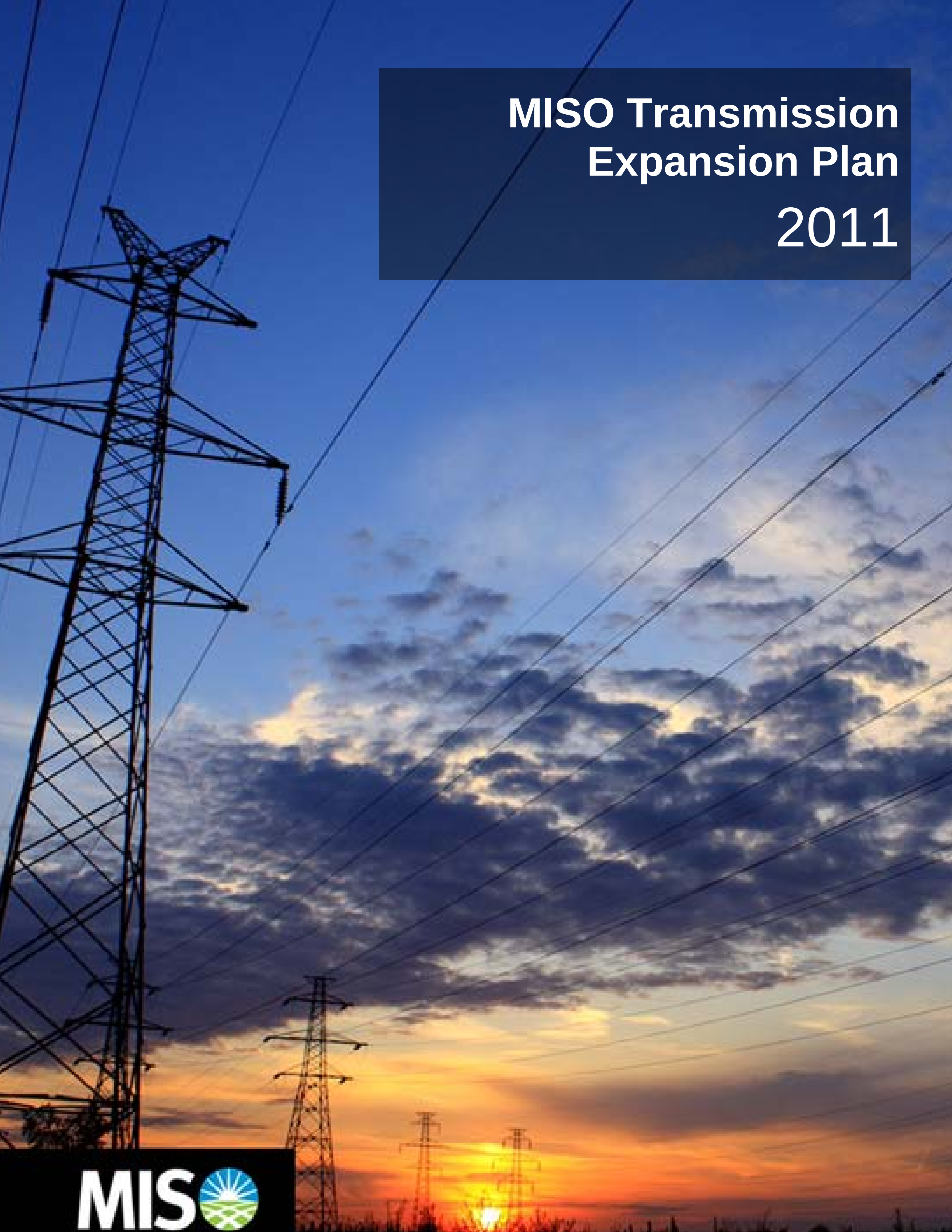
MISO Transmission Expansion Plan 2011



Appendices

1. Executive Summary

The annual MISO Transmission Expansion Plan (MTEP) identifies solutions to meet transmission needs and create value opportunities over the next decade and beyond. These solutions are defined via the implementation of a comprehensive planning approach which identifies essential transmission projects for approval and subsequent construction. MISO staff recommends the projects listed and described in MTEP11 Appendix A[1] to the MISO Board of Directors for their review and approval.

MTEP11, the eighth edition of this publication, is the culmination of more than 18 months of collaboration between MISO planning staff and stakeholders. The primary purpose of this and other MTEP iterations is to identify transmission projects that:

- 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.

MTEP11 recommends $6.5[2] billion in new transmission expansion through the year 2021 for inclusion in Appendix A and construction. This is part of a continuing effort to ensure a reliable and efficient electric grid that keeps pace with energy and policy demands. Key findings and activities from the MTEP11 cycle include:

- **Recommendation of the first Multi Value Project portfolio for approval by the MISO Board of Directors:** The portfolio is comprised of 17 projects, costing $5.6 billion.[3] The proposed Multi Value Project (MVP) portfolio will create a regional network that provides reliability, public policy and economic benefits spread across MISO, such as
    - **Reliability benefits:** The proposed MVP portfolio mitigates approximately 650 reliability violations for more than 6,700 system conditions, increasing the transmission system's robustness under normal operation and extreme events.
    - **Public policy benefits:** The proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy.
    - **Economic benefits:** The proposed MVP portfolio provides benefits in excess of the portfolio cost under all scenarios studied. These benefits are spread throughout the system, and each zone[4] receives benefits of at least 1.6 and up to 2.8 times the costs it incurs.
    - **Qualitative benefits:** The proposed MVP portfolio provides a number of additional qualitative benefits. For example, the transmission will support a variety of generation policies through utilizing a set of energy zones which support wind, natural gas and other fuel sources
    - **Job creation:** The construction of the proposed MVP portfolio will create between 17,000 and 39,800 direct jobs, or between 28,400 and 74,000 total jobs, including construction, supplier and downstream impacts.
- **Recommendation of 199 new Baseline Reliability, Generation Interconnection, or Other projects totaling $1.4 billion for approval by the MISO Board of Directors[5]:** These projects, together with proposed projects listed in Appendix B, ensure compliance with all reliability standards

[1] Projects in Appendix A reflect planned projects approved by or recommended for approval by the Board of Directors. Projects in Appendix B represent proposed projects for which a need has been identified, but are not timely or require additional analysis. Appendix C contains projects for which the need has not been verified.

[2] $6.5 billion figure includes the $849 million in projects that were either approved or conditionally approved at the June 2011 MISO Board of Directors meeting.

[3] Portfolio cost is as submitted and reflects nominal in-service date costs in whole or in part; the portfolio cost is equivalent to $5.2 billion in 2011 dollars. Total portfolio cost includes the Brookings County project, conditionally approved in June 2011 and the Michigan Thumb project, approved in December 2010.

[4] Benefits were calculated based on the MISO proposed Local Resource Zones for Resource Adequacy

[5] Total includes $118.5 million of projects that were approved during the June approval cycle.

and requirements and allow for the interconnection of approximately 2,700 MW of wind, nuclear, and other generation.

- **Economic assessment of transmission expansion:** In addition to the proposed Multi Value Project portfolio, Appendices A and B contain a variety of planned and proposed transmission projects. Although premised largely on reliability, a subset of these projects will deliver market congestion reduction benefits of 0.9 to 1.0 times their cost beginning in 2016.
- **Confirmation of Long-Term Generation Resource Adequacy:** The system has adequate capacity to meet its reserve requirements or Loss of Load Expectation (LOLE) criteria through 2021 based on currently announced generation retirements. However, these conclusions do not take into account capacity retirements that might be required by regulations imposed by the U.S. Environmental Protection Agency (EPA), which could significantly, and rapidly, erode reserve margins**.**
- **Determination of the potential impacts of EPA regulations on generation retirements:** At the direction of stakeholders and Board of Directors, MISO evaluated the potential impacts of four new EPA regulations, including the impact of carbon reduction requirements. This study found the following potential impacts:
  - **Units at risk for retirement:** Depending on economic conditions, including the cost of environmental regulation compliance, approximately 13 GW of existing coal generation is at-risk for retirement.
  - **Potential cost of compliance:** The total 20-year net present value capital cost of compliance is expected to exceed $30 billion. This value includes the cost of retrofits on the system, the cost of replacement capacity, the cost of fixed operations and maintenance and the cost of transmission upgrades. This cost of compliance could increase the cost of energy by $5/MWh.
  - **Generation Resource adequacy impacts:** If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.6 percent in 2021. The 2021 reserve requirement is 18.2 percent.
- **Full implementation of a regional transmission planning approach:** The proposed MVP portfolio is the realization of more than eight years of process, policy and engineering analysis. These solutions are premised on the integration of local and regional needs into a transmission solution that, when combined with the existing transmission system, provides the least cost delivered energy to customers.

In MTEP11, MISO completed analyses showing the near and long term affects of proposed transmission lines. In the coming years, MISO, through the continued integration of reliability, economic and public policy projects, will continue to drive grid efficiencies by ensuring that near-term projects support long-term goals.

The MISO planning approach

MISO is guided in its planning efforts by a set of principles established by its Board of Directors. These principles were created to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, confirmed in August 2011, are as follows:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

To support these principles, a transmission planning process has been implemented reflecting 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 new energy policy imperatives. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors 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.

The following activities were undertaken to fulfill these conditions and—through them—the planning principles enunciated by the Board of Directors:

- **Safeguarding local and regional reliability:** System reliability must be maintained throughout all MISO planning efforts, both on a local and interconnection-wide basis. This requirement can be difficult, in the face of changing generation and energy policy standards. Throughout 2011, MISO continued the transformation of the planning process to create an integrated transmission network that supports current and future reliability needs, while minimizing the cost of delivered energy. This value-based planning approach demonstrates a robust view of project benefits, through the analyses of many potential reliability, economic and policy-driven variables.
- **Distributing benefits commensurate with costs**: The MISO planning approach is premised on the allocation of transmission costs in a manner that is commensurate with their benefits. To ensure this goal was met, MISO created a complete business case for the proposed Multi Value Project portfolio which demonstrated the regional spread of the economic benefits of the portfolio. In the future, MISO will continue to refine the business case for transmission projects and portfolios, as staff seek to optimize the transmission system to deliver the least-cost energy to consumers.
- **Responding to evolving energy policy:** MISO examines multiple future scenarios in order to capture the impact of a wide array of potential policy outcomes. These future scenarios include varied demand and energy growth levels, and they also include the implementation of new policies which may have large impacts on the transmission system. For example, MISO conducted a thorough analysis of the U.S. Environmental Protection Agency (EPA) regulations to determine the impacts and action which will need to be taken as the regulations go into effect.

Investments in system reliability and efficiency

To respond to existing energy mandates and safeguard the system reliability, MTEP11 recommends 214 new projects for inclusion in Appendix A. These projects represent an incremental $6.5 billion in transmission infrastructure investment within the MISO footprint and fall into the following four categories:

- **Multi Value Projects (16 projects, $5.1[6] billion):** Projects providing regional public policy, reliability and/or economic benefits.
- **Baseline Reliability Projects (40 projects, $424 million):** Projects required to meet North American Electric Reliability Corporation (NERC) reliability standards. These standards impact facilities of a voltage greater than 100kV and represent the minimum standard applied across the MISO footprint.
- **Generator Interconnection Projects (26 projects, $273 million[7]):** Projects required to reliably connect new generation to the transmission grid. The projects recommended for approval will allow for the connection of approximately 2,700 MW of wind, nuclear, and other generation
- **Other Projects (133 projects, $681 million):** A wide range of projects, such as those designed to provide local economic benefit but not meeting the threshold requirements for qualification as Market Efficiency Project (MEP), and projects required to support the lower voltage transmission system.

The addition of new transmission projects in MTEP11 brings the total number of projects in Appendix A to 553, representing an expected investment of $10.0 billion through 2021. When completed, the projects will result in approximately 6,600 miles of new or upgraded transmission lines. Since the first MTEP cycle closed in 2003, transmission projects recommended for approval total $14.3 billion, of which $4.3 billion is associated with projects already in service.

MTEP11 contains 24 new Appendix A projects meeting cost-sharing eligibility criteria under the Baseline Reliability Project or Generator Interconnection provisions of the MISO Tariff. This report also features 16 projects meeting Multi Value Project cost sharing methodology criteria.

Economic assessment of planned and proposed projects

As previously described, projects currently contained in Appendices A and B are primarily intended to address a reliability issue or need on the transmission system. However, those projects also have potential to create additional value, including the following:

- Adjusted Production Cost Savings
- Reduced Energy And Capacity Losses
- Reduced Reserve Margins

For example, Table 1-1 shows an estimated Adjusted Production Cost benefit of $867 million in 2016 against a first year modeled transmission portfolio cost of approximately $1.1 billion. This benefit will lead to 20 to 40 year present value benefits of $9.1 to $20.6 billion, and economic benefit-to-cost ratios of 0.9 to 1.0. These economic benefits are in addition to the benefits derived from increased system reliability considerations initially driving the need for the majority of these projects.

	2016 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO East	$367	$5,627	$3,844	$8,742	$4,638
MISO Central	$145	$2,210	$1,509	$3,433	$1,821
MISO West	$355	$5,436	$3,714	$8,447	$4,482
MISO	$867	$13,273	$9,066	$20,622	$10,941

Table 1-1: Adjusted Production Cost benefits, in millions of 2016 dollars

6 Portfolio cost shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars. The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above figure.

7 Project cost shown is the total cost, not just the cost shared or Transmission Owner contribution.

The value-based planning process

Uncertainties surrounding future policy decisions create challenges for those involved in the planning function and cause hesitancy for those with the resources to undertake transmission expansion projects. To minimize the risk in building a system under such conditions, the planning process must allow consideration of transmission projects in the context of potential outcomes. The goal is to identify plans resulting in the optimum amount of future value and the least amount of future regrets in areas such as cost incurred, right of way used, and benefits achieved.

MTEP11 identified and examined a wide array of future scenarios, which include the following:

- **The Business As Usual (BAU) with Mid-Low Demand and Energy Growth Rates Future Scenario** is considered a status quo future scenario and continues the economic downturn-affected growth in demand, energy and inflation rates.
- **The Business as Usual (BAU) with Historic Demand and Energy Growth Rates Future Scenario** is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections.
- **The Carbon Constraint Future Scenario** models a declining cap on future CO2 emissions. The carbon cap is modeled after the Waxman-Markey Bill, which has an 83 percent reduction of CO2 emissions from a 2005 baseline by the year 2050.
- **The Combined Energy Policy Future Scenario** includes a 20 percent federal RPS, a carbon cap modeled after the Waxman-Markey Bill, a "smart" transmission grid, and electric vehicles.

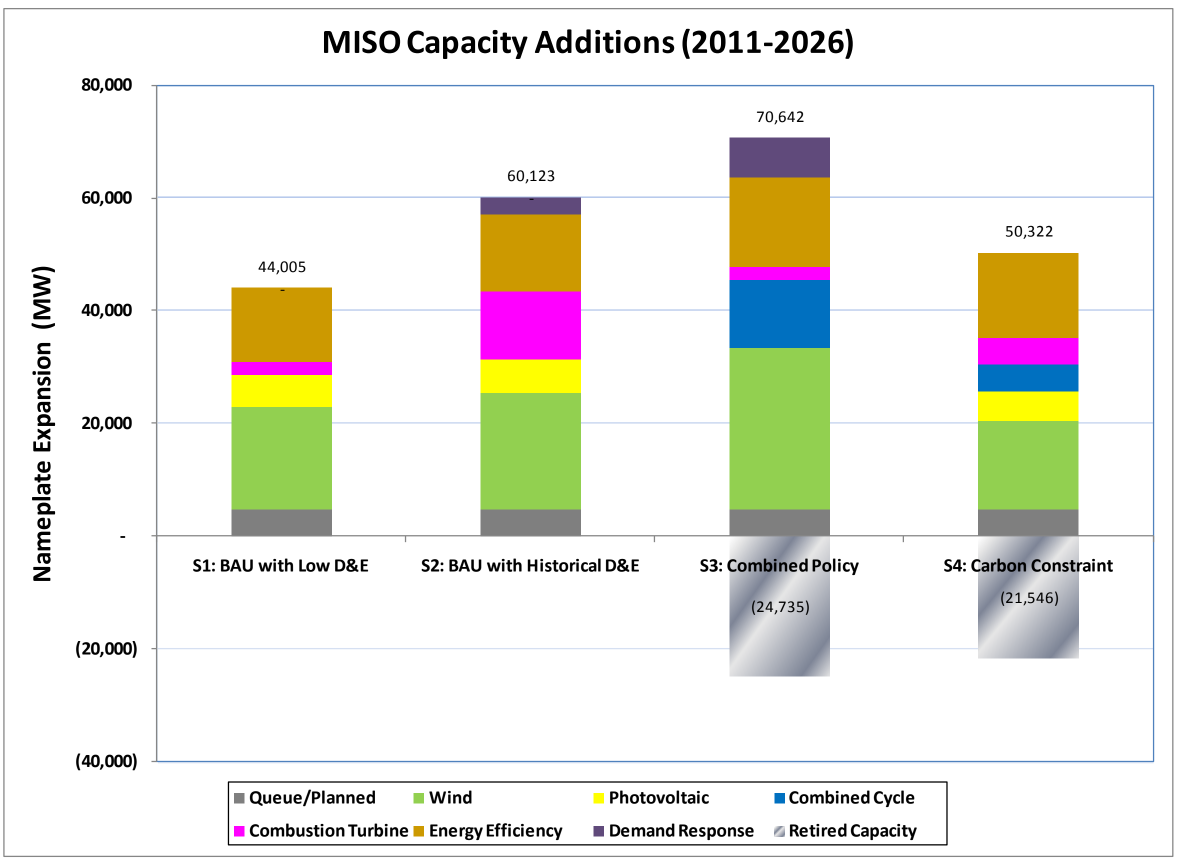


Figure 1-1: Generation Resources per Future Scenario

Potential retail rate impacts for future policy scenarios

To measure the potential impact to rate payers under each of the future scenarios, MISO projected potential impacts to the 2026 retail rate by calculating the impact of wholesale costs related to generation capital investment, production costs, transmission capital investment and distribution costs across the forecasted energy usage levels. In general, these rate impacts reflect differences between the type of generation and the associated transmission needed to integrate the generation in the various scenarios. Refer to Figure 1-1 for additional detail on theoretical impacts under various futures.

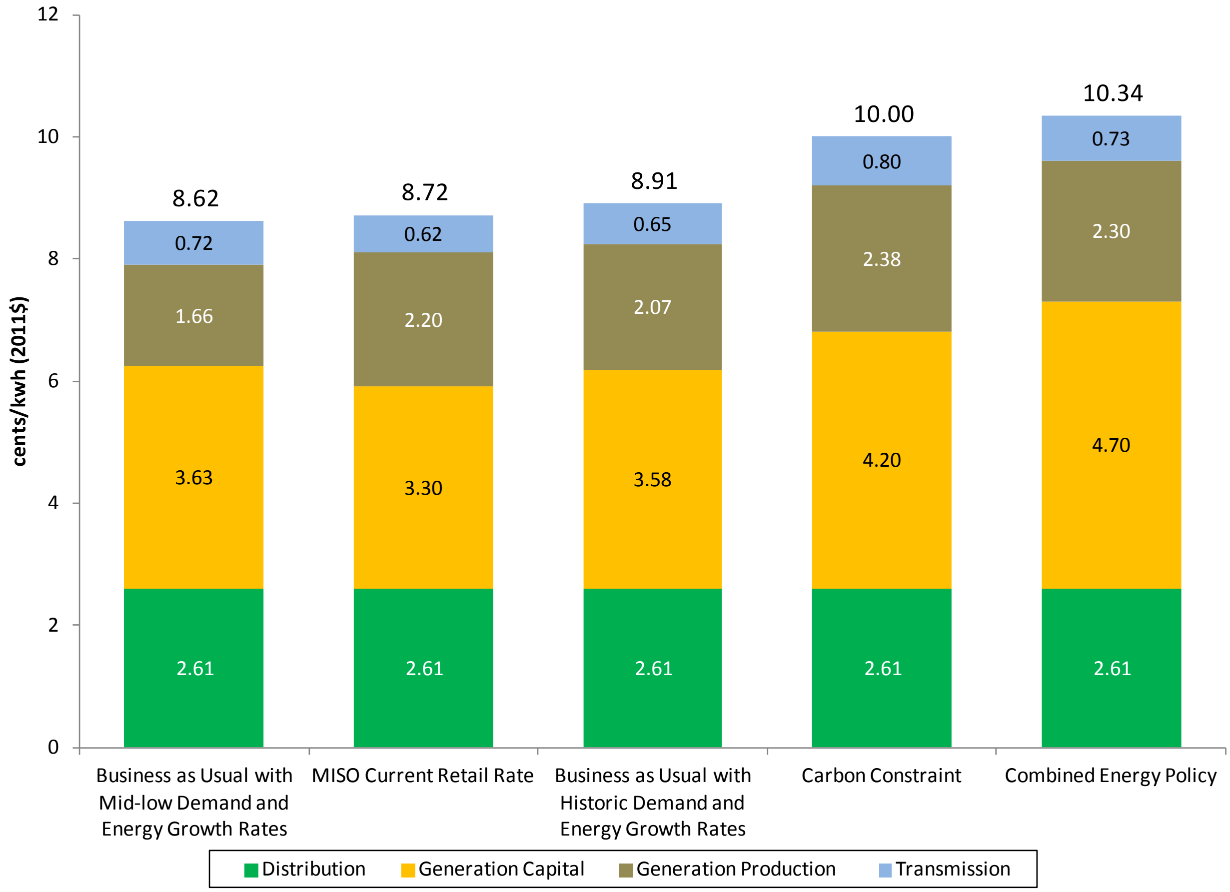


Figure 1-2: Comparison of estimated retail rate for each future scenario (cents per KWh in 2011 dollars)

Assuming that wholesale costs flow through to retail rates, rates for retail customers are projected to increase faster than inflation in all but one scenario, but the magnitude of the rate increases will vary greatly depending on actual economic and policy conditions. Assuming that all of the increase or decrease in wholesale costs flows through to the retail customer, this impact could range from a decrease of 1 percent for the Business as Usual with Mid-low Demand and Energy Growth Rate Future to an increase of 18.7 percent for the Combined Energy Policy Future.

Proposed MVP portfolio

The proposed MVP portfolio is the culmination of more than eight years of transmission planning solutions, as transmission projects identified in MTEP03 through MTEP10 were brought together to form a cohesive, regional plan. Approximately 11 months of intensive studies were performed on the candidate portfolio, with heavy stakeholder involvement and review. At the end of the study, MISO recommends a proposed MVP portfolio for review and approval by the Board of Directors.

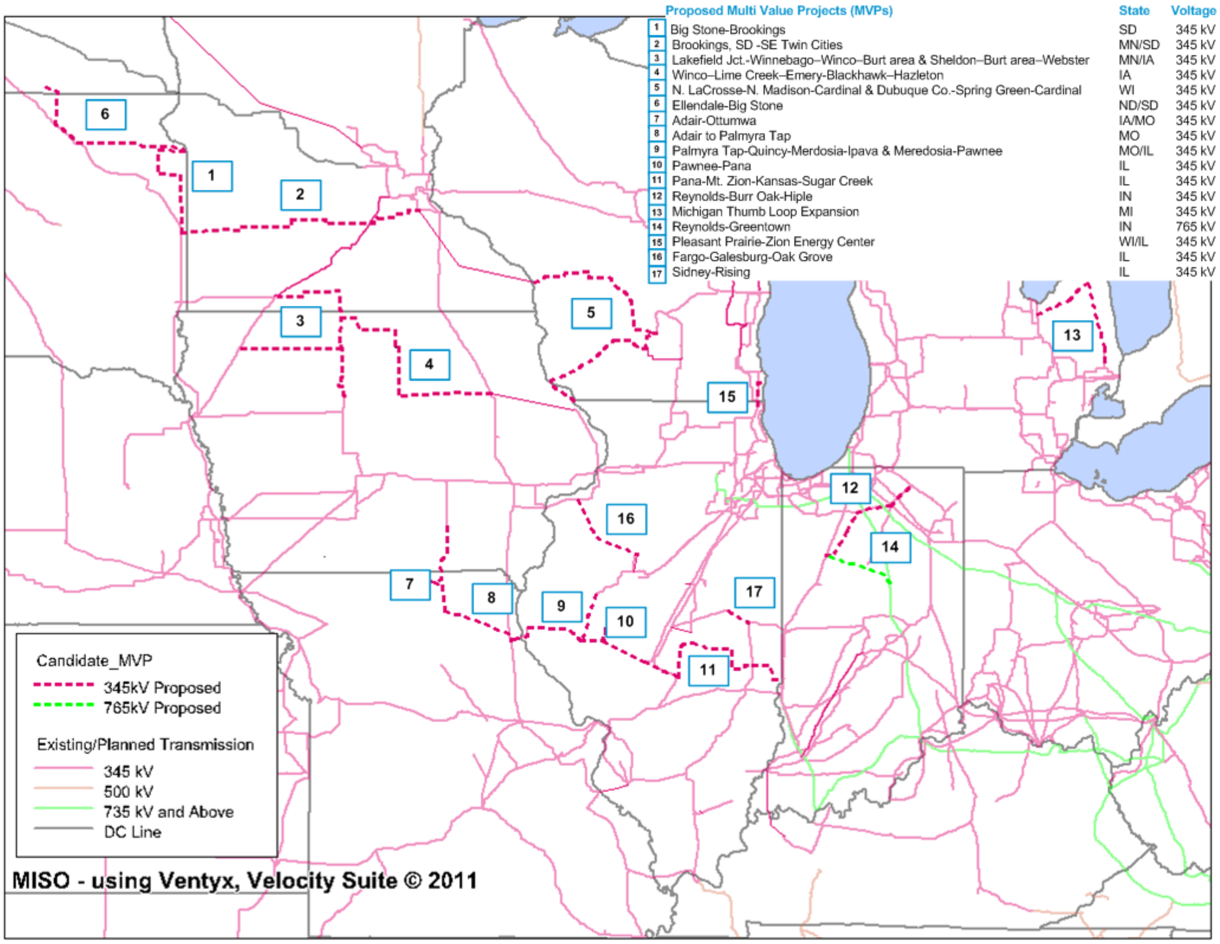


Figure 1-3: Proposed MVP portfolio

The proposed MVP portfolio combines reliability, economic and public policy drivers to provide a transmission solution that provides benefits in excess of its costs throughout the MISO footprint. This portfolio, when integrated into the existing and planned transmission network, resolves about 650 reliability violations for more than 6,700 system conditions, enabling the delivery of 41 million MWh of renewable energy annually to load. The portfolio also provides strong economic benefits; all zones[8] within the MISO footprint see benefits of at least 1.6 to 2.8 times their cost.

[8] Benefits were calculated based on the MISO proposed Local Resource Zones for Resource Adequacy

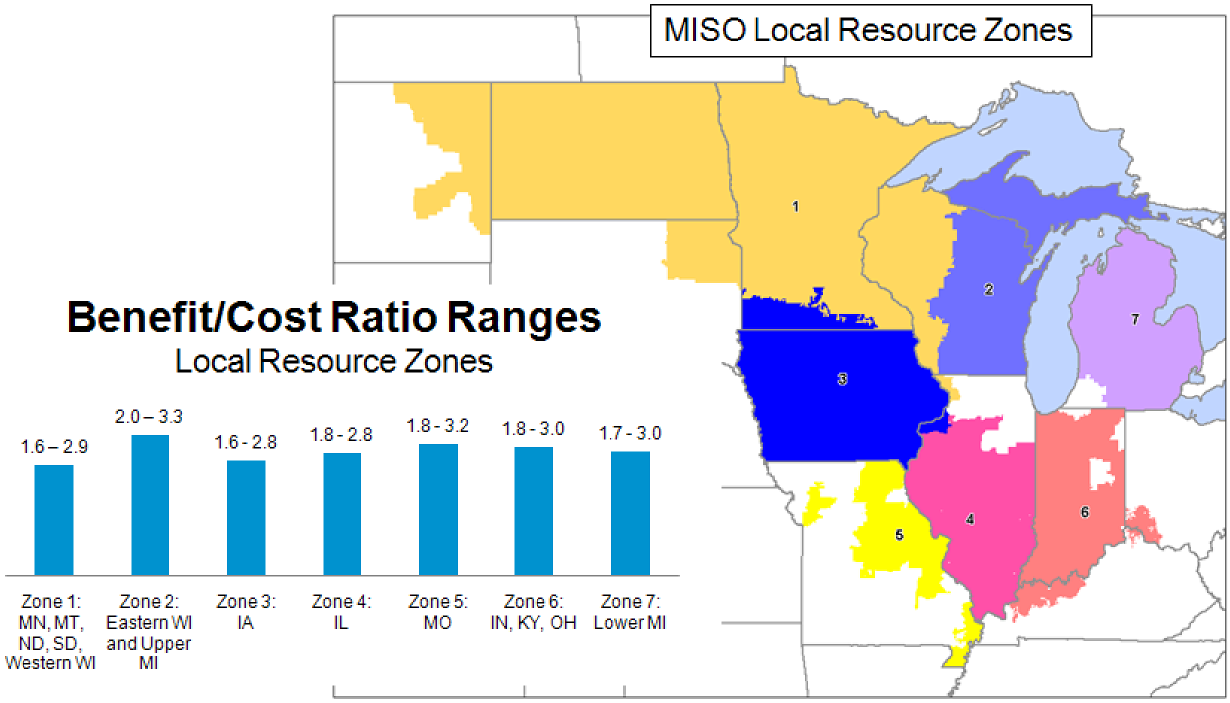


Figure 1-4: Proposed MVP portfolio Zonal benefit-cost ratios

The portfolio also creates a transmission network that is able to respond to the ever-evolving reliability, generation and policy-based needs of the MISO footprint. For example, although the study was premised on a set of energy zones created to distribute wind capacity throughout the footprint in a least-cost pattern, these energy zones were also located with respect to existing infrastructure, such as transmission lines and natural gas pipelines. As a result the transmission will support a variety of different generation fuel sources, and with the fuel sources, a variety of generation policies.

Resource adequacy and risk assessment

MTEP11 includes a forecast of resource adequacy based on projections of future generation and load to supplement and inform the assessment of the transmission system. The results of a study of the period 2012–2021 indicate that MISO will have sufficient generating capacity to meet demand through 2021, excluding the impacts of the EPA regulations. Net internal demand is expected to be 89 GW in 2012 and 97 GW in 2021[9]. A total of 113 GW of resources are expected to be available to meet this demand in 2012 for the MISO region, increasing to 115 GW in 2021.

9 Net internal demand is equal to the median forecasted load. There is a 50 percent chance that peak load levels will exceed this prediction, while there is a 50 percent likelihood that peak load levels will be less than this prediction.

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 1.2: 2012-2021 forecasted reserves

The MISO Planning Reserve Margin requirement varied throughout the 10-year period studied, from 17.4 percent in 2012 to 18.2 percent in 2021. The reserve margins projected through the assessment time frame varies from 27.0 percent to 18.6 percent for 2012-2021. The expected ability of forecasted resources to meet demand projections is anticipated to exceed the reliability levels represented by the accepted industry standard of one day in 10 years through 2019. However, these conclusions do not take into account capacity retirements that might be required by regulations imposed by the U.S. Environmental Protection Agency (EPA) which could significantly, and rapidly, erode reserve margins**.**

EPA impact analysis

The U.S. Environmental Protection Agency (EPA) is finalizing four proposed regulations that will affect the MISO system. They require utilities to choose between retrofitting their generators with environmental controls or retiring them. At the direction of stakeholders and the Board of Directors, MISO evaluated the potential impacts of the new regulations, including the impact of carbon reduction requirements. This study evaluated the effects on capacity cost, resource adequacy, cost of energy and transmission reliability.[10]

A survey of the current fleet within MISO revealed 298 generation units will be affected by the four proposed regulations. The capacity of the units at risk for retirement is 12.7 GW, based on the assumptions surrounding the cost of environmental regulation compliance.

The compliance cost of retrofitted units and replacement generation due to the EPA regulations are estimated to exceed $30 billion. Identifying all the costs to maintain regulation compliance and system reliability, a 7.0 to 7.6 percent increase in retail rates could be realized.

[10] The EPA Regulation Impact Analysis was based on assumptions for proposed EPA regulations. The finalization of these regulations has the potential to introduce change and uncertainty.

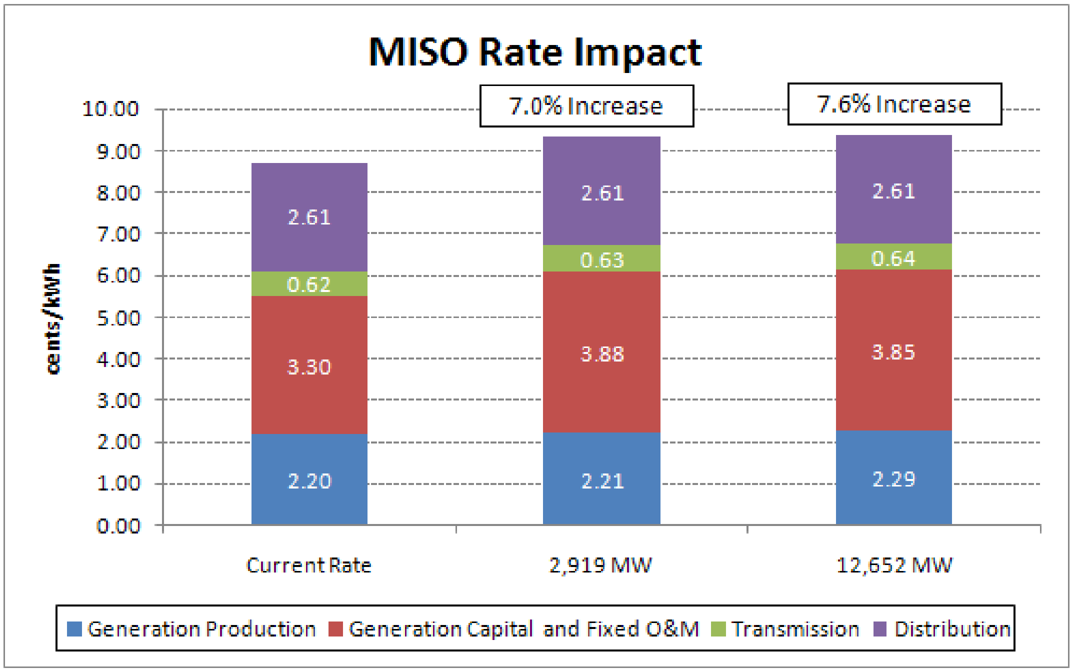


Figure 1-5: MISO rate impact

The proposed EPA regulations could also have an impact on the system's ability to meet demand. If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.6 percent in 2021. The 2021 reserve requirement is 18.2 percent. However, if capacity is replaced with new and more reliable resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by 0.2 to 1.0 percent.

Reserve margin	Forecasted reserves, without EPA regulations		Forecasted reserves, with EPA regulations	
	2016	2021	2016	2021
Adjusted resources (percent)	22.5	18.6	10.1	6.6
Reserve requirement (percent)	17.4	18.2	17.4	18.2

Table 1-3: Potential EPA impacts on resource adequacy

Conclusion

MISO is proud to have an independent, transparent and inclusive planning process that is well positioned to study and address future transmission and policy-based needs in the region. We are also grateful for the input and support from our stakeholder community, which allows us to create well-vetted, cost-effective and innovative solutions to energize the heartland. We welcome feedback and comments from stakeholders, regulators and interested parties on the evolving electric transmission power system. For detailed information about MISO, MTEP11, renewable energy integration, cost allocation and other planning efforts, please visit www.misoenergy.org.

2. MTEP11 overview

2.1 Investment summary

This section provides investment summaries of transmission system upgrades identified in MTEP11 and past MTEP studies that are still in the construction planning or execution processes.[11] Chapter 2.4 describes the definitions of Appendix A, B, and C.

- Approximately $6.5 billion is being added to Appendix A in this planning cycle, of which about $5.1[12] billion is the proposed Multi Value Project portfolio.
- The estimated investment of the projects in MTEP11 Appendix A and Appendix B for 2011–2016 is $7.5 billion.
- Appendix A contains $6.99 billion in investment through 2016 and an additional $3.2 billion from 2017-2021.
- Appendix B contains $0.48 billion of investment through 2016. Appendix B also contains $29 billion in investment for 2017–2026, primarily comprised of two alternate Regional Generation Outlet Study (RGOS) plans.
- Appendix C contains $6.5 billion in investment through 2016 and $37 billion in investment for 2017–2021.

Included in Appendix C is the MTEP08 reference future extra high voltage conceptual transmission overlay in 2018. Portions of the MTEP08 extra high voltage plan have been moved to the RGOS planning effort. There are also a number of large transmission proposals to address the renewable energy requirements in the region, with a $12 billion proposal in 2020. Therefore, there are many alternative and competing plans for renewable energy integration working their way through the planning process. Not all these proposals will reach Appendix A.

Approximately $6.5 billion is being added to Appendix A in this planning cycle, of which about $5.1 billion is the proposed Multi Value Project portfolio.

The expected project spending by year for Appendices A and B from 2011-2021 is in Figure 2.1-1. Projects may be comprised of multiple facilities. Investment totals by year assume that 100 percent of a project's investment occurs when the facility goes into service. Since a large facility may require capital investment over multiple years, this assumption causes these numbers to appear 'lumpier' than the actual expenditures.

[11] A summary of MTEP transmission investment including projects which have gone into service is included in section 3.

[12] Cost shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars. The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above figure.

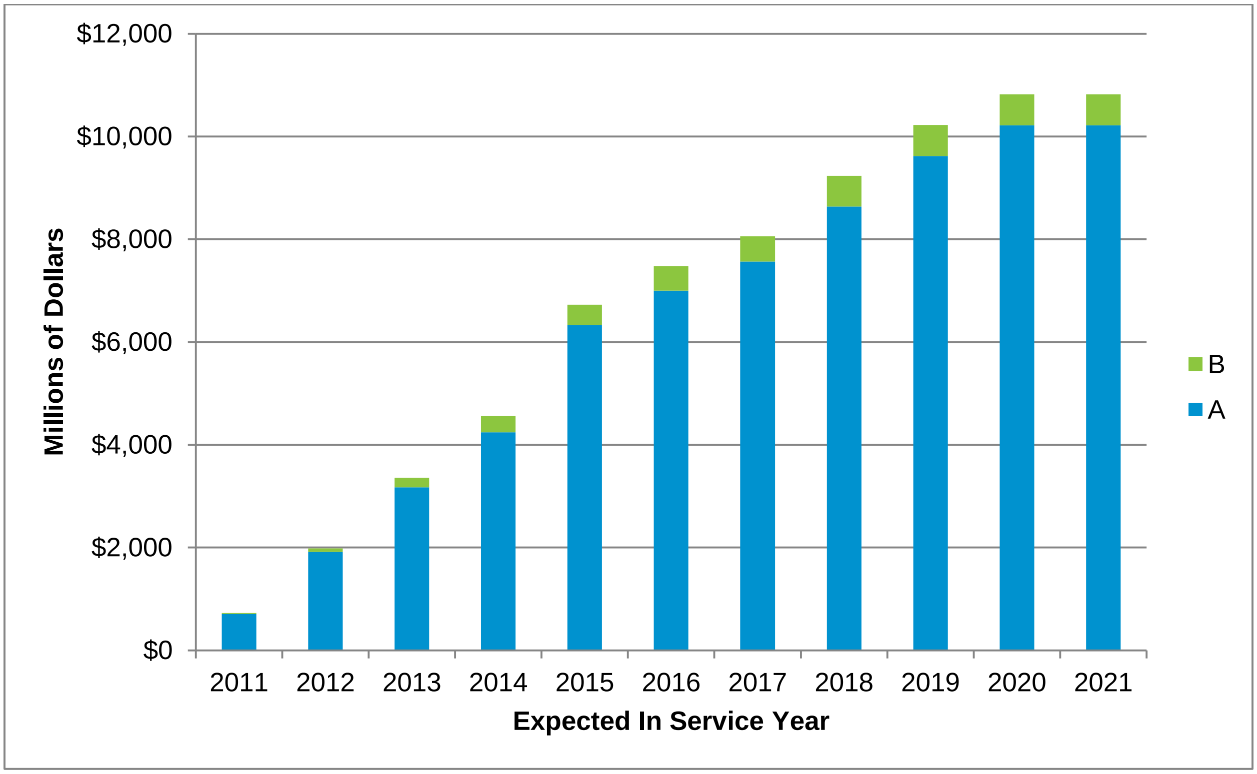


Figure 2.1-1: MTEP11 cumulative projected investment by year and Appendix

Transmission investment by Planning Region through 2021 is shown in Table 2.1-1. This table includes projects in Appendix A approved in prior MTEP planning cycles. Note that the projects are associated with a single planning region, though some projects may be in more than one planning region. These statistics are representative of investment in the planning regions.

Region	Appendix A	Appendix B	Appendix C
Central	$2,265,830,000	$219,152,000	$8,996,773,000
East	$1,537,876,000	$148,701,000	$6,872,277,000
West	$6,415,878,000	$233,899,000	$27,929,197,000
Total	$10,219,584,000	$601,752,000	$43,798,247,000

Table 2.1-1: Projected transmission investment by Planning Region through 2021

Table 2.1-2 shows new investment in 2011 Appendix A projects by preliminary cost allocation category and eligibility for cost sharing. Those categories are Baseline Reliability Project, Generation Interconnection Project, Transmission Service Delivery Project, Multi Value Projects, Market Efficiency Project and other. There were no Market Efficiency Projects and transmission delivery service projects in MTEP11. The numbers in Table 2.1-2 are a subset of Appendix A values shown in Table 2.1-1. These have a target Appendix of 'A in MTEP11' and are new to Appendix A in this planning cycle. Approximately $6.5 billion of investment is being added to Appendix A in this planning cycle. Actual cost allocations for shared projects are based on annual carrying charges and not total project investment; shared means that these projects are eligible for cost sharing. Not all costs of shared projects are eligible for sharing. For example, some Baseline Reliability Project costs and Generation Interconnection Projects are not shared, though only 10 percent of some Generation Interconnection Project costs may be shared to pricing zones. Projects are associated with single planning region, though they may have investment in multiple planning regions.

Region	Share status	BRP	GIP	MVP[13]	Other
Central	Not shared	$8,351,000	$22,620,000		$62,111,000
	Shared	$40,826,000		$1,749,703,000	
Central total		$49,177,000	$22,620,000	$1,749,703,000	$62,111,000
East	Not shared	$11,700,000			$122,661,000
	Shared	$113,900,000	$22,180,000	$271,000,000	
East total		$125,600,000	$22,180,000	$271,000,000	$122,661,000
West	Not shared	$52,094,000	$37,494,000		$491,850,000
	Shared	$197,357,000	$191,094,000	$3,105,021,000	
	Excluded				$4,900,000
West total		$249,451,000	$228,588,000	$3,105,021,000	$496,750,000
Grand total		$424,228,000	$273,388,000	$5,125,724,000	$681,522,000

Table 2.1-2: MTEP11 new Appendix A investment by allocation category & Planning Region

[2] The Michigan Thumb Loop Expansion project with a cost of $510 million (2011 dollars) was approved in MTEP 10 and is part of the proposed Multi Value Project Portfolio. Its costs are not included in the above table. Costs shown is as submitted and reflects nominal in-service date costs in whole or in part; equivalent to $4.7 billion in 2011 dollars.

A breakdown of new Appendix A project data reveals the new transmission build is spread over many states, with Illinois, Wisconsin, Iowa and Minnesota getting around $1 billion in new investment. The majority of that investment comes from the proposed Multi Value Project portfolio. South Dakota, Indiana, and Missouri also have significant projects. These geographic trends change over time as existing capacity in other parts of the system is consumed and new build becomes necessary there.

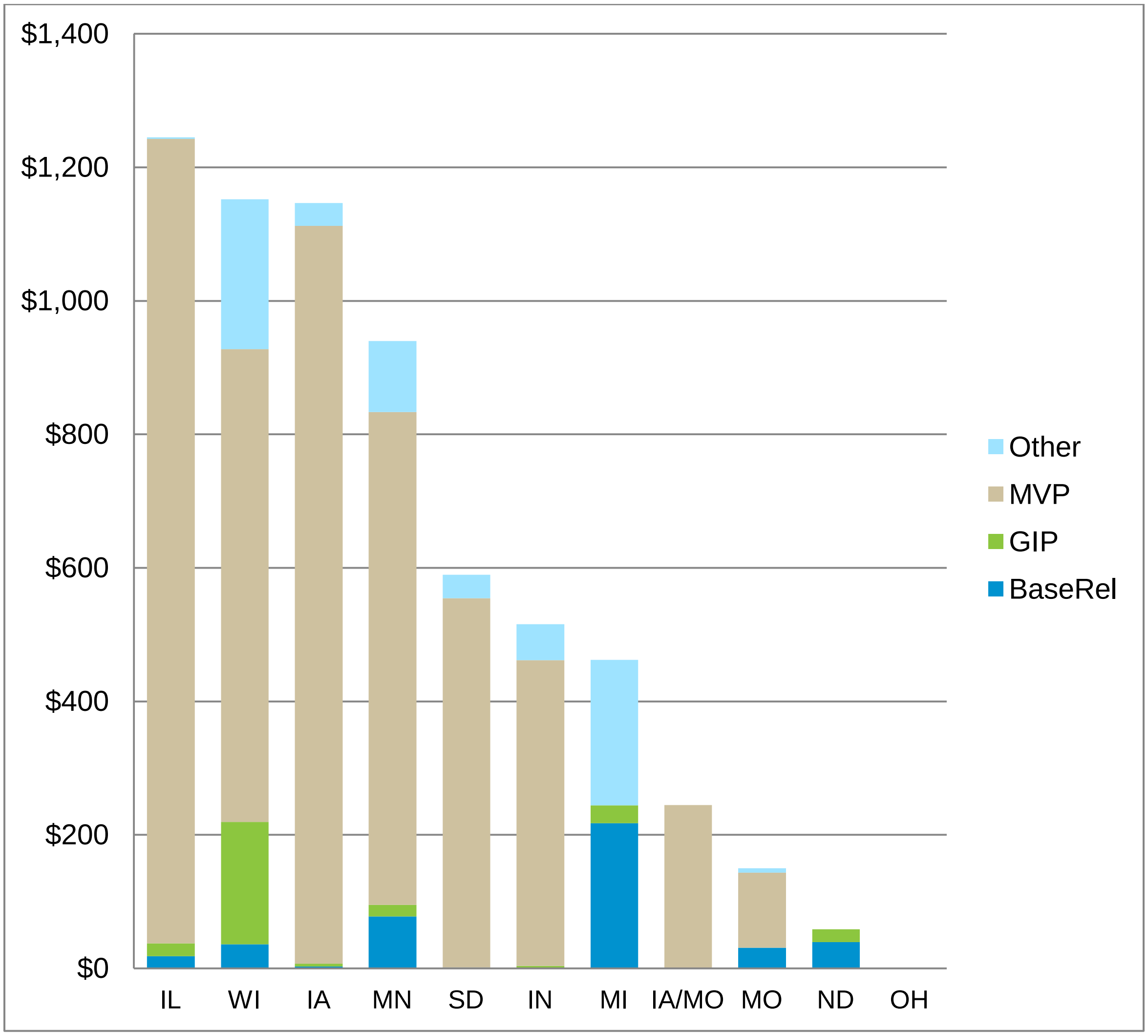


Figure 2.1-2: New Appendix A investment with allocation categorized by state

2.2 Appendix overview

Appendix A and B line summary

There are approximately 6,600 miles of new or upgraded transmission lines projected from 2011-–2021 in MTEP11 Appendices A and B.

- Of approximately 53,200 miles of line under MISO functional control, about 2,965 miles of transmission line upgrades are projected through 2021.
- About 3,695 miles of transmission involving lines on new transmission corridors is projected through 2021.
- Figure 2.2-1 depicts miles of new or upgraded lines by voltage class identified in Appendices A and B.

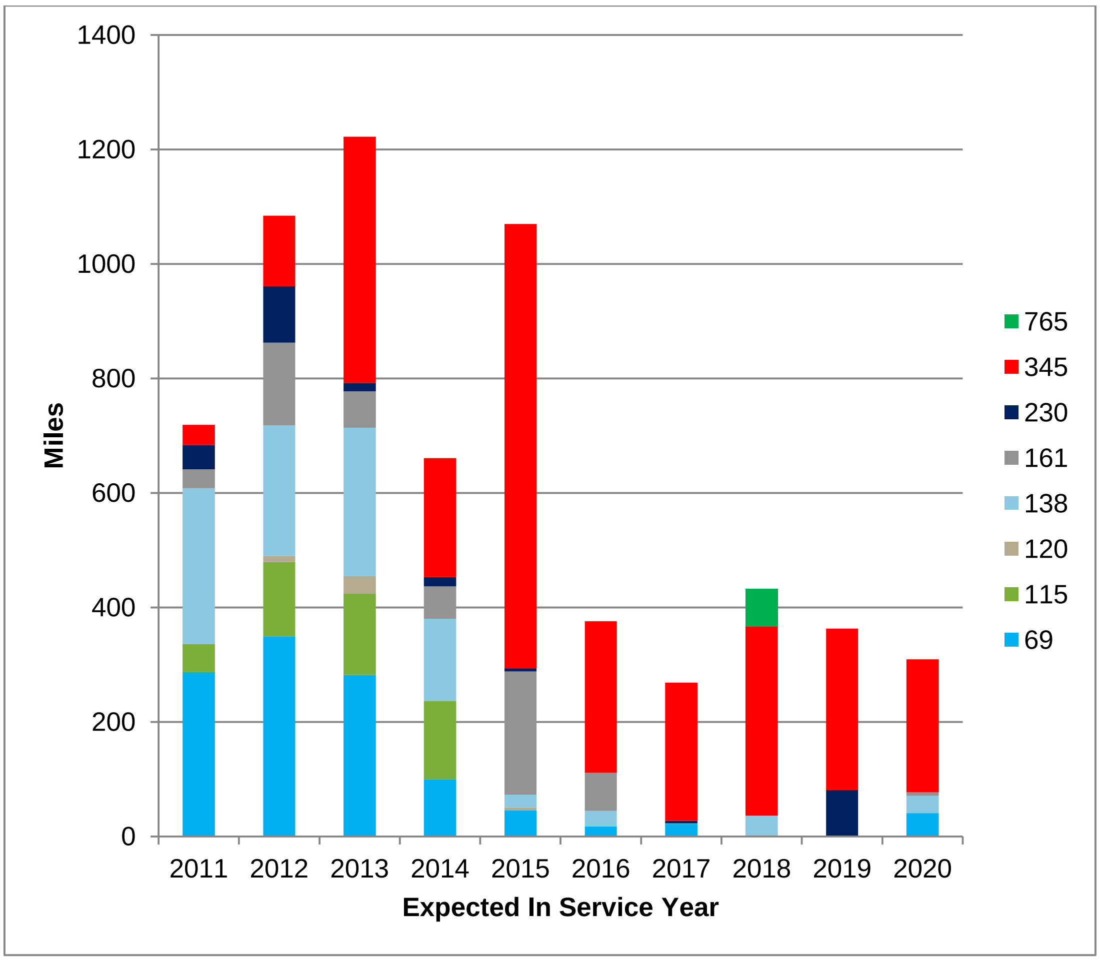


Figure 2.2-1: New or upgraded line miles by voltage class in Appendix A & B through 2021

Refer to Figure 2.2-2, which delineates new transmission line mileage by state for Appendices A and B through expected in service date of 2021.

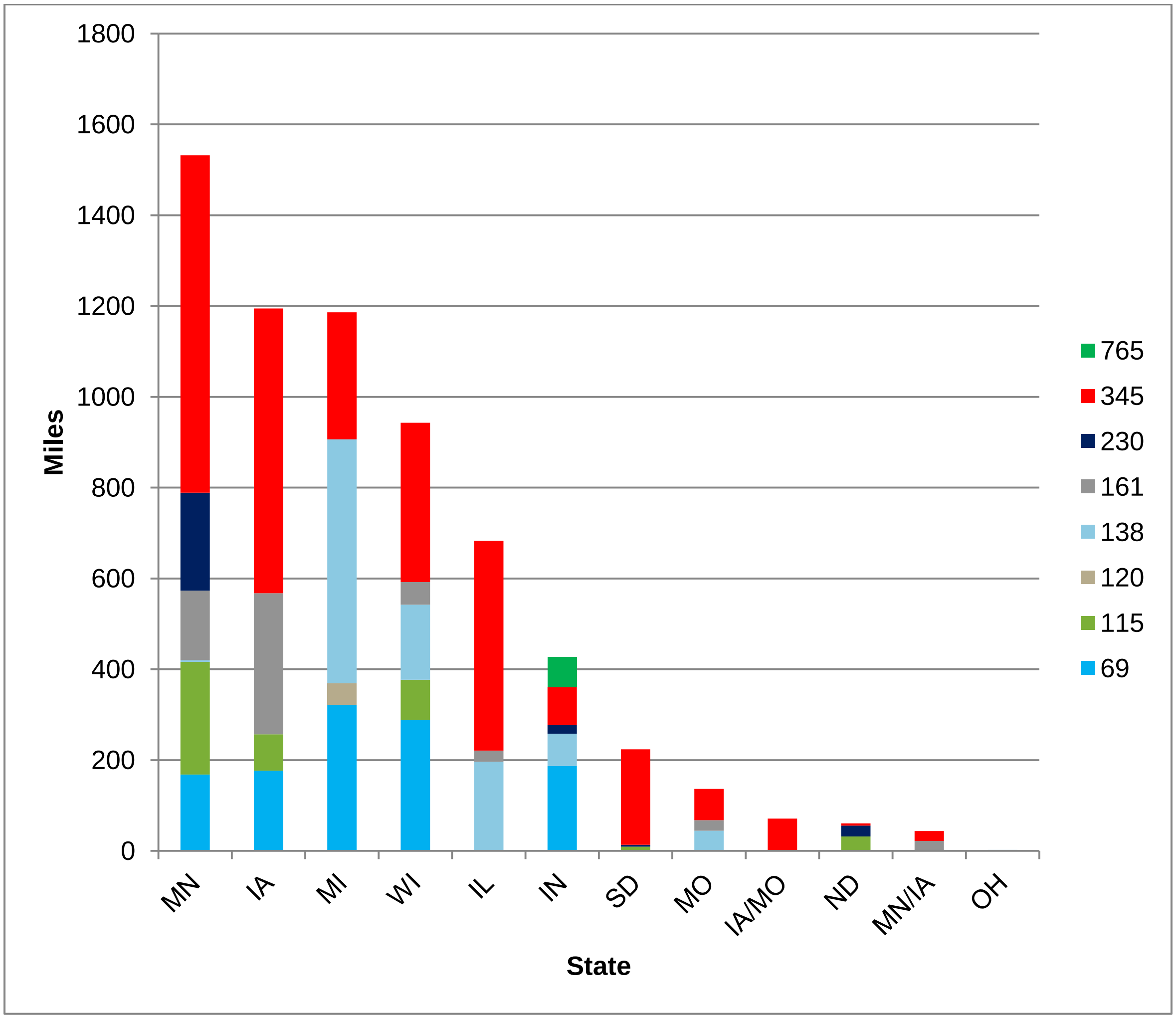


Figure 2.2-2: New or upgraded line miles by state for Appendices A and B through expected in service date of 2021 by voltage class (kV)

Appendix C summary

MTEP11 Appendix C lists and describes $48.6 billion of conceptual and proposed transmission investment. The MTEP08 reference future Extra High Voltage (EHV) conceptual overlay is $14 billion in 2018, comprised of approximately 65 projects. A number of those projects have been integrated into the Regional Generation Outlet Study effort and are now in Appendix B. Eleven of the MTEP08 reference future projects are now part of six proposed projects in the proposed Multi Value Projects portfolio. There are multiple proposals to enable integration and delivery of large amounts of renewable energy. One 765 kV proposal is for $12 billion in 2020. There are two direct current proposals for renewable energy, —$1.9 billion and $1.6 billion, respectively — in 2014. There is a proposal for 765 kV backbone transmission in lower Michigan for $2.5 billion in 2016. Some of these are competing proposals, so not all of the investment is expected. Many of the project proposals in Appendix C were added in order to address traditional reliability needs in the future. Some of these projects have just entered the planning process or are being revisited due to changes, such as load forecast adjustments caused by the economic downturn.

2.3 Cost sharing summary

Multi Value Projects

Multi Value Projects represent a new project type eligible for cost sharing effective since July 16, 2010, and conditionally accepted by the Federal Energy Regulatory Commission on December 16, 2010. Multi Value Projects provide numerous benefits, including, improved reliability, reduced congestion costs, and meeting public policy objectives. As discussed in more detail in Section 4.1, MISO staff is recommending a portfolio of Multi Value Projects to the MISO Board of Directors for inclusion into Appendix A of MTEP 11. The proposed Multi Value Project portfolio includes the Michigan Thumb Loop project, approved in August 2010; the Brookings to Minneapolis-St. Paul project, conditionally approved in June 2011; and 15 additional projects being proposed to the MISO Board of Directors for the first time. The cost of the proposed MVP portfolio in 2011 dollars is $5.2 billion, including the $1.2 billion in projects that have previously been approved or conditionally approved by the MISO Board of Directors. See Table 4.1-1 for individual project costs.

The costs of Multi Value Projects will have a 100 percent regional allocation and will be recovered from customers through a monthly energy usage charge calculated using the applicable MVP Usage Rate.

The costs of Multi Value Projects will have a uniform 100 percent regional allocation based on withdrawals and will be recovered from customers through a monthly energy usage charge. This charge will apply to all MISO load, excluding load under Grandfathered Agreements, and also to export and wheel-through transactions not sinking in PJM.

Figure 2.3-1 shows a 40-year projection of indicative annual MVP Usage Rates based on the proposed MVP portfolio using current year cost estimates and estimated in-service dates. Additional detail on the indicative MVP Usage Rate, including indicative annual MVP charges by Local Balancing Authority, is included in Appendix A-3.

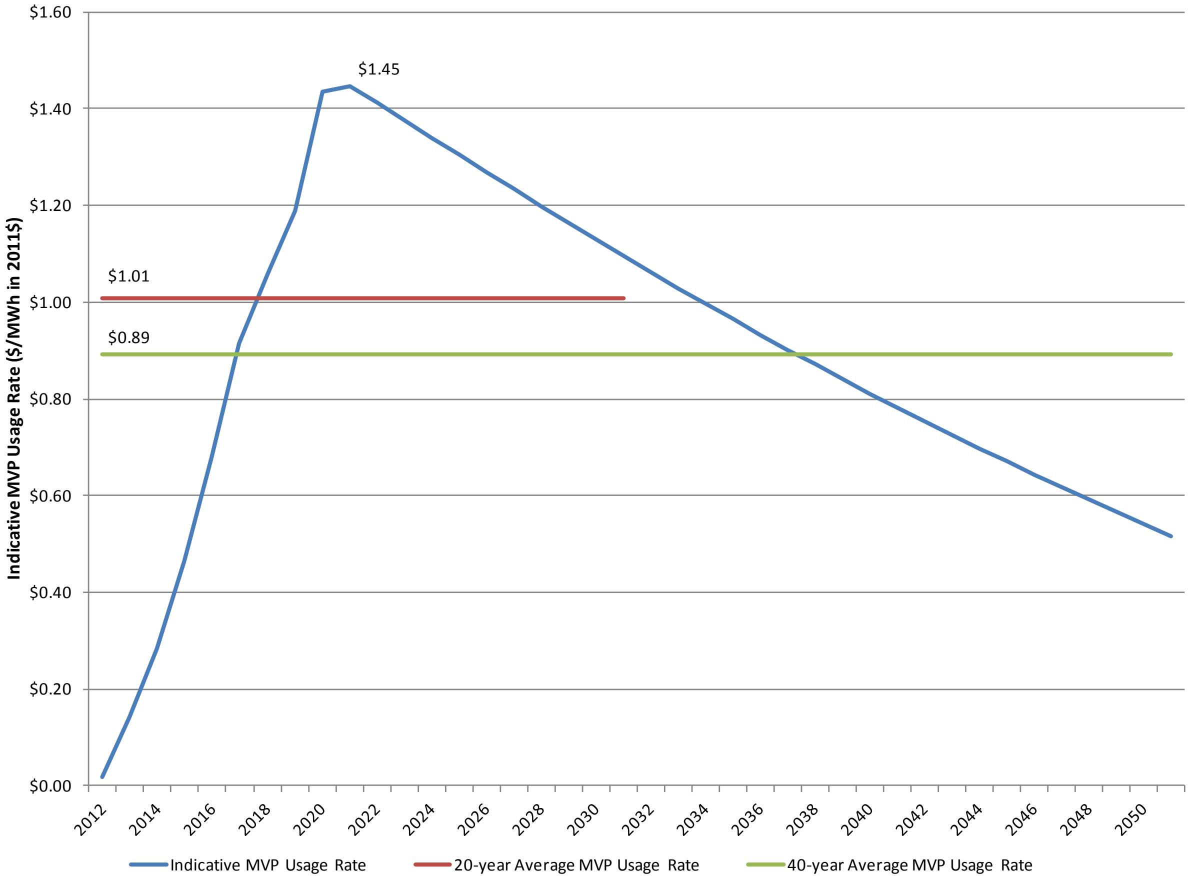


Figure 2.3-1: Indicative MVP usage rate for proposed MVP portfolio from 2012 to 2051

Baseline Reliability, Market Efficiency, and Generation Interconnection Projects

A total project cost of $446.6 million, associated with new Baseline Reliability Projects and Generation Interconnection Projects for inclusion in MTEP 11 Appendix A, are eligible for cost sharing. The cost includes 12 Baseline Reliability Projects at $247.2 million and 10 Generation Interconnection Projects at $199.3 million. A total of $99.7 million of that goes directly to the generator. Of the $346.9 million in project costs, excluding the portion allocated to generators and eligible for cost sharing, 88.7 percent or $307.8 million remains in the pricing zone where the project is located. The remaining 11.3 percent, or $39.1 million, is allocated to neighboring pricing zones or system-wide to all pricing zones. Additional details on the new Baseline Reliability Projects and Generation Interconnection Projects eligible for cost sharing in MTEP 11 are in Appendix A-1.

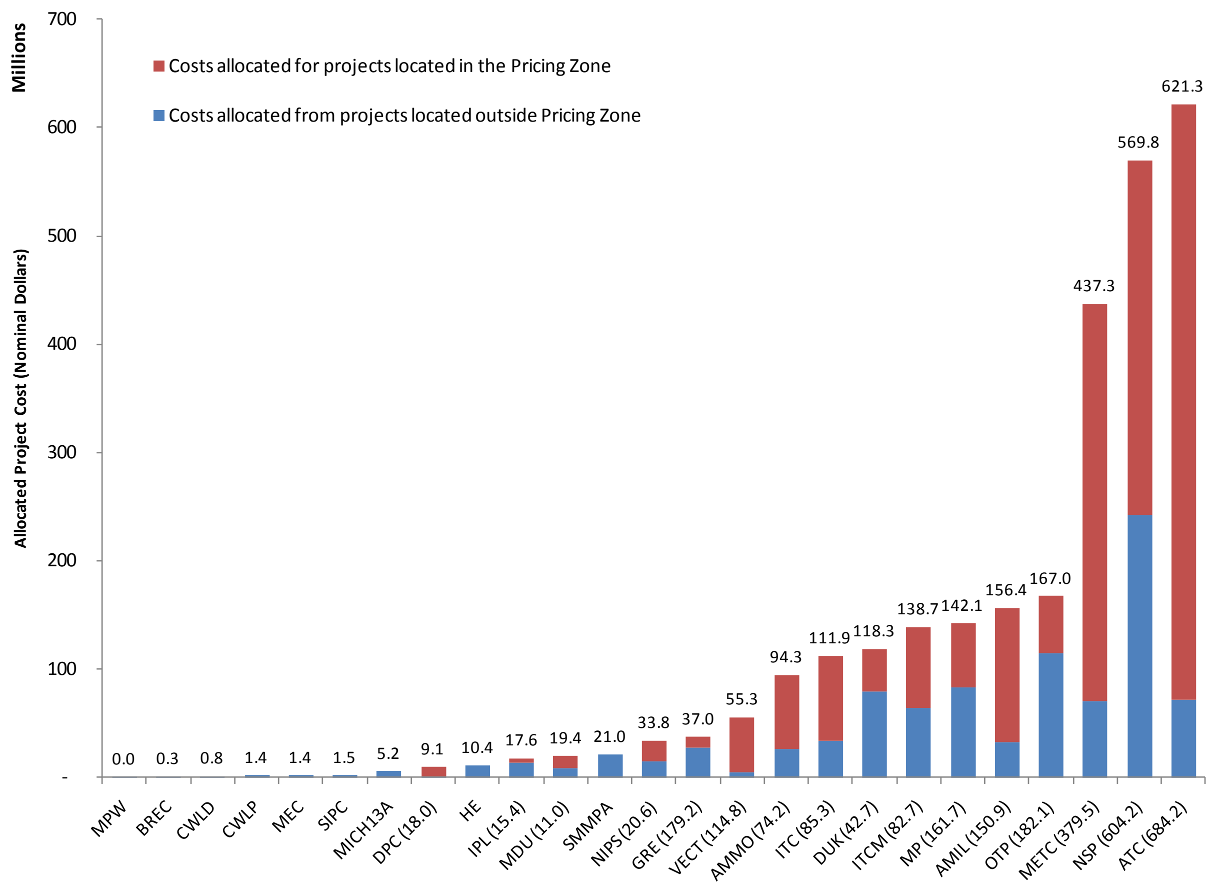
Since the cost sharing methodologies for Baseline Reliability Projects, Generation Interconnection Projects, and Market Efficiency Projects were implemented in 2006, there have been 136 projects eligible for cost sharing. That's $3.4 billion in transmission investment, with each project type representing the following number of projects and total project cost:

- Baseline Reliability Projects – 79 projects, $2.9 billion.
- Generation Interconnection Projects – 56 projects, $550.4 million with $279.1 million allocated directly to the generator.
- Market Efficiency Project – 1 project, $5.6 million.

Figure 2.3-2 provides the breakdown, by pricing zone, of all project costs assigned to the zone based on the cost allocation at the time of approval for Baseline Reliability Projects, Generation Interconnection Projects, and Market Efficiency Projects from MTEP06 to the current MTEP11 report. The costs of approximately $2.8 billion, allocated to each pricing zone from prior MTEP report cycles, have been updated to reflect the current estimates on in-service project cost and in-service date. They do not include projects that have been withdrawn.

The red bar represents the Transmission Owner's share of project costs not allocated to other pricing zones, equal to $1.8 billion across all pricing zones. The blue bar represents the portion of project costs allocated to a pricing zone for projects located in other pricing zones, equal to $927 million across all pricing zones. Note that the values shown in Figure 2.3-2 exclude the portion of Generation Interconnection Projects assigned directly to the generator.

Additional detail by pricing zone on the information shown in Figure 2.3-2 is located in Appendix A-2.2. The cost values for the new MTEP11 cost shared projects have been converted to reflect indicative annual charges for those projects for 2012 to 2021. See Appendix A-2.1.



() = Transmission Owner transmission investment

Figure 2.3-2: Allocated project cost from MTEP06 to MTEP11 for approved Baseline Reliability, Generation Interconnection, and Market Efficiency Projects.[14]

[14] Costs allocated for projects located in the now non-existent First Energy pricing zone are included in the values shown. The MI13AG and MI13ANG zones have been combined into the MICH13A zone.

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, 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.

MTEP11 Appendix A lists projects approved by the MISO Board of Directors in prior MTEPs but have not been built, and also lists projects and associated facilities recommended to the MISO Board of Directors for approval in this cycle. The new projects are indicated as “A in MTEP11” in the target Appendix field in the Appendix listing. The Appendix ABC field is indicated as B>A, or C>B>A, for new projects and A for previously approved projects. Projects in Appendix A are classified on the basis of their respective designation in Attachment FF to the Tariff.

- Baseline Reliability Projects are required to meet North American Electric Reliability Corp. (NERC) standards. Costs for a Baseline Reliability Projects may be shared if the voltage level and project cost meet the thresholds designated in the Tariff.
- Generation Interconnection Projects 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 GIPs are eligible for cost sharing.
- Transmission Service Delivery Projects are required to satisfy a Transmission Service request. The costs are assigned to the requestor.
- Market Efficiency Projects, formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion. Market Efficiency Projects are shared based on benefit to cost ratio of the project, cost and voltage thresholds.
- Multi Value Projects 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.

Projects start in Appendix C when submitted into the MTEP process, transfer to Appendix B when MISO has documented the project need and effectiveness, then move to Appendix A after approval by the MISO Board of Directors.

A project not meeting any of these classifications is designated as ‘Other.’ The ‘Other’ category incorporates a wide range of projects, including those intended to provide local reliability or economic or similar benefits; but not meeting requirements as Market Efficiency Projects or Multi Value Projects (MVPs). Many other projects are required on the transmission system, less than 100 KV, which is 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 the North American Electric Reliability Corporation (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 required to enable public policy requirements, such as current state renewable portfolio standards. All projects in Appendix A address one or more MISO documented transmission issues.

Projects in Appendix A may be eligible for regional cost-sharing per provisions in Attachment FF of the Tariff. Such a project must go through the following process to be moved into Appendix A:

- MISO staff must validate that the project addresses one or more transmission issue.
- MISO staff must consider and review alternatives with the Transmission Owner.
- MISO staff must consider and review costs with the Transmission Owner.
- MISO staff must endorse the project.
- MISO staff must verify that the project is qualified for cost-sharing as a Baseline Reliability Project, Generation Interconnection Project, Market Efficiency Project or Multi Value Project per provisions of Attachment FF.
- MISO staff must hold a stakeholder meeting to review any such 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.
- MISO staff must take the new project to the Board of Directors for approval. Projects are moved to Appendix A following a presentation at any regularly scheduled Board meeting.

Appendix A is periodically updated and posted as projects go through the process and are approved. Projects are generally moved to Appendix A in conjunction with the annual review of the MTEP report. A June mid-cycle approval option is available for projects which 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. However, should circumstances dictate, recommended projects need not wait for completion of the next MTEP for Board of Directors approval and inclusion in Appendix A.

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 process or still in the MISO review and recommendation process. It 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. There may be some potential Baseline Reliability Projects, Market Efficiency Projects or Multi Value Projects for which MISO staff has not been able to prove the need. 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 may contain projects still in the early stages of the Transmission Owner planning process or have just entered the MTEP study process and have not been reviewed. Like those projects in Appendix B, they are not evaluated for cost sharing. There are also some long-term conceptual projects in Appendix C which will require significant planning before they are ready to go through the MTEP process and move into Appendix B or Appendix A. Appendix C may also contain project alternatives to the best alternative in Appendix B. Therefore, a project could revert from B to C if a better alternative is determined and the Transmission Owner is not ready to withdraw the previous best alternative. Appendix C projects are not included in the MTEP initial power flow models used to perform baseline reliability studies.

2.5 Economic assessment of recommended and proposed expansion

Expansion plan

MISO MTEP Appendix A/B contains planned/proposed projects that primarily address reliability needs. However, these projects may also provide economic benefits, including:[15]

- Adjusted Production Cost (APC) savings
- CO_2 emission reductions
- Energy loss benefits

Study results

The PROMOD® simulations and economic analysis show that the Appendix A/B projects will bring not only reliability, but substantial economic benefit to MISO. Over the 20 to 40 years following 2016, Appendix A and B projects will create approximately $9.1 to 20.6 billion in present value benefits.

This analysis models a subset of Appendix A and B projects scheduled to be in-service by 2016. Not all Appendix A and B projects are modeled. The analysis models projects that have expected in-service dates between July 15, 2011, and December 31, 2016. Except the Michigan Thumb Loop Expansion, the proposed MVP portfolio is excluded. Projects not driving economic benefits, such as capacitor banks, circuit breaker upgrades and control room upgrades, are excluded as well.

The PROMOD® simulations and economic analysis show that the Appendix A/B projects will bring not only reliability, but substantial economic benefit to MISO. In 2016, these projects will create $867 million in annual Adjusted Production Cost savings, when a total of $5.2 billion of new transmission projects are modeled. Over the following 20 to 40 years, these projects will create $9.1 to $20.6 billion dollars in Adjusted Production Cost savings, creating benefits that range from 0.9 to 1.0 times the cost of the projects modeled. Additionally, these projects will provide even greater economic benefits under higher load growth or higher gas price assumptions.

The simulations and analysis also show that the Appendix A/B projects create benefits through a reduction in line losses. In 2016, the annual energy loss decrease is about 45.8 GWH, which equates to about $41 million in annual savings.

Finally, the Appendix A/B projects provide CO_2 relief for the MISO system. The increased transmission capacity will allow for less expensive power to be imported and less wind to be curtailed. This leads to a forecasted decrease in coal unit generation and therefore a CO_2 reduction of 8 million tons.

More detailed methodology and benefit calculation assumptions are described later in this chapter.

[15] MISO benefits include all MISO members as of 12/6/2011. First Energy is excluded.

Economic benefits

Table 2.5-1 shows the Adjusted Production Cost savings for the MTEP11 Appendix A/B projects. The MTEP11 Appendix A/B projects will provide MISO $867 million in Adjusted Production Cost savings.

	2016 Adjusted Production Cost savings	20 Year Present Value, 3 percent Discount Rate	20 Year Present Value, 8.2 percent Discount Rate	40 Year Present Value, 3 percent Discount Rate	40 Year Present Value, 8.2 percent Discount Rate
MISO East	$367	$5,627	$3,844	$8,742	$4,638
MISO Central	$145	$2,210	$1,509	$3,433	$1,821
MISO West	$355	$5,436	$3,714	$8,447	$4,482
MISO	$867	$13,273	$9,066	$20,622	$10,941

Table 2.5-1: Economic benefits, in millions of 2011 dollars

As discussed, the full portfolio of Appendix A and B projects is not modeled. Thus, the total cost of the MTEP11 Appendix A/B projects in the MTEP11 2016 power flow case is $5.2 billion. Table 2.5-2 shows the Benefit- to-Cost ratio of the Appendix A/B projects, based on the economic benefits in 2.5-1 and $5.2 billion project cost, under different timeframes and discount rates.

Discount Rate	Present Value Timeframe	B/C Ratio
3 percent	20 Years	0.88
8.2 percent	20 Years	0.86
3 percent	40 Years	1.00
8.2 percent	40 Years	0.91

Table 2.5-2: B/C ratio of MTEP11 Appendix A/B projects

Benefits will change with variation in the underlying assumptions. To see how the benefits are affected by other factors, MISO conducted sensitivity runs. The sensitivities tested were:

1) Higher load growth: Load is 5 percent higher than the load in reference future;
2) Lower load growth: Load is 5 percent lower than the load in reference future;
3) Higher gas price: Gas prices are 40 percent higher than those in the reference future;
4) Lower gas price: Gas prices are 40 percent lower than those in the reference future;

	Base case	5 percent higher load	5 percent lower load	40 percent higher gas price	40 percent lower gas price
Annual Adjusted Production Cost savings (million $)	$867	$1,047	$748	$1,062	$716
20 Year Present Value, 3 percent Discount Rate (million $)	$13,273	$16,012	$11,457	$16,244	$10,959
20 Year Present Value, 8.2 percent Discount Rate (million $)	$9,066	$10,937	$7,826	$11,096	$7,485
40 Year Present Value, 3 percent Discount Rate (million $)	$20,622	$24,877	$17,800	$25,239	$17,026
20 Year Present Value, 8.2 percent Discount Rate (million $)	$10,941	$13,198	$9,444	$13,390	$9,033

Table 2.5-3: The Adjusted Production Cost savings, Load Cost savings and market congestion benefits of the MTEP11 Appendix A/B project for MISO in different sensitivities

Discount Rate	Present Value Timeframe	Annualized project cost (million $)	Base case	5 percent higher load	5 percent lower load	40 percent higher gas price	40 percent lower gas price
3 percent	20 Years	$901	0.88	1.06	0.76	1.08	0.73
8.2 percent	20 Years	$924	0.86	1.04	0.74	1.05	0.71
3 percent	40 Years	$792	1.00	1.21	0.87	1.23	0.83
8.2 percent	40 Years	$872	0.91	1.10	0.79	1.11	0.75

Table 2.5-4: Benefit-to-cost ratio sensitivity

The base case benefits-to-cost ratio of MTEP11 Appendix A/B projects range from 0.71 to 1.23. The benefits-to-cost ratio tend to be higher in the high load case and high gas price case, and lower in the low load case and low gas price case.

The benefits captured in this section only include the economic benefits in generation production cost savings. Benefits not captured include operating reserve benefits, planning reserve margin benefits and reliability benefits. Benefits to cost ratios will be larger and may be greater than 1.0 if all those benefits are captured. Furthermore, the projects in current MTEP11 Appendix A/B are mainly reliability projects. They need to be built to relieve the reliability violations in the system. Economic benefits are side benefits from those projects. A benefit to cost ratio of less than 1 does not imply the projects are not needed.

The proposed Multi Value Project portfolio provides a wide range of benefits, as described in MTEP11 Chapter 4.1.

Loss benefits

Loss benefits refer to the benefit of reduced line losses that occur when new high voltage transmission lines (Appendix A/B) are added to the system.

Loss benefits attributed to Appendix A/B projects are summarized in Table 2.5-5. The decrease in losses in 2016 is 45,781 MWH. Using the company's hourly load-weighted LMP to price this energy loss yields a savings of approximately $41 million.

Loss benefits refer to the benefit of reduced line losses that occur when new high voltage transmission lines (Appendix A/B) are added to the system.

The loss at peak hour in MISO increases approximately 346.8MW from without Appendix A/B case to with Appendix A/B case, so the capacity loss benefits are actually negative. This is because Appendix A/B projects will allow more long-distance import from non-MISO entities at peak hour to displace MISO generation. Consequently, the long distance power transportation increases losses. Since the capacity loss benefit is negative, the value of capacity loss benefit will be $0.

	Energy loss benefit	Value of energy loss benefit	Capacity of loss (peak) benefit	Value of capacity loss benefit	Maximum hourly loss decrease
MISO	45,781 MWH	$41 million	-346.8 MW	$0	391.4 MW

Table 2.5-5: MISO loss benefits with Appendix A/B project in 2016

Other benefits

Table 2.5-6 shows the annual generation and capacity factor changes for different types of MISO units. After adding the Appendix A/B projects, capacity factors on fossil fuel generators stay the same or decline somewhat. MISO generation (excluding wind) decreases by about 10,457 GWH. Adding the Appendix A/B projects leads to less wind energy being curtailed (10,143 GWH).

This drives annual CO_2 emission to decrease by approximately 8 million tons.

Table 2.5-6 also indicates that coal units and combined cycle units generate less in the case, including Appendix A/B projects. This drives annual CO_2 emission to decrease by approximately 8 million tons. That reduction is relative to the case without Appendix A/B projects, not the case without added wind generation. From Table 2.5-6, we can see the reduction in ST Coal, CT Gas and combined cycle units. The combined effect in CO_2 emission is about 2 percent.

		Generation (MWH)	Capacity Factor
Combined Cycle	No Appendix projects.	25,267,913	21.22 percent
	With Appendix projects.	20,804,817	17.47 percent
	Change	-4,463,096	-3.75 percent
CT Gas	No Appendix projects.	3,252,613	1.61 percent
	With Appendix projects.	2,352,304	1.16 percent
	Change	-900,309	-0.45 percent
CT Oil	No Appendix projects.	68,820	0.16 percent
	With Appendix projects.	15,908	0.04 percent
	Change	-52,913	-0.12 percent
Hydro	No Appendix projects.	3,744,454	34.25 percent
	With Appendix projects.	3,744,116	34.25 percent
	Change	-338	0.00 percent
IGCC	No Appendix projects.	5,860,686	76.29 percent
	With Appendix projects.	5,854,798	76.21 percent
	Change	-5,888	-0.08 percent
Nuclear	No Appendix projects.	71,312,762	88.91 percent
	With Appendix projects.	71,312,762	88.91 percent
	Change	0	0.00 percent
ST Coal	No Appendix projects.	383,096,341	68.34 percent
	With Appendix projects.	378,307,444	67.49 percent
	Change	-4,788,897	-0.85 percent
ST Gas	No Appendix projects.	708,331	2.86 percent
	With Appendix projects.	453,482	1.83 percent
	Change	-254,849	-1.03 percent
ST Oil	No Appendix projects.	12,209	0.24 percent
	With Appendix projects.	12,399	0.24 percent
	Change	189	0.00 percent
Wind	No Appendix Projects	42,108,491	27.99 percent
	With Appendix Projects	52,251,508	34.73 percent
	Change	10,143,018	6.74 percent

Table 2.5-6: 2016 generation and capacity factor change for different type units

	CO_2 emission (ton)
No Appendix projects.	423,370,598
With Appendix projects.	415,237,057
Emission decrease	8,133,541

Table 2.5-7: 2016 annual CO2 emission change for different type units

Study methodology and assumptions

The data for the economic benefit assessment comes from two PROMOD® case runs: one case without the Appendix A and B projects, and one case with these projects.

Only those projects that will not drive economic benefits are excluded to provide a more accurate analysis. Examples of projects not adding economic benefit include capacitor banks, circuit breaker upgrades, rebuilds of existing lines or substations and control room upgrades. These projects will not cause impedance or rating changes to existing lines, and will not affect system topology from steady-state economic study perspective.

PROMOD® cases

The MTEP11 2016 summer peak power flow case, which has been reviewed by MISO stakeholders and incorporates the latest PJM system update, was used as the starting point for this study. Two 2016 PROMOD® cases were developed:

- 2016 PROMOD® case with Appendix A/B projects.
- 2016 PROMOD® case without Appendix A/B projects.

Both cases use the same MTEP11 BAU (Business As Usual with low demand and energy growth rate) Future database (containing all the generator, load, fuel and environmental information). The detailed information associated with the BAU Future can be found in Appendix E2. The only difference between these two PROMOD cases is the power flow cases (i.e., the transmission topologies) that are used.

Power flow case

To develop these two PROMOD® cases, two power flow cases are required:

- One power flow case with Appendix A/B projects.
- One power flow case without Appendix A/B projects.

For both power flow cases, the Transmission Systems outside of the MISO footprint are the same; from the Eastern Interconnection Regional Reliability Organization (ERAG) 2010 series 2016 summer peak power flow case. The MISO portion, in the power flow case with Appendix A/B projects, is from the MTEP11 2016 summer peak power flow case, including all Appendix A/B projects except proposed Multi Value Projects. The MISO portion, in the power flow case without Appendix A/B projects, is from the ERAG 2010 series 2011 summer peak power flow case, representing the current transmission topology in MISO. Table 2.5-8 summarizes the differences between these two power flow cases.

	Power flow case with Appendix A/B	Power flow case without Appendix A/B
MISO transmission	MTEP11 2016 summer peak (ERAG 2011 summer peak + Appendix A/B)	ERAG 2011 summer peak
Non-MISO transmission	ERAG 2016 summer peak	ERAG 2016 summer peak
Generation/load/interchange	Not used in PROMOD(R)	Not used in PROMOD(R)

Table 2.5-8: Power flow cases difference

In the power flow case with the Appendix A/B projects, the Michigan Thumb Loop project is in the case. None of the other proposed Multi Value Projects were included in the case because the proposed MVP portfolio is not finalized. Among them, only 3 out of 16 projects have an expected in-service date on or before 2016. The benefits of proposed MVP projects are evaluated together as a portfolio in the proposed MVP Portfolio Study. They are not included in the power flow case with Appendix A/B projects used in this study.

New generators

The new generators identified in MTEP11 Steps 1 and 2, under the BAU Future, are included in this study. More details on these generators can be found in Appendix E2.

Event file

The event file contains the list of flow gates which will be treated as transmission constraints. The quality of the event file has a big impact on the quality of the study results. As PROMOD® has a limit on the number of events, all N-1 or N-2 contingencies cannot be included in the event file. The event file for this 2016 PROMOD® case includes the flowgates from:

- MISO master flowgates file.
- NERC book of flowgates.
- Appendix A/B projects that have rating upgrades were also included in the event file with different ratings in each of the two PROMOD® cases.

The PROMOD® Analysis Tool (PAT) was also used to identify events with potential reliability problems. Those events were also included in the event file.

Economic benefits

From each PROMOD® case, The Adjusted Production Cost (APC) was calculated. The APC is equal to the production cost adjusted by sales revenue and purchases cost.

The comparison of the economic indices from two PROMOD® cases (with Appendix A/B case, and without Appendix A/B case) yields the Adjusted Production Cost savings. These savings are the annual Adjusted Production Cost decrease from the case without Appendix A/B projects to the case with Appendix A/B projects, so there is a cost savings.

Loss benefits

- Energy loss benefit (MWH) is the annual loss decrease (MWH) from without Appendix A/B case to with Appendix A/B case.
- Capacity loss benefit (MW) for MISO is the loss decrease (MW) from without Appendix A/B case to with Appendix A/B case in MISO's peak load hour.
- Dollar value of energy loss benefit is the annual MISO loss cost decrease from without Appendix A/B case to with Appendix A/B case. Company loss cost is calculated by multiplying a company's hourly losses by its load- weighted LMP. The annual sum of these values for all MISO companies is the annual MISO loss cost.
- Dollar value of capacity loss benefit represents the value of deferring additional generation construction. It is calculated using $650/kW-$1200/kW, the price range for the construction of

different units. If the capacity loss benefit is positive, the corresponding dollar value is the capacity loss benefit multiplied by these prices. If the capacity loss benefit is negative, this value will be 0.

- Maximum hourly loss decrease is the maximum hourly loss decrease (MW) from without Appendix A/B case to with Appendix A/B case.

Other impacts

- Generation, capacity factor and CO_2 emission change compares two things: 1) the change of generation and the capacity factor of different types of units and 2) change of CO_2 emission between with and without Appendix A/B projects cases.

2.6 MTEP 11 futures retail rate impact

The electricity industry is facing significant policy changes from the state and federal level. These changes are generating uncertainty for the industry and its customers, including potential rate increases to retail electricity customers. As shown in Figure 4.1-2, all but 1 of the 12 states in the MISO footprint has enacted a Renewable Portfolio Standard (RPS) mandate or goal. There is a great deal of uncertainty about how these goals will be achieved, including the location of future generation and the required transmission to enable renewable integration. In addition to state policies, there is on-going discussion at the federal level on implementation of policies, including federal RPS, carbon reduction, smart grid and others. To address these potential futures, MISO examines multiple scenarios through its long-term planning process to capture the wide range of potential policy outcomes.

Current retail electricity rates

The current cost of electricity to the retail customer must be considered before examining the potential impact of the future scenarios. In MISO the current average retail rate, weighted by load in each state, for residential, commercial and industrial sector, is 8.7 cents/kWh, about 10 percent lower than the national average of 9.7 cents/kWh.[16] Refer below to Figure 2.6-1, which provides the average retail rate in cents per kWh for each state in the MISO footprint. It shows the rate paid by consumers varies greatly across the MISO footprint. Based on information provided by the Energy Information Administration (EIA) in Annual Energy Outlook 2011; the generation, transmission and distribution cost components of the retail electricity rate in 2011 are estimated to average 63.0 percent, 7.1 percent and 29.9 percent, respectively.[17] This equates to approximately 5.5 cents/kWh for generation, 0.6 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 $1,044; based on an 8.7 cents/kWh retail rate.

> The electricity industry is facing significant policy changes from the state and federal level. These changes are generating uncertainty for the industry and its customers, including potential rate increases to retail electricity customers.

[16] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly from March 2011. MISO average rate was calculated by taking the load weighted average of the 12 states in the MISO footprint.

[17] MISO average generation, transmission and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2011 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.

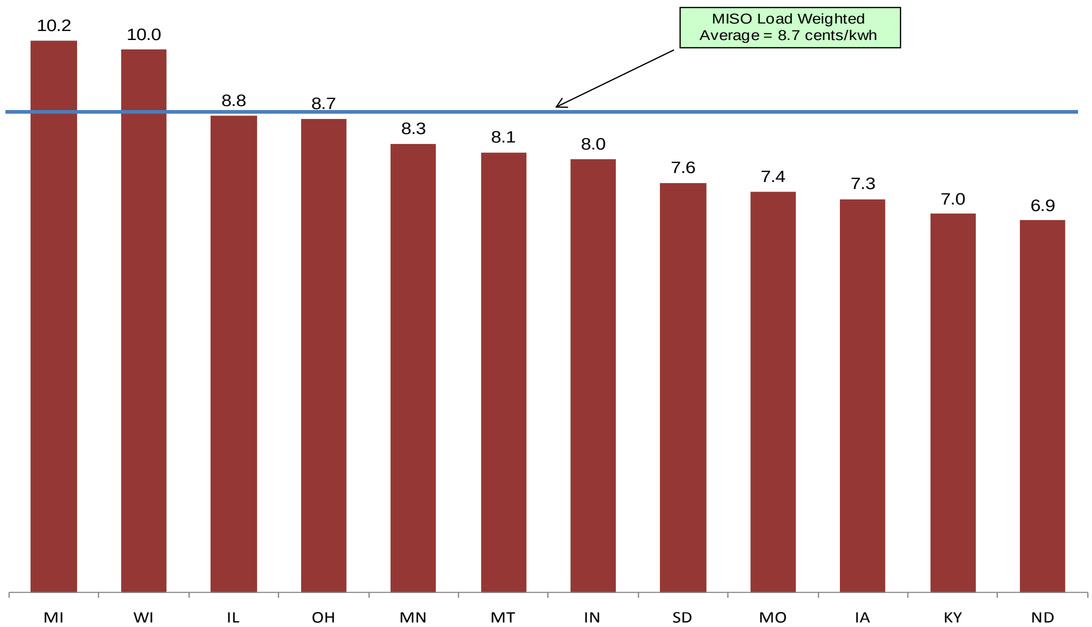


Figure 2.6-1: MISO retail rate for all sectors in cents/kWh (2011 dollars)

Future policy scenarios

MISO examined a number of policy-driven future generation expansion scenarios to develop an array of "best plans" for a range of possible outcomes. These scenarios derive from policy discussions, and they will evolve depending on the direction of legislation. The scenarios represent a range of potential policies and have been used to estimate potential impacts to retail rate payers in the MISO footprint.[19]

- Business as Usual with Mid-low Demand and Energy Growth Rates assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for resource adequacy, renewable mandates and little or no change in environmental legislation.

- Business as Usual with Historic Demand and Energy Growth Rates assumes a quicker recovery from the economic downturn and a return to historic demand and energy growth rates. This scenario assumes existing standards for resource adequacy, renewable mandates and little or no change in environmental legislation.

- Carbon Constraint models a declining cap on CO_2 emissions. The carbon cap is modeled after the Waxman-Markey bill, with a modified timeline to reach a 42 percent reduction by 2033 from 2005 levels. For the 2026 rate impacts calculated in this analysis, a 25 percent carbon reduction is targeted.

- Combined Energy Policy combines the impact of multiple policy scenarios into one future. Smart grid is modeled within the demand growth rate. It is assumed an increased penetration of smart grid applications will lower overall demand growth. Growth in electric vehicle usage is captured with a higher energy growth rate and is assumed to increase off-peak energy usage.

[19] For additional description of the MTEP 11 scenarios refer to section 4.3 and Appendix E.2

To meet the various policy objectives, all scenarios included in this rate impact analysis require significant investment in generation and transmission expansion across the 15-year study horizon. This is expected to affect retail electricity rates, especially since a large share of generation and transmission assets have or soon will reach the end of their recoverable book-life. For example, approximately 55 percent of the generating capacity in the MISO footprint is at least 30 years old. As shown in this analysis, all but one of the scenarios shows retail rates increasing at a rate greater than inflation.

Overview of rate impact methodology and results

To measure the potential impact to rate payers under each of the scenarios; MISO projected a 2026 retail rate by estimating annual revenue requirements for the generation, transmission and distribution rate components.[20] This projection was based on the following assumptions:

- Transmission component
  - Includes proposed MVP portfolio (constant across all scenarios).
  - Additional required reliability transmission investment through 2026 (constant across all scenarios).[21]
  - Non-depreciated current transmission that would still be recoverable in 2026 (constant across all scenarios).
- Generation component
  - Production costs for MISO generation resources associated with each scenario in 2026; including fuel, emissions, and variable operations and maintenance expenses.
  - Capital costs, including fixed operations and management, associated with the capacity expansion for each scenario through 2026.[22]
  - Non-depreciated current generation that would still be recoverable in 2026 (constant across all scenarios).
- Distribution component
  - Assumes that the distribution component of the current MISO retail rate at 2.6 cents/kWh will grow at the assumed rate of inflation through 2026.

To calculate MISO's 2026 retail rate, revenue requirements for the generation, transmission and distribution components described above were distributed uniformly across the forecasted 2026 energy usage levels. The 2026 rate was then discounted, using the assumed inflation rate to 2011 for comparison to the current MISO retail rate. The results of this calculation for each scenario are shown in Figure 2.6-2, which depicts the impact the scenarios could have on customer's retail rates. Note that the rates calculated for the future scenarios include costs for generation, transmission and distribution; but do not include general and administrative costs.

All but one of the scenarios shows that retail rates can be expected to grow at a rate faster than would be experienced if rates simply increased by inflation.

All but one of the scenarios shows that retail rates can be expected to grow at a rate faster than would be experienced if rates simply increased by inflation. However, the magnitude of this impact varies greatly across the four scenarios, from a 1 percent decrease for the Business as Usual with Mid-low Demand and Energy Growth Rate scenario to a 19 percent increase for the Combined Energy Policy Future. Major rate drivers for each scenario are discussed in more detail in the next section.

[20] Additional detail on the rate calculation methodology is provided in Appendix E.3.

[21] Based on the proposed MVP portfolio listed in Table 4.1-1 in Section 4.1 with a total project cost of more than $5.2 billion.

[22] Refer to Section 4.3 for details on the capacity expansion, by fuel type, for each MTEP 11 Future. Generation siting maps for each MTEP 11 Future are also provided in Section 4.3.

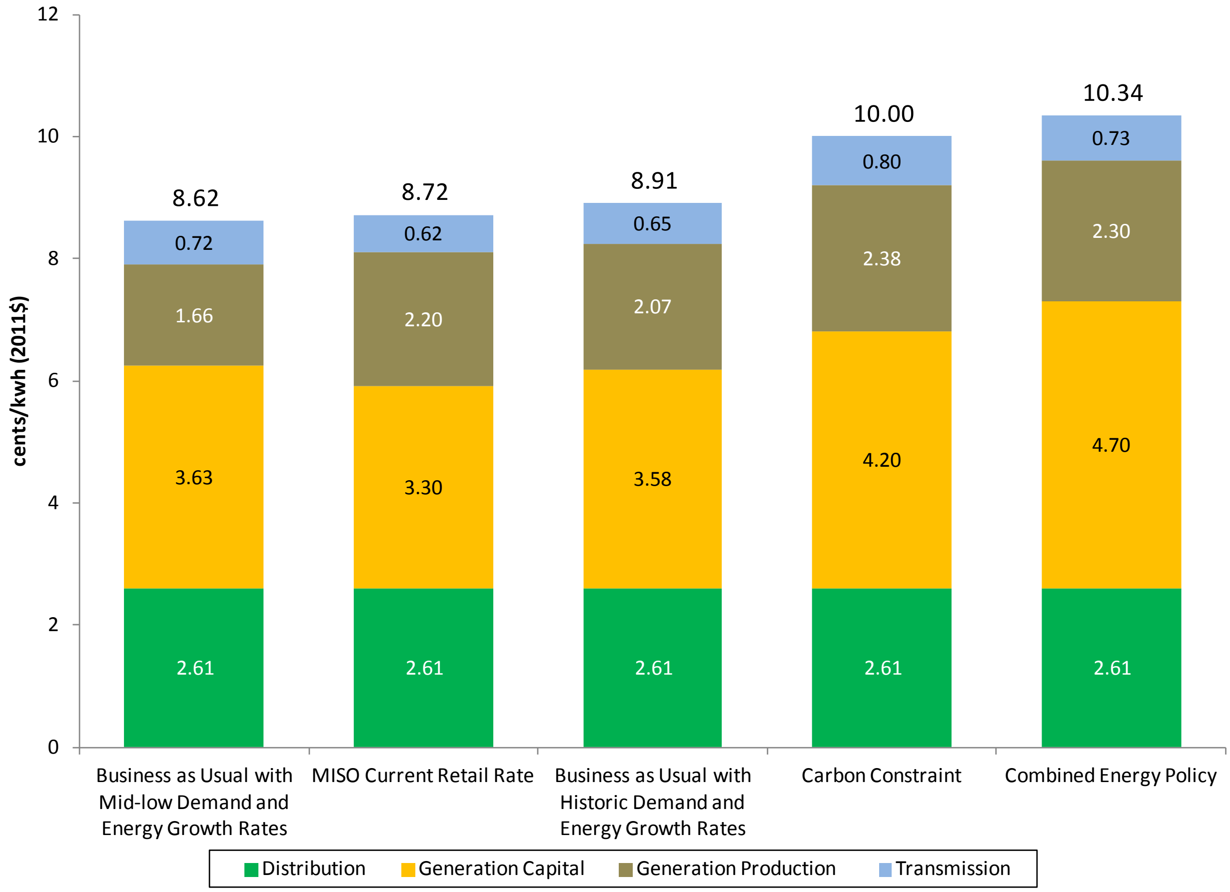


Figure 2.6-2: Comparison of estimated retail rate for each future scenario
(Cents per KWh in 2011 Dollars)

Scenario	Rate (cents/kWh)	Percent (Change from current retail rate)
BAU with Mid-low Demand and Energy Growth Rates	8.62	-1.2 percent
MISO Current Retail Rate	8.72	0.0 percent
BAU with Historic Demand and Energy Growth Rates	8.91	+2.1 percent
Carbon Constraint	10.00	+14.7 percent
Combined Energy Policy	10.34	+18.6 percent

Table 2.6-1: 2026 retail rate impacts in 2011 dollars of for each future scenario

Rate impact drivers under future policy scenarios

Table 2.6-2 compares the Business as Usual with Mid-low Demand and Energy Growth Rates (BAUMLDE) scenario's estimated retail rate to the current retail rate. This is done by using the rate components to illustrate what is driving the overall estimated decrease of $12 to the average residential ratepayer's annual electricity costs.[23] The BAUMLDE is the only scenario where we find an estimated retail rate marginally lower than the current MISO retail rate. Two factors contribute to this lower rate:

1) The lower demand growth rate will require fewer new capacity resources, though there are 23,900 MW of wind and solar resources added to meet the state renewable mandates.
2) The increased output of renewable resources, which typically have no fuel costs, and therefore very low production costs, from 8 percent of output in 2011 to 16 percent in 2026, reduces generation production cost.

	Rate component				
	Generation capital[24]	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh2011 dollars)	3.30	2.20	0.62	2.61	8.72
BAUMLDE future retail rate (cents per kWh2011 dollars)	3.63	1.66	0.72	2.61	8.62
Percentage change in projected retail rate	10.1 percent	-24.4 percent	16.4 percent	-	-1.2 percent
Projected change in avg. residential rate payer's annual electricity bill	$39.96	$(64.26)	$12.14	-	$ (12.15)

Table 2.6-2: Comparison of BAUMLDE future retail rate to current

[23] Residential annual electricity costs calculated assuming average monthly usage of 1,000 kWh.
[24] Generation Capital includes both annual capital charges and fixed O&M expenses.

Table 2.6-3 below compares the Business as Usual with Historic Demand and Energy Growth Rates (BAUHDE) scenario estimated retail rate to the MISO current retail rate to illustrate which component is influencing the overall estimated annual increase of $22 to the average residential ratepayer's electricity costs. The increase in generation capital and transmission in the BAUHDE scenario is in part driven by the need to meet the state renewable mandates included in the study. To meet the current state RPS mandates in the MISO footprint, an additional 26,800 MW of wind and solar resources are added through 2026. Offsetting the increase in generation and transmission investment is a reduction in generation production costs as low cost renewable resources deliver an increasing share of total energy, accounting for 8 percent of output in 2011 and increasing to 16 percent in 2026.

	Rate component				
	Generation capital	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh 2011 dollars)	3.30	2.20	0.62	2.61	8.72
BAUHDE future retail rate (cents per kWh 2011 dollars)	3.58	2.07	0.65	2.61	8.91
Percentage change in projected retail rate	8.4 percent	-6.0 percent	6.1 percent	-	2.1 percent
Projected change in avg. residential rate payer's annual electricity bill	$33.33	$ (15.76)	$ 4.52	-	$22.09

Table 2.6-3: Comparison of BAUHDE future retail rate to current

Table 2.6-4 below compares the estimated rate under the Carbon Constraint scenario, which targets a 25 percent reduction in CO_2 emissions by 2026 from 2005 levels, leading to an estimated 15 percent increase over the current MISO retail rate, equating to a $154 increase over the current residential ratepayer's annual electricity costs.

In the Carbon Constraint scenario, there is approximately 21,600 MW of resources retired to achieve required carbon reduction levels. However, due to the very low effective demand growth rate after considering demand response, only 10,000 MW of non-renewable generation is added. Approximately 21,000 MW of renewable resources are added to meet the state RPS mandates. This additional 31,000 MW of resources is driving the 28 percent increase in the generation capital component of the carbon constraint scenario compared to the current retail rate.

One of the drivers for the 9 percent increase in the generation production component is the increase in energy served by natural gas fueled resources -- from 2 percent in 2011 to 18 percent in 2026. For the transmission component, note that while the percentage increase is much higher than for the BAUMLDE and BAUHDE scenarios, this does not represent an increase in transmission investment, since the same level of transmission investment is assumed for all scenarios. The energy growth rate is lower, so the cost per kWh is higher, and the transmission costs are spread over less energy.

	Rate component				
	Generation capital	Generation production	Transmission	Distribution	Total
MISO current retail rate (cents per kWh2011 dollars)	3.30	2.20	0.62	2.61	8.72
Carbon Cap Constraint future retail rate (cents per kWh2011 dollars)	4.20	2.38	0.80	2.61	10.00
Percentage change in projected retail rate	27.5 percent	8.5 percent	30.5 percent	-	14.7 percent
Projected change in average residential rate payer's annual electricity bill	$108.63	$ 22.37	$22.52	-	$153.51

Table 2.6-4: Comparison of Carbon Constraint future retail rate to current

Table 2.6-5 below compares the Combined Energy Policy estimated retail rate - including a 20 percent Federal RPS, carbon constraint, smart grid investment and increased electric vehicle usage - to the MISO current retail rate by rate component. This illustrates the drivers of the overall estimated increase of 19 percent, equating to a $195 increase for the average residential ratepayer's annual electricity cost.

Similar to the Carbon Constraint future, the Combined Energy Policy future assumes the retirement of 24,500 MW of generation resources to achieve the 25 percent reduction in carbon emissions from 2005 levels by 2026. The estimated 43 percent increase in the generation capital component is driven by the 43,200 MW of new resources, including 28,800 MW of new wind generation to meet the 20 percent Federal RPS.

For the generation production component, the increased usage of natural gas resources for the Combined Energy Policy scenario (from 2 percent of energy served in 2011 to 18 percent in 2026) is slightly less than for the Carbon Constraint Future. That's likely due to the increased percentage of energy served by low-production cost wind generation -- from 8 percent in 2011 to 21 percent in 2026.

	Rate Component				
	Generation capital	**Generation production**	Transmission	Distribution	**Total**
MISO current retail rate (cents per kWh 2011 dollars)	3.30	2.20	0.62	2.61	8.72
Combined energy policy future retail rate (cents per kWh 2011 dollars)	4.70	2.30	0.73	2.61	10.34
Percentage change in projected retail rate	42.5 percent	4.6 percent	19.0 percent	-	18.6 percent
Projected change in average residential rate payer's annual electricity bill	$168.35	$ 12.25	$14.01	-	$194.61

Table 2.6-5: Comparison of combined energy policy future retail rate to current

Potential rate impacts from the four future scenarios demonstrate that higher electricity rates are likely. The magnitude of the increase will vary, depending on actual economic and policy situations. The range of outcomes illustrates the importance of performing long-term scenario analyses to provide decision-makers with the information needed to minimize rate increases to customers.

3. Historical MTEP plan status

This section provides an update on the implementation of projects approved in the MISO Transmission Expansion Plan (MTEP) - and furnishes a historical perspective of all past MTEP approved plans. These projects were approved by the MISO Board of Directors in previous MTEP cycles or are recommended for approval in MTEP11. Any given MTEP Appendix A contains newly approved projects, along with previously approved projects not in service when the MTEP Appendices were prepared.

3.1 MTEP10 status report

MISO transmission planning responsibilities include monitoring progress and implementation of essential expansions identified in the MTEP. The MISO Board of Directors approved the last MTEP (MTEP10) in December 2010. This section provides a review of the status of previously approved projects listed in MTEP10 Appendix A.

The MISO Board of Directors has been receiving quarterly updates on the status of active plans since December 2006. The information in this report reflects the 2nd Quarter of 2011 status report to the Board of Directors, which included status on MTEP10 Appendix A projects through June 30, 2011.

Tracking the progress of projects ensures a good faith effort to move projects forward, as prescribed in the Transmission Owner's agreement. Most approved projects do move forward, despite possible complications, such as equipment procurement delays, construction difficulties and regulatory processes taking longer than anticipated. A project is only considered 'off-track' if MISO cannot determine a reasonable cause for delays, as described above. These approved MTEP projects have completed the planning process and are the solution to Transmission System issues. They may be driven by reliability issues, Transmission Service requests, Generation Interconnection requests or market flow constraints. More than half of the MTEP Appendix A projects is comprised of multiple facilities.

MTEP10 Appendix A has 586 projects comprised of 1,025 facilities. These figures have been updated to reflect the progress of members' projects. MTEP10 Appendix A includes expansion facilities through 2020. A total of 99 percent of the approved facilities included in MTEP10 are in service, on track or have encountered reasonable delays. That translates to $4.680 billion of the $4.727 billion included in MTEP10 Appendix A.

There were 101 in-service date adjustments to projects. Little or no impact on reliability is expected because in-service date adjustments were primarily driven by the economic slowdown. Transmission Owners may adjust project in-service dates to match system needs.

Withdrawn projects should be examined to ensure the planning process of MISO and its members address required system additions, and there was a good reason for withdrawing the project, or a different project covers the need. MTEP10 Appendix A contains projects approved in past MTEPs not yet in service, so withdrawn facilities may have been approved in prior MTEPs but withdrawn after MTEP10 was approved. There were 33 facilities (3 percent of 1025) withdrawn for the following reasons:

- The customer's plans changed or the service request was withdrawn.
- The plan was replaced with another plan.
- The plan was redefined to better meet the needs.
- The load forecast dictated that the project was no longer needed.

All withdrawn facilities were withdrawn for valid reasons. The majority were cancelled because service requests were withdrawn or load forecast was reduced.

3.2 MTEP implementation history

This section encompasses the implementation and status of all approved MTEP plans, including the current MTEP plan. A historical perspective shows extensive variability in transmission plan development. This is normal, caused by the long development time of transmission plans and the regular and periodic updating of the transmission plans.

Refer to Figure 3.2-1, which depicts cumulative investment dollars for projects, categorized by plan status, for MTEP03 through the current MTEP11 cycle. MTEP11 data depicted in Figure 3.2-1, subject to Board approval, is from the current MTEP study and will be added to the data tracked by the MISO Board of Directors. The steady increase in planned facilities testifies to the coordinated planning efforts of MISO and its Transmission Owners. These statistics include only MISO members who participated in this planning cycle.

- Since MTEP03 $4.4 billion of approved projects have been constructed and are in service.
- $199 million of MTEP projects are currently flagged as being under construction. However, there are over $900 million of projects with expected in service dates in 2011.
- $9.3 billion of MTEP projects are currently planned.
- Since MTEP03 $480 million of MTEP projects have been withdrawn.

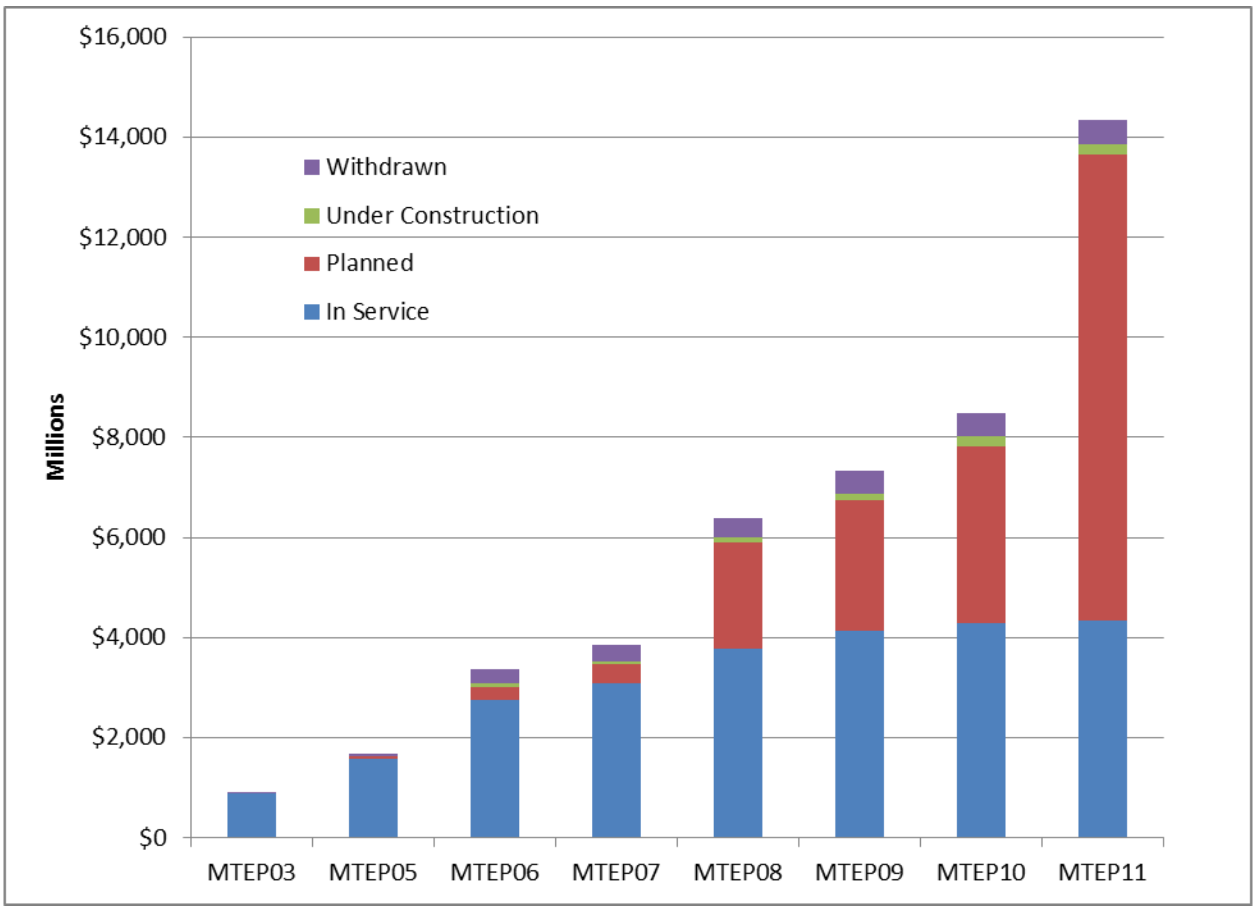


Figure 3.2-1: Cumulative approved investment by facility status

Figure 3.2-2 depicts MTEP project investment by facility status for each MTEP iteration. The historical perspective shows extensive variability in development. This is caused by the long development time of transmission plans and the regular and periodic updating of the transmission plans. The irregular shape of the graph represents the maturation of the MTEP process, and demonstrates the good faith effort of MISO Transmission Owners to implement the approved plan.

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small number of projects in MTEP07.
- In MTEP08, the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analysis and determination of the best plans to serve those needs. The in-service category can be seen increasing in past MTEPs as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts and presents a transmission planning approach driven by proposed Multi Value Projects (MVPs), an adaptable rather than fixed methodology, which takes into account market and policy uncertainties and defines an array of multiple facility scenarios capable of performing well no matter what the future holds, integrating mandated renewable energy sources and providing market benefits.
- MTEP11 contains most of the proposed Multi Value Project (MVP) portfolio which is comprised of approximately $5.1 billion in transmission investment.

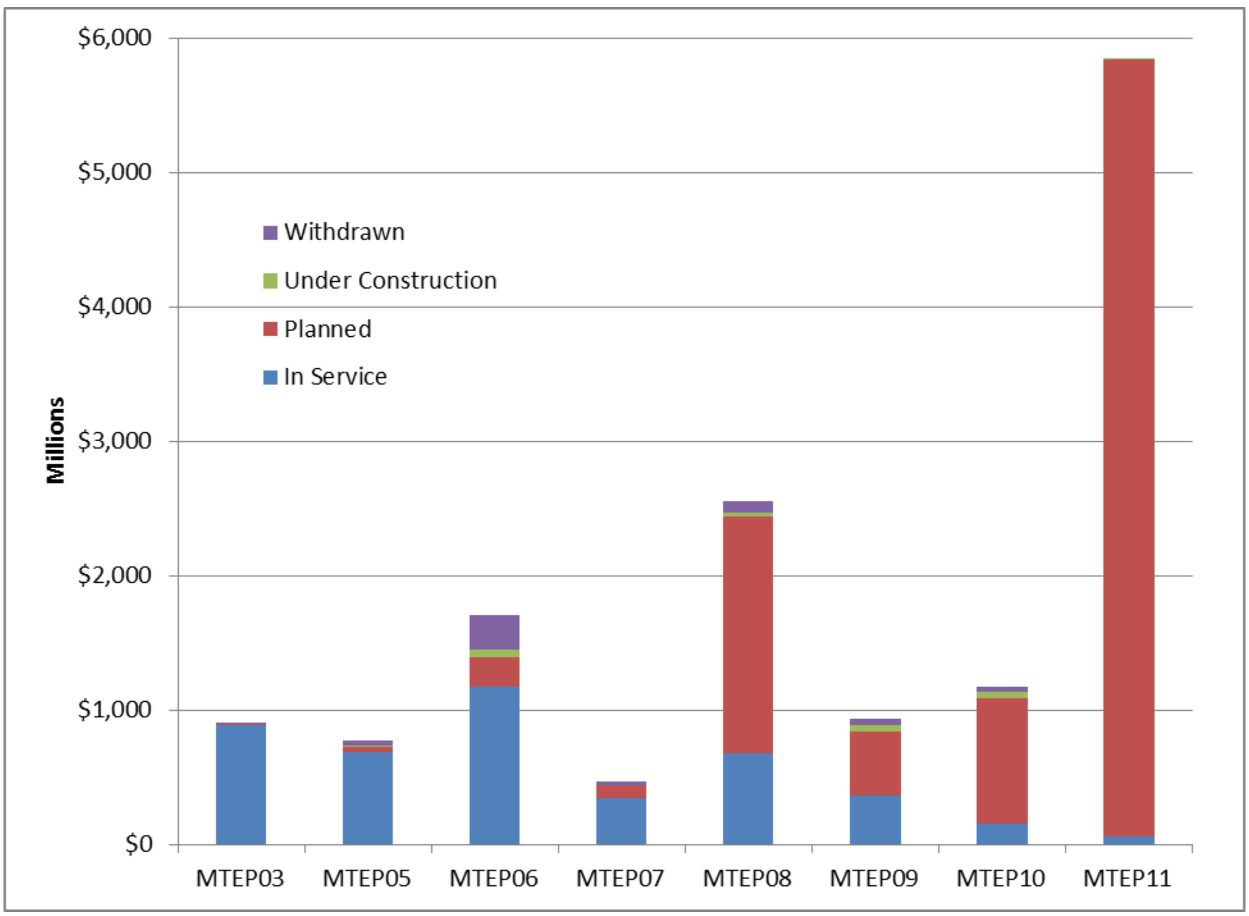


Figure 3.2-2: Approved MTEP investment by facility status

4. Regional energy policy studies

4.1 Proposed Multi Value Project portfolio

MISO staff recommends that the proposed Multi Value Project (MVP) portfolio be approved by the MISO Board of Directors for inclusion into Appendix A of MTEP11. This recommendation is based on the strong reliability, public policy and economic benefits of the portfolio that are distributed across the MISO footprint in a manner that is commensurate with the portfolio's costs. In short, the proposed portfolio will:

- Provide benefits in excess of its costs under all scenarios studied, with its benefit to cost ratio ranging from 1.8 to 3.0.
- Maintain system reliability by resolving reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions.
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million.
- Support a variety of generation policies by using a set of energy zones which support wind, natural gas and other fuel sources.

This report summarizes the key reliability, public policy and economic benefits of the proposed MVP portfolio, as well as the scope of the analyses used to determine these benefits. Additional information on the portfolio and study analyses will be available in the full MVP portfolio report, which is scheduled to be published later in 2011.

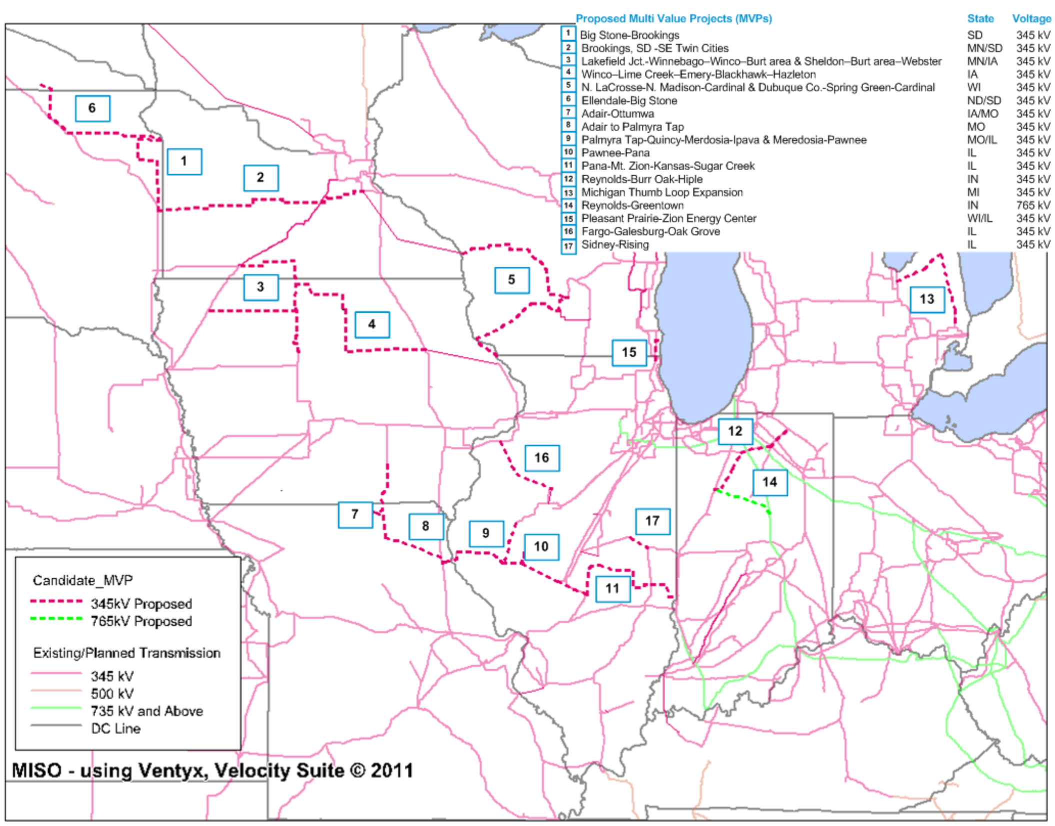


Figure 4.1-1: Proposed MVP portfolio

The proposed MVP portfolio includes the Brookings Project, conditionally approved in June 2011, and the Michigan Thumb Loop project, approved in August 2010. It also includes 15 additional projects which, when integrated into the transmission system, provide multiple kinds of benefits under all studied future scenarios[25].

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[26]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Blackhawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2018	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 4.1-1: Proposed MVP portfolio

25 More information on these scenarios may be found in the business case description.
26 Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.

Public policy decisions over the last decade have driven changes in how the transmission system is planned. The recent adoption of Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

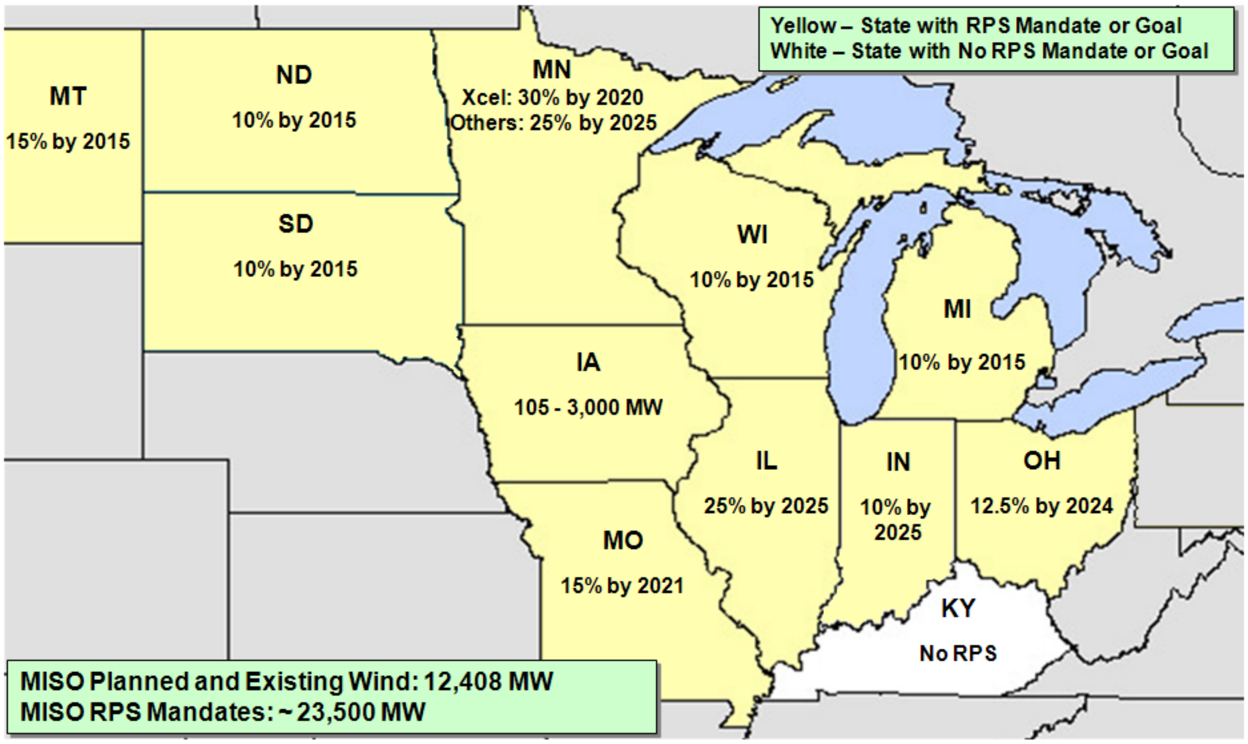


Figure 4.1-2: Renewable energy mandates and clean energy goals within the MISO footprint[27]

Beginning with the MTEP03 Exploratory Studies, MISO and stakeholders began to explore how to best provide a value added regional planning process to complement the local planning of MISO members. These explorations continued in later MTEP cycles and in specific targeted studies. In 2008, MISO, with the assistance of state regulators and industry stakeholders such as the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI) and the Organization of MISO States (OMS), began the Regional Generation Outlet Study (RGOS) to identify a set of value based transmission portfolios necessary to enable Load Serving Entities (LSEs) to meet their RPS mandates.

> The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

The goal of the RGOS analysis was to design transmission portfolios that would enable RPS mandates to be met at the lowest delivered wholesale energy cost. The cost calculation combined the expenses of the new transmission portfolios with the capital costs of the new renewable generation, balancing the trade offs of a lower transmission investment to

[27] Existing and planned wind as included in the Candidate MVP Portfolio. State RPS mandates and goals include all policies signed into law by June 1, 2011.

deliver wind from low wind availability areas, typically closer to large load centers; against a larger transmission investment to deliver wind from higher wind availability areas, typically located further from load centers.

While much consideration was given to wind capacity factors when developing the energy zones utilized in the RGOS and Candidate MVP Portfolio Analyses, the zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of the zones. As such, although the energy zones were created to serve the renewable generation mandates, they could be used for a variety of different generation types, to serve various future generation policies. Figure 4.1-3 depicts the correlation between the natural gas pipelines in the MISO footprint and the energy zones.

The zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of zones.

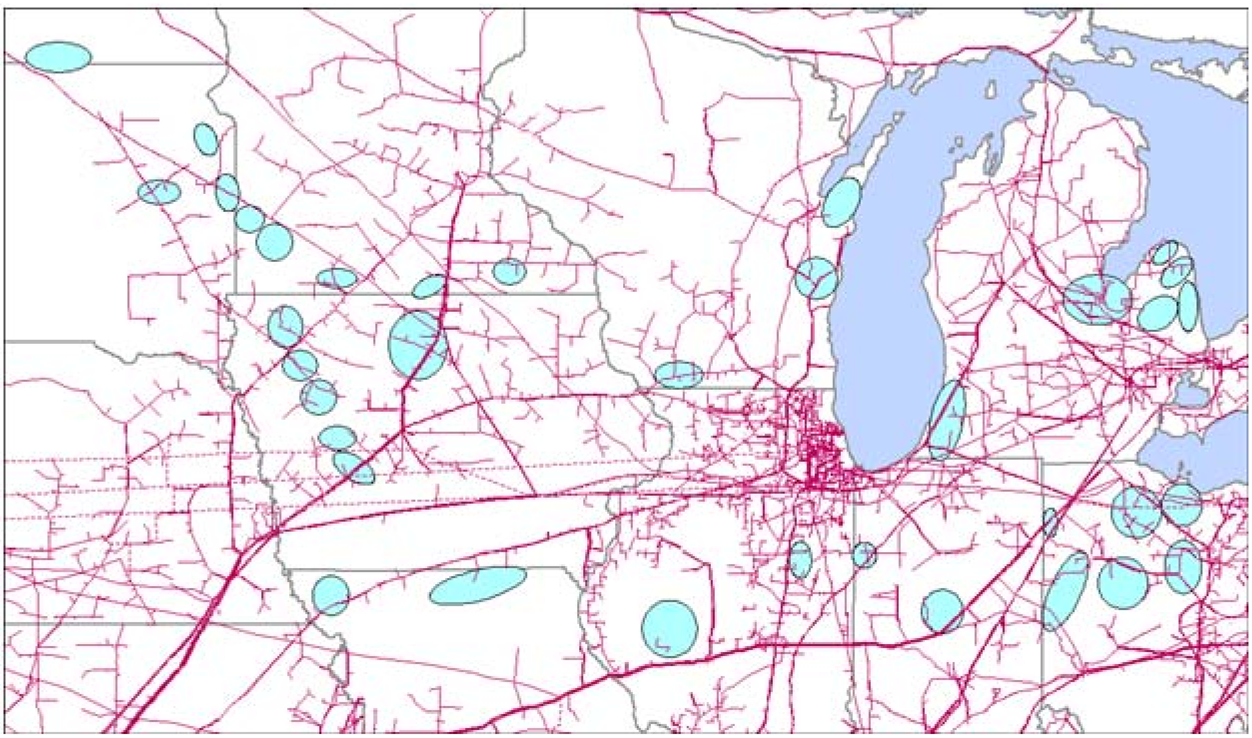


Figure 4.1-3: RGOS and Candidate MVP Incremental Energy Zones and natural gas pipelines

The output from the study, a proposed MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

The RGOS analysis produced three reliable transmission portfolios. Elements common between these three portfolios, and common with previous reliability, economic and generation interconnection analyses, were identified to create the 2011 Candidate MVP portfolio. This portfolio represented a set of "no regrets" projects which were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied.

The 2011 Candidate MVP Portfolio Analysis hypothesized that this set of candidate projects creates a high value transmission portfolio, enabling MISO states to meet their near term RPS mandates. This study evaluated the Candidate MVP portfolio against the MVP cost allocation criteria to prove or disprove this hypothesis, as well as to confirm that the benefits of the portfolio would be widely distributed across the footprint. The output from the study, a proposed MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

Over the course of the Candidate MVP Portfolio Analysis, the MVP portfolio was refined into the proposed portfolio that is now recommended to the MISO Board of Directors for approval. The portfolio was refined to ensure that the portfolio as a group and each project contained within it was justified under the MVP criteria, discussed below, and to ensure that the portfolio benefit to cost ratio was optimized.

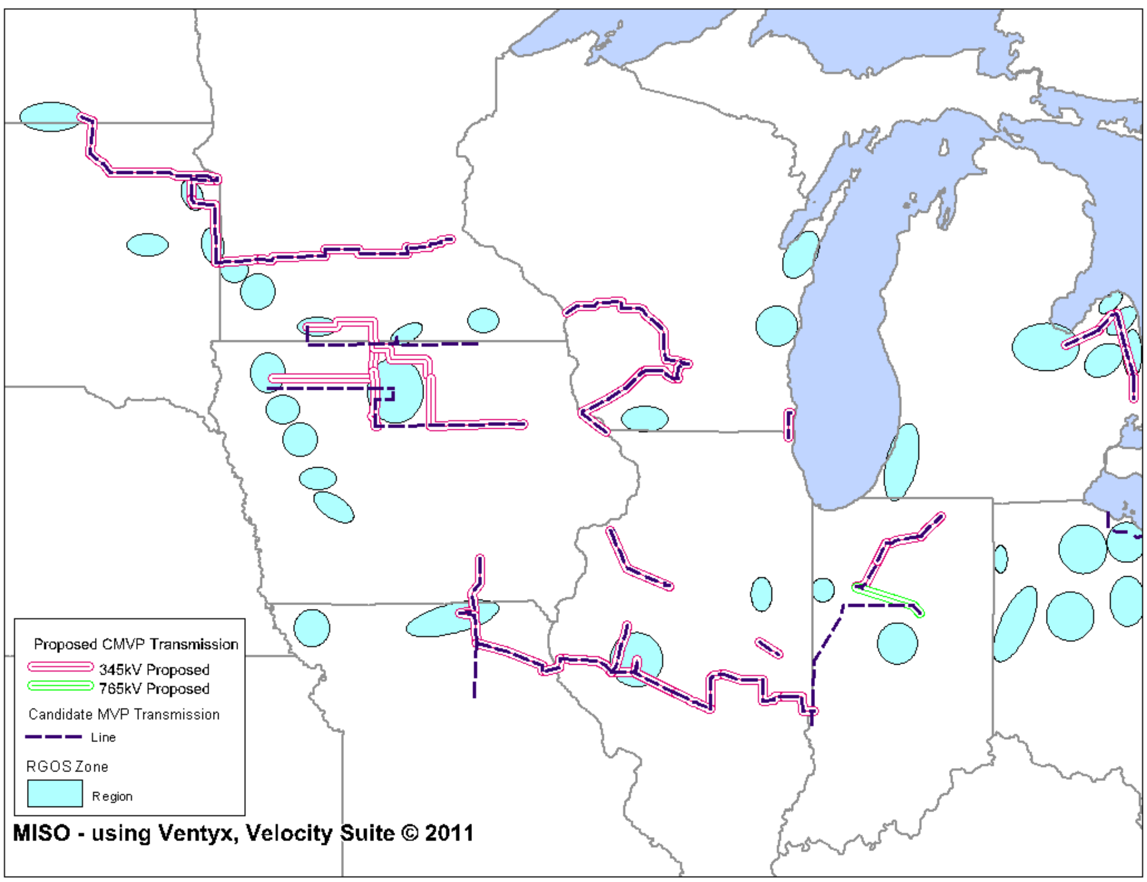


Figure 4.1-4: Candidate versus proposed MVP portfolio

The proposed MVP portfolio will enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. Specifically, the portfolio mitigates approximately 650 reliability constraints under 6,700 different transmission outage conditions, for steady state and transient conditions under both peak and shoulder load scenarios. Some of these conditions could be severe enough to cause cascading outages on the system. By mitigating these constraints, approximately 41 million MWh per year of renewable generation can be delivered to serve the MISO state renewable portfolio mandates.

Under all future policy scenarios studied, the proposed MVP portfolio delivers widespread regional benefits to the transmission system. For example, based on scenarios that did not consider new energy policies, the benefits of the proposed portfolio were shown to range from 1.8 to 3.0 times its total cost. These benefits are spread across the system, in a manner commensurate with their costs, as demonstrated in Figure 4.1-5.

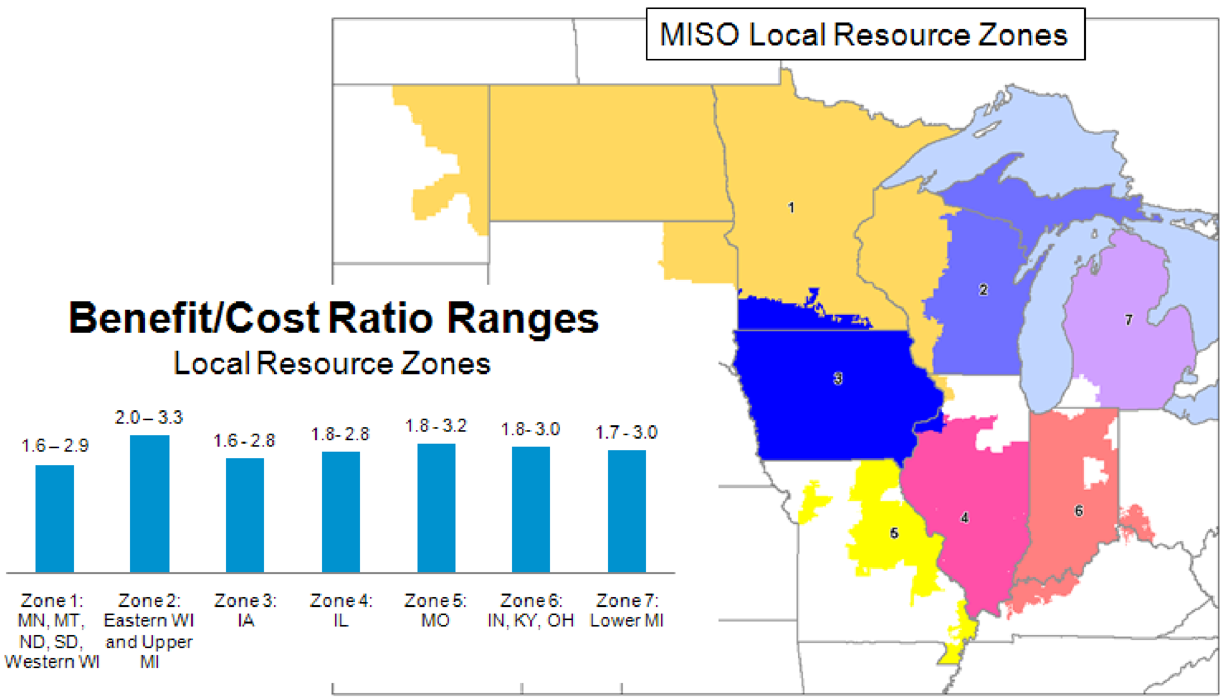


Figure 4.1-5: Proposed MVP portfolio benefits spread

The benefits created by the proposed MVP portfolio are spread across the system, in a manner commensurate with its costs.

Taking into account the significant economic value created by the portfolio, the distribution of these value, and the ability of the portfolio to meet MVP criterion 1 through its reliability and public policy benefits, MISO staff recommends the 2011 proposed MVP portfolio to the MISO Board of Directors for their review and approval.

Additional information on the proposed MVP portfolio, and the analyses used to design the portfolio, will be summarized in the full MVP portfolio report. This report will be published later in 2011.

MISO planning approach

The goal of the MISO planning process is to develop a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons. This process is guided by a set of principles established by the MISO Board of Directors, adopted on August 18, 2005. The principles were created in an effort to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, modified and approved by the MISO Board of Directors System Planning Committee on May 16, 2011, are:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

A number of conditions must be met to build longer term transmission able to support future generation growth and accommodate new energy policies. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and supported by an integrated, inclusive transmission planning approach. The conditions that must be met to build transmission include:

- A robust business case that demonstrates value sufficient to support the construction of the transmission project.
- Increased consensus on current and future energy policies.
- A regional tariff that matches who benefits with who pays over time.
- Cost recovery mechanisms that reduce financial risk.

Multi Value Project portfolio drivers

The 2011 Candidate MVP Portfolio Analysis was based on the need to economically and reliably help states meet their public policy needs. The study identified a regional transmission portfolio that will enable the MISO Load Serving Entities (LSEs) to meet their Renewable Portfolio Standards (RPS). The analyses and their results describe a robust business case for the portfolio. This business case demonstrates that not only will the proposed MVP portfolio reliably enable Renewable Portfolio Standards to be met, but it will do so in a manner where its economic benefits exceed its costs.

While the study focused upon the RPS requirements, the transmission portfolio will ultimately have widespread benefits beyond the delivery of wind and other renewable energy. It will enhance system reliability and efficiency under a variety of different generation build outs. It will also open markets to competition, reducing congestion and spreading the benefits of low cost generation across the MISO footprint. The Candidate MVP Portfolio Analysis focused on identifying and increasing the benefits of the transmission portfolio, including the reliability, economic and public policy drivers.

Tariff requirements

The Candidate MVP Portfolio Analysis and the recommendation of the proposed MVP portfolio were premised on the MVP criteria described in Attachment FF of the MISO Tariff and shown below.

Criterion 1

A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

Criterion 2

A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.

Criterion 3

A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

The MVP cost allocation criteria requires evaluation of the portfolio on a reliability, economic and energy delivery basis. The scope of the analysis was designed to demonstrate this value, both on a project and portfolio basis. The projects in the MVP portfolio were evaluated against MVP criteria 1 and their ability to reliably enable the renewable energy mandates of the MISO states was quantified.

In addition, the Tariff identifies specific types of economic value which can be provided by Multi Value Projects. These values are:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.

- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

The full proposed portfolio was evaluated against the benefits defined in the Tariff for MVP projects. In addition to the benefits described above, the operating reserve and wind siting benefits for the portfolio were quantified, as allowed under the last Tariff defined economic value. These benefits are described more fully in the economic benefit section later in the report.

Public policy needs

Twelve of 13 states in the MISO footprint have enacted either RPS requirements or renewable energy goals which require or recommend varying amounts of load be served with energy from renewable energy resources. The Candidate MVP Portfolio Analysis focused on the transmission necessary to economically and reliably meet the state RPS mandates. Figure 4.1-6 below provides additional details on these renewable energy requirements and goals.

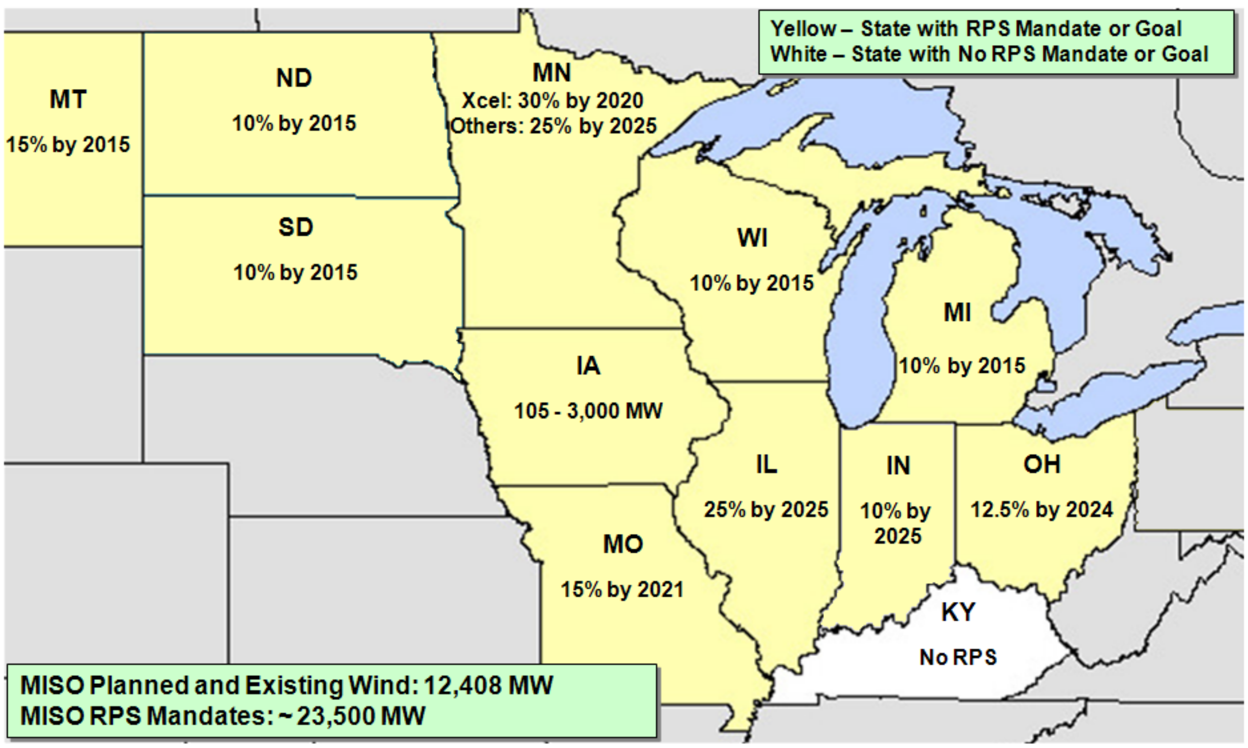


Figure 4.1-6: RPS mandates and goals within the MISO footprint

RPS mandates vary from state to state in their specific requirement details and implementation timing, but they generally start in about 2010 and are indexed to increase with load growth. While state laws support a number of different types of renewable resources, and multiple types of renewable resources will play a role in meeting state RPS mandates, the majority of renewable energy resources installed in the foreseeable future will likely focus on harnessing the abundant wind resources throughout the MISO footprint.

Enhanced reliability and economic drivers

The ultimate goal of the MISO planning process is to reliably deliver energy to load at the lowest possible cost. This requires a strategy premised upon a low cost approach to transmission and generation investment. This premise supports the overall constructability of the transmission portfolio, while reducing financial risk associated with overbuilding the system.

Transmission strategy

A transmission strategy addressing both local needs and regional drivers allows the MISO system to realize significant economic and reliability benefits. Regional transmission, such as the transmission in the proposed MVP portfolio, increases reliability in the MISO footprint, opens the market to increased competition and provides access to low cost generation, regardless of fuel type. Development of a strong regional transmission backbone is analogous to the development of the U.S. Interstate Highway System. While developed for specific wartime reasons, the system has realized significant additional benefits in subsequent years. Similarly, the proposed MVP portfolio will create reliability, economic and public policy benefits that reach beyond the immediate needs exhibited in this analysis.

The goal of the Candidate MVP Portfolio Analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system.

The overall goal for the Candidate MVP Portfolio Analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system. The portfolio was designed using reliability and economic analyses, applying several futures scenarios to determine the robustness of the designed portfolio under a number of future potential energy policies.

Development of the Candidate MVP portfolio

In order to provide widespread benefits commensurate with costs, MISO developed an initial portfolio of candidate MVP projects that were hypothesized to provide widespread benefits across the footprint. The projects selected as candidates for possible inclusion in the broader portfolio were then intensively evaluated in the Candidate MVP Portfolio Analysis to ensure they were justified and contributed to the portfolio business case.

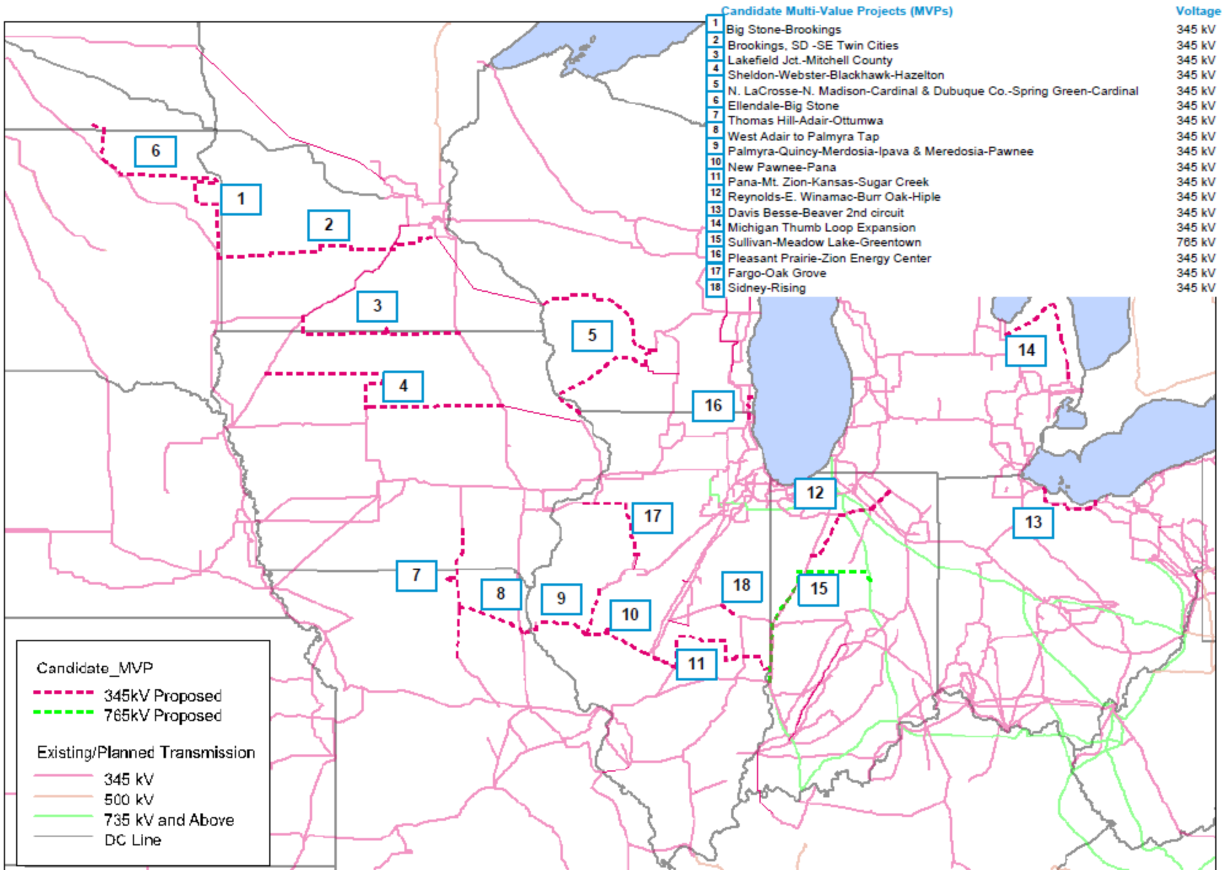


Figure 4.1-7: Initial 2011 Candidate MVP portfolio

The Candidate MVP portfolio was the first portfolio developed for review under the recent Tariff revisions establishing the MVP cost allocation classification. It was developed by considering regional system enhancements that could potentially provide multiple types of value, including enhanced reliability, reduced congestion, increased market efficiency, reduced real power losses and the deferral of otherwise needed capital investments in transmission. The portfolio was designed to enhance and complement the existing system performance, working cohesively with the individual elements of the portfolio and with the existing transmission grid, to produce a more robust and efficient system. Ultimately, the first portfolio represents a set of "no regrets" projects, providing benefits to the system in all futures scenarios studied.

Historical studies

MISO began to investigate the transmission required to integrate wind and provide the best value to consumers in 2002. The analyses continued through subsequent MTEP cycles, with exploratory and energy market analyses. As the demand for renewable energy grew, driven largely by an increasing level of renewable energy mandates or goals, additional regional studies were conducted to determine the transmission necessary to support these policy objectives. These studies included the Joint and Coordinated System Plan (JCSP), the Regional Generation Outlet Studies (RGOS), and analyses by the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) group.

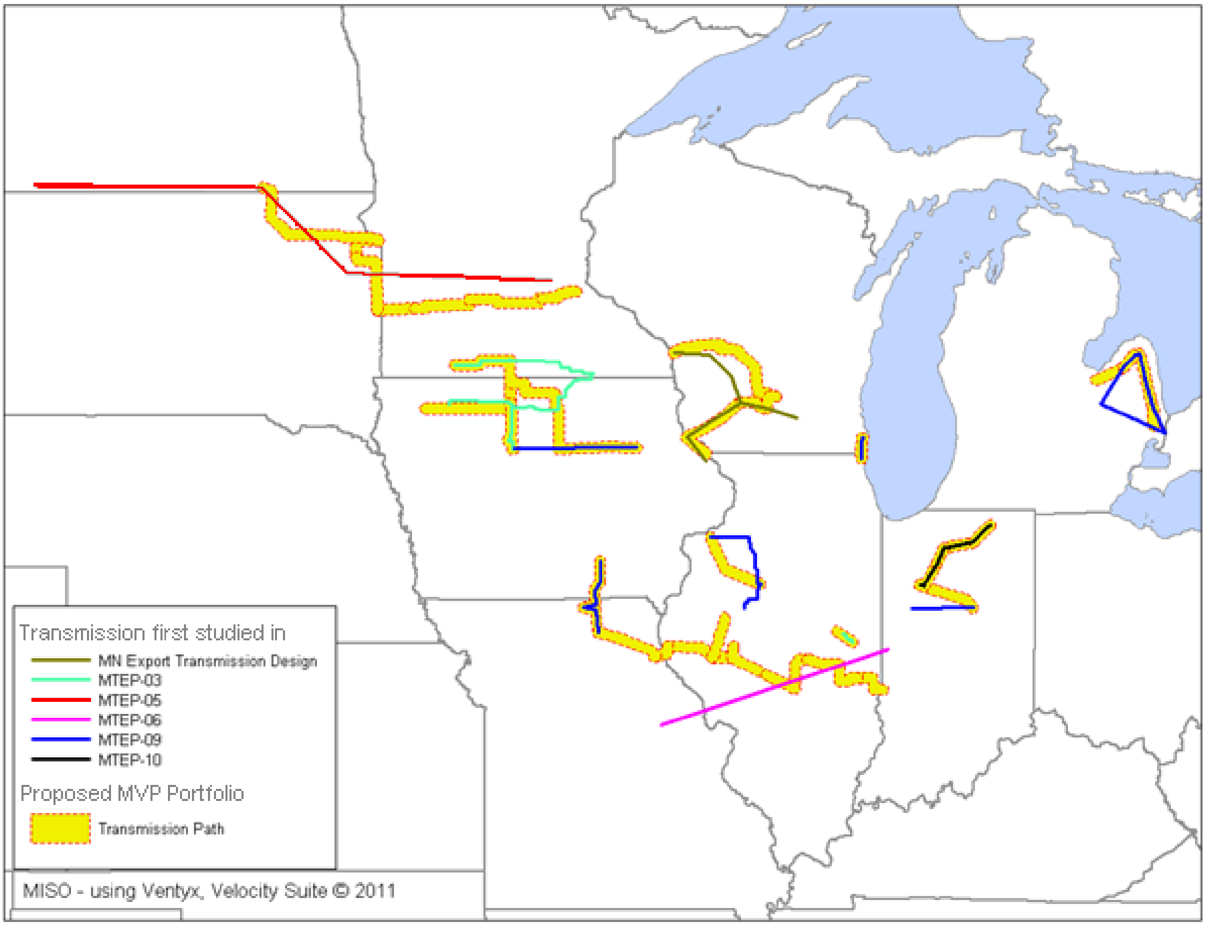


Figure 4.1-8: Prior study input into Candidate MVP portfolio

As analyses continued, the policy and economic drivers behind a regional transmission plan continued to grow. This growth was partly fueled by the development of the MISO energy and operating reserve market, which allows for regional transmission to provide regional benefits through increasing market efficiency, enabling low cost generation to be delivered to load. Simultaneously, an increase in state energy policy mandates drove the need for a robust regional transmission network, capable of responding to legislated changes in generation requirements.

Wind siting strategy

As an increasing number of states in the MISO footprint began to enact renewable energy mandates or goals, a strategy for siting wind generation was required to minimize the cost of delivered energy to consumers. To determine the low cost solution, encompassing generation and transmission capital cost, MISO developed a set of potential energy zones or locations where wind generation could feasibly be located, on a state by state basis[28]. In conjunction with state regulators and other stakeholders, MISO used these zones to explore a number of long term transmission and generation strategies to meet the state RPS requirements. These analyses focused on the tradeoffