resource Adequacy Survey presentation

Per individual state mandates, MISO's current 20d13 non-controllable demand response totaling 1,489 MW may grow to 1,561 MW by 2016, an increase of 72 MW, and MISO's current 2013 energy efficiency programs totaling 208 MW may grow to 1,294 MW by 2016, an increase of 1,086 MW. Assuming that none of this growth is embedded in MISO's 10-year Total Internal Demand forecasts and that the incremental Demand Side Management registers as a "Load Modifying Resource" per Module E of MISO's Tariff, this incremental growth increases the 2016 Anticipated Reserve Margin by 1.4 percent.

The MISO 2013 Summer Coordinated Seasonal Transmission Assessment analyzed a high South to North transfer from the MISO Southern Region into MISO Midwest Region Local Resource Zones 4 and 6 (Illinois and Indiana). The analysis indicates an inter-regional transfer capability of at least 1,400 MW. The assumption of an additional 1,400 MW[29] into the Midwest Region from the Southern Region increases the 2016 Anticipated Reserve Margin by 1.5 percentage points.

MISO's generation fleet contains 1,471 MW of Existing-Other Transmission-Limited Resources based on generation deliverability test results. Of this, 1,236 MW transmission-limitations in aggregate are generator units limited by 10 MW or more. Assuming the applicable network upgrades are done by 2016 to mitigate these 1,236 MW of transmission-limitations, the 2016 Anticipated Reserve Margin increases by 1.3 percentage points.

MISO's generation fleet contains 2,124 MW of Existing-Other Energy-Only Resources with no firm point-to-point transmission. Assuming the applicable network upgrades are done by 2016 to convert these Energy-Only Resources to Network Resources, the 2016 Anticipated Reserve Margin increases by 2.3 percentage points.

Several possible measures could completely mitigate the projected shortfall in 2016 (Figure 6.2-5). It should be noted that uncertainty factors for each potential measure are unknown at this time. MISO expects gaining further certainty through the joint MISO-OMS survey with further understanding on LSE plans and continued Forward Resource Assessment.

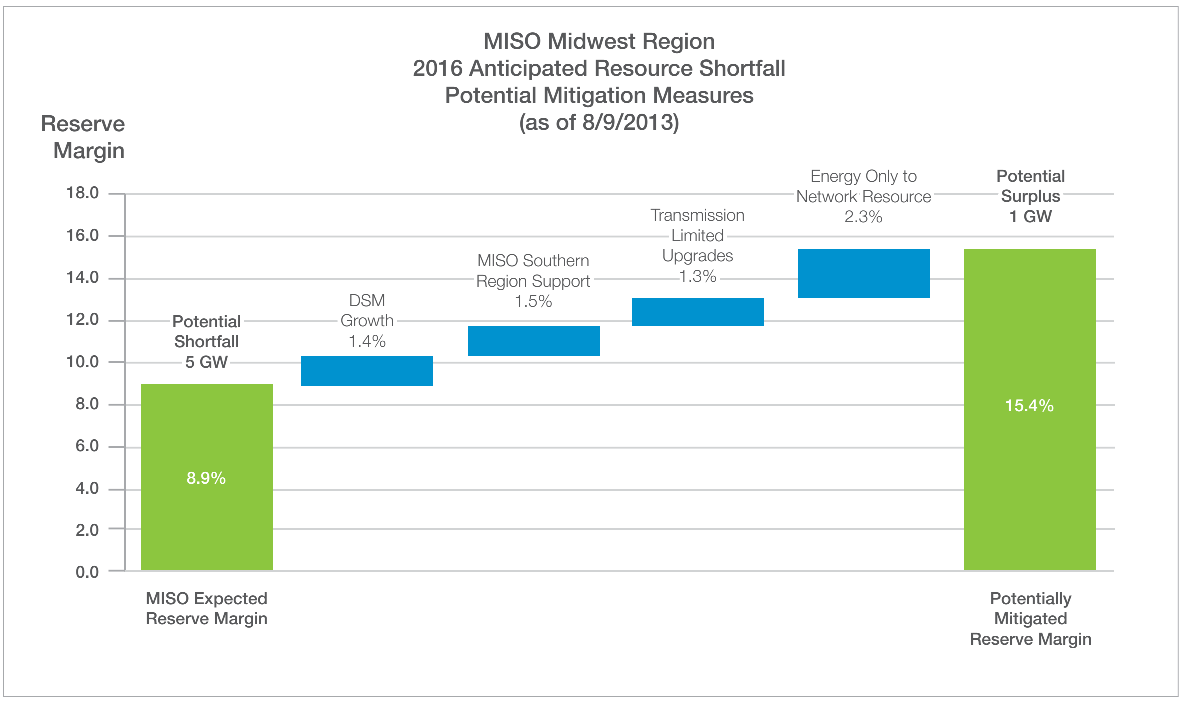


Figure 6.2-5: MISO's potential mitigation measures

[29] MISO 2013 Summer Coordinated Seasonal Transmission Assessment section 8.12

6.3 Asset Owner Compliance with EPA Regulations

In 2013, MISO continued its quarterly survey of asset owners for information on their compliance plans with EPA regulations, particularly the Mercury and Air Toxics Standard (MATS). Currently, 10.7 GW of additional capacity has a potential to be either retired or suspended in the crucial compliance timeframe of 2015 to 2016. That amount of retirements and suspensions will have a negative impact on the reserve margin in 2015 to 2016. If compliance plans do not consider greenhouse gas regulations and additional resulting retirements; the reserve margin could be even more severely impacted.

Going forward, the surveys may evolve to include new questions, based on President Barack Obama's broad plan to reduce climate-changing emissions, announced in his June 29, 2013, weekly address. The most recent asset owner compliance survey was complete before this announcement. While the outlined plan did not contain specific reduction targets, the uncertainty on how climate-changing emissions will be addressed continues to put pressure on coal assets on the margin of the retire/retrofit decision.

Compliance Plans

In the second quarter 2013 survey, the majority of coal resource asset owners are choosing to retrofit their units with some type of emission reduction equipment. Out of the 247 coal resources impacted by the MATS regulations, 114 resources are installing emission equipment. The remaining 133 resources amounting to 9.8 GW, are either retiring/suspending or under evaluation for how to comply (Figure 6.3-1). MISO has conducted the compliance survey from the onset of the EPA Impact Analysis, completed at the end of 2011, and has been keeping track of coal retirements since that time. Since the initial survey, 2.0 GW of actual coal resources have retired.

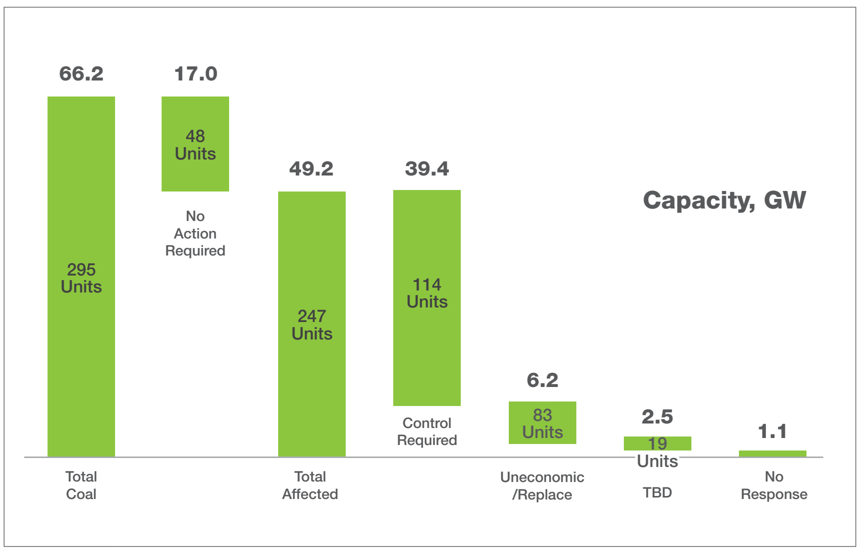


Figure 6.3-1: Coal resource compliance plans from the second quarter 2013 survey

Outage Coordination and Compliance Deadlines

Each retrofit technology has different implementation and outage characteristics. MISO's survey requests information on the progress of the planning and implementation phases of the emission equipment retrofits. The more expensive technology choices flue-gas desulfurization (FGD) and selective catalytic reduction (SCR) require similar durations to implement. Choosing one of these technologies would be quite risky to begin at this time. In fact, all but two technology choices may not meet the compliance deadline, even the one-year extension deadline (Figure 6.3-2).

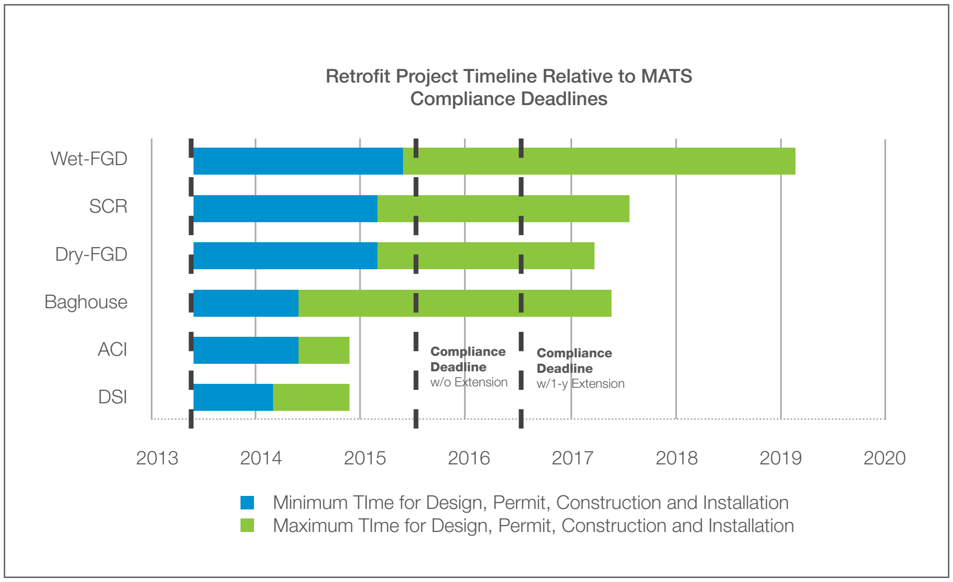
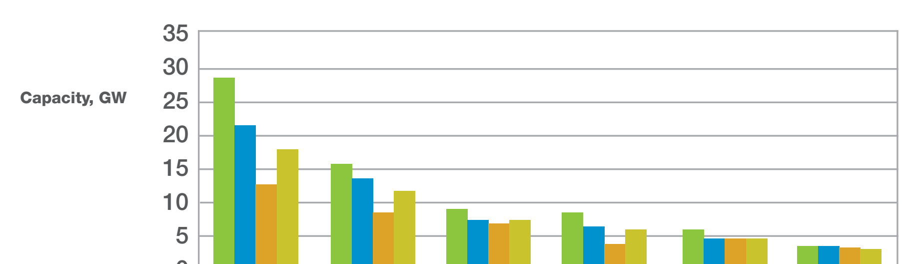


Figure 6.3-2: Retrofit timeline for various control technologies

Two technology choices, activated carbon injection (ACI) and Dry Sorbent Injection (DSI), are the only remaining technologies that allow enough time to implement within the compliance deadlines. Therefore, ACI and DSI are the technologies of choice for a vast majority of the resources in MISO. Both technologies have a gap between the required work versus what was submitted to MISO's CROW Outage Scheduling System. Based on conversations and survey information it is possible, in some circumstances, that an additional outage beyond normal annual maintenance would not be needed for either ACI or DSI. This could explain some of the gap between the work required and scheduled outages for those technologies (Figure 6.3-3).

Most resources installing FGD, SCR and baghouse technologies are in the design, permit and construction phases and should have time to meet the compliance deadline. However, there are a few that are not as far along. These resources could require extensions of the compliance deadline.



	ACI	DSI	FGD	Baghouse	SCR	ESP
Work Required (GW)	29.2	15.3	9.2	8.5	5.9	3.3
Work Scheduled (GW)	20.8	12.9	7.4	6.4	4.8	3.3
Work Contracted (GW)	13	8.7	6.9	3.9	4.8	3.2
Outage Scheduled (GW)	18	11.7	7.4	6.2	4.8	3.2

Figure 6.3-3: Asset owner technology selections and implementation phases from the second quarter 2013 survey

A third of the coal resource asset owners in MISO are looking to get a one-year extension, bringing the compliance date into 2016. About 11.8 GW of resources have received approval from individual state environmental authorities with 4.1 GW in the process of submitting their request. Also 8.2 GW of resource asset owners have not yet decided if a one-year extension is needed (Figure 6.3-4). In addition to the one-year extensions, 2.1 GW of coal resource owners have stated that an Administrative Order (AO) could possibly be needed. An AO is part of the Clean Air Act that allows for extra time where the EPA will not seek penalties for non-compliance.

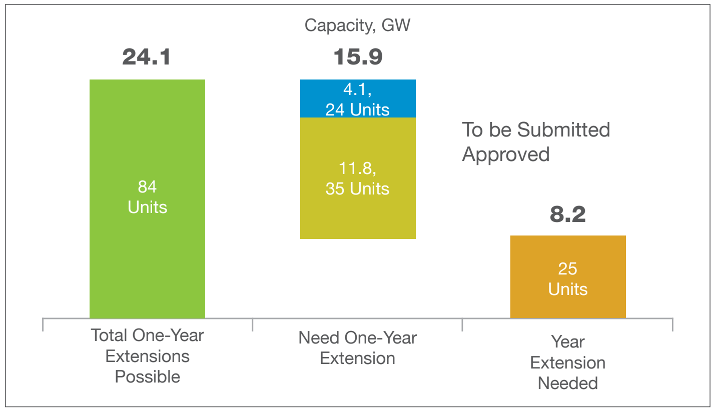


Figure 6.3-4: Compliance timeline extensions from the second quarter 2013 survey

Retirements and Suspensions

Combining the asset owner survey with Attachment Y submissions allows MISO to get a better look at retirements and suspensions going forward. Public announcements reveal that 2.0 GW of coal capacity has retired since starting the EPA Impact Study in 2010. Looking at total retirements and suspensions for all fuel types going forward, there is a potential for 10.7 GW of additional retirements and suspensions (Figure 6.3-5). This amount of additional resources unavailable during the critical compliance timeframe, 2015-2016, will negatively impact reserve margins in MISO. Also of note: if numbers are crossed-checked between figures 6.3-5 and 6.3-1, a difference of 1.3 GW appears. This difference comes from resource asset owners that have stated in the survey that they plan on using a control, but have also submitted an Attachment Y-2 request. Those particular units would be shown in the Att-Y2 retirement group (Figure 6.3-5).

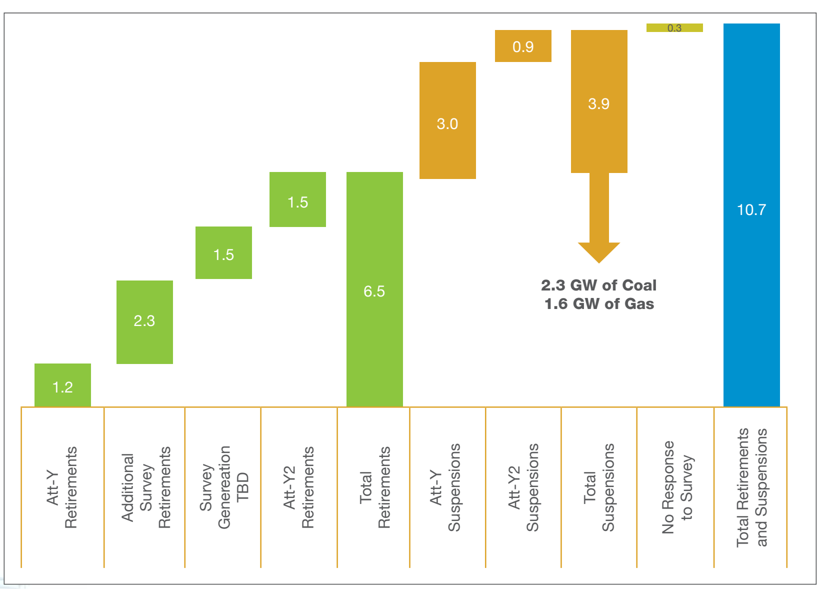


Figure 6.3-5: Expected additional retirements and suspensions going forward (GW)

The total cumulative retirement and suspension forecast for all fuel types begins to drop after 2015 because of the suspensions coming back online (Figure 6.3-6). The treatment of suspended coal resources is of particular importance. Right now, it is not clear if these resources will continue to run after suspension.

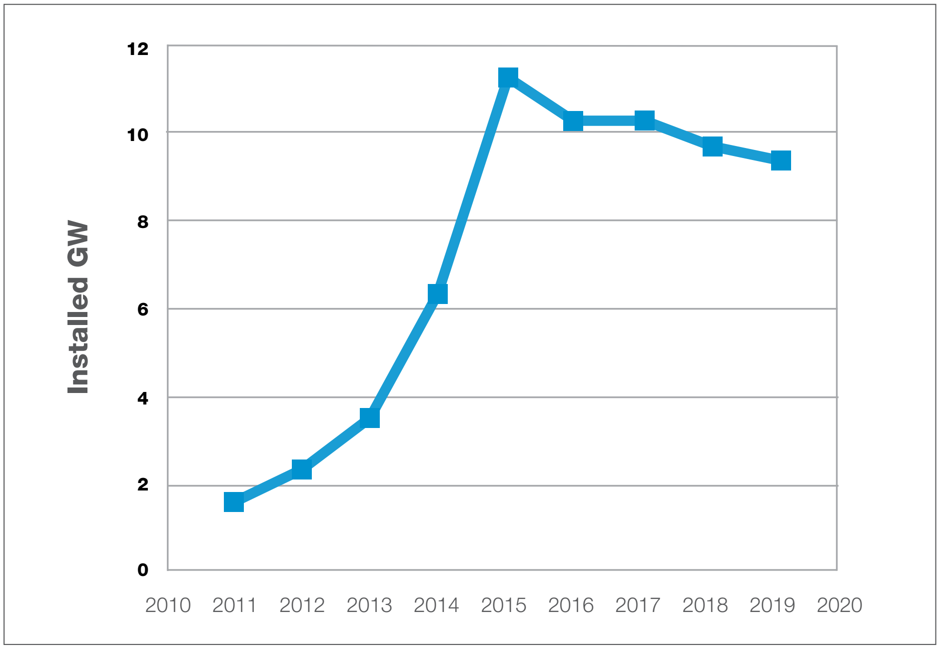


Figure 6.3-6: Cumulative retirement and suspension forecast by year

Greenhouse Gases

On June 29, 2013 the federal government outlined a broad plan to reduce greenhouse gases. The plan consists of three major points:

- Reduce the emission of carbon into the atmosphere
- Prepare to adapt to climate change that is already occurring
- Work internationally to reduce carbon and other greenhouse gas emissions

Most relevant to MISO is the directive to reduce carbon emissions in the U.S. The strategy instructs the U.S. Environmental Protection Agency (EPA) to develop rules to limit carbon emissions from new and existing power plants. Specifically, it calls for the EPA to issue a rule for new power plants by Sept. 20, 2013, with a final rule to be done expeditiously (required by law no later than Sept. 20, 2014). This strategy also requires the EPA to propose a rule for existing plants by June 1, 2014, and issue a final rule by June 1, 2015. States must submit implementation plans by June 30, 2016. The details of the rules are to be developed expeditiously with the states and other stakeholders.

The greenhouse gas rules timeframe overlaps with the MATS extensions periods in 2015 and 2016 (Figure 6.3-7). The renewed interest in reducing greenhouse gas emissions comes at a time when many companies are deciding how to comply with the MATS. If current MATS compliance plans do not account for future greenhouse gas emission reductions those compliance plans should be re-evaluated. In the 2011 MISO EPA Impact Study, there were scenarios that contained greenhouse gas emissions reduction strategies showing 23 GW of at-risk capacity. Without knowing the details of the eventual reduction strategy it is difficult to judge exactly how greenhouse gas regulations will impact the resources in MISO.

For example, if a past baseline year of 2005 was chosen, similar to previously proposed greenhouse gas legislation, MISO would have a head start in greenhouse gas reduction because wind and low natural gas prices have helped achieve a reduction from a 2005 baseline. MISO is conducting a carbon analysis similar to the one presented in the MTEP10 report, in order to evaluate potential carbon reduction strategies.

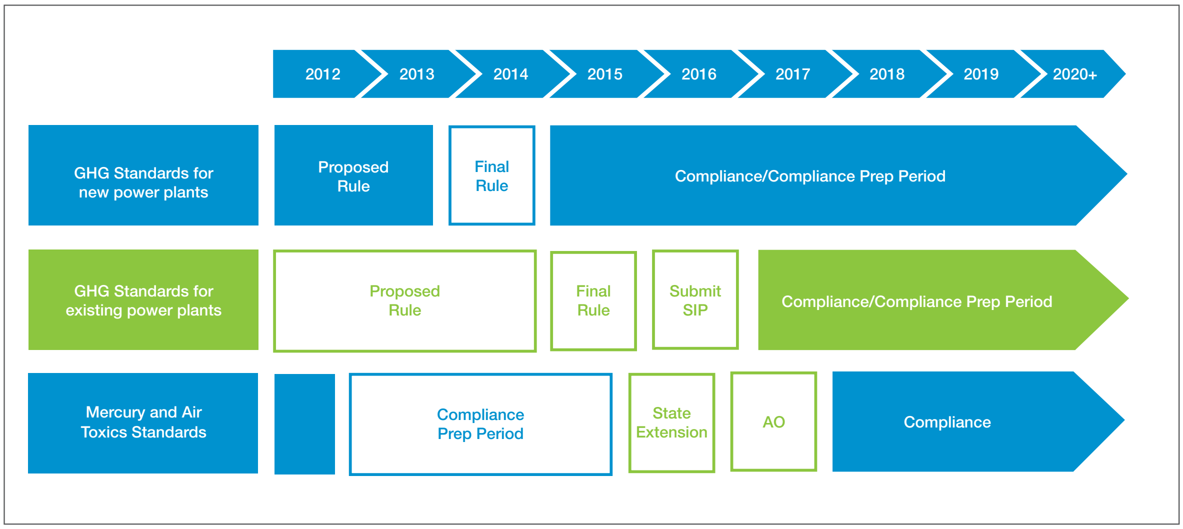


Figure 6.3-7: Compliance timeframe for greenhouse gases

6.4 Gas-Electric Coordination

Abundant natural gas supplies in the U.S., along with the coming retirement or retrofit of a large amount of coal-fired electric generation capacity, are transforming natural gas into a competitive fuel for electric power generation. In MISO Midwest, the contribution from natural gas-fueled generation resources to total energy served has increased over the past few years, while coal resource contributions have declined (Figure 6.4-1).

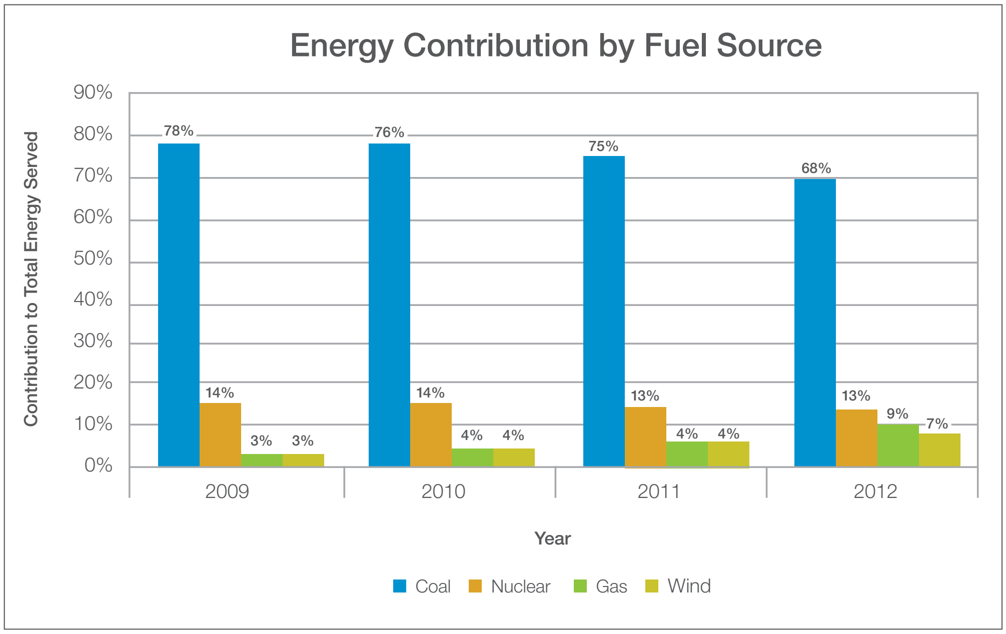


Figure 6.4-1 Contribution per fuel source to total energy served in MISO Midwest

As the portion of demand served by gas-fired generators grows, so does the interdependency of the electric power system and natural gas infrastructure. MISO's efforts to investigate this issue began in late 2011 with a commissioned study of the adequacy of natural gas infrastructure in the Midwest. Since then, MISO has engaged its stakeholders and the natural gas industry in an ongoing conversation about gas-electric interdependency, its challenges and potential solutions.

Natural Gas Analyses

MISO's initial Gas and Electric Infrastructure Interdependency Analysis (Phase I) was commissioned in late 2011 and published in February 2012. This study was a high-level look at the ability of existing natural gas infrastructure in the Midwest to handle increasing demand from gas-fired electric generation. Using a modified backcast approach, it accounted for projected coal unit retirements, based on proposed environmental emissions regulations, and relied upon publicly available historical pipeline flow data. Phase I found that gas supply availability at the wellhead for use in power generation is not an issue. However, the investigation identified three major areas of concern: gas storage, pipeline capacity and timing for infrastructure build-out.

In the months following the release of the Phase I study, natural gas commodity prices dropped significantly. In response to this trend, MISO commissioned a Phase II gas study using the same methodology and coal unit retirement assumptions as Phase I, but adjusted gas price forecasts. This investigation revealed potential peak-day constraints on more than 90 percent of the pipelines in the MISO Midwest footprint beginning in 2016, given existing demand plus forecasted demand from gas-fired electric generation. The results of the Phase II study were shared with stakeholders over the course of the summer of 2012 and spurred conversation on a variety of topics related to gas-electric interdependency.

As a result of these conversations, MISO initiated a third gas infrastructure analysis. This investigation, which complements the modified backcast used in Phase I and II with a forward balancing analysis, provides a robust picture of gas pipeline capacity in the next three to five years. This approach allows for an examination of gas pipeline capacity under static and dynamic market conditions. The Phase II gas study extends to the MISO South footprint, with a corridor flow analysis of the natural gas infrastructure. This assessment characterizes natural gas in-flows and out-flows on a grouped pipeline (corridor) basis and provides baseline information for MISO on this newly integrated portion of the overall MISO footprint.

Stakeholder Engagement

In May 2012, MISO began to engage its stakeholders on the issue of gas-electric coordination challenges and potential tariff changes. The timeline, showing all three gas studies, includes an overview of MISO's gas-electric activities since that initial meeting, including a series of zonal gas-electric workshops, meetings with individual pipeline companies, and on-going participation in Federal Energy Regulatory Commission (FERC) technical conferences (Figure 6.4-2).

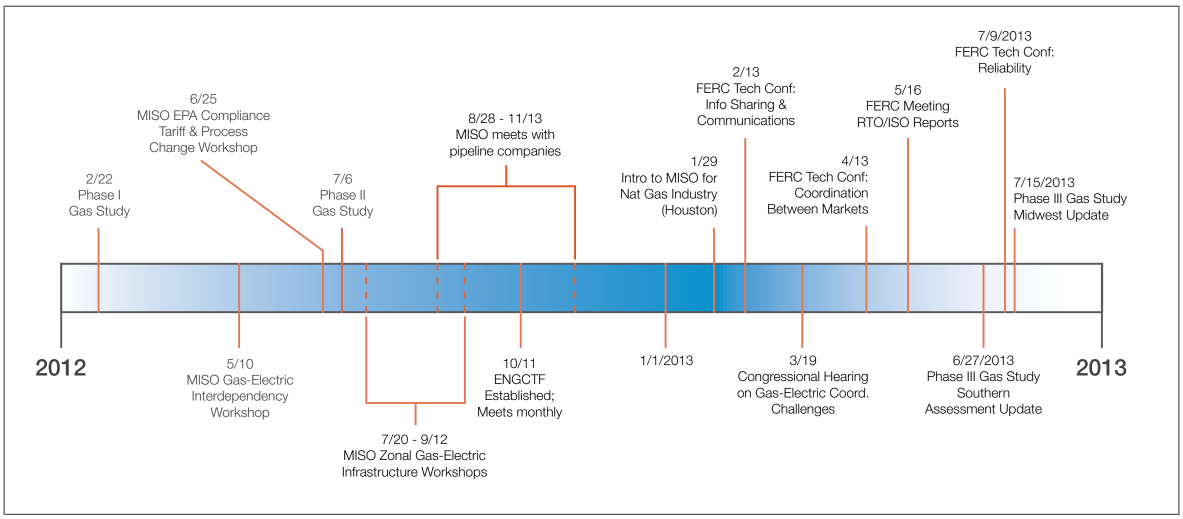


Figure 6.4-2: Timeline of gas-electric coordination efforts at MISO

These meetings have improved communication and understanding between the gas and electric industries and, in the MISO footprint, led to the creation of the Electric and Natural Gas Coordination Task Force (ENGCTF). This stakeholder group serves as a forum for collaboration and cross-industry education, and has been given the task of identifying and investigating issues around gas-electric interdependency.

Current ENGCTF initiatives address:

- Fuel supply uncertainty
- Scheduling differences between the gas and electric industries
- Coordinated industry operations
- Information sharing

Fuel Supply Uncertainty

The discussion around this issue has focused on ways to better capture fuel supply uncertainty within MISO planning models and processes. The ENGCTF passed a motion in April 2013 to scope a Loss of Load Expectation (LOLE) study that takes into account the probability that a generator will be able to get fuel when it needs it. MISO subject matter experts are working with task force members and the natural gas industry to determine the best way to fulfill the motion's directive. The target date for completion of this study is the first quarter of 2014.

The issue of fuel supply risk is tied to the question of who pays for build-out of natural gas infrastructure. Regulatory and business constructs of the natural gas industry currently dictate that a natural gas pipeline will not be built without long-term, firm commitments to contract for gas transportation on that pipeline. MISO does not require firm fuel contracts or dual-fuel capability, and does not explicitly incentivize the purchase of fuel or fuel transportation on a firm basis. If the MISO planning construct can effectively capture fuel supply risk, MISO asset owners will have the flexibility to achieve reliability targets as they see fit.

Finally, the task force recently highlighted concerns surrounding the level of granularity of event reports to NERC's Generator Availability Data System (GADS). GADS data is critical in MISO's resource adequacy calculations. A discussion of recommendations for improvements is underway.

Misalignment of the Gas Day and the Electric Day

The natural gas and electric industries use different 24-hour schedules for their respective operating days. As such, gas-fired generators must procure their daily fuel supply and transportation across two electric operating days. Additionally, the announcement of the schedule for generators' operation the next day (via MISO Day Ahead Market awards) falls after the first opportunity for natural gas-fired generators to schedule delivery of gas for the next day.

These misaligned schedules have been discussed in-depth in ENGCTF meetings and through a Task Force Issue Paper with cross-industry authorship. This document provides examples of ways asset owners manage risks surrounding misalignment. It also overviews potential impacts of moving up the posting of MISO Day Ahead awards, as well as the implications of shifting the Gas and/or Electric Days.

Stakeholders have expressed varied views on the value of aligning operating days and market schedules. The ENGCTF will make a recommendation to the MISO Steering Committee in late summer 2013 to survey asset owners on their preference regarding moving up the clearing time of MISO's Day Ahead Market.

Coordinated Operations

Given the interrelated nature of the gas and electric industries, MISO sees tremendous value in collaborating with both the natural gas industry and stakeholders to determine how the planning and operations functions of the two can become more integrated.

Cross-Industry Education

The task force continues to serve as a forum for information exchange between the electric and natural gas industry. Numerous topics have been covered by industry and MISO subject matter experts including gas price trends; gas and electric industry regulatory and planning constructs; and various MISO protocols and processes. Additionally, the group works to keep members up-to-date on planned and recently published major gas-electric coordination studies.

BOOK 3
POLICY LANDSCAPE STUDIES

In a world of constantly evolving state and federal policies, fuel prices, load patterns and transmission configurations, MISO strives to provide meaningful analyses to help inform policy discussions and decisions.

MTEP13 included efforts to integrate new MISO South Region members into the MISO planning process. The South Region will fully participate in MTEP14.

Finally, Book 3 describes the increased interregional planning during MTEP13 through Order 1000 and cross-border studies.

Book 3 – **Chapter 7**
Midwest Region Studies

Midwest Region Studies

7.1 Northern Area Study

The Northern Area Study was a regional evaluation of production cost savings potential and related reliability issues in MISO's northern footprint.

The study was performed to look at three main sensitivities: demand and energy levels; EPA-induced generation retirements; and increased imports from Manitoba Hydro.

Large-Scale regional transmission expansion in MISO's northern footprint is not cost-effective based soley on production cost savings, under current business-as-usual conditions.

The study began in June 2012 and was completed in July 2013. It focused on the areas of Manitoba, North Dakota, Minnesota, Wisconsin and Michigan (Figure 7.1-1). The study echoed results seen in other recent, similar studies by indicating decreased demand equals a decreased development need. However, it also showed potential opportunities for cost efficiencies and economic gains. The full study report is posted on the MISO website.

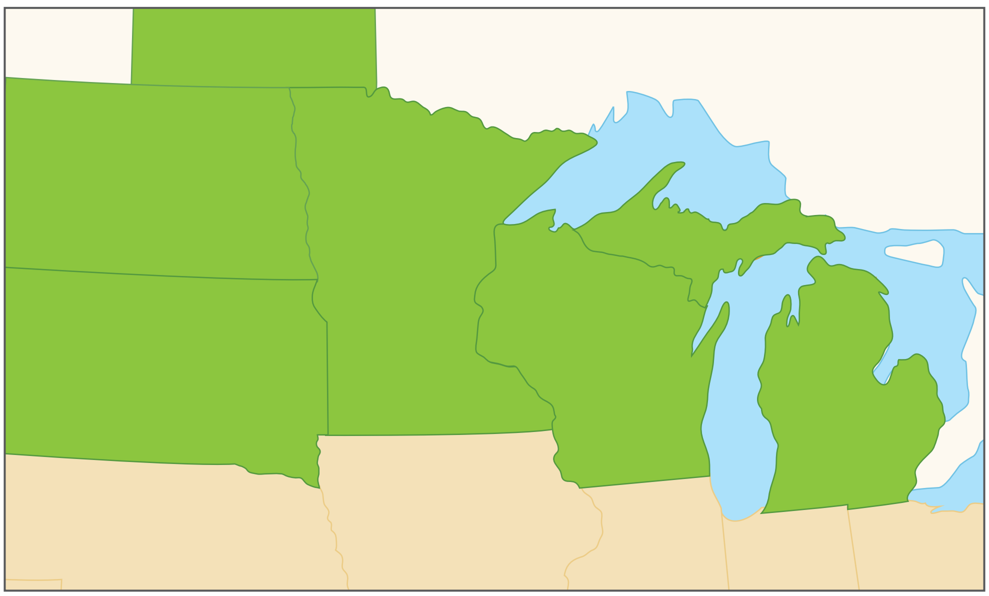


Figure 7.1-1: Northern Area Study Footprint

The Northern Area Study found that large-scale regional transmission expansion in North Dakota, Minnesota, Wisconsin and Michigan is not cost-effective based on production cost savings, under current business-as-usual conditions.

The study discovered that MISO could see economic benefits with minimal incremental transmission investment from new potential Manitoba Hydro to MISO tie-lines.

Economic benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission inverstment beyond the tie-lines.

The Northern Area Study identified Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrade as a cost-effective option to mitigate the remaining out-year congestion from wind on the western Minnesota border with a benefit-cost ratio of 3.46 – 14.74

(depending on scenario assumption). The Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV option is being further analyzed in the Market Efficiency Planning Study.

With Presque Isle Power Plant staying online, the production cost saving potential for new transmission lines decreases for Michigan's Upper Peninsula. Even under the scenarios that increased Upper Peninsula mining industry load levels by an incremental 300 MW, Upper Peninsula transmission options' benefit-to-cost ratios peaked at 0.4 in the tested conditions. The Northern Area Study results show there are economic benefits of equalizing Michigan locational marginal prices with the rest of the footprint; however, production cost benefits for these options do not exceed project costs. Northern Area Study high voltage direct current (HVDC) options require significant additional upgrades to uphold reliability, but were most effective at mitigating Lake Michigan congestion. New high-voltage Upper Peninsula transmission lines could potentially change operating schemes and may require additional operations studies.

With Presque Isle staying online, the production cost savings potential for new UP transmission lines declined.

The Northern Area Study makes no conclusions regarding the broader Multi-Value Project-type benefits that might be achieved, nor the need for future localized reliability upgrades.

Study Scope

The Northern Area Study is a first-take exploratory study to understand the reliability and economic drivers and magnitude of transmission build-out opportunities. The Northern Area Study originated because of multiple transmission proposals and reliability issues located in the northern area of MISO. The objectives of the Northern Area Study were to:

- Identify the economic opportunity for transmission development in the area
- Evaluate the reliability and economic effects of drivers from a regional, rather than local, perspective
- Develop indicative transmission proposals to address study results from a regional perspective
- Identify the most valuable proposal(s) and screen for robustness

This exploratory study was created to understand how various drivers dictate transmission investment. The Northern Area Study's results and findings will determine and feed future studies. Given the hypothetical nature of the study drivers, transmission solutions stemming from the Northern Area Study analysis were excluded from MISO MTEP Appendix A or B consideration. The Northern Area Study followed MISO's Seven-Step Planning Process and was performed in an open and transparent manner.

The Northern Area Study was a collaborative effort between stakeholders and MISO staff. Meetings were open to all stakeholders and interested parties. Study participants included state regulatory agencies, transmission owners, market participants, environmental groups and industry experts. A stakeholder technical review group (TRG) was involved in all discussions and decisions.

The study used the MTEP12 reliability and economic models and assumptions as the starting point for analysis. Multiple Northern Area Study scenarios were developed to understand the effects on transmission investment from the study drivers and ensure transmission development was robust and beneficial under various policy, economic and industry uncertainty. Northern Area Study scenarios focused on three study drivers: increased/decreased industrial load levels, the potential for new imports from Manitoba Hydro, and the retirement of thermal generating units.

The Northern Area Study benefits were evaluated solely based on production cost savings. The broader economic values of a Multi-Value Project (MVP) were not considered in this study. The MVP Portfolio report identified a fuller range of economic values including congestion and fuel saving and reductions in operating reserves, system planning reserve margins and transmission line losses. Additionally other qualitative and social benefits were not explored including enhanced generation policy flexibility, increased system robustness, decreased variable generation volatility, local investment and job creation, and carbon reduction.

Throughout the Northern Area Study, a total of 38 different mitigation plans were proposed and evaluated (Figure 7.1-2). The Northern Area Study used an iterative process to refine projects. Generally, production cost saving potential for the Northern Area Study footprint was low as a result of the inclusion of the MVP Portfolio approved in MTEP11, decreased forecasted demand growth rates, and low natural gas prices.

Generally, production cost savings potential for the Northern Area Study footprint was low as a result of the inclusion of the Multi-Value Project (MVP) Portfolio approved in MTEP11, decreased forcasted demand growth rates, and low natural gas prices.

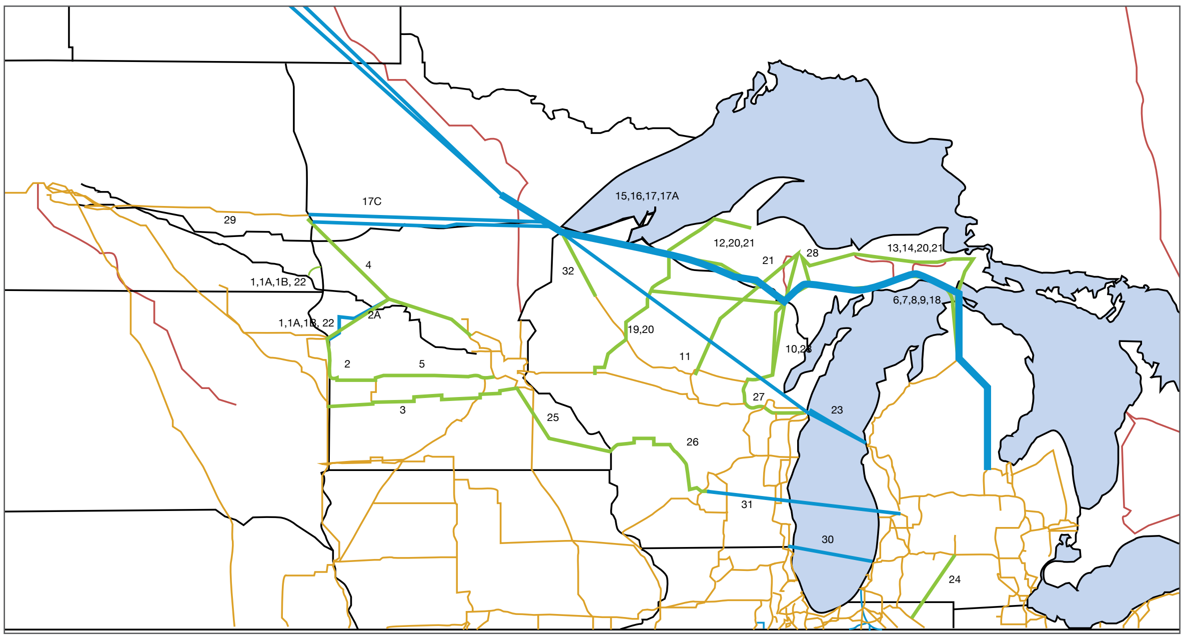


Figure 7.1-2: Northern Area Study Transmission Options

Portfolios were formed by combining the most cost-effective transmission options for each of the three identified congestion interfaces through a collaborative TRG effort. The Northern Area Study identified three transmission portfolios as the most economic options available to accomplish study objectives.

- **HVDC:** Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Kewaunee –Ludington 500 kV HVDC
- **High-Voltage AC:** Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, National/Arnold – Livingston 345 kV
- **Low-Voltage AC:** Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Marquette – Mackinac County 138 kV

All portfolios include an MWEX upgrade in MH-Duluth tie-line scenarios.

The Northern Area Study portfolios mitigate 50 to 100 percent of the area congestion, produce synergic production cost savings, and nearly equalize northern area locational marginal prices, but projected production cost savings generally do not exceed costs (Table 7.1-1). Northern Area Study HVDC options require significant additional upgrades to uphold reliability; minimal reliability upgrades needed for AC portfolios (Table 7.1-2).

Three Northern Area Study developed portfolios mitigate 50 to 100 percent of the area congestion, produce synergic production cost savings, and nearly equalize area LMPs.

Northern Area Study Portfolio	Capture Rate[30] (%)	Synergic Benefits[31] (%)	Benefit to Cost Ratio
HVDC	94 – 100+	15	0.21 – 0.72
High-Voltage AC	61 - 86	7	0.19 – 0.74
Low-Voltage AC	50 - 68	0	0.29 – 1.22

Table 7.1-1: Economic Results-Northern Area Study Portfolios

Northern Area Study Portfolio	Thermal Violations[32]	Voltage Violations[33]	Transient Stability Violations
HVDC	157	9	14
High-Voltage AC	6	4	0
Low-Voltage AC	1	0	Not evaluated

Table 7.1-2: Reliability Results-Northern Area Study Portfolios

The Northern Area Study was developed as an exploratory study to understand how the development of new potential Manitoba-MISO tie-lines, changing mining/industrial load levels, and the retirement of generating units drive transmission investment in MISO's footprint. Northern Area Study results will determine and feed future studies. MISO, through its MTEP process, analyzes congestion annually to reassess if transmission expansion is justified based on updated congestion patterns. While the Northern Area Study's transmission options' projected benefits did not exceed costs under the study assumptions, the results present a prioritized and shortened list of options for future studies if benefits in addition to production cost savings are included or assumptions about future conditions or needs change.

[30]Capture rate is the percentage of the Northern Area Study area congestion relief measured as a ratio of the portfolio's APC savings to the area's maximum economic potential. Historical MISO average capture rate is 70 percent.
[31]Synergic benefits are the percentage the portfolio's APC savings that exceed the summation of the individual options APC savings measures if a portfolio performs together as a whole
[32]Summer peak model; summation of new and worsened elements
[33]Summer peak model; summation of low and high voltage areas

7.2 Manitoba Hydro Wind Synergy Study

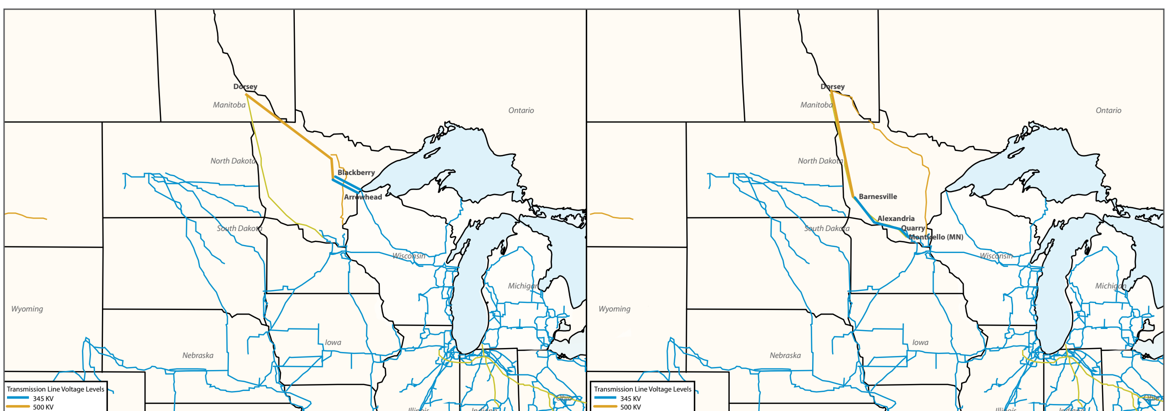
The variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges. MISO conducted this study to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market.

The Manitoba Hydro Wind Synergy Study found significant benefits can be realized from adding a 500 kV transmission line from Manitoba to MISO.

MISO completed its first comprehensive study that looks at the synergy between hydro power and wind power in June 2013. The purpose of the study, called the Manitoba Hydro Wind Synergy Study, assessed how Canadian hydro power can work with MISO wind to provide benefits to MISO and Manitoba Hydro.

The Manitoba Hydro Wind Synergy Study found significant benefits can be realized from the addition of either an eastern 500 kV line between Dorsey, Manitoba, and Duluth, Minn., or a western 500 kV line between Dorsey, Manitoba, and Fargo, N.D./Moorhead, Minn. (Figure 7.2-1).

The study also found that expanding the External Asynchronous Resource (EAR) structure from unidirectional to bidirectional would provide near-term benefits.



East Option: Dorsey to Blackberry	West Option: Dorsey to Fargo/Moorhead Area
- 500kV line from Winnipeg to Grand Rapids	- 500kV line from Winnipeg to Fargo/Moorhead Area
- 345kV double circuit line from Grand Rapids to Duluth	- 345kV line from Fargo/Moorhead to Monticello

Figure 7.2-1: East and west transmission options

Benefits

MISO evaluated the projects for benefits that included the following measures:

- Production cost savings and modified production cost savings
- Load cost savings
- Reserve cost savings
- Wind curtailment reduction

The benefit metrics are indicative of savings MISO may experience if either of the transmission plans were constructed, but they cannot be used to justify cost sharing of either project under the current MISO tariff. The benefits found in this study cannot be used in the Market Efficiency Planning Study (MEPS) to justify project eligibility since the studies use different assumptions and different benefit metrics.

The main difference between the two studies is the Manitoba Hydro Wind Synergy Study includes the benefits of incremental hydro generation in the benefit metric. A hypothetical Market Efficiency Project eligibility test was conducted and found that MISO would receive no Adjusted Production Cost benefit from the construction of either line under the current MISO tariff and using the current MTEP12 models. Looking at these projects from market efficiency prospective does not capture the purpose of the transmission plans.

The modified production cost metric was created to address the challenges presented by this study. Adjustments are made to the production cost to reduce the biases between the simulations. Biases can occur because of changes in the amount of water used by hydro generators or imports and exports from a particular region.

The benefit-to-cost ratios for the East and West plans ranged from 1.69 to 3.84 using the modified production cost metric developed specifically for this study. These plans show similar benefits across a wide range of plausible futures (Figure 7.2-1).

Based on these preliminary analyses, MISO recommends both projects for inclusion in MTEP13 Appendix B on the basis that they show potential merit under possible future benefit metric constructs or as parts of a possible future more expansive Multi-Value Project Portfolio. Neither, however, would qualify for cost sharing under the current provisions of the MISO tariff.

Transmission Options	20 Year Present Value Benefits ($M-2012)	20 Year Present Value PV Costs, transmission only ($M-2012)	Benefit-Cost Ratio averaged over all futures[34]	2012 Cost Estimate ($M-2012)
East 500 kV Option	$1,588	$666	2.39	$685
West 500 kV Option	$1,588	$582	2.73	$598

Table 7.2-1: Weighted Present Value benefits and costs (averaged across futures)

External Asynchronous Resource

The Manitoba Hydro Wind Synergy Study also evaluated whether expanding the EAR structure from unidirectional to bidirectional would provide economic benefits. An EAR is a market-designated resource separated from the main market by a DC tie. EAR participants, under the current real-time market structure, are only allowed to sell into MISO, but not buy from MISO. Allowing a bidirectional EAR enables Manitoba Hydro to buy and sell in a real-time market. The study found $8.74 million dollars in production cost savings to MISO and $100,000 in reserve cost savings for the planning year 2012. The changes are currently being evaluated and are expected to take effect in 2015.

Synergy

Wind synergy benefits from the expanded use of hydro generators in Manitoba Hydro are demonstrated in three ways: by wind curtailment reduction in MISO; by an inverse correlation between imports from Manitoba Hydro and MISO wind generation; and by a better utilization of both wind and hydro resources.

Wind curtailment in the northern MISO region was reduced by 50 to 100 GWh depending on the plan studied and future examined during the 2027 planning year. The interface between Manitoba Hydro and wind generation in northern MISO showed an inverse correlation between the two of between -0.2 to -0.5 demonstrating the strong response of the hydro generators to fluctuations in MISO wind. The wind synergy between Manitoba Hydro and MISO wind leads to a reduction in cost for MISO and expanded revenue for Manitoba Hydro.

[34]Capital costs associated with the addition of the 1485 MW Conawapa project were excluded from the benefit-to-cost ratio calculation.

Context and Methodology

The Manitoba Hydro Wind Synergy Study set out to evaluate the benefits and costs of expanding the interface between Manitoba Hydro and MISO. The study looked at adding an additional hydro generator in Manitoba Hydro along with the addition of one of three new tie lines. The combined benefits were examined including production cost savings, modified production cost savings, load cost savings, reserve cost savings, thermal generator ramping changes and wind curtailment changes. Given the wide variety of benefit metrics along with the exploratory nature of the study, the specific allocation of benefits was not possible. This study simply showed that the total benefits in the MISO area are greater than the costs to build either line.

MISO currently has 12 GW of wind online and 15 GW of active wind projects in the MISO generator interconnection queue. Manitoba Hydro is currently looking to expand its hydro system by 2,230 MW over the next 15 years. Manitoba Hydro's current export capacity is limited to 1,850 MW, which cannot meet the needs of future wind variability. Thus this study looked at expanding transmission capacity between MISO and Manitoba Hydro to facilitate the realization of these benefits.

This study came at the request of various stakeholders who asked MISO to look into the best way to resolve the problems described above. MISO developed a four-phase study to address these concerns and develop a cost-benefit analysis for an expanded Manitoba Hydro to MISO interface.

Given the goal to look at the synergy between wind and hydro, MISO developed models that were much more detailed than those used in the past. The uncertainty of wind and load can only be seen when examining the real-time market and cannot be effectively captured using the traditional techniques of day-ahead market simulations. MISO then developed a novel approach to extract the additional synergy benefits.

MISO used a new simulation tool, PLEXOS, to model the day-ahead and real-time markets as well as to capture the uncertainties of wind and load between what is forecasted in the day-ahead market and actual conditions in the real time market. Significant effort was employed throughout the study to validate and improve the software. Many new concepts and modeling techniques were developed over the course of this study.

Statistics were gathered from historical MISO market data to create a year's worth of wind data at the individual wind farm level and load data at the company level. Generating resources were committed and dispatched against the day-ahead forecasted profiles and then re-dispatched against the real-time profiles leaving a gap filled by flexible resources such as gas turbines and dispatchable hydro units.

A new market bidding technique was developed for these simulations to best capture trading behavior in both the day-ahead and real-time markets. A value of water in storage (VWS) curve was introduced to take into account the opportunity cost of water of the entire planning period to allow for daily bids. Real-time bidding offers were calculated from the VWS curve along with offer bands representing the uncertainty presented between the day ahead and real time markets. New offers were determined after each simulated day.

MISO developed a new process, named Interleave, to capture the uncertainties of the real-time market caused by changing forecasts. This planning study is the first to use this advanced technique. The Interleave simulation best represents the activity of the day-ahead and real-time markets acting together. After completion of a single day-ahead simulation, the unit commitment and other outputs are passed to the real-time simulation. After this simulation is completed, the ending conditions are then passed into the next day-ahead simulation. This continues for every day of the planning year, interleaving the days to create a realistic market simulation (Figure 7.2-2).

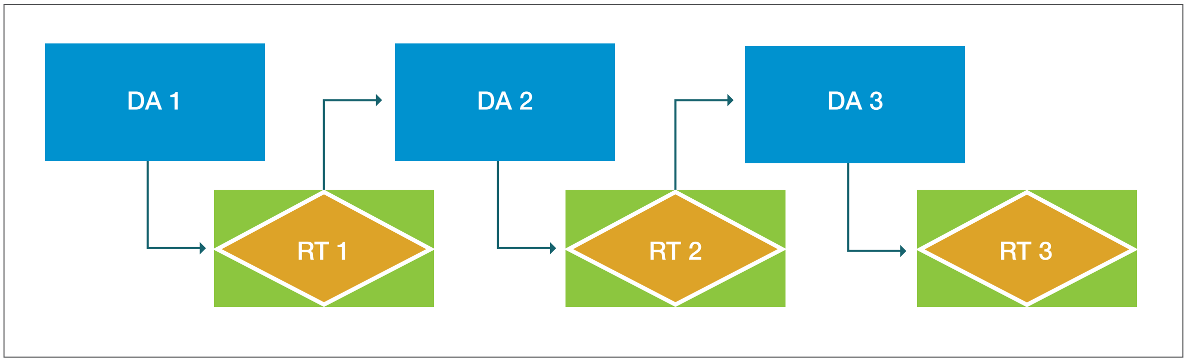


Figure 7.2-2: Interleave Method

A combination of traditional simulation techniques and new ones developed specifically for this study allowed for a diverse set of benefits to be examined. The synergy between wind and hydro was explored in great detail along with the cost savings of increasing energy delivered into MISO. The benefits of these findings are plentiful and show that expanded participation of Manitoba Hydro in the MISO market through increased transmission, generation and market changes would benefit all parties involved.

Over the course of this study, significant amount of effort was spent integrating and validating a new simulation tool, creating detailed hydraulic systems for Manitoba Hydro, simulating the uncertainties of the real time market, developing new methods to examine the benefits of wind-hydro synergy and determining the benefits of new transmission and generation to the MISO footprint. Many lessons were learned over this time. It takes a long time and a lot of effort to fully integrate and test a new production cost model, though it is worth the effort to ensure the accurate representation of the electric and hydraulic systems. Also, determining the benefits additional hydro generation and transmission have on MISO's wind resources is a difficult task.

Ultimately, the benefits of hydro-wind synergy will be reflected in production cost savings, but separating the benefits of the synergy itself from the other benefits to the system is a challenge. The best methods to capture the benefits include examining the reduction in wind curtailment, visually inspecting the wind and hydro outputs and looking at the correlation between wind and hydro. This provides some evidence that the total cost savings include hydro-wind synergy benefits.

Book 3 – **Chapter 8**
South Region Studies

South Region Studies

8.1 ICT Reliability Assessment

On December 1, 2012, MISO assumed the role of Independent Coordinator of Transmission (ICT) for Entergy's transmission network. MISO's key responsibility as the ICT is to provide an independent assessment of the long-term reliability planning process within the Entergy footprint. This assessment occurs in two steps: developing transmission system powerflow models; and employing those models to conduct long-term reliability evaluations of Entergy's transmission network.

This process culminates with the creation of a stakeholder-reviewed, and independently verified, ICT Base Plan. Base Plan development runs parallel to the development of Entergy's Construction Plan. MISO's Base Plan is the result of its independent validation of Entergy's analyses. The ICT Base Plan includes all transmission projects for which construction is to be initiated within the next five years to meet reliability needs. Entergy's Construction Plan, on the other hand, contains all the upgrades indicated through Entergy's reliability assessment using applicable reliability criteria. It contains "Supplemental Upgrades," which address needs such as enhanced reliability, economic benefits and Generator Interconnection/Transmission Service Requests.

Development of Transmission System Models

Reliability models are used to calculate the performance of the transmission system during several snapshots in time by analyzing the impact of outages and disturbances. MISO coordinated with Entergy and its stakeholders to develop the annual and seasonal Base Case powerflow models used to study Entergy's transmission network, per Attachment K of Entergy's Open Access Transmission Tariff (OATT). These network models represent the planning horizon and are updated quarterly.

These cases include current and planned topologies, load levels (representing appropriate seasonal load), generation modeling and dispatch assumptions, and facility approval status. Updates may incorporate changes to any of the previous assumptions based on new service requests or system changes. They may also include changes developed as a result of stakeholder comments.

Long Term Reliability Assessment

Once the transmission models were developed, they were used to conduct a long-term reliability assessment of the Entergy system. This analysis focused on summer peak conditions in 2015, 2018 and 2023, as well as winter and light-load conditions in 2018. These models included all transmission facilities approved for funding in the 2013-2017 Entergy Construction Plan. A second set of models, which contained all proposed projects from the 2014-2018 Entergy Construction Plan, were also used to test the effectiveness of the construction plan in mitigating any reliability constraints identified.

All scenarios, as listed above, were tested against the NERC TPL standards and the Entergy local planning criteria. Results of this analysis are being used to develop the 2014-2018 ICT Base Plan. This plan will include projects from the Entergy Construction Plan that were found to mitigate reliability issues in the ICT reliability analysis, or alternatives to these construction plan projects that were determined to resolve these issues more effectively. The Base Plan will also include projects required to solve identified reliability issues without a construction plan solution.

Stakeholder Participation

Stakeholder involvement is an essential part of the ICT reliability assessment process (Figure 8.1-1). Transmission Summits – held in February, July and September 2013 – were held to discuss the scope, timeline and preliminary results of the ICT reliability analysis. The final reliability assessment results and the Base Plan were reviewed at the September summit. Stakeholder feedback was also requested on the Entergy local area planning criteria, modeling assumptions, study results, and project alternatives.

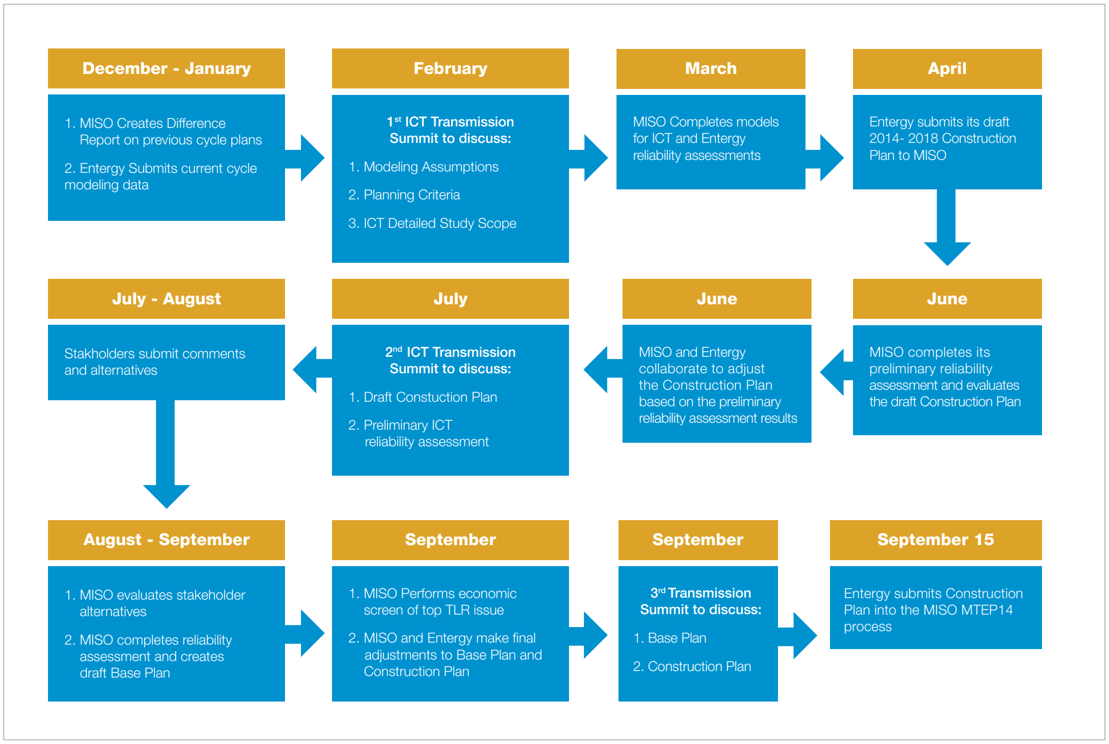


Figure 8.1-1: The ICT reliability assessment process, 2013

Integration into the MTEP Process

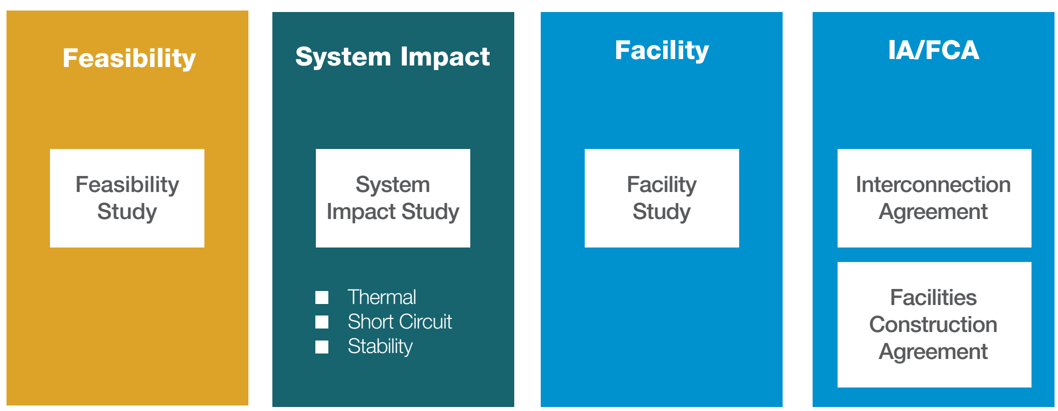
Upon completion of the ICT reliability assessment, MISO will incorporate the final 2014-2018 construction plan projects into the 2014 MTEP planning cycle. Projects that have been fully planned, and undergone sufficient stakeholder review, will be included in the MISO models as pre-planned projects. The remainder of the construction plan will be placed into Appendix B or C, depending on the amount of review and development each project has received. Subsequently, based on system needs, construction lead time requirements, and pending stakeholder review, these projects will be recommended for inclusion into Appendix A, if justified.

8.2 ICT Transmission Access Planning

MISO assumed the role of Independent Coordinator of Transmission (ICT) for Entergy in December 2012. Part of the ITC's role includes processing Generator Interconnection (GI) requests and Transmission Service Requests (TSR). Processing of GIs and TSRs will merge into regular MISO processes with the full integration of Entergy on December 19, 2013.

Generator Interconnection Process

MISO evaluates Transmission Customer requests to connect a generation facility to Entergy's transmission system, as defined in Attachment N of Entergy's Open Access Transmission Tariff (OATT). The purpose of this process is to ensure continued system reliability while interconnecting new or upgraded generating facilities. A series of three studies is required before granting an interconnection request: a Feasibility Study, a System Impact Study and a Facility Study. At the conclusion of each study phase, the Transmission Customer is tendered an agreement, to which it must execute and return within 30 days to continue the study process (Figure 8.2-1).



- Feasibility Study (45-day limit to complete)
- System Impact Study (90-day limit to complete)
- Facility Study (90-day limit to complete for a +/-20 percent cost estimate, 180-day limit for a +/-10 percent cost estimate)

Figure 8.2-1: Generator Interconnection process

Each study phase has a time limitation for completion, which can be extended with an appropriate explanation.

A Feasibility Study provides the Transmission Customer a high-level indication of potential constraints on the system, determined through analysis based upon the identified Point of Interconnection and various generator parameters. Steady-state load flow and short-circuit analysis are performed in the Feasibility Study.

The more-detailed System Impact Study identifies all constraints ton the transmission system that the Transmission Customer needs to mitigate in order to achieve the requested level of service specified in the Interconnection Request. The System Impact Study consists of load flow, short circuit and stability analyses and includes detailed results as well as planning-level cost estimates for required upgrades.

MISO manages the Facility Study process and contracts with Entergy to perform the analysis necessary to fine-tune the scope and cost estimates of the upgrades identified in the System Impact Study phase. Entergy's analysis is subject to MISO's review, validation and posting to the Open Access Same-Time Information System (OASIS).

There have been four generator interconnection studies conducted since MISO assumed ICT duties in December 2012 (Table 8.2-1). The small number of studies completed reflects the relative small GI queue. After completion of the Facility Studies, the generators can begin Interconnection Agreement negotiations. Once a Large Generator Interconnection Agreement (LGIA) is signed, the customer may begin construction of their facility and any necessary transmission upgrades, though some may go into suspension.

Study Type	Completed
Feasibility Studies	1
System Impact Studies	1
Facility Studies	2

Table 8.2-1: GI study summary from December 1, 2012, to July 15, 2013

Long-Term Transmission Service Request Process

In order to gain access to long-term transmission service on the Entergy system, a Long-Term Service Request must be submitted on OASIS by an eligible transmission customer, and evaluated and confirmed by the MISO ICT. Requests for long-term service or short-term monthly requests that extend partially or completely outside the 18-month study horizon require a System Impact Study and, if needed, a facility study (Figure 8.2-2).

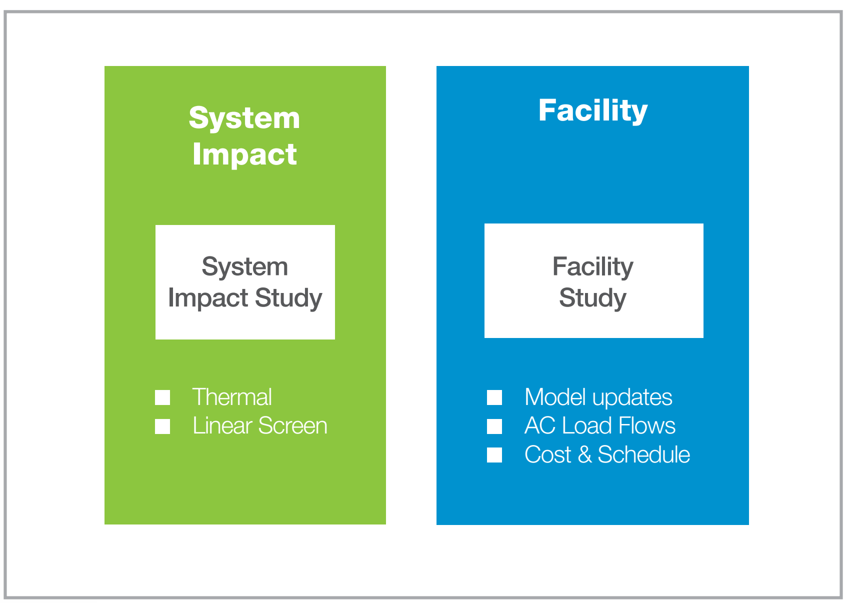


Figure 8.2-2: Transmission Service Request process

The System Impact Study scope includes thermal linear transfer analysis and planning-level cost estimates for identified upgrades. The study is performed by MISO planning personnel and MISO's contractors. The Facility Study scope, completed by Entergy, includes AC load flows and detailed cost estimates and construction schedules. The final facility study is subject to review, validation and posting by MISO. Both the System Impact Study and Facility Study must be completed within 60 calendar days. As a result of these studies MISO determines there are either:

- No constraints identified: the TSR is confirmed and no Facility Study is needed
- Constraints identified: a Facility Study is initiated. Upon completion of the Facility Study, the customer either funds the construction of any necessary upgrade(s), or withdraws the request. Where constraints are identified but partial service is available without constraints, the customer can take the partial service without completion of a Facility Study.

Since assuming ICT TSR responsibilities in December 2012, MISO's evaluation of TSRs on the Entergy system has produced 44 completed studies; 27 System Impact Studies and 17 Facility Studies (Table 8.2-2):

Study Type	Completed
TSRs Evaluated	85
TSRs Confirmed	50
System Impact Studies Completed	27
Facility Studies Completed	17

Table 8.2-2: TSR study summary from December 1, 2012 to July 15, 2013

Upon integration into the MISO market, Point to Point Transmission Service internal to the MISO footprint will be largely eliminated. There will continue to be instances of Point to Point Transmission Service between external systems in the MISO South footprint following integration.

MISO continues to stay active in customer outreach and in fielding numerous stakeholder questions about the ICT Generator Interconnection and TSR processes, as well as the upcoming transition to full integration into MISO. Multiple training sessions and meetings have been held to assist the regional stakeholders on these topics.

8.3 South Region Generator Deliverability Analysis Results

A MISO South Region Generator deliverability analysis was performed as part of the MISO South Region Integration to assess the amount of megawatts (MW) that will be Network Resources going forward. The Market Transition Deliverability Test (MTDT) is representative of the Deliverability Study generators and is evaluated in order to achieve Network Resource Interconnection Service (NRIS) as defined in FERC Order 2003. The MTDT is separate from the Independent Coordinator of Transmission (ICT) role that MISO has provided for the Entergy Operating Co.'s behalf since December 2012. The MTDT included all generators in the Southern Region that are expected to participate in the energy market; this includes generators in the imbedded Entergy Balancing Authority Areas.

Approximately 57,000 MW of generation was studied for the Southern region. Of that, a total of 7,400 MW is restricted.

This transitional deliverability study provides a baseline for future deliverability studies and to determine the generators that qualify to participate in the MISO Capacity Auction.

Approximately 57,000 MW of generation was studied for the Southern region. Of that, a total of 7,400 MW is restricted due to constraints identified in the transition study, and 1,200 MW of that 7,400 MW is considered locally deliverable. Locally deliverable units are Energy Resource generators that have existing Transmission Service Reservations associated with the generator. This transitional deliverability study provides a baseline for future deliverability studies and determines the generators that qualify to participate in the MISO Capacity Auction under Module E-1 of the MISO Tariff. Network upgrades are not identified in a transition deliverability analysis.

The most restrictive constraints are facilities with more than 100 MWs restricted (Table 8.3-1). This analysis revealed 37 constraints that restrict a total of 7,400 MW. Deliverability was tested up to each generator's capability (Pmax). See the updated MISO Southern MTDT for the detailed results with a list of impacted generators and a complete list of constraints.

Column headings in Table 8.3-1 include:

- An "Overload Branch" is caused by bottling-up of aggregate deliverable generation
- The "Area" is the Transmission Owner of the facility
- Use the "Map ID" to find an approximate location of the overloaded element (Figure 8.3-1)
- "Contingency" is the outage causing the overload. In some cases, the system may be system intact, so there is no outage.
- "Rating" is the rating of the overloaded element used in the analysis. It's normal if the system is intact, but emergency for post-contingent constrained branches.
- "MW Restricted", the total MWs that the specific constraint restricts (includes locally deliverable MWs)

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	MW Restricted
Widows Creek to Sequoyah 500 kV line	TVA	1	Maury to Browns Ferry 500 kV line	1,697.5	1,054.9
Horn Lake to Allen 161 kV line	EES-EMI	2	Freeport 500/161/13.2 kV transformer	221.5	614.8
Woodward to Altheimer 115 kV line	EES-EAI	3	Stuttgart Ricuskey 115/230 kV transformer	103.9	206.0
White Bluff to Genpower Keo EHV 500 kV line	EES-EAI	3	Sheridan to Mabelvale 500 kV line	2,121.7	1,399.2
Arklahoma to Hot Springs EHV 115 kV line	EES-EAI	4	Hot Springs EHV 115/500 kV transformer	234.2	215.2
Winnfield 230/115 kV transformer	EES	5	Montgomery to Clarence 230 kV line	294.0	556.4
Coughlin to Plaisance 138 kV line	CLEC	6	Cocodrie to Ville Platte 230 kV line	352.8	139.1
Nelson 230/500 kV transformer	EES	7	Sabine to Big Three to Carlyss 230 kV line	548.8	138.2
PPG 230/69 kV trans-former ckt 2	EES	7	PPG 230/69 kV transformer ckt 1	196.0	146.2
Linde to Sabine 138 kV line	EES	8	Port Neches Bulk to Sabine 138 kV line	282.2	451.4
Helbig to Georgetown 230 kV line	EES	8	China to Sabine 230 kV line	344.0	315.8
Scott to Louis Bonin 138 kV line	EES	9	Breaux Bridge to Nickerson Tap 69 kV line, Flanders 138/230 kV transformer, Sellers Rd to TJ Labbe 230 kV line, Wells to Pont Des Mouton 230 kV line,Wells to TJ Labbe 230 kV line, Bonin 230/138 kV transformers ckt 1 and 2, Bonin 69 kV line ckt 1, 2, and 3	220.5	110.2
Addis to Tiger 230 kV line	EES	10	Dow Meter Point to Air Liquid to Chenango 230 kV line	420.4	952.4
Frisco to Tezcuco 230 kV line ckt 2	EES	11	Frisco to Tezcuco 230 kV line ckt 1	628.2	205.2
Frisco to Tezcuco 230 kV line ckt 1	EES	11	Frisco to Tezcuco 230 kV line ckt 2	628.2	157.0

Table 8.3-1: The Southern Region Transition Deliverability constraints that limit deliverability of about 7,400 MW of generation, determined to be Energy Resource

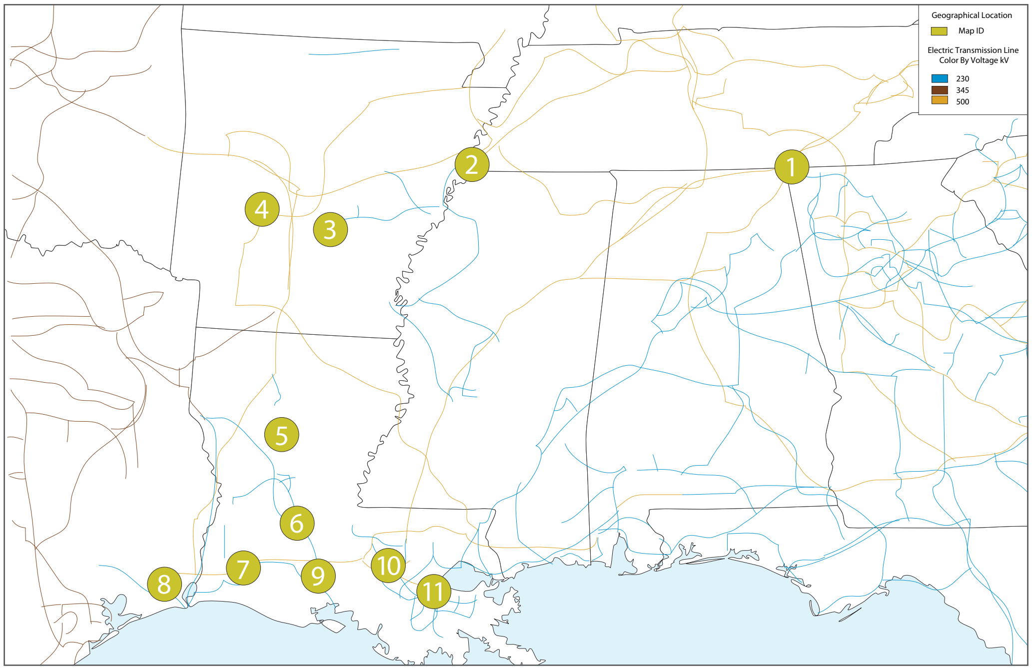


Figure 8.3-1: General location of Southern Region Transition Deliverability summer peak baseline generator deliverability constraints

8.4 MISO South Market Efficiency Planning Study

In order to sync MISO South with the MTEP14 economic planning process, MISO is conducting a Marketing Efficiency Planning Study focused on the MISO South region. This study incorporates stakeholder informed futures, capacity expansion analysis, model building and economic analysis. This process may result in the recommendation of economically justified projects for approval in MTEP14 or the determination of economic opportunities or project ideas for future planning cycles. Post MTEP14, this type of analysis will be part of the regular economic planning process.

Building some new high-voltage transmission could take up to 10 years to implement; hence a planning horizon of at least 15 years is needed to study for long-range economic transmission planning purposes. Performing a credible economic assessment over this timeframe is challenging as it requires development of long-range resource forecasting, powerflow and security-constrained economic dispatch models. Since no single model can perform all of the functions for integrated transmission development, a value-based planning process was developed that integrates the best models available.

In recognition of the uncertainty around energy policies and availability of associated resources in the 15- to 20-year time frame, a multi-dimensional regional resource forecast (RRF) is required to identify what is necessary to supplement generation interconnection queue capacity. The regional resource forecast model determines, on a least-cost basis, the type and timing of new generation needs. It is driven by energy policies and other long-term integrated resource generation not reflected in the current queue.

Futures Development

One focus of the MTEP13 planning effort is the development of a set of futures that capture current and future potential energy policy outcomes. Futures are a set of postulates that aim to capture a plausible range of future outlooks. The futures development considers environmental regulations, renewable portfolio standards, demand-side management programs and other potential policies.

The following describes the four futures MISO developed in collaboration with MISO South stakeholders:

- **The Business as Usual (BAU)** future is considered the status quo scenario and continues current economic trends. This future models the power system as it exists today with reference values and trends.
- **The Limited Growth (LG**) future models a future with low demand and energy growth rates due to a very slow economic recovery and impacts of EPA regulations. This can be considered a low side variation of the BAU future.
- **The Robust Economy (RE)** future models significant economic development in Southern Louisiana and Southeast Texas areas with considerable development occurring in all the areas due to consistently low fuel prices providing economic opportunity for electric growth and system expansion. The future assumes that the development of liquefied natural gas (LNG) facilities will not increase the price of natural gas above a $6/MMBtu real value.
- **The South to Midwest Transfer (S2M)** future models a limitation in the Midwest region to expanding its natural gas pipeline infrastructure and assumes increased reliance on the Southern gas fleet to meet Midwest's resource adequacy and energy needs in the light of EPA regulations driving 12,600 MW of coal retirements. Lower natural gas fuel price inflation rates enable this to happen while modeling increased capacity and energy transfer from the South to the Midwest.

There is a relationship between all the variables as assumed for the various futures that are input into the PROMOD PowerBase, Electric Generation Expansion Analysis System (EGEAS) – capacity forecasting model, and the PROMOD – production costing models. Each future is defined by a set of uncertainty variables, such as the variables that change from one future to another (Table 8.4-1). Three categories low (L), medium (M) and high (H) are used to indicate the relative value of the variable for the specific future (Table 8.4-2).

MISO South Uncertainties Matrix				
Uncertainty	Unit	Low (L)	Mid (M)	High (H)
New Generation Capital Costs[1]				
Capital Costs	($/KW)	10% Lower	EIA Cost Estimates	25% Higher
Demand and Energy				
Demand Growth Rate[2]	%	0.45%	0.90%	1.35% + Expansion related Demand Growth
Energy Growth Rate[3]	%	0.47%	0.93%	1.4% + Expansion related Energy Growth
Demand Response Level*	%	TX DR Goal	TX DR Goal	2 * TX DR Goal
Energy Efficiency Level*	%	AR EE Goal 0.75%	AR EE Goal 0.75%	2*AR EE Goal 1.5%
Fuel Prices (Starting Values)				
Gas[4]	($/MMBtu)	20% lower than Mid Value	NYMEX forward curve for the first 3 years followed by EIA growth rates	20% Higher than Mid Value
Oil	($/MMBtu)	Powerbase default 20%	Powerbase default[5]	Powerbase default + 20%
Coal	($/MMBtu)	Powerbase default 20%	Powerbase default[6]	Powerbase default + 20%
Uranium	($/MMBtu)	0.91	1.14	1.37
Fuel Prices (Escalation Rates)				
Gas	%	1.5	2.5	4.0
Oil	%	1.5	2.5	4.0
Coal	%	1.5	2.5	4.0
Uranium	%	1.5	2.5	4.0
Pipeline Costs				
Midwest Gas Pipeline Transportation Adder	($/MMBtu)	0	Powerbase default	2 * Powerbase default

Emissions Costs				
SO_2	($/ton)	0	0	500
NO_x	($/ton)	0	0	NOx: 500 Seasonal NOx: 1,000
CO_2	($/ton)	0	0	50
Other Variables				
Inflation	%	1.5	2.5	4.0
Retirements in the Midwest	MW	12,600	12,600 MW + 8,300 MW age-related retirements = 20,900	23,000
Retirements in the South	MW		77 MW	
Renewable Portfolio Standards	%		State mandates only	State mandates and goals

Table 8.4-1: MISO South uncertainties matrix

[1] All costs are overnight construction costs in 2013 dollars

[2] Mid value for demand growth rate is the powerbase default (sourced from FERC 714 filing) and is the South Regional growth rate

[3] Mid value for energy growth rate is the powerbase default and is the South Regional growth rate

[4] Prices reflect the Henry Hub natural gas price

[5] Powerbase default for oil is $19.39/MMBtu

[6] Powerbase range for coal is $1 to $4, with an average value of $1.69/MMBtu

* Based on Stakeholder feedback to incorporate goals. TX has a demand reduction goal, AR has an EE goal. Source: www.dsireusa.org. The goals driven reduction will only be modeled to the TX and AR loads.

Futures	Costs	Demand and Energy				Fuel Cost (Starting Price)				Fuel Escalations				Pipeline Cost	Emission Cost			Other Variables			
	Capacity Costs	Demand Growth Rate	Energy Growth Rate	Demand Response Level	Energy Efficiency Level	Natural Gas	Oil	Coal	Uranium	Natural Gas	Oil	Coal	Uranium	Midwest Gas Pipeline Transportation Adder	SO_2	NO_x	CO_2	Inflation	Retirements in the Midwest	Retirement in the South	Renewable Portfolio Standards
Business As Usual	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	M	L	M	M
Limited Growth	M	L	L	M	M	M	M	L	M	L	L	L	L	M	L	L	L	L	L	M	M
Robust Economy	M	H	H	M	M	L	L	L	L	L	L	L	L	M	L	L	L	H	L	M	M
South to Midwest Transfer	M	M	M	M	M	M	M	H	M	L	M	M	M	H	L	L	L	M	M	M	M

Table 8.4-2: Futures Matrix

Regional Resource Forecasting (RRF)

MISO completed an assessment of generation required for the MISO footprint using the Electric Generation Expansion Analysis System (EGEAS) model. Using assumed projected demand and energy for each company and common assumptions for resource forecasting, 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.

In all futures except the Robust Economy, the MISO South Region has excess capacity for the duration of the 20-year study period (Figure 8.4-1). To meet the resource adequacy target in the Robust Economy future, the system will need 7,200 MW of thermal capacity in excess of goal-driven Demand Response and Energy Efficiency resource additions.

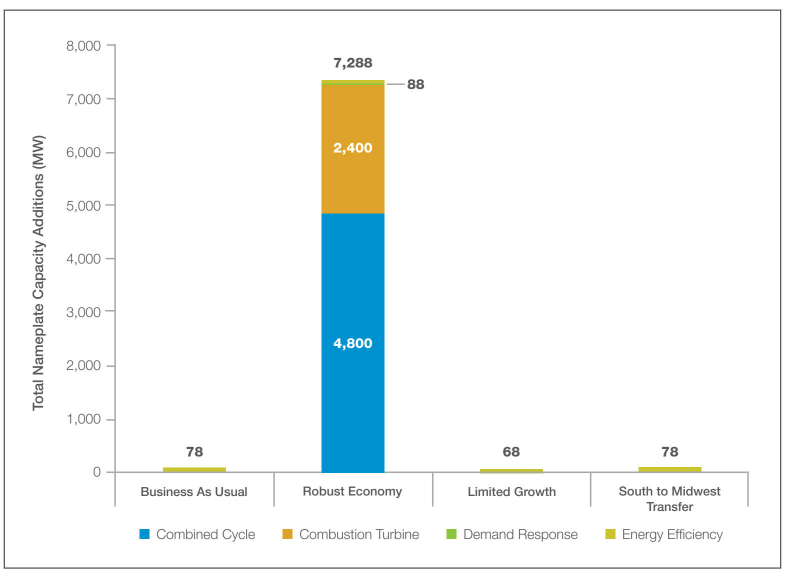


Figure 8.4-1: Nameplate capacity additions by future for MISO South

Siting the Regional Resource Forecasting units

Regional Resource Forecast is specified by fuel type and timing, but these resources are not site-specific. The second step in the MISO's Value-Based Planning process is to tie the future resource additions (RRF units) to a bus location in the powerflow for production cost modeling purposes only. MISO uses a siting methodology to identify a bus location in the powerflow model using Geographical Information System (GIS) software, MapInfo Professional 10.0.

For the BAU future, no new thermal capacity was added in the MISO South region (Figure 8.4-2). In most other study regions, Combined Cycle resources were forecasted due to the thermal capacity retirement assumption. The least-cost peaking capacity Combustion Turbine resources were also added. Renewable Portfolio Standards mandate wind (shown in green) and solar (yellow) additions for the footprint.

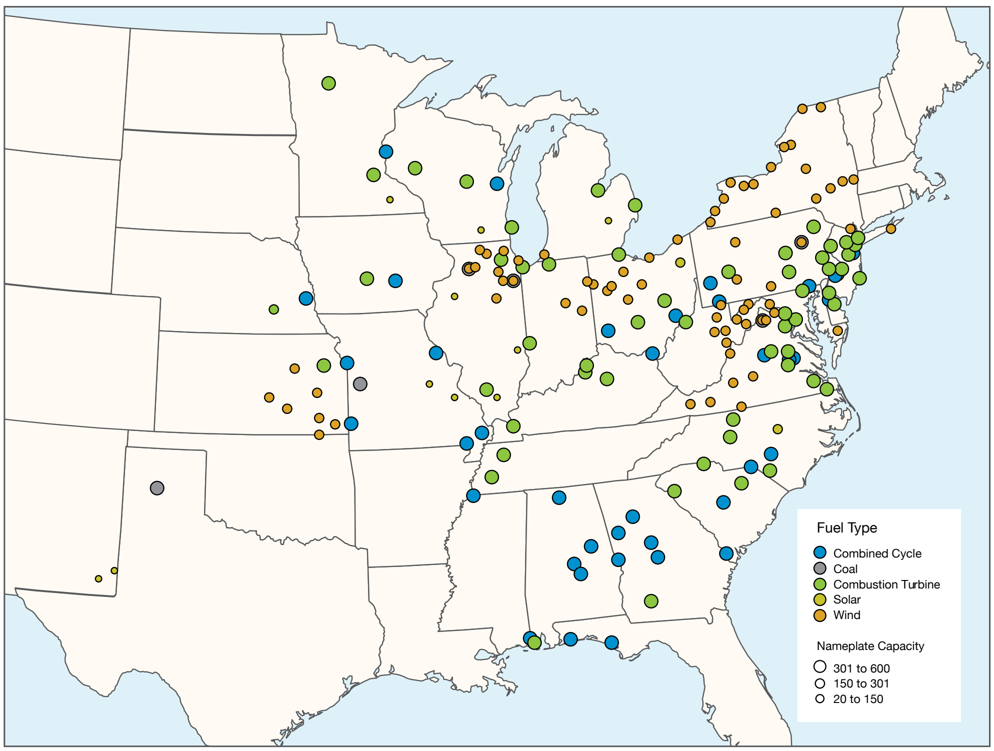


Figure 8.4-2: Regional resource forecast sites for the Business as Usual future

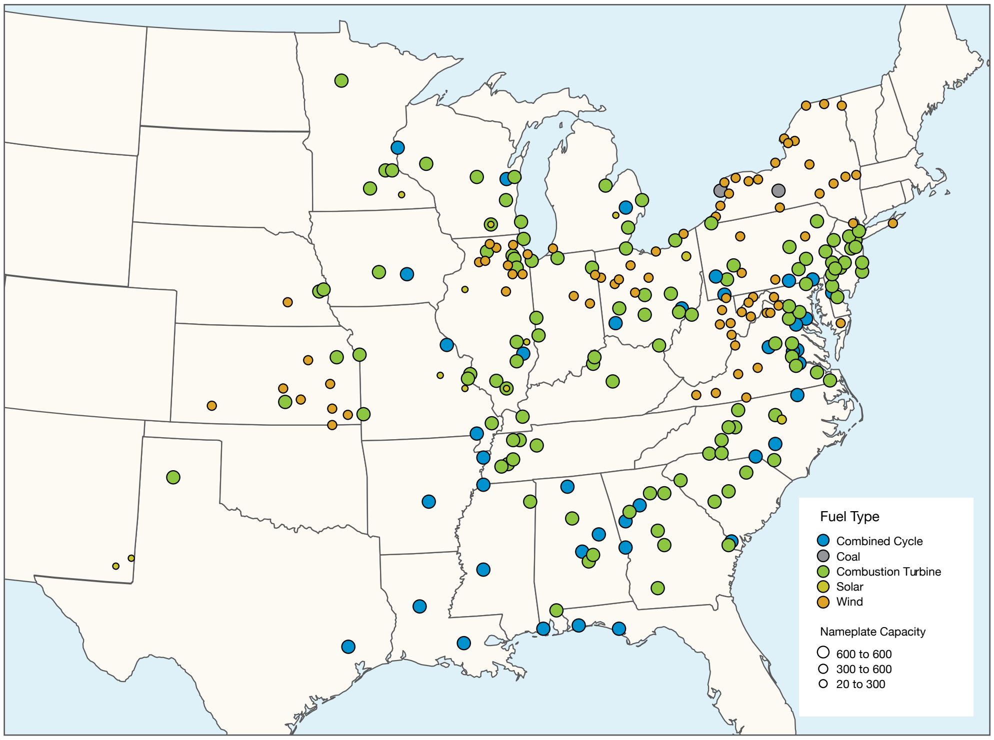
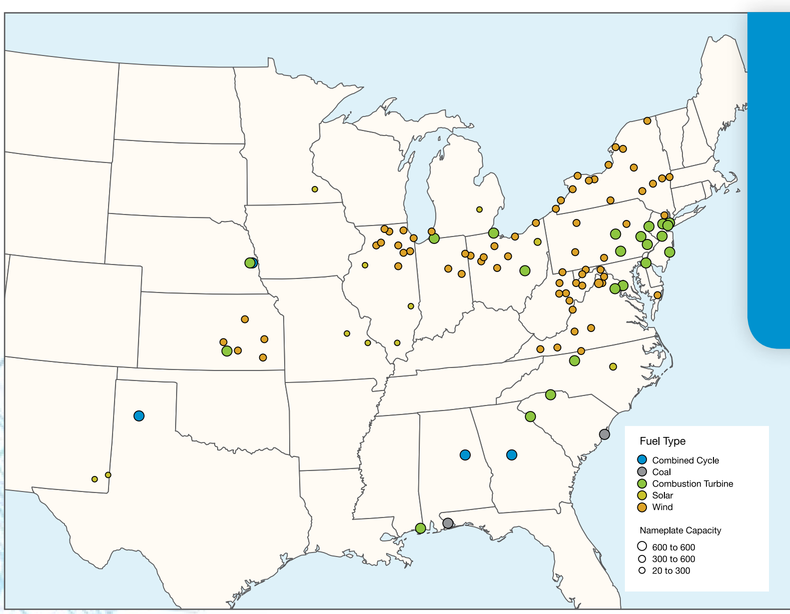


Figure 8.4-3: Regional resource forecast sites for the Robust Economy future

The Robust Economy future requires more Combined Cycle (CC) units, compared to the BAU future, because it models higher demand and energy growth rates. The MISO South region will need a total of 7,200 MW of thermal capacity for the 20-year study period (through 2032), all of which comes in during the second half of the study period (Figure 8.4-3).

For the Robust Economy Furture, the MISO South region will add a total of 7,200 MW of thermal capacity required for the 20 year study period (through 2032).



The Limited Growth future models the lowest demand and energy growth rate and hence not all regions require new capacity additions within the next 15 years.

Figure 8.4-4: Regional resource forecast sites for the Limited Growth future

The Limited Growth future models the lowest demand and energy growth rates; hence not all regions require new capacity additions within the next 15 years (Figure 8.4-4). The figure shows mostly the renewable portfolio standards-driven solar and wind additions while the PJM, SPP and SERC regions see some thermal capacity expansion.

> **The South to Midwest Future models increased reliance on the southern gas fleet.**

The South to Midwest Future Models increased reliance on the southern gas fleet. The overall system would require less capacity and the South regions excess would support the Midwest resource adequacy needs (Figure 8.4-5). The intent of this future is to study and identify what the transmission needs will be if such a future were to occur. The MISO Midwest region needs about 16,800 MW of CCs and CTs while the South region needs no new thermal capacity. MISO South has 8,400 MW of excess capacity that is assumed to support the MISO Midwest capacity needs through 2023. The remaining 8,400 MWs of the 16,800 MWs has to be sited. This future also assumes an abundance of natural gas in the South region and a limitation for natural gas pipeline infrastructure development in the Midwest. Therefore, 1,200 MWs of CC capacity is sited as two units of 600 MW each in the MISO South region and the 7,200 MWs of CT capacity is sited within the MISO Midwest footprint closer to load centers.

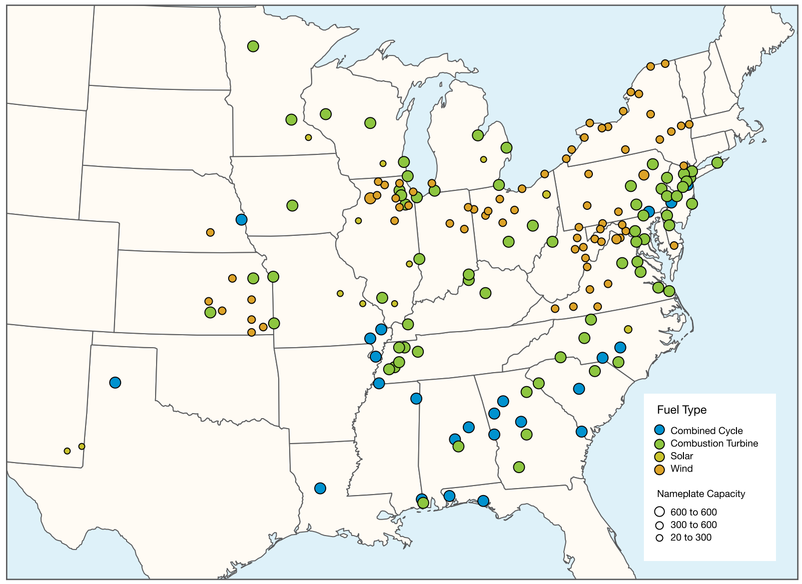


Figure 8.4-5: Regional resource forecast sites for the South to Midwest transfer

Demand Response units have been sited at the top-five highest load buses by Load Serving Entity (LSE), by state, based on their load ratio share of that particular state's program capacity. Texas is the only state within the MISO South footprint with a demand reduction goal; Arkansas is the only state in the MISO South Region with an energy efficiency goal (Figure 8.4-6). Energy Efficiency has been accounted for in both the effective demand and energy growth rates.

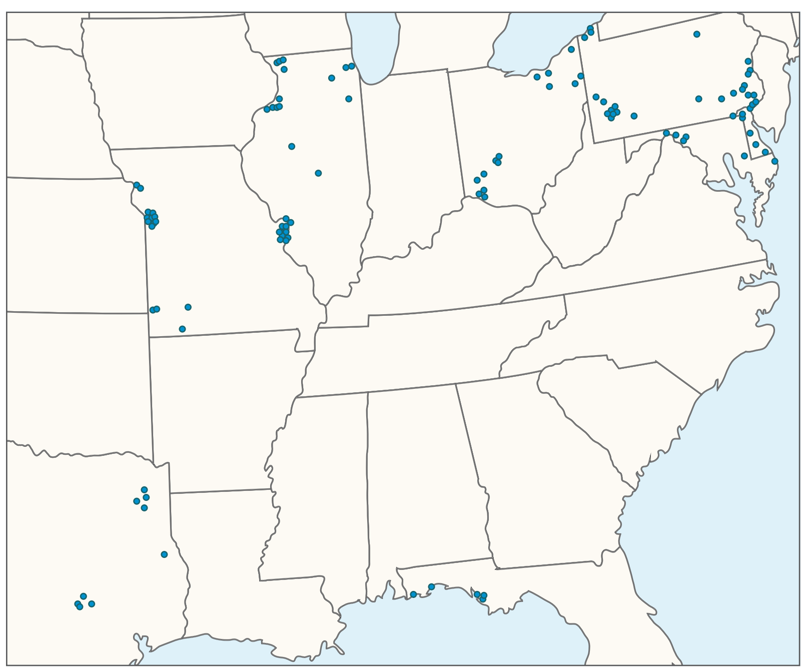


Figure 8.4-6: Regional resource forecast sites for MISO's Future DR sites

8.5 MISO South EPA Compliance Studies

With the integration of the South Region into MISO, the 2011 EPA Regulation Impact Analysis has been extended to capture the impacts on the new MISO region. The objective of the MISO South EPA Regulation Impact Analysis is to quantify the level of cost and generation retirement attributable to the new EPA regulations in the MISO South region. The study found only 77 MW of coal capacity is potentially at-risk for retirement under several likely scenarios.

The detailed results of the analysis were derived from a set of economic assumptions that included gas and carbon price variations. Retirement impacts can change with different assumptions for these variables. To better understand the effects of changing inputs and risks of the uncertainty of carbon, additional analysis needs to be performed.

Three different system configurations were studied: MISO Midwest, MISO South, MISO Midwest and South combined. In the combined system case there's a potential benefit from increasing fuel diversity in terms of baseload, intermediate and peaking resources. Separately, MISO South reduces fuel diversity converting any coal to gas. While this may have carbon reduction benefits, it leaves more of the system susceptible to gas price fluctuations. In the combined system, that fuel diversity mix is maintained.

Only 77 MW of coal Capacity is potentially at-risk for retirement in several likely scenarios.

MISO has no intention or authority to direct generation unit strategies as that authority belongs exclusively to the individual asset owners. The MISO analysis provides an overview of the impacts from the MISO regional perspective. Any sub-regional evaluation of the data would be an incorrect interpretation and application of the results.

This analysis identified impacts on the resource fleet, system energy costs and the transmission system. Under tariff reliability requirements, it is required that the bulk power system maintain generation and transmission reliability. The EPA regulations add a constraint to the system that must be mitigated. Because of this, the risk of implementing the EPA regulations is not reliability, but the cost to maintain that reliability (Table 8.5-1).

	77 MW of Retirements
Energy Cost Impacts	\$0.36 - \$0.62/MWh
EPA Compliance Retrofit Capital Costs	\$2.8B
New Capacity Capital Fixed Charges	\$0.0B
Fixed O&M Capital Costs	\$0.4B
Transmission Impacts	\$0.0B
Total Capital Costs	**\$3.2B**

Table 8.5-1: System costs attributed to implementation of EPA regulations (2013 dollars)

In addition to the cost impact there is a compliance risk with the proposed regulations. Additional investment in the generation fleet and the transmission system will maintain bulk power system reliability at a cost. However, another risk that must be recognized is the timeframe within which units must be compliant. If it is determined that capacity should be retired, it would take at least two to lthree years to build a combustion turbine to replace it. However, there is no foreseeable need for these replacements in MISO South, due to its current high capacity surplus. Also, if transmission system reliability requires bulk transmission upgrades, it could require a minimum of five years for a transmission line to become operational. Due to the limited amount of at-risk capacity (77 MW), there are no foreseeable bulk transmission upgrades necessary.

MISO South Region Generating Assets

The MISO South Region contains 50,092 MW of generating capacity, of which about 18 percent is coal-fired generation (Figure 8.5-1). The average age of the coal fleet is 33 years and the majority of the coal units are greater than 500 MW in size.

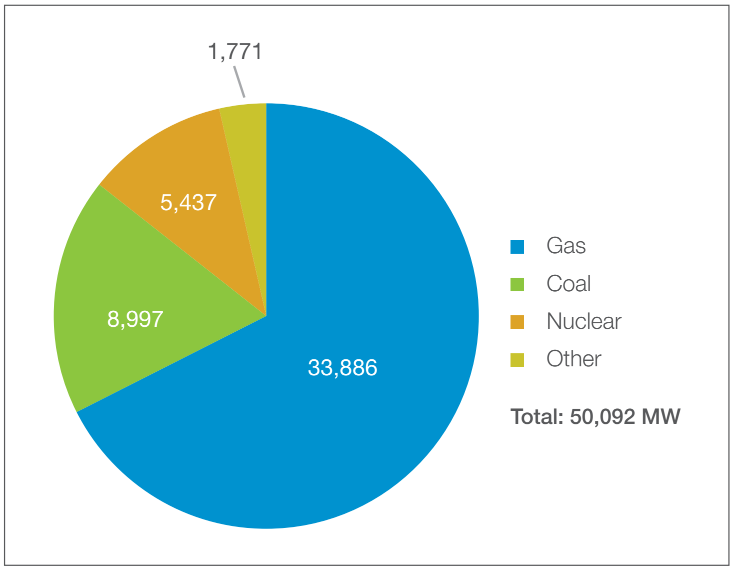


Figure 8.5-1: MISO South capacity mix

Within the three EPA regulations investigated Mercury and Air Toxics Standards, Section 316(b) of the Clean Water Act, and the Coal Combustion Residuals 18 units in the MISO South region were impacted by at least one rule (Figure 8.5-2).

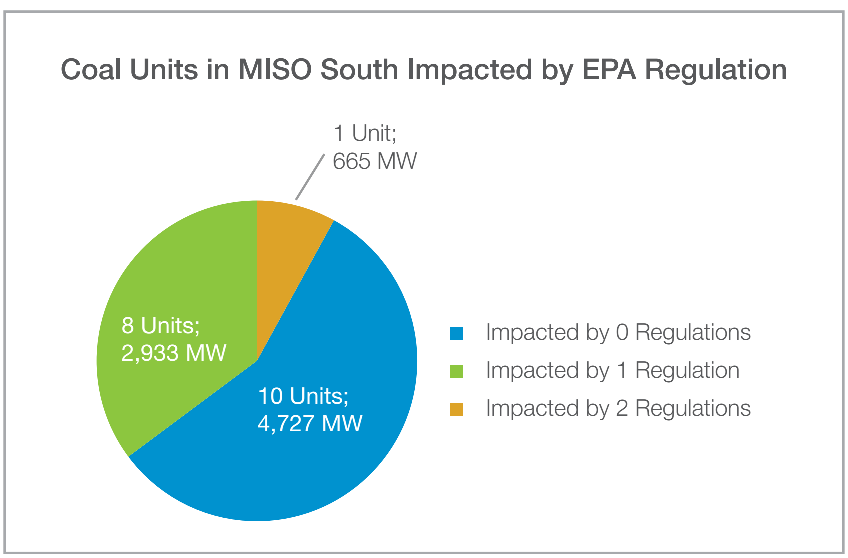


Figure 8.5-2: Number of units affected by EPA regulations

Capacity Cost Impacts

Of the sensitivities studied, the biggest impact to the capacity cost is the cost of retrofits. This is due to the fact that MISO South has a high capacity surplus. In all cases, the $400 million capacity cost is due to a committed unit already planning for construction. The cost for retrofits is estimated to be $2.8 billion to comply with all three regulations studied (Figure 8.5-3).

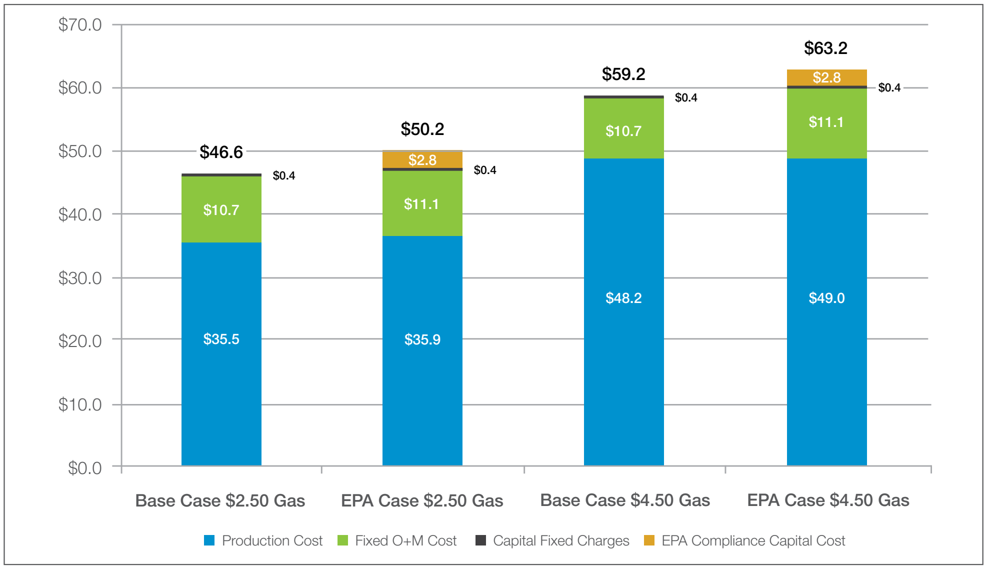


Figure 8.5-3: Total System Costs for MISO South in the low and mid-gas costs, no CO2 costs (In Billions of USD cumulative over the study period)

Energy Impacts

A test year of 2027 was used in the Electric Generation and Expansion Analysis System (EGEAS) to evaluate the energy impacts. The MISO South Region system energy required to serve load is estimated to be 200,775 GWh for the year 2027. Calculating the production cost differences and dividing by that energy requirement, it is estimated that the production cost impacts are in the range of $0.36 to $0.62 per megawatt-hour. The impact is due mainly to the increased operating cost of installed retrofits (Table 8.5-2).

	Base Production Cost ($B)	EPA Retrofits Production Cost ($B)	Production Cost Difference ($B)
$2.50 Gas Case	$4.91	$4.99	$0.07
$4.50 Gas Case	$6.81	$6.94	$0.12

Table 0-2- MISO South Production Cost Differences for test year 2027 ($ billions)

Transmission Impacts

Assessment of the aforementioned retirements modeled under contingency conditions showed no transmission overloads. This means there are no bulk transmission upgrades necessary for this potential 77 MW of at-risk capacity to retire.

Regulation Timing

There is a high-level timetable of rule implementation and compliance deadlines. If it is determined that capacity should retire, it would take a minimum of two to three years to build a combustion turbine to replace that capacity and five years for a combined cycle gas plant. Also, if transmission system reliability requires bulk transmission upgrades, it could take at least five years for a transmission line to come into service. The time from regulation to compliance may be difficult for some situations throughout the system.

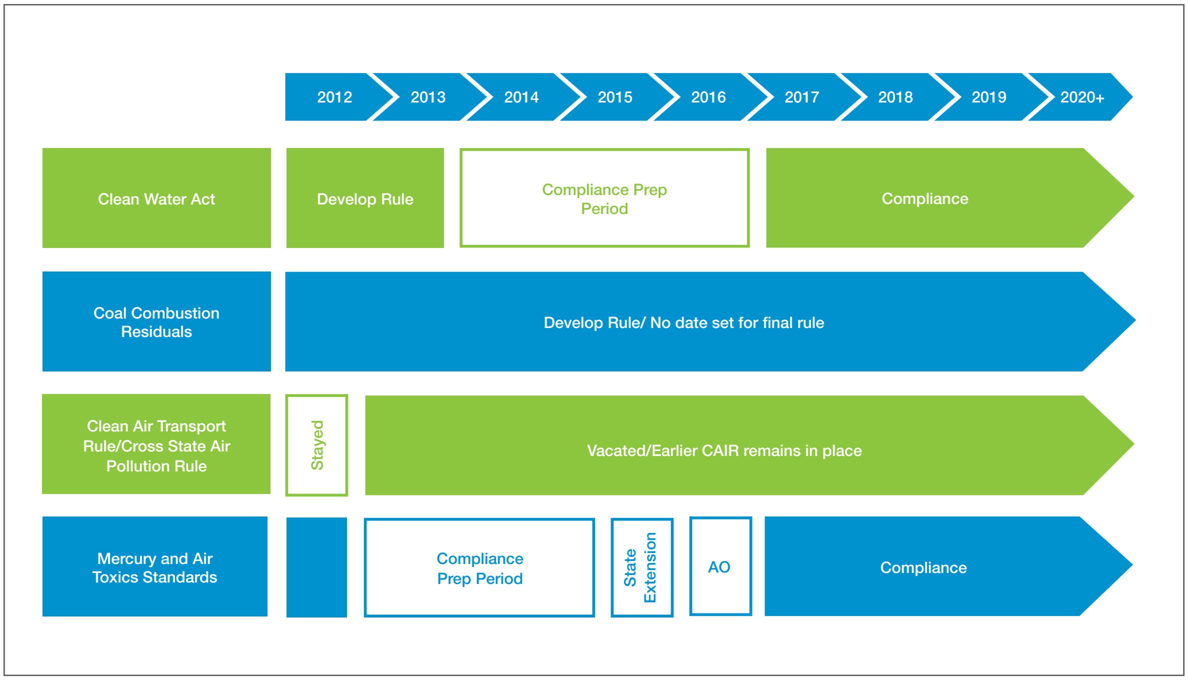


Figure 8.5-4: Estimated timeline for regulation development and implementation

Carbon Restrictions

There are no regulations directing the amount of carbon produced from the existing fleet. However, recent endangerment findings that classify greenhouse gases, CO_2 among them, as hazardous air pollutants obligate the EPA to regulate their production.[35] There have also been legislative proposals with certain targets for the reduction of carbon. Waxman-Markey required that the output of carbon should be reduced by 40 percent from 2005 levels by 2030, and 83 percent by 2050. The EPA has set the New Source Performance Standard (NSPS) that reflects the Best Available Control Technologies (BACT). This output based standard is set at 1,000 lbs/MWh of CO_2. Additionally, the Clean Air Act requires that the U.S. EPA set guidelines for state standards of performance to control emissions from existing sources within the same source category when New Source Performance Standards are issued. These guidelines can be less stringent than the New Source Standard. Although carbon is not currently regulated, prudence dictates that it be considered in the evaluation of the proposed EPA regulations.

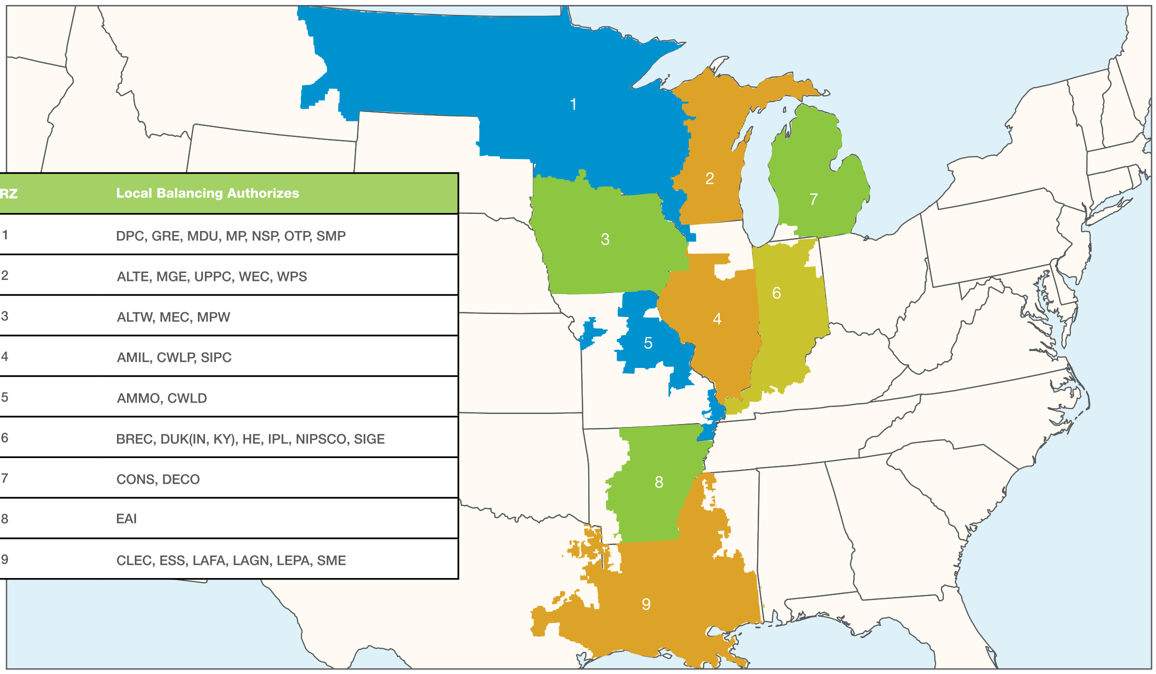
MISO South has limited opportunities to reduce carbon emissions by fuel switching from coal to gas, due to the majority of the capacity already being gas-fired. The next “fuel switch” for carbon reduction purposes would be from coal and gas to something with fewer carbon emissions.

[35] http://epa.gov/carbonpollutionstandard/

8.6 South Region Local Resource Zone Identification

With the addition of the South Region to MISO's footprint, MISO evaluated how to incorporate the incoming set of Local Resource Zones (LRZ), into the Resource Adequacy (RA) construct.

After collaboration from the stakeholder committee and analysis of a completed Proof-Of-Concept (POC) study, MISO's final recommendation for the new South Region zones consists of a two-zone configuration with Arkansas being LRZ-8 and remaining Southern Region making up LRZ-9 (Figure 8.6-1)
MISO presented the final recommendation of South Region zones at both the June 6, 2013, Supply Adequacy Working Group[36] (SAWG) and June 12, 2013, Loss of Load Expectation Working Group[37] (LOLEWG) stakeholder meetings. MISO filed its complete LRZ map with FERC on July 22, 2013



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, KY), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, ESS, LAFA, LAGN, LEPA, SME

Figure 8.6-1: MISO Local Resource Zones

(Stakeholder discussions about the new MISO South LRZs started early in the integration process with initial workshops kicking off on December 18, 2012[38] and February 19 2013[39] . These meetings included discussion on a plan with two key items pertaining to the identification of South Region LRZs.

The two-part plan started with an evaluation of the proposed new MISO South LRZs with a POC analysis. The next step was to develop a final recommendation on the LRZs before July 2013[40] the final recommendation could be filed with FERC by the end of July. With the filing of the new LRZs, the zones for the November 2013 new South Region transitional RA capacity auction have been established, unless FERC has changes in its pending review of the filing.

MISO South Proof-Of-Concept Study

The MISO South POC Study consisted of three major parts: selection of the test zones, transfer analysis and Loss-Of-Load-Expectation (LOLE) analysis. MISO performed a POC study to test proposed MISO South LRZ combinations by calculating example output results similar to the

[36] www.misoenergy.org/Events/Pages/SAWG20130606.aspx
[37] www.misoenergy.org/Events/Pages/LOLEWG20130612.aspx
[38] www.misoenergy.org/Events/Pages/ModuleE-2Workshop.aspx
[39] www.misoenergy.org/Events/Pages/20130219RAWorkshop.aspx
[40] Docket No. ER13-1999-000 was filed on 2013-07-22

process used for the annual Planning Reserve Margin (PRM) study. This analysis was very similar to the POC study used to demonstrate the initial set of MISO LRZs in the development of the new RA process. These results and findings of the MISO South POC study performed were presented at the May 8, 2013, LOLE Working Group meeting[41] in New Orleans.

The test zones of the POC study were based on the following criteria:

- State regulatory authority
- Geographical boundaries
- Zone size (load and generation totals)
- Local Balancing Authorities (LBA) definitions

Based on these selection criteria, the MISO South POC study looked at two different configurations. The first configuration consisted of two zones with Arkansas as a single zone and the rest of the MISO South Region in the other new zone (Figure 8.6-2). The second test configuration had three zones comprised of an Arkansas zone, a Mississippi zone and a Louisiana and Texas zone (Figure 8.6-3). Both of these configurations were studied in the transfer and LOLE analyses.

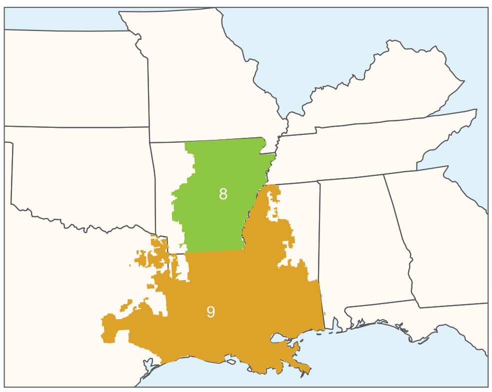


Figure 8.6-2: Two New LRZs
(Arkansas and remainder)

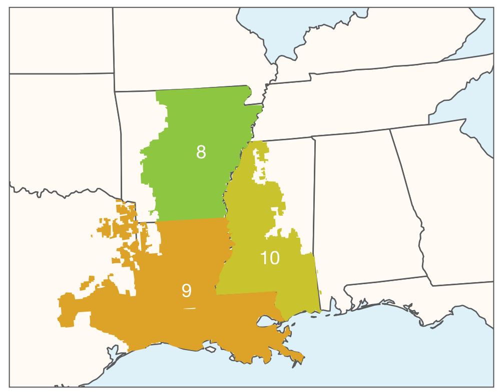


Figure 8.6-3: Three New LRZs
(Arkansas, Mississippi and remainder)

Transfer Analysis

The transfer analysis was performed to calculate and illustrate example Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values. As part of this review of transfer analysis findings, the most limiting transmission constraints and contingencies were shared with the stakeholders. These values were for demonstration purposes as well as to test out various configurations in the new zones. A more detailed and thorough analysis will be performed during the annual PRM study (due November 1, 2013); those results will be used in the South Region transitional capacity auction.

Local Reliability Requirement

Another part of the POC study performed an LOLE analysis to determine the Local Reliability Requirement (LRR) of each of the test zones. The LRR is calculated by determining how much capacity is needed by each zone to maintain a one-day in 10-years LOLE value. The Local Clearing Requirement (LCR) of each zone tested was calculated and demonstrated by using information from both the LOLE and transfer analysis. The LCR was calculated by taking the Local Reliability Requirement minus the Capacity Import Limit of each zone. These LCR value examples illustrated the amount of capacity needed internally for an LRZ to meet the one-day in 10-years LOLE criteria and still be considered resource adequate. The LCR findings from the MISO South POC study showed that the LRZs tested in both the two-zone and three-zone configurations had enough capacity internally to meet their calculated LCRs. The two-zone selection was made based on analysis results and stakeholder feedback.

[41] www.misoenergy.org/Events/Pages/LOLEWG20130508.aspx

Book 3 – **Chapter 9**
Interregional Studies

Interregional Studies

9.1 FERC Order 1000

The Federal Energy Regulatory Commission's (FERC) Order 1000 rule mandates how public utility transmission providers must plan for and allocate the costs of new projects on a regional and interregional basis. Order 1000 builds upon Order 890, which required transmission planning based on open, transparent and coordinated processes.

The major components of Order 1000 include:

- Regional transmission planning
- Regional cost allocation
- Elimination of the federal right of first refusal (ROFR)
- Interregional planning coordination
- Interregional cost allocation

Order 1000 seeks to ensure that regional and interregional processes consider plans that more efficiently or cost-effectively address transmission needs.

Schedule

MISO filed documentation with FERC on October 25, 2012, that stated how it does or will comply with the regional components (the first three items above). A second filing covering the interregional components (the fourth and fifth items) was filed on July 10, 2013.

Guiding Principles

Order 1000 seeks to ensure more efficient or cost-effective regional planning and interregional coordination. It requires that public utility transmission providers participate in a regional transmission planning process to produce regional plans; that local and regional transmission planning processes consider local, state and federal public policy requirements; and that public utility transmission providers coordinate with neighboring planning regions to meet transmission needs in an efficient or cost-effective manner.

The order establishes cost allocation principles for new regional and interregional transmission facilities included in regional plans. The principles ensure that allocated costs are roughly commensurate with estimated benefits. Order 1000 allows different cost allocation methods for different types of transmission facilities. Additionally, it allows allocation of costs to a neighboring region only if the other region agrees.

Finally, to promote competition in regional transmission planning, Order 1000 requires the removal of a federal right of first refusal from FERC-approved tariffs and agreements for new transmission facilities that have regional cost allocation.

Regional Accomplishments

MISO has completed and submitted documentation to FERC that demonstrates how it does or will comply with the regional components of Order 1000. This was accomplished through a regional compliance filing submitted on October 25, 2012, and a subsequent further compliance filing submitted on July 22, 2013. Each set of filings involved collaboration with stakeholders over a time period stretching from late October 2011 through July of 2013.

MISO's regional filing, submitted to FERC on October 25, 2012, highlighted that MISO was already largely compliant with the regional transmission planning, including consideration of public policy requirements, and cost allocation requirements of Order 1000. It also included revisions to the Tariff and the Transmission Owners Agreement to address the elimination of the federal ROFR as required by Order 1000, beginning with the MTEP 14 planning cycle. The revisions to eliminate the federal

ROFR will apply to transmission facilities that are categorized as Market Efficiency Projects (MEP) or Multi-Value Projects (MVP). The developer(s) that will construct, own, operate and maintain these facilities will be selected through an open selection process for qualified developers. This process will request qualified developers to submit proposals to construct, own, operate and maintain applicable facilities approved by the MISO Board of Directors. The developer selection process is a defined part of the MISO planning process (Figure 9.1-1). The evaluation of developer's proposals submitted to MISO will consider, at a minimum, the following components:

- Project design and life cycle cost
- Developer implementation (i.e. construction) abilities and strengths
- Developer operation and maintenance abilities and strengths
- Planning process participation and analyses conducted by the developer

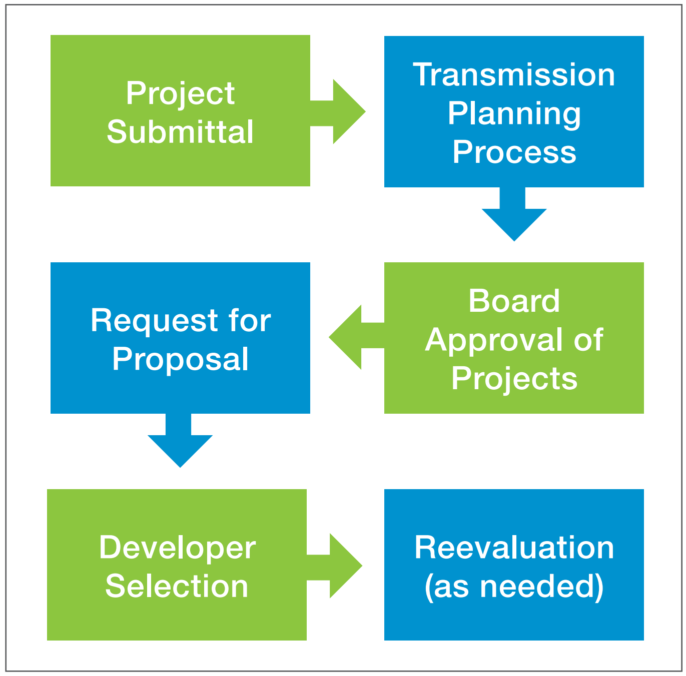


Figure 9.1-1: The selection process

Re-evaluation of projects and their selected transmission developer will occur, as defined further in the Tariff, if there are project cost increases, schedule delays or changes in developer qualifications.

FERC, on March 22, 2013, found MISO's regional filing largely compliant with the regional planning and cost allocation requirements adopted in Order 1000. As part of its conditional approval, FERC ordered MISO to submit a subsequent compliance filing to further justify and address items that partially complied with the requirements of Order 1000 with most of the further compliance items having to do with the elimination of federal ROFR process. MISO again collaborated with stakeholders to address these items and submitted the additional compliance filing on July 22, 2013.

More information is available on MISO's FERC Order 1000 web page.

Interregional Accomplishments

One of the objectives of Order 1000 is to improve the coordination between neighboring planning regions to ensure there is a process for identifying and for developers to propose interregional transmission solutions that may be more efficient or cost-effective than separate regional transmission solutions, and to have a mechanism in place to cost share identified interregional projects between the neighboring planning regions.

MISO's interregional compliance filings required development of planning coordination and cost allocation processes with each of MISO's four neighboring planning regions: Midcontinent Area Power Pool (MAPP), PJM Interconnections, Southeastern Regional Transmission Planning group (SERTP), and Southwest Power Pool (SPP). To accomplish this, MISO worked with each of the four neighboring planning regions, along with stakeholders, through interregional workshops from April 2012 through July 2013. MISO has completed and submitted documentation to FERC that demonstrates how it does or will comply with the interregional coordination and cost allocation components of Order 1000. This was accomplished through a set of interregional compliance filings with PJM, SPP and SERTP made on July 10, 2013.[42]

For the Order 1000 interregional compliance filings (with each of MISO's neighboring planning regions), it was easier to reach agreement on the provisions to address the interregional coordination items than to reach full agreement on interregional cost allocation. The challenge with reaching full agreement on interregional cost allocation can largely be attributed to the differences across the planning regions in their respective regional cost allocation provisions. These differences in regional cost allocation approaches resulted in MISO's July 10 FERC filing not being in complete agreement on interregional cost allocation with those of PJM and SPP (Table 9.1-1).

Neighboring Planning Region	Interregional Coordination	Interregional Cost Allocation	Provisions in Joint Operating Agreement or Tariff
MAPP	Extension Granted – Due date TBD (120-days after MAPP submits Order 1000 regional compliance filing)		
PJM	Agreement	Partial Disagreement	Updates to Article IX in MISO-PJM JOA
SERTP	Agreement	Agreement	New Section X in Attachment FF
SPP	Agreement	Partial Disagreement	Updates to Article IX in MISO-SPP JOA

Table 9.1-1: Status of MISO's Order 1000 Interregional Coordination and Cost Allocation Compliance filings

MISO expects to continue to work with stakeholders and its neighboring planning regions in 2014 to address further compliance items related to Order 1000 and implementing the processes developed as part of Order 1000.

[42]An extension was requested from and granted by FERC, for the MISO-MAPP interregional compliance requirements. Request for extension was submitted on June 13, 2013, in Docket No. RM10-23-000 and granted on July 8, 2013.

9.2 Cross-Border Planning

MISO PJM Joint Planning Study

MISO and PJM launched a Joint Planning Study in October 2012 to evaluate cross-border seams issues and identify transmission solutions that promote market efficiency. The study consists of two phases:

1) Assessment of recent Market-to-Market (M2M) congestion issues

2) Joint market efficiency planning analysis

The MISO-PJM Joint Operating Agreement (JOA) requires a comprehensive, coordinated regional planning study to occur at least once every three years. Previous collaborative studies in compliance with the JOA protocols have included the Joint Coordinated System Plan (JCSP) and Cross-border Top Congested Flowgates studies. To continue the collaborative interregional planning efforts, this study is intended to enhance seams coordination; to address, as appropriate, persistent market inefficiencies; and provide a framework under which inter-regional planning studies are conducted.

Recognizing the complexity of the MISO-PJM seams (Figure 9.2-1), a joint study approach provides a common platform for the combined Regional Transmission Owners' (RTO) stakeholders to participate in the evaluation and review of identified cross-border transmission plans.
Developing joint and common planning models that are consistent with both the MISO and PJM regional planning processes will create an improved foundation for joint analyses for evaluation of potentially actionable transmission plans.

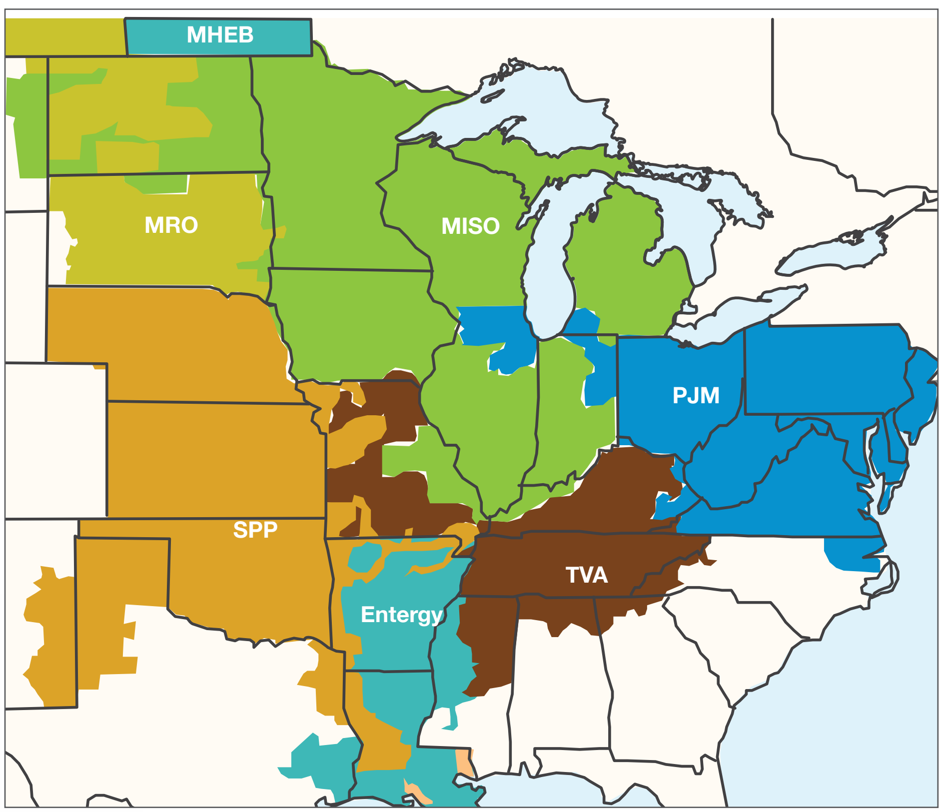


Figure 9.2-1: MISO Interregional planning entities

Phase 1: Assessment of Recent Market-To-Market Congestion Issues

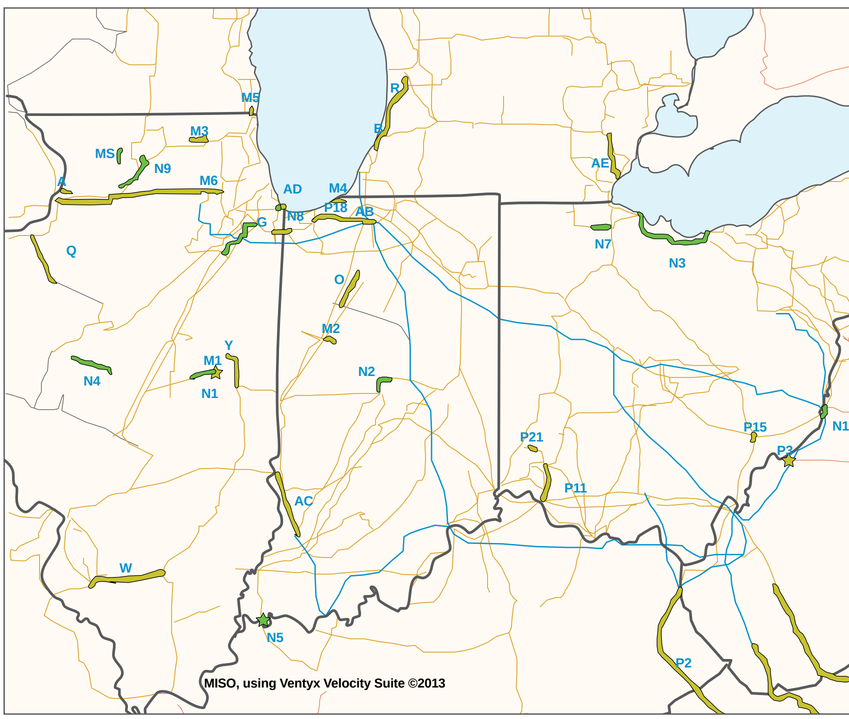
Phase I of the study gathered RTO and stakeholder information about M2M congestion issues and supporting information quantifying historical congestion and possible causes. Using historical data (January 2011 to October 2012) of both RTOs' congestion cost levels and settlement dollars for all M2M flowgates, a total of 33 M2M flowgates (27 unique monitored lines) were selected as most impactful.

In addition to these M2M flowgates, a total of 11 non-M2M flowgates that showed significant congestion and a high shift factor from generators in both RTOs were selected to be monitored during the study.

27 Flowgates were Selected as Top Historical M2M flowgates based on MISO and PJM historical congestion costs and settlement dollars.

The majority of top historically congested flowgates are located along the MISO-PJM seams (Figure 9.2-2). As noted above, the flowgates were selected using both MISO and PJM historical data: flowgates A–AE are the common flowgates selected by both MISO and PJM analyses, M1–M6 were uniquely selected from MISO analysis, while P2–P21 were a result of PJM analysis. N1–N11 are the top selected MISO-PJM non-M2M flowgates.

Phase I served as a screening analysis to determine if these identified congestion issues lend themselves to modified market protocols or transmission upgrades.



A	Beaver Channel - Albany 161kV
B	Benton Harbor - Palisades 345kV
E	Cordova - Nelson 345kV
G	Crete - St Johns 345kV
M	Marengo - Woodstock 138kV
O	Monticello - East Winimac 138kV
Q	Oak Grove - Galesburg 161kV
R	Palisades - Roosevelt 345kV
W	Prairie State - Mt Vernon 345kV
Y	Rantoul - Rantoul Junction 345kV
AB	Stillwell - Dumont 345kV
AC	Breed - Wheatland 345kV
AD	Sheffield - Marktown 138kV
AE	Monroe - Wayne 345kV
M1	Rising 345/138kV XFMR (Fg z)
M2	Cumberland - Bush 138kV (Fg h)
M3	Marengo - Pleasant Valley 138kV (Fg L)
M4	Michigan City - Laporte 138kV (Fg N)
M5	Kenosha - Lakeview 138kV (Fg J)
M6	Nelson - Electronic Junction 345kV (Fg P)
P2	AEP - DOM interface
P3	Belmont500/765 XMFR
P11	Pierce - Foster 345kV
P15	Waterford - Muskingum 345kV
P18	Babcock - Stillwell 345kV
P20	Rantoul Jct - Sidney 138kV
P21	Toddhunter - Trentton 138kV
N2	Whitestown - Guion 345kV
N3	Ottawa - Lakeview 138kV
N4	Havana - Elkhart 138kV
N5	AB Brown 138/345kV Xfmr
N6	Marylan - Bailey 138kV
N7	Lemoyn - Bowling Tap 138kV
N8	Hegewisch - Burnham 138kV
N9	Dixon - Still 138kV
N10	Braidwood - E Frankfort 345kV
N11	Kammer - Natrium 138kV

Figure 9.2-2: Top congested M2M and non-M2M flowgates

Phase 2: Joint market efficiency planning analysis

The primary focus of Phase 2 is to perform a joint market efficiency analysis to examine and project system congestion trends based on historical market data as well as forward-looking future congestion patterns based on out-year production cost model simulations.

The ongoing analysis seeks to identify and mitigate, with a coordinated portfolio of expansions as appropriate, highly congested flowgates that have a significant contribution to existing or projected congestion in either or both markets.

Phase 2 seeks to identify and mitigate highly congested flowgates that have a significant contribution to existing or projected congestion in MISO and PJM.

The flowgates under consideration for study are those that have historically demonstrated consistent transmission congestion impact on either or both planning regions and are projected to continue to be congested into the future. Information examined to find such flowgates includes:

- Historical binding constraints identified from market-to-market operations
- Future projected congested transmission elements identified via out-year production cost model simulations using the mutually agreed upon joint planning model assumptions

Initial evaluation of out-years shows a congestion pattern fairly consistent with Market Efficiency Planning Studies (MEPS) (Table 9.2-1).

Congestion Level	2027 Congestion Cost (k$)		
	Future 1	Future 2	Future 3
MISO Internal Flowgates	1,005,177	1,198,728	1,884,872
PJM Internal Flowgates	1,439,262	2,409,128	1,973,190
MISO-PJM Cross Border Flowgates	183,420	336,215	168,758
MISO and PJM Companies On Seams	1,182,227	2,287,742	1,950,202

Table 9.2-3: Indicative 2027 congestion across MISO-PJM

The sum of MISO Internal Flowgates and PJM Internal Flowgates for each future gives the total congestion in both MISO and PJM. A comparison of this sum to the numbers from the MISO and PJM Companies On Seams category reveals that a majority of the congestion seen in the entire MISO-PJM region is on flowgates located in the companies along the seams. Depending on the future scenario, these flowgates will provide a good pool from which many of the top congested flowgates will be selected.

Intial analysis shows that a big percentage of the total congestion in the combined MISO-PJM area is located on flowgates in companies along the seams.

The candidate flowgates, for which solutions will be offered, may be located solely within one planning region or across the seams between MISO and PJM. However, to be included on this list, consistent with the MISO-PJM JOA, these flowgates must have at least one generator in the adjacent market with a generation to load distribution factor (GLDF) greater than 5 percent. The flowgates that will be studied may or may not include the top historically congested flowgates identified in Phase 1.

The output of this analysis will be a mutually agreed upon list of highly congested flowgates that have material impact on both planning regions. The flowgates will then be addressed with proposed solutions that will be jointly evaluated against the qualification criteria for Cross-Border Market Efficiency Projects (CBMEP). The JOA delineates these criteria as:

- Minimum project cost of $20 million evaluated as part of a Coordinated System Plan or joint study process
- Meets the benefit-to-cost ratio threshold of 1.25 under JOA for CBMEP
- Meets the benefit-to-cost ratio threshold under each of MISO and PJM tariff provisions for MEPs
- Address one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5 percent or greater with respect to serving load in that adjacent market

To determine benefit-to-cost ratios for proposed transmission solutions, a multi-year analysis will be required to cover, at a minimum, the first 10 years of project life, and up to a 20-year horizon from the current year. The benefit metrics with which each transmission plan will be measured are:

- Cross Border: 70 percent Adjusted Production Cost Savings (APCS) plus 30 percent Net Load Payment Savings over the first 10 years of project
- MISO: 100 percent APCS over the first 20 years of project life
- PJM: 70 percent Production Cost Savings plus 30 percent Net Load Payment Savings over the first 15 years of project life

Potential transmission solutions, which can be proposed by any interested party, will be jointly identified and evaluated through a focused MISO/PJM stakeholder process in an open and transparent manner. Out-year production cost model simulations reveal transmission needs opportunities to help formulate more efficient and cost-effective transmission solutions.

Model Development

In support of coordinated system planning, jointly developed planning models consistent with regional planning requirements and processes are necessary to address common transmission issues. The joint and common models allow each entity to evaluate issues and transmission solutions on a comparable basis, with a common set of agreed upon study assumptions reviewed in joint MISO/PJM open stakeholder meetings (Table 9.2-2).

Variable	JOA Future Assumption	
Demand and Energy Growth	Provided by respective RTO	
Demand Response and Energy Efficiency	Provided by respective RTO	
Regional Generation Forecast	Provided by respective RTO	
Fuel Prices	Natural Gas	NYMEX forward curve for the first 3 years and escalated thereafter
	Oil	PowerBase Default
	Coal	PowerBase Default
	Uranium	PowerBase Default
Escalation Rates	2.50 percent (except 3.44 percent for Natural Gas)	
Emission Costs	Zero Emission Costs	
Regional Coal Retirements	~12.6 GW in MISO ~14 GW in PJM	

Table 9.2-4: Key joint model assumptions for the current cycle study

With these assumptions as a foundation, MISO-PJM have agreed upon three future scenarios to capture different policy issues around state renewable portfolio standards. For each of these futures, detailed planning models have been developed for 2017, 2022 and 2027, consistent with models used in each region's planning process (Table 9.2-3).

	MISO		PJM	
	Renewable Portfolio Standards	Approx. Nameplate Wind (MW 2027)	Renewable Portfolio Standards	Approx. Nameplate Wind (MW 2027)
Scenario 1	State Mandates	27,643	Queue Only	27,911
Scenario 2	State Mandates	27,643	State Mandates	35,396
Scenario 3	State Mandates + Goals	31,541 +13,500 Export to PJM	State Mandates	21,896

Table 9.2-5: Regional generation forecast for the three futures

Stakeholder Process

The joint and common planning model, scope and study processes are overseen by the Joint RTO Planning Committee (JRPC), comprised of respective staff from each planning region, and reviewed with stakeholders through the Interregional Planning Stakeholder Advisory Committee (IPSAC), consistent with the Coordinated System Plan development provisions of the JOA. The JRPC presents the following mutually agreed upon information to the IPSAC for their review and input:

- Study scope and approach
- Joint and Common planning models including assumptions to be used
    - Study footprint
    - Inter-market transactions
    - Base data assumptions including Powerbase database and Powerflow models (subject to all applicable Confidentiality and Critical Energy Infrastructure Information requirements)
    - Assumptions on uncertainty and economic variables
    - Regional capacity forecasts and Siting
- Identified seams transmission issues or opportunities
- Proposed transmission solutions and alternatives
- Recommendations on transmission solutions to be evaluated against each RTO's cost allocation criteria in accordance with the JOA protocols
- Joint Coordinated System Plan report

Future Efforts

Consistent with the requirements of Order 1000, following the completion of Phases I and II of this effort, MISO and PJM will periodically re-execute joint market efficiency planning analysis pursuant to the requirements of the Joint Operating Agreement in effect at that time. This is currently contemplated to be an annual assessment with planning studies executed along timeframes dictated by the Regional planning analysis.

In addition to the efforts required by the current Joint Operating Agreement and compliance with Order 1000, a broader and more effective interregional coordination of multiple regional planning entities will be undertaken on a three- to five-year cycle, which may be used to inform each RTO's respective regional and interregional planning decisions. It will firstly focus on developing a process for building joint models across multiple seams, with other interregional efforts such as the Eastern Interconnection Planning Collaborative (EIPC) being leveraged where possible, and provide periodic coordinated transmission studies to identify indicative interregional transmission plans across multiple seams.

9.3 Eastern Interconnection Planning Collaborative

Since 2009, MISO has been one of nine principal investigators on the Eastern Interconnection Planning Collaborative (EIPC) Department of Energy (DOE) Grant.

The EIPC, a group of 25 planning authorities in the Eastern Interconnection, was selected by the DOE in 2009 for a grant through the American Recovery and Reinvestment Act. The project included two phases of economic and reliability planning as well as a Gas-Electric Study.

Phase I of the DOE grant consisted of developing interconnection-wide base cases, a macroeconomic study of resource needs under various futures and choosing three scenarios for further analysis. Phase II dealt with detailed build-outs of the selected scenarios, production cost analysis and cost estimates for generation and transmission development. Phase I work was completed in 2011 and Phase II in 2012. The final Phase II report for the DOE-funded project is posted at http://eipconline.com/Phase_II_Documents.html.

In 2013, MISO continued its support of the DOE-funded Gas-Electric System Interface Study. Additionally, MISO renewed its involvement, along with the other 24 planning authorities, in a non-DOE funded two-year EIPC study, which will run through 2014. The latest information about the EIPC, Gas-Electric Study or the non-DOE funded study can be found at http://eipconline.com/.

BOOK 4
REGIONAL ENERGY INFORMATION

Understanding the complexities of regional electric energy systems requires looking at the data from as many perspectives as possible. The first three books of the MTEP13 Report focus on regional information largely related to the MTEP13 planning cycle. However, MISO collects, produces and calculates additional information that can provide insights on the state of the regional energy system. Book 4 presents additional regional energy information, placing special emphasis on historical trends, to provide MISO observers with a more complete picture of the regional energy system.

Book 4 – **Chapter 10**
Regional Energy Information

Regional Energy Information

10.1 MISO Overview

The Midcontinent Independent System Operator Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets. MISO has 46 Transmission Owner members with $20.3 billion in transmission assets under MISO's functional control, and 97 non-transmission owner members. MISO manages one of the world's largest energy and operating reserves markets from its control centers in Carmel, Ind., and St. Paul, Minn. (Figure 10.1-1).

Generation Capacity (as of June 2013):

- 131,522 MW (market)
- 205,759 MW (reliability)

Historic Peak Load (set July 23, 2012):

- 98,576 MW (2012 market footprint)
- 133,368 MW (2012 reliability footprint)

Miles of transmission (reliability):

- 49,528 miles in MISO – Midwest Region
- 15,752 miles in MISO – South Region
- 65,250 miles in MISO – Overall

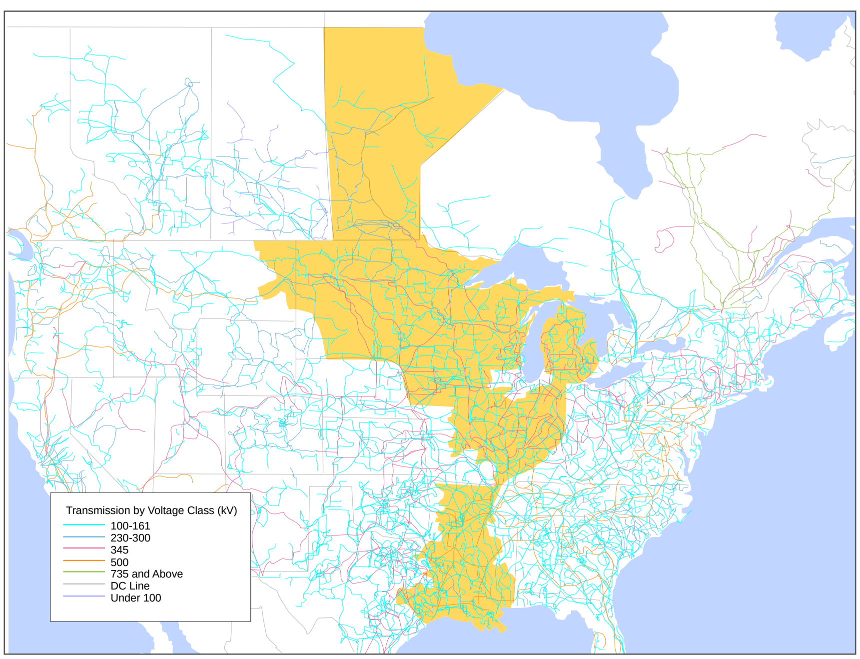


Figure 10.1-1: MISO's reliability footprint over the North American transmission system

Markets Overview:

- $18.4 billion annual gross market charges (2012)
- 1,948 pricing nodes
- Five-minute dispatch
- Offers locked in 30 minutes prior to the scheduling hour
- Spot market prices calculated every five minutes
- 362 Market Participants who serve 48 million people

Network Model (as of June 2013):

- 43,382 network buses
- 282,163 SCADA data points
- 1,823 generating units (reliability)
- 1,271 generating units (market)

Renewable Integration:

- 16,330 MW active projects in interconnection queue
- 12,151 MW wind in service
- 12,239 MW registered wind capacity
- 9,546 MW registered Dispatchable Intermittent Resource capacity (MISO Midwest Region – June 2013)

The geographic area of the MISO reliability footprint (Figure 10.1-2) includes the MISO South region new members. The pre-December 19, 2013, market footprint (Figure 10.1-3) is the primary reporting region for Book 4 data.

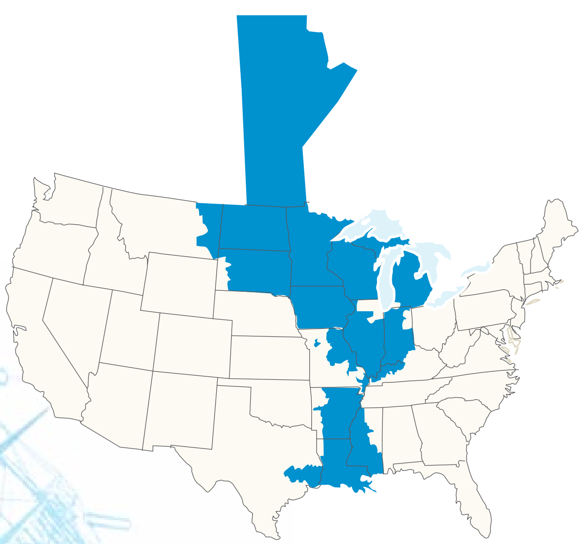


Figure 10.1-2: MISO Reliability Footprint

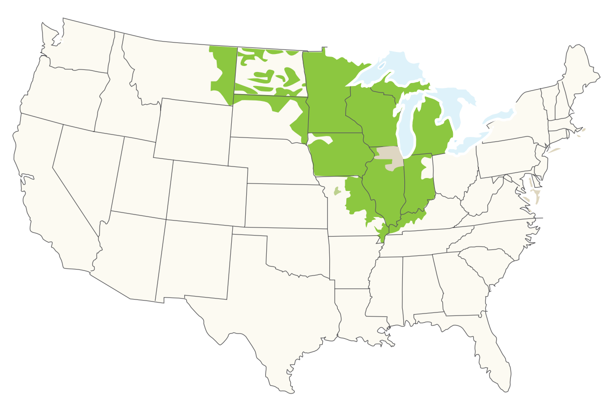


Figure 10.1-3: MISO Market Footprint

10.2 Electricity Prices

Wholesale Electricity Rates

MISO operates a market for the buying and selling of wholesale electricity. The cost of wholesale electricity varies by geography and time of day, based on supply and demand and level of congestion. These differences are captured through locational marginal prices (LMP) (Figure 10.2-1). The maps capture snapshots of the LMP differences on the peak day in 2012 – July 23. The maps illustrate the LMP prices ($/MWh) at 4:00 AM, 11:00 AM, 4:00 PM, and 8:00 PM EST. A real-time look at MISO LMPs can be found on the MISO LMP Contour Map.

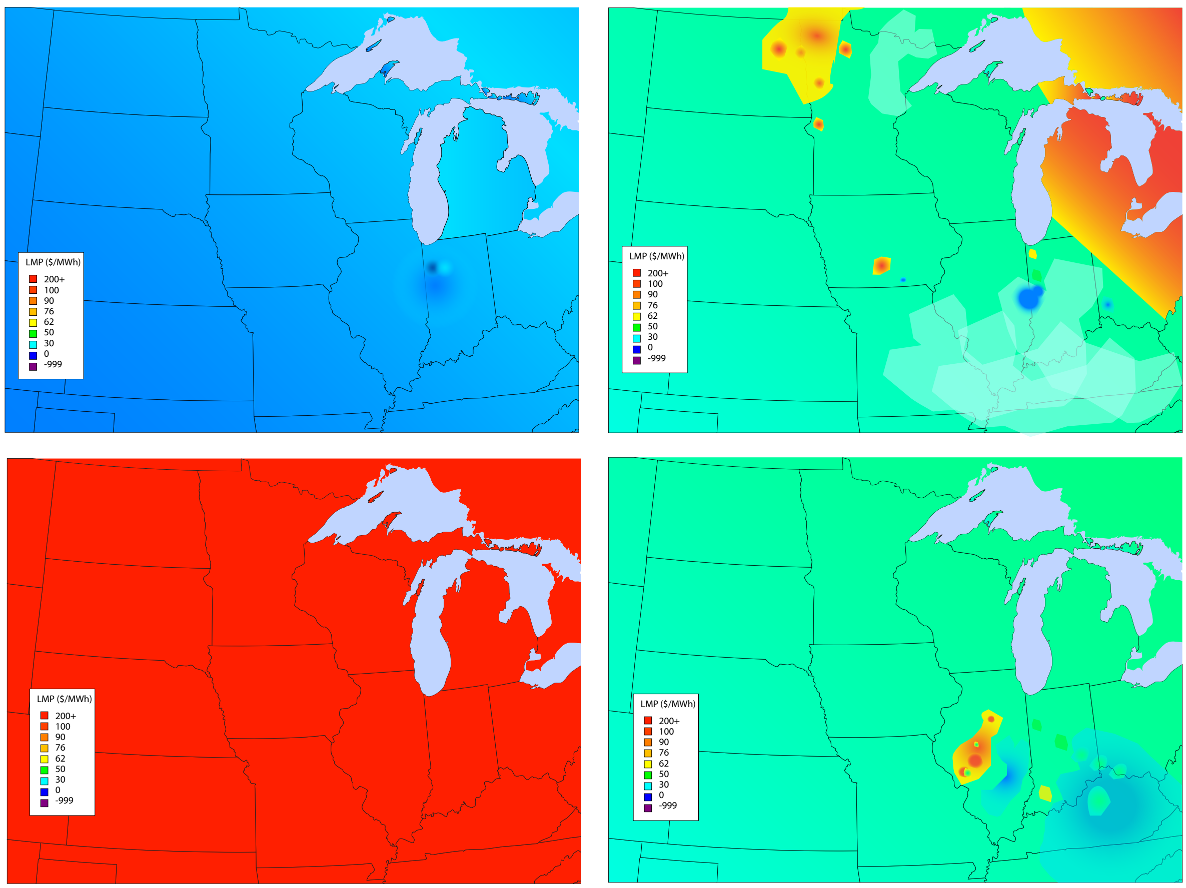


Figure 10.2-1: MISO locational marginal prices (LMP) for July 23, 2012[43]

[43]Source: MISO Real-time Historical LMP Market Data

These LMPs also vary by year and month (Figure 10.2-2). LMPs generally trended downward between 2006 and 2012, with most of the reduction occurring after mid-2008 following such things as the economic downturn and decrease in natural gas price.

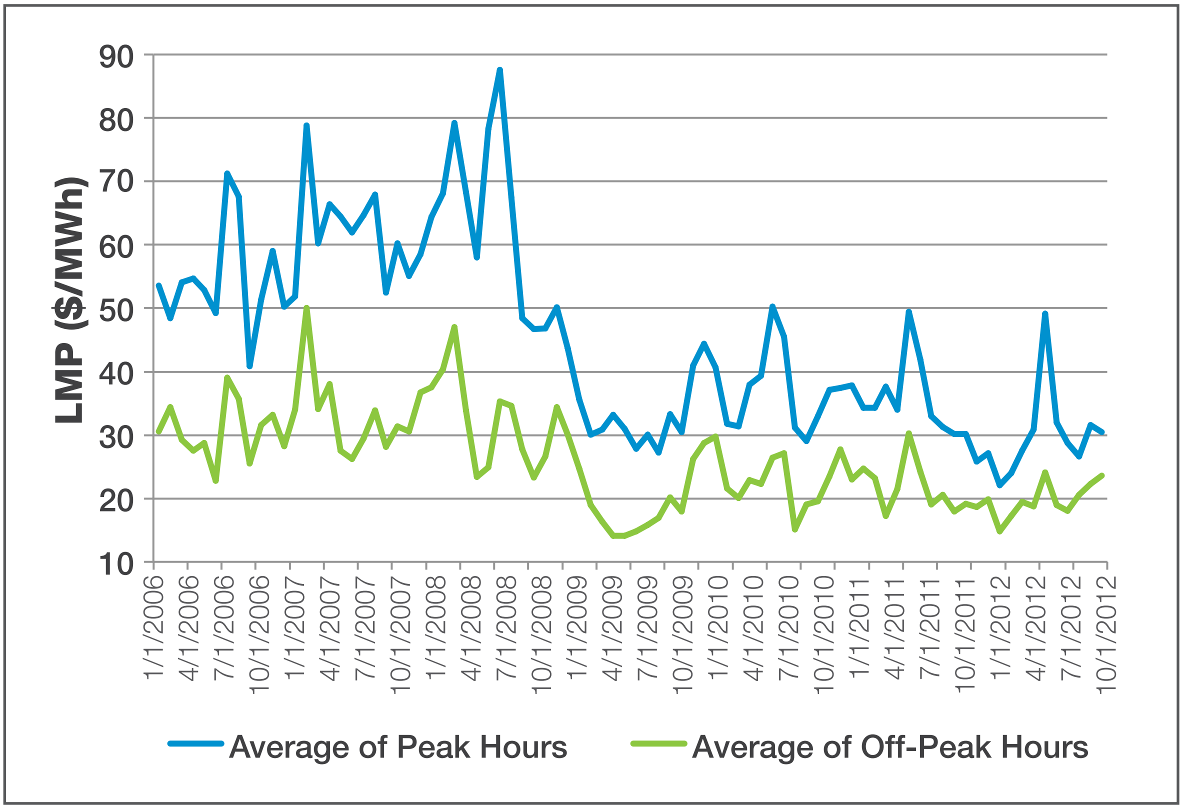


Figure 10.2-2: MISO average monthly locational marginal price (LMP): 2006–2012[44]

[44] Source: MISO Historical Average Monthly LMP Data

Current Retail Electricity Rates

The current MISO-wide average retail rate, weighted by load in each state, for residential, commercial and industrial sector, is 9.3 cents/kWh, about 5 percent lower than the national average of 9.7 cents/kWh.[45] The average retail rate in cents per kWh varies by 3.9 cents/kWh per state in the MISO footprint (Figure 10.2-3). The Energy Information Administration (EIA) in Annual Energy Outlook 2013 estimates the 2013 cost components of the retail electricity rate average 61.1 percent for generation; 11.2 percent for transmission and 27.7 percent for distribution.[46] This equates to approximately 5.7 cents/kWh for generation, 1.0 cents/kWh for transmission and 2.6 cents/kWh for distribution[47].

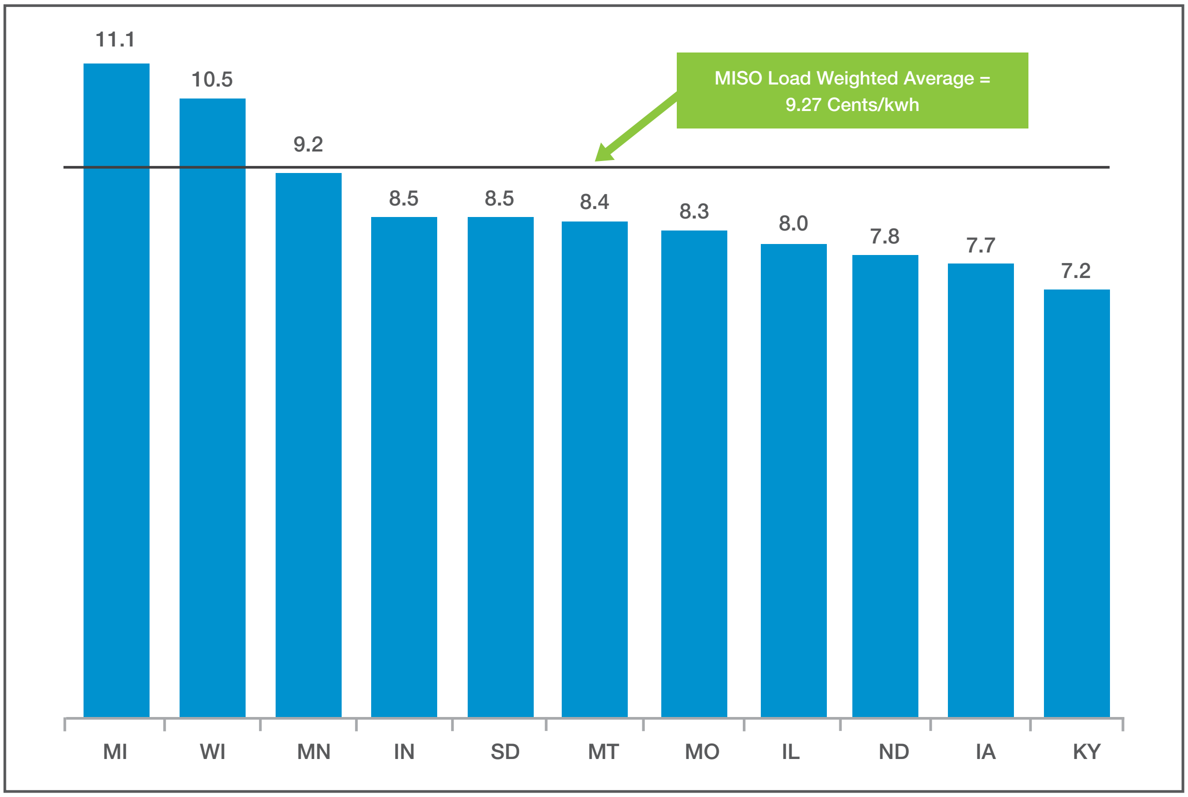


Figure 10.2-3: MISO retail rate for all sectors in cents/kWh (2012 dollars)

[45] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly from June 2013. MISO average rate was calculated by taking the load weighted average of the 11 states in the MISO footprint.

[46] MISO average generation, transmission and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2013 for the following modeling regions: MRO-East, MRO-West, RFC-MI, RFC-West, SERCCentral, and SERC-Gateway. The modeling regions were weighted based on MISO load in each of the regions.

[47] Each category assumes some allocation of general and administrative expenses.

Current Residential Electricity Consumption

Reflective of the large geographic area that the MISO region covers, there is a wide variation in the average residential electricity consumption by state. The average residential electricity consumption varies by states in the MISO region[48] (Table 10.2-1). For comparison the MISO-weighted average residential consumption at 850 kWh is lower than the U.S-weighted average of 940 kWh.

State	MISO Load Ratio Share	Average Monthly Residential Consumption (kWh)
Kentucky	1.9%	1,175
North Dakota	1.6%	1,147
Missouri	9.4%	1,112
South Dakota	0.7%	1,035
Indiana	16.5%	1,030
Iowa	8.2%	898
Montana	0.2%	871
Minnesota	13.9%	813
Illinois	11.3%	770
Wisconsin	15.3%	709
Michigan	21.1%	683
	MISO Weighted Average	**850**
	U.S. Weighted Average	**940**

Table 10.2-1: 2011 MISO weighted average monthly residential consumption (kWh)

[48] Courtesy of the EIA for 2011

10.3 Generation

Part of MISO's mission is to maintain reliability by keeping generation and load in balance, both in realtime and longer-term horizons. Fuel prices are key variables affecting the choice of generation. Among the major fuels, natural gas has traditionally been the most volatile. With its recent decline, the price of natural gas, in terms of dollars per MMBtu, became more competitive with coal[49] (Figure 10.3-1). This price decline produced a corresponding increase in electricity generated from natural gas (Figure 10.3-2). A real-time look at MISO's fuel mix can be found on the MISO Fuel Mix Chart.

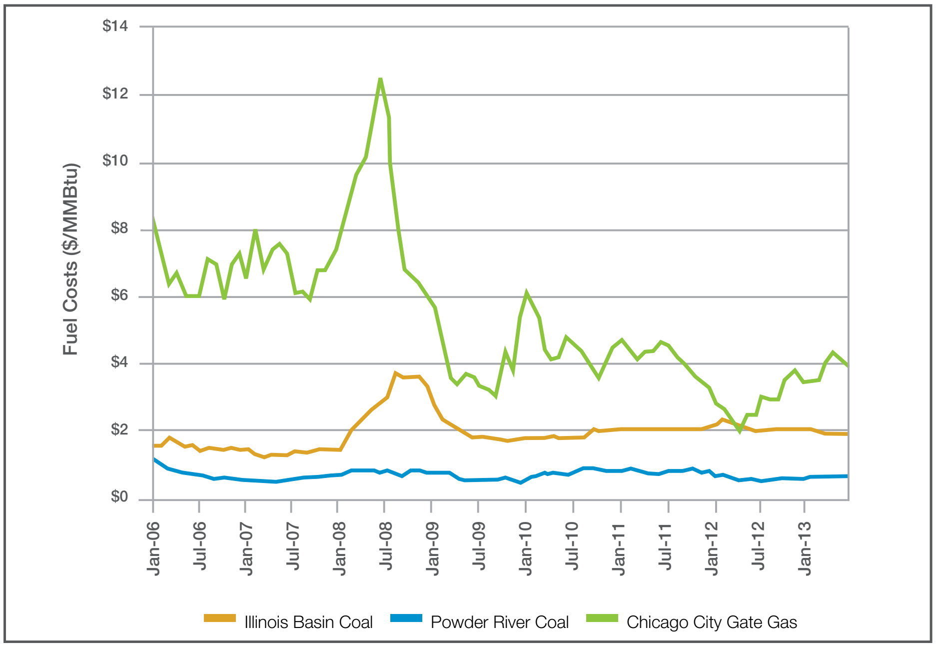


Figure 10.3-1: MISO fuel cost (2006–2013)[50]

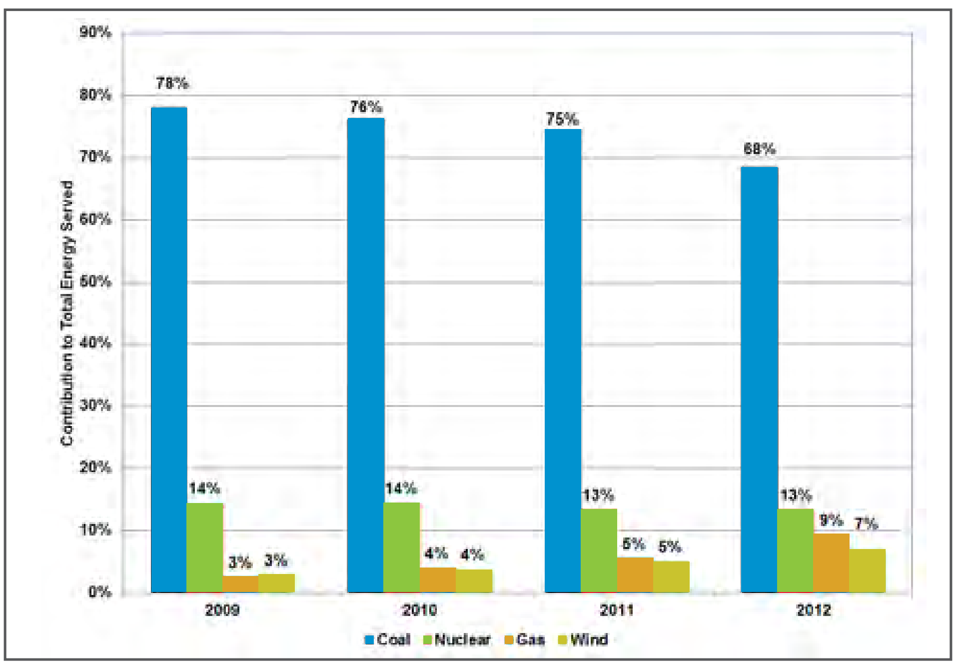


Figure 10.3-2: Contribution per fuel source to total energy served in the MISO Midwest Region[51]

[49] Gas prices from ICE (https://www.theice.com/homepage.jhtml) Coal prices from EIA (www.eia.doe.gov)

[50] Illinois Basic coal heat content = 11,800 btu/lb; Powder River Coal heat content = 8,800 btu/lb

[51] Source: MISO Monthly Market Reports (2009-2012)

Capacity Additions

From a nameplate capacity perspective, MISO's registered nameplate capacity varied between 131,877 MW to 129,341 from 2009 through 2013 (Figures 10.3-3 and 10.3-4). Total nameplate wind capacity installed increased significantly during that time. As earlier figures demonstrate, natural gas energy usage also increased significantly as the natural gas commodity price became more competitive with other fuel costs. The other increases and decreases are attributable to many variables, including new capacity installations, retirements and membership changes.

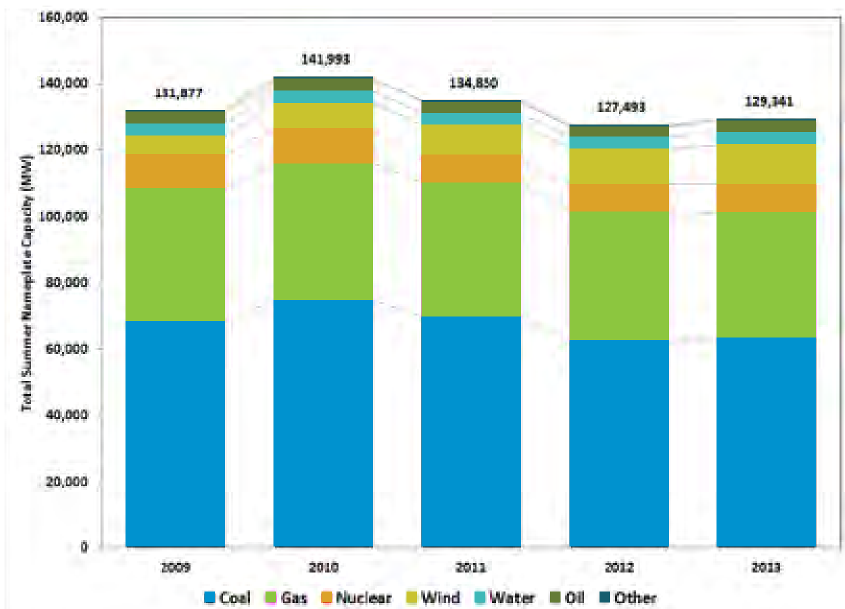
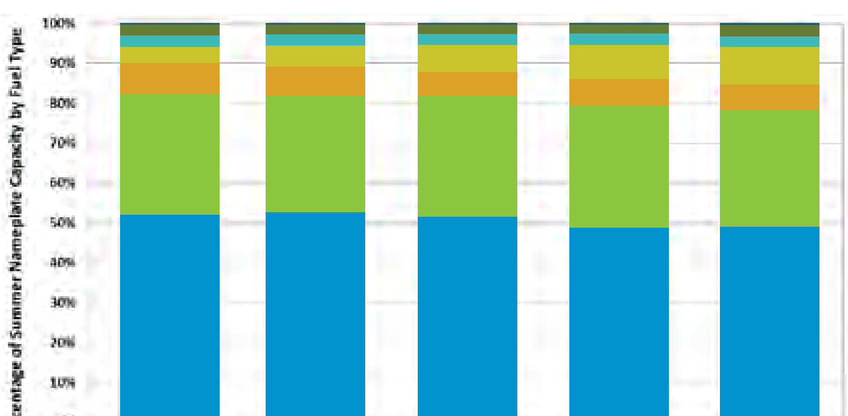


Figure 10.3-3: Nameplate capacity in MISO Midwest Region[52]



	2009	2010	2011	2012	2013
Other	0%	0%	0%	0%	1%
Oil	3%	3%	2%	2%	3%
Water	3%	3%	3%	3%	3%
Wind	4%	5%	7%	8%	9%
Nuclear	8%	7%	6%	7%	6%
Gas	30%	29%	30%	31%	29%
Coal	52%	53%	52%	49%	49%

Figure 10.3-4: Percentage of nameplate capacity in MISO Midwest Region

[52] Source: MISO Summer and Long Term Resource Assessments

Wind

The amount of wind capacity and energy in the MISO region increased significantly from 2006 through 2012 (Figure 10.3-5). Capacity increased from about 1,000 MW to more than 12,000 MW. As Chapter 4.2 explained, wind represents the majority of capacity currently in the Generation Interconnection Queue. In terms of wind energy output, the increase was almost as dramatic. Wind energy in MISO increased from about 8,000 GWh in 2008 to about 32,000 GWh in 2012. The monthly breakdown of each year demonstrates how wind production varies over the year with the non-summer months typically producing more energy than in the summer months (Figure 10.3-6).

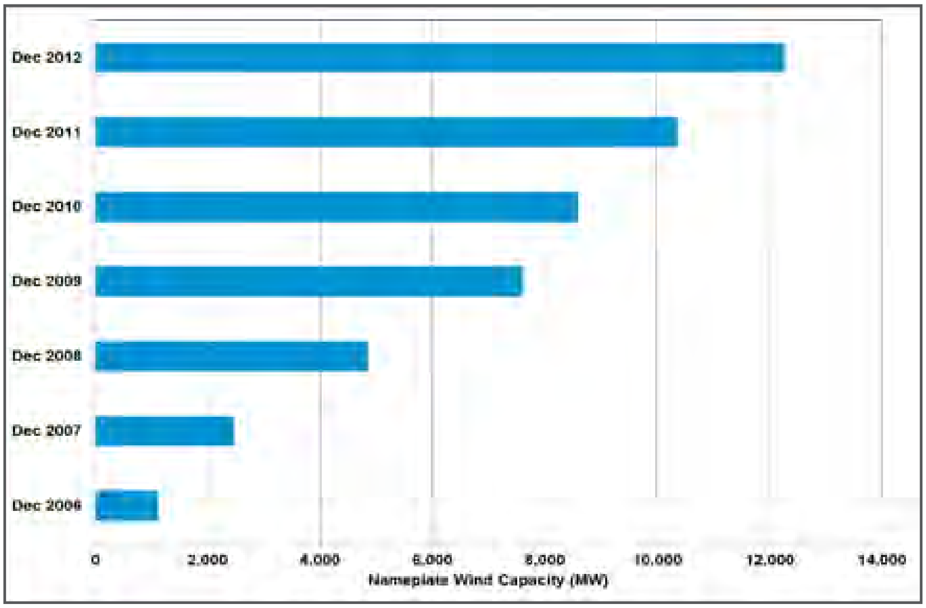


Figure 10.3-5: MISO historical installed wind capacity – MW[53]

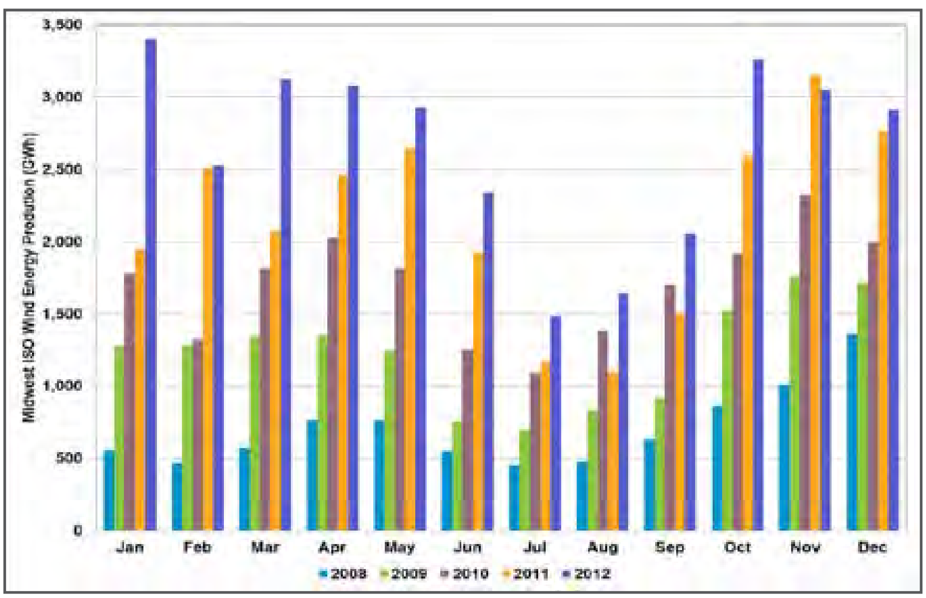


Figure 10.3-6: MISO historical wind energy output – GWh[54]

[53] Source: MISO Commercial Model from 2006 to 2012

[54] Source: MISO Monthly Market Reports

Renewable Energy Standards

The growth of wind has allowed MISO Load Serving Entities (LSE) to meet and surpass the estimated Renewable Portfolio Standard (RPS) energy requirements from 2009 through 2012 (Figure 10.3-7). In fact, the amount of 2012 wind energy would be sufficient to meet this standard into 2014. But in order to meet RPS requirements beyond 2014, the MISO region will need to continue to add wind or other renewable energy.

The forecasted all-MISO RPS requirement is calculated by combining the mandates and goals of each MISO state, for each year, through 2025. The state-by-state mandates and goals generally increase through 2025, though at varying paces. The combined requirements are applied to an aggregated energy level forecasted to grow at 1 percent a year.

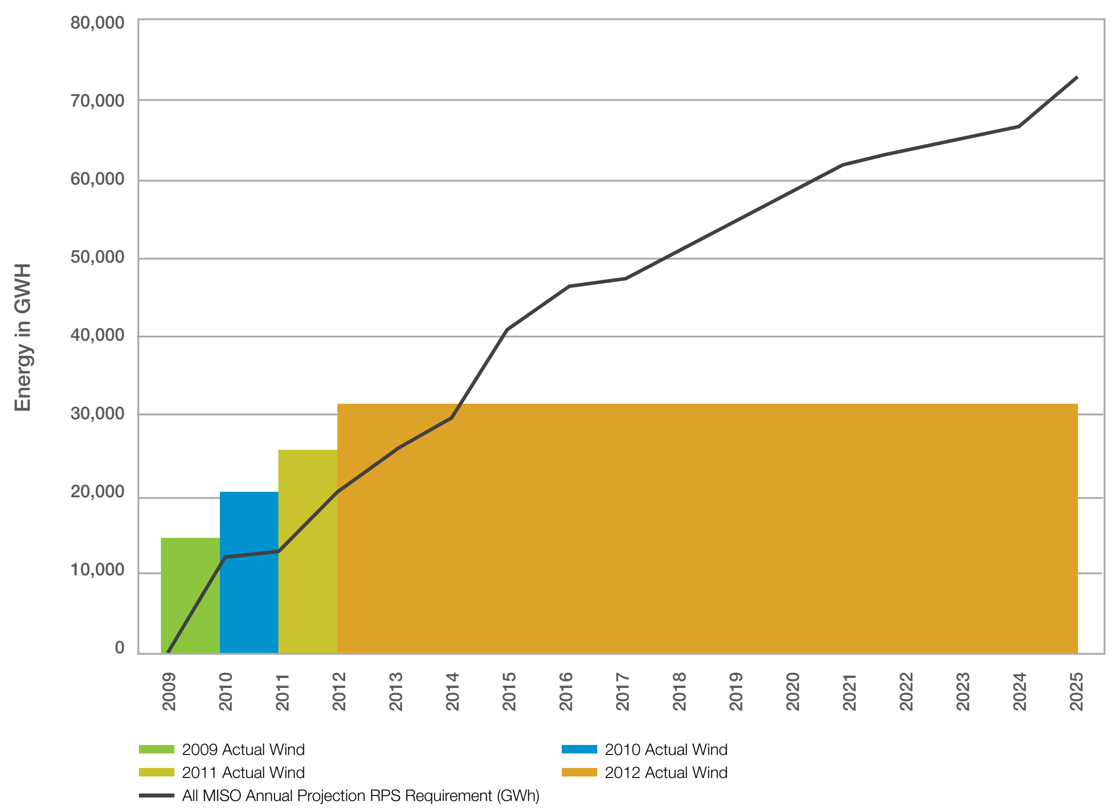


Figure 10.3-7: MISO Projected Annual Renewable Energy Requirement (GWh)[55]

[55] Source: Mandate and goal information from www.dsireusa.org, yearly wind production data aggregated from Monthly Market Reports, wind mandate requirement calculated using EIA data

10.4 Load

Load Growth vs Gross National Product

Load growth has traditionally correlated strongly with gross national product (GNP) growth rates from 1950 through 2012 (Figure 10.4-1). Both values have been trending down, with energy growth declining slightly more than GNP growth. The decade by decade comparisons reveal the same pattern (Table 10.4- 1).

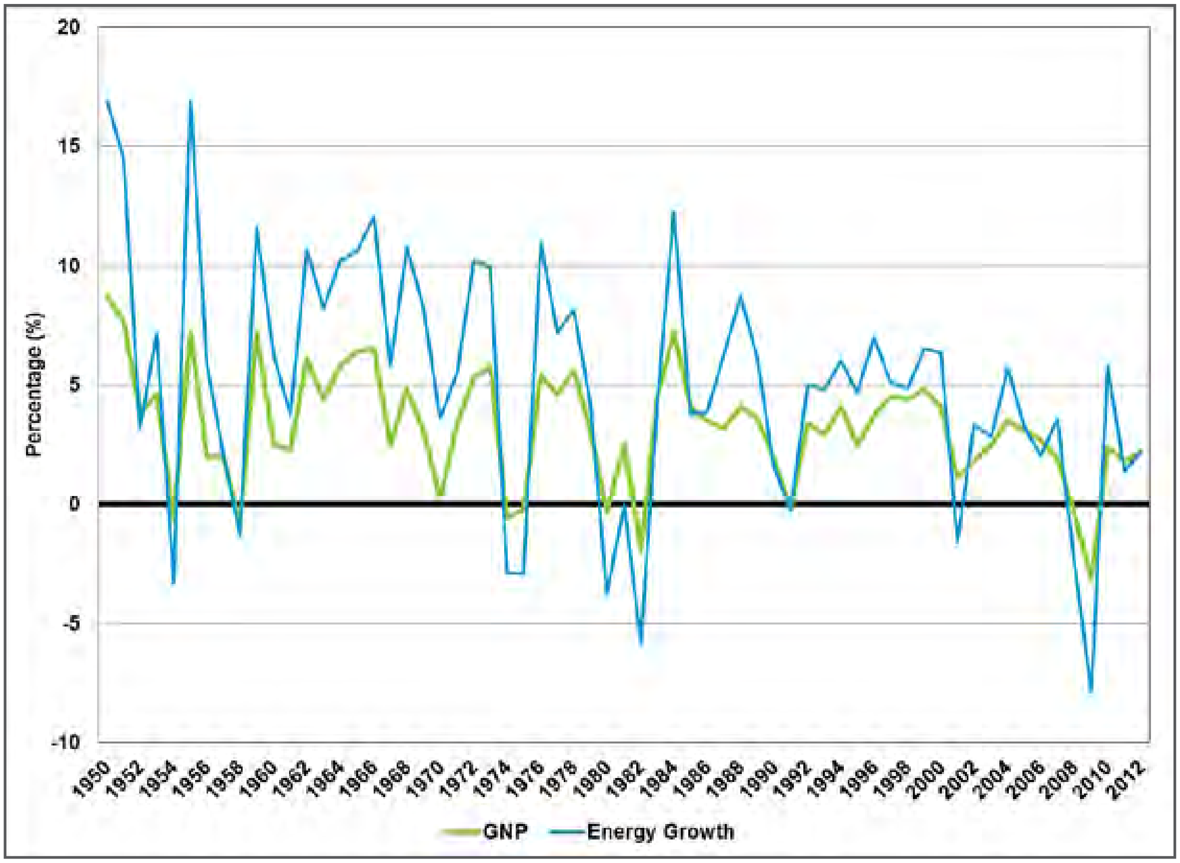


Figure 10.4-1: GNP growth vs. energy consumption growth rates – 1950–2012[56]

	1950s	1960s	1970s	1980s	1990s	2000s
GNP	4.17%	4.44%	3.26%	3.05%	3.20%	1.73%
Energy Growth	3.19%	4.21%	2.15%	0.52%	1.32%	-0.19%

Table 10.4-1: GNP growth vs. energy consumption growth rates by decade

[56] Sources: Bureau of Economic Analysis and the Energy Information Administration

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. Figure 10.4-2 shows the annual peaks, summer and winter, from 2007 through 2012. Within a single year load varies on a weekly cycle, with weekdays experiencing higher load; and on a seasonal cycle, peaking during the summer, with a lower peak in the winter, and with low load periods during the spring and fall seasons (Figure 10.4-3). The Load Curve shows load characteristics over time (Figure 10.4-4). Showing all 366 days in 2012, these curves show the highest instantaneous peak load of 98,576 MW on July 23, 2012; the minimum peak load of 48,767 MW on April 8, 2012; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

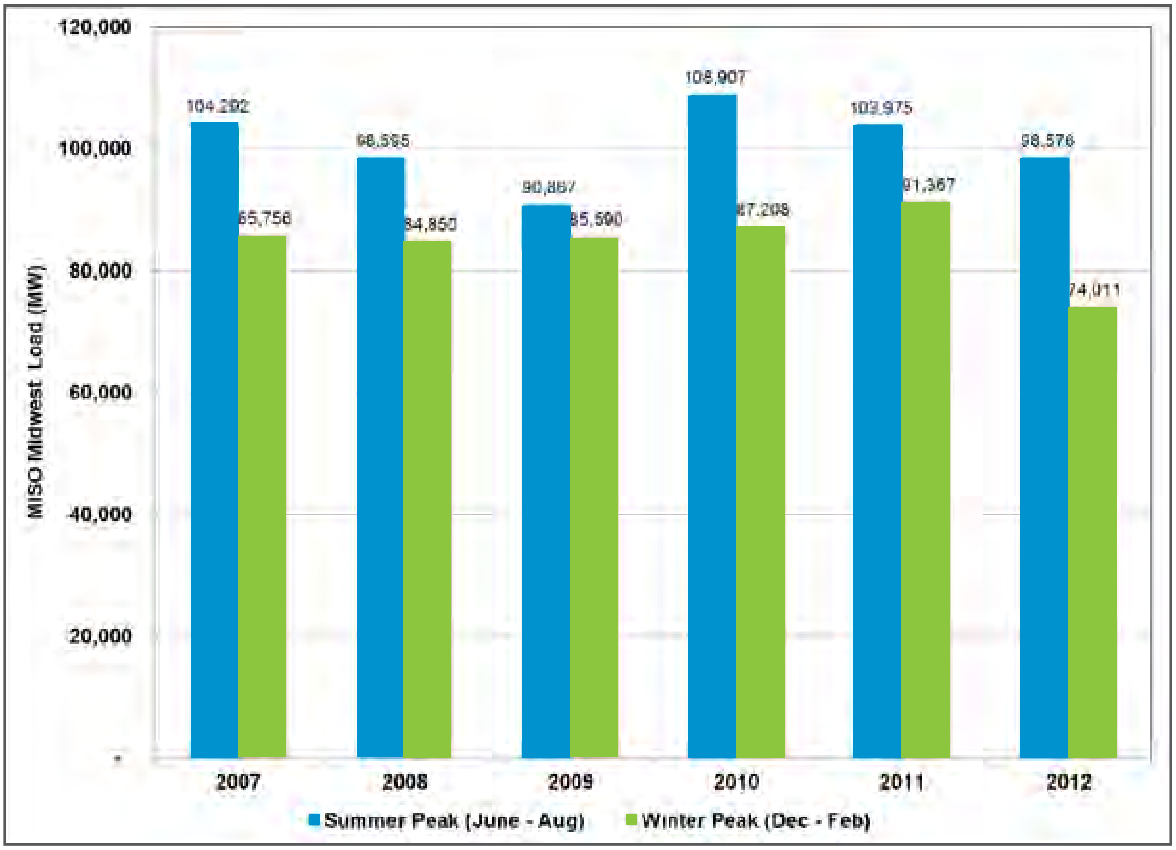


Figure 10.4-2: MISO Summer and Winter Peak Loads – 2007 through 2012[57]

[57] Source: MISO Market Data (2007-2012)

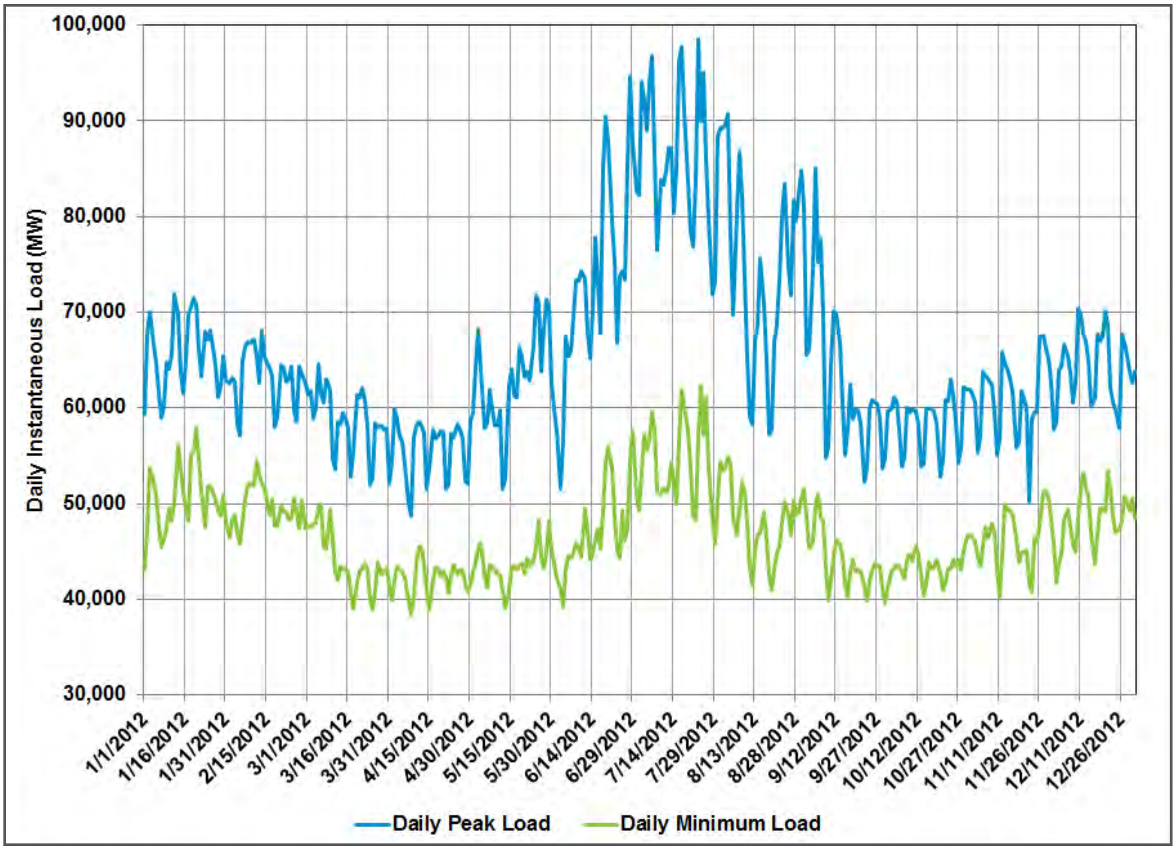


Figure 10.4-3: 2012 MISO-Midwest Daily Load[58]

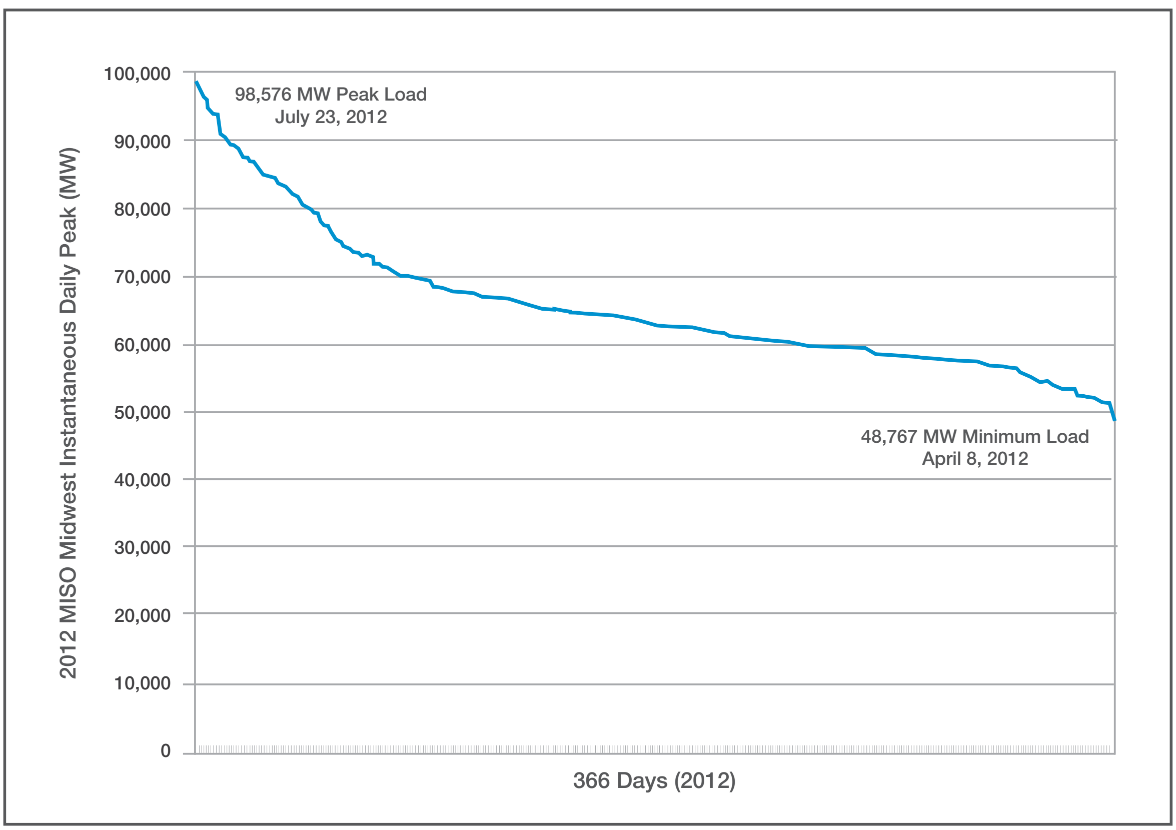


Figure 10.4-4: MISO Load Duration Curve – 2012[58]

[58] Source: MISO Market Data (2007–2012)

End-Use Load

The structure of electrical end-user consumption, or load, is complex and constantly changing with time and over different geographic regions.

MISO relies on individual Load Serving Entities (utilities) to submit data to the MISO Module E Capacity Tracking (MECT) tool for all long-term load forecasting conducted in MTEP, including: Long Term Reliability Assessment, Seasonal Assessments and Planning Reserve Margin.

The development of accurate information on the composition of load data on a continuous basis can be challenging. The Energy Information Administration (EIA) provides historical data on the amount of residential, commercial, industrial and transportation energy sales by state. The current MISO footprint has roughly equal percentages of industrial, commercial and residential loads from 2006 to 2010 (Figure 10.4-5), even though individual states may have somewhat different percentages by sector.

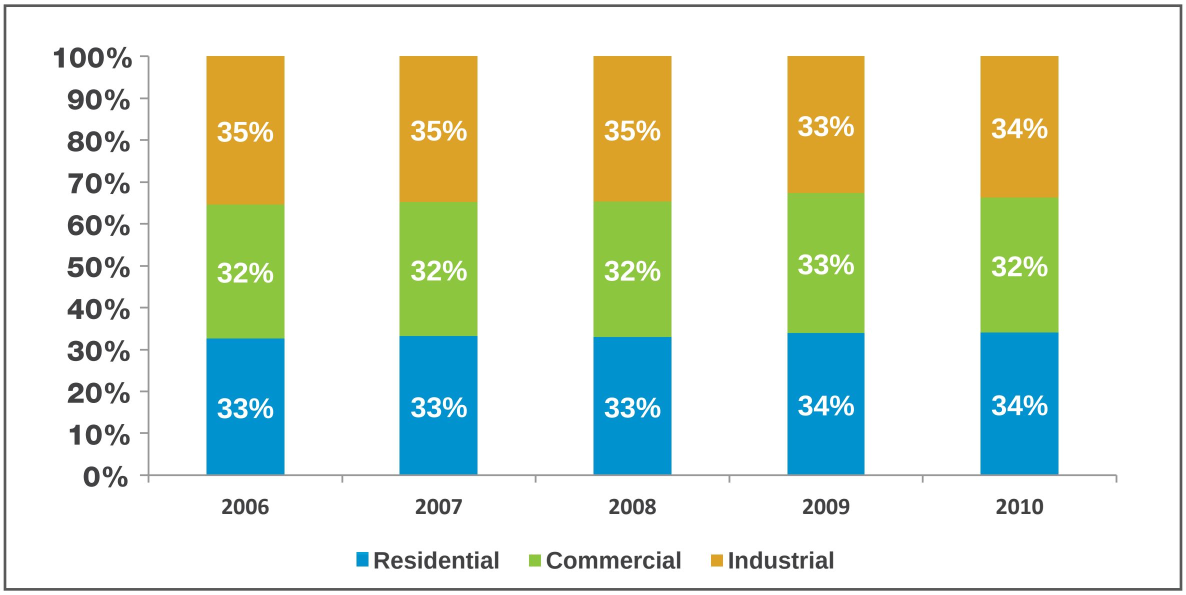


Figure 10.4-5: Historical energy breakdown by sector in the MISO footprint

Residential Sector Energy End Uses

End uses in the residential sector vary. Accounting for even the major end-use categories without metering and monitoring energy usage at the customer level would be both difficult and expensive. Therefore, EIA develops forecasts, by census division, for the residential energy sector based on end-use samples gathered for the entire U.S (Figure 10.4-6). The largest percentage, "electric other," includes a variety of electricity-operated items including dehumidifiers, ceiling fans and spas. The main end-uses in the residential sector are cooling, lighting, electronics, refrigeration and water heating—comprising almost 55 percent of total residential load. These top five uses are good candidates for energy efficiency improvements. All these classifications are based on total energy usage and not on their contribution to the system peak load.

MISO obtained this data for census divisions 3 and 4 (Midwest region) and calculated the percentage of energy usage by type in the residential sector for the MISO footprint. This data is the projected energy usage for 2012 developed using the National Energy Modeling System (NEMS) model. The results shown are indicative only and the percentages shown are the best-available data for the MISO footprint.

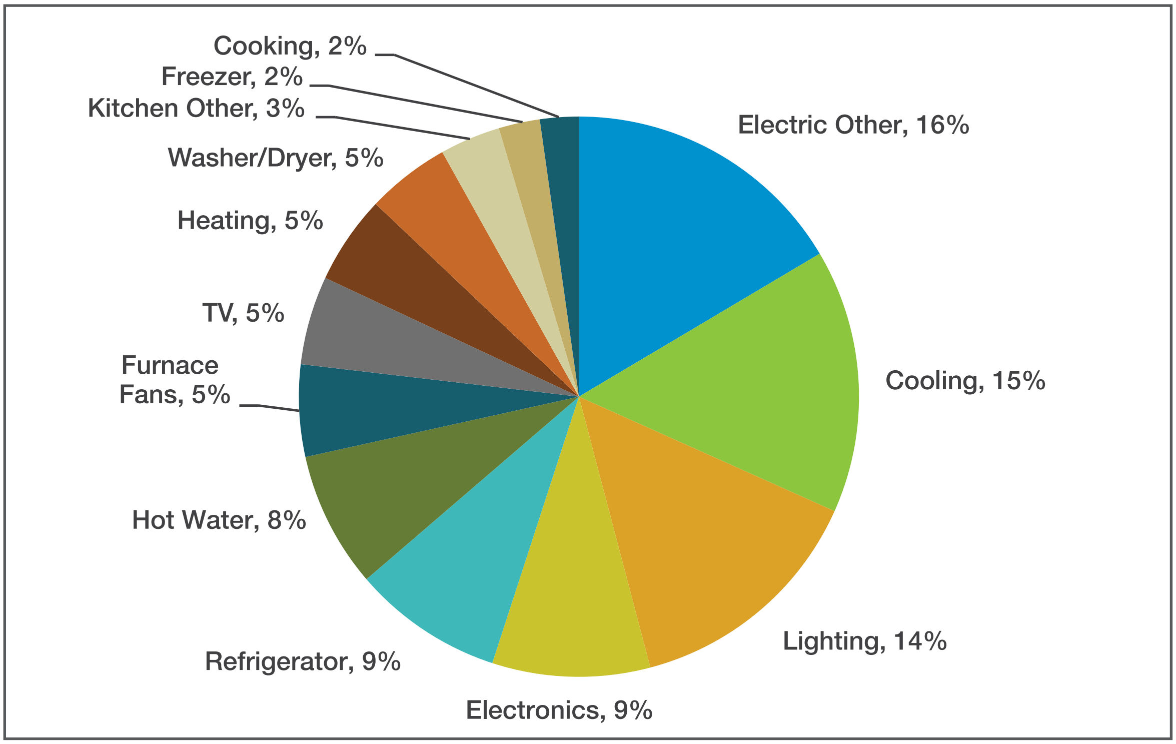


Figure 10.4-6: Percentage of anticipated residential sector energy use in 2012 for the MISO footprint

Commercial Sector Energy End Uses

Similar to the residential consumption data, EIA provided the commercial end-use energy data for the Midwest region (Figure 10.4-7). Heating, ventilation and air-conditioning (HVAC) and lighting comprise almost 54 percent of energy usage in the commercial sector. The results shown are indicative only and the percentages shown are the best available data for the MISO footprint. All these classifications are based on total energy usage and not on their contribution to the system peak load.

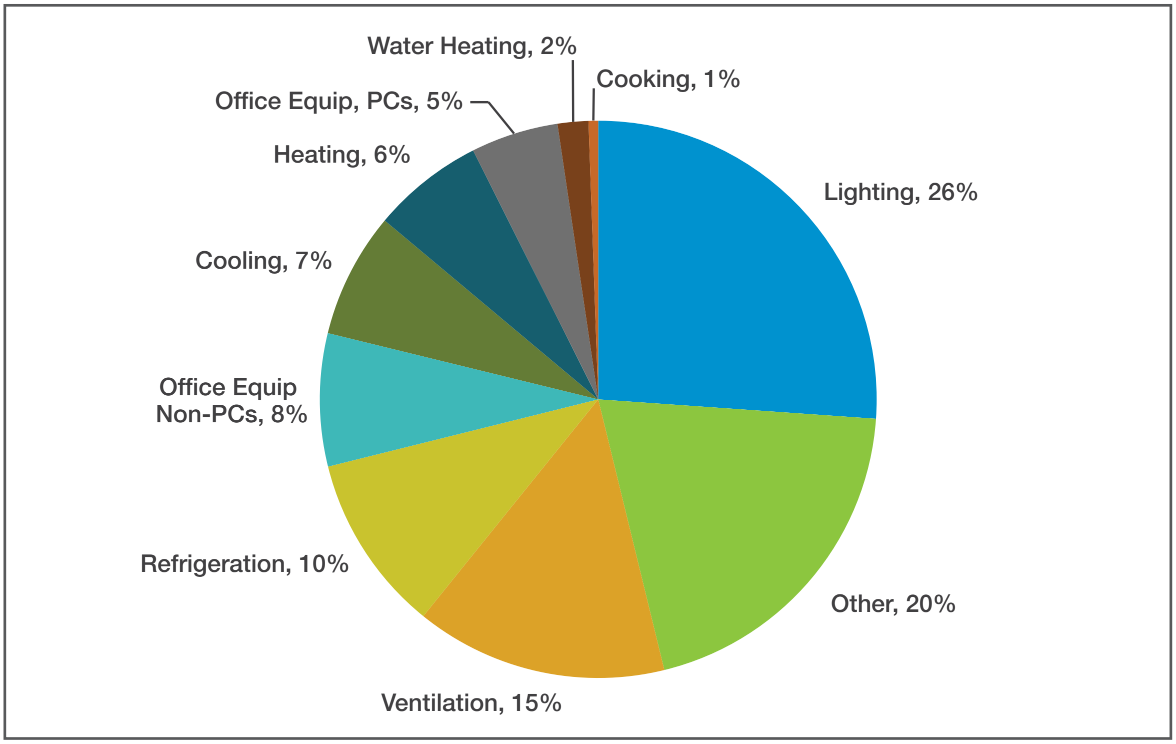
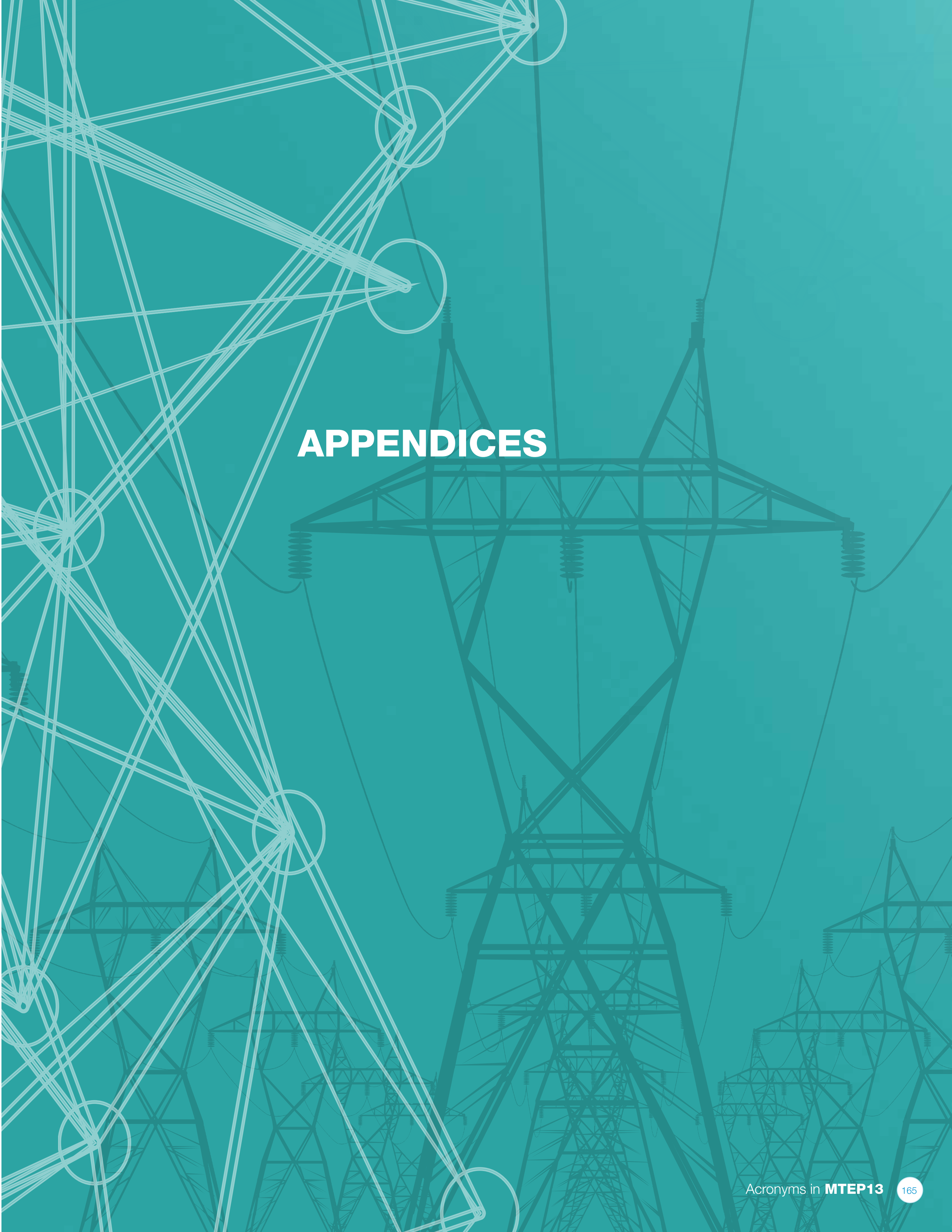


Figure 10.4-7: Percentage of anticipated commercial sector energy use by end-use type in 2012 in the MISO footprint



APPENDICES

Appendices

Most MTEP13 appendices are available and accessible on the MISO public webpage. Confidential appendices, such as D2 - D8, are available on the MISO MTEP13 FTP site. Access to the FTP site requires an ID and password.

A link to the MTEP13 appendices, on the MISO public website, is located at:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP13.aspx

The confidential appendices are located at FTP site.

Appendix A: **Projects recommended for approval**

Section A.1, A.2, A.3: Cost allocations

Section A.4: MTEP13 Appendix A new projects

Appendix B: **Projects with documented need and effectiveness**

Appendix C: **Projects in review and conceptual projects**

Appendix D: **Reliability studies analytical details with mitigation plan (ftp site)**

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

Appendix E: **Additional MTEP13 Study support**

Section E.1: Reliability planning methodology

Section E.2: Generation futures development

Section E.3: MTEP13 futures retail rate impact methodology

Appendix F: **Stakeholder substantive comments**

Acronyms in MTEP13

ACI	Activated carbon injection
AO	Administrative Order
APCS	Adjusted Production Cost Savings
ARR	Auction Revenue Rights
BACT	Best Available Control Technologies
BAU	Business as Usual
BRP	Baseline Reliability Projects
BTMG	Behind-the-meter generation
CBMEP	Cross Border Market Efficiency Project
CC	Combined cycle
CEII	Critical Energy Infrastructure Information
CEL	Capacity Export Limit
CIL	Capacity Import Limit
DCLM	Direct Control Load Management
DOE	Department of Energy
DPP	Definitive Planning Phase
DR	Demand response
DSI	Dry Sorbent Injection
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	Demand-side management
EAR	External Asynchronous Resource
EE	Energy efficiency
EGEAS	Electric Generation Expansion Analysis System
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ENGCTF	Electric and Natural Gas Coordination Task Force
ENV	Environmental
EPA	Environmental Protection Agency (U.S.)
EPB	Estimated potential benefit
ERAG	Eastern Reliability Assessment Group
ERO	Electric Reliability Organization
ERR	Energy Efficiency Resources
FERC	Federal Energy Regulatory Commission
FGD	Flue-gas desulfurization
FTR	Financial Transmission Rights
GADS	Generator Availability Data System
GI	Generator Interconnection
GIP	Generator Interconnection Projects
GIS	Geographical Information System
GLDF	Generation to load distribution factor
GLSF	Generation to load shift factor
GNP	Gross national product
GS	Generation Shift
HCDC	High voltage direct current
HVAC	Heating, ventilation, air conditioning
HVDC	High voltage direct current
ICT	Independent Coordinator of Transmission
IL	Interruptible Load
IMM	Independent Market Monitor
IPSAC	Interregional Planning Stakeholder Advisory Committee
JCSP	Joint Coordinated System Plan
JOA	Joint Operating Agreement
JRPC	Joint RTO Planning Committee
LBA	Local Balancing Authorities
LCR	Local Clearing Requirement
LFU	Load forecast uncertainty
LG	Limited Growth
LGIA	Large Generator Interconnection Agreement
LMP	Locational marginal price
LMR	Load Modifying Resources
LNG	Liquified natural gas

LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local resource zones
LSE	Load Serving Entity
LTTR	Long-Term Transmission Rights
M2M	Market to market
MAPP	Midcontinent Area Power Pool
MATS	Mercury and Air Toxics Standard
MEP	Market Efficiency Projects
MEPS	Market Efficiency Planning Study
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MH	Manitoba Hydro
MTDT	Market Transition Deliverability Test
MTEP	MISO Transmission Expansion Plan
MOD	Model on Demand
MMWG	Multi-regional Modeling Working Group
MVP	Multi-Value Projects
MW	Megawatt
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corp.
NRIS	Network Resource Interconnection Service
NSI	Net scheduled interchange
NSPS	New Source Performance Standard
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	Organization of MISO States
PAC	Planning Advisory Committee
POC	Proof-of-concept
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
RA	Resource adequacy
RE	Robust Economy
RECB	Regional Expansion Criteria and Benefits
RGOS	Regional Generator Outlet Study
RMD	Regional Merit-Order Dispatch
ROFR	Right of first refusal
RPS	Renewable Portfolio Standard
RRF	Regional resource forecast
RTO	Regional transmission operator
S2M	South to Midwest Transfer
SAWAG	Supply Adequacy Working Group
SCED	Security Constrained Economic Dispatch
SCR	Selective catalytic reduction
SERTP	Southeastern Regional Transmission Planning
SFT	Simultaneous feasibility test
SPC	System Planning Committee
SPM	Subregional Planning Meetings
SPP	Southwest Power Pool
TCFS	Top congested flowgate study
TO	Transmission Owner
TPL	Transmission Planning Standards
TRG	Technical review group
TSD	Transmission Service Delivery
TSR	Transmission Service Request
TSTF	Technical Study Task Forces
VWS	Value of water in storage.

MISO would like to thank the many stakeholders who provided MTEP13 report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region.

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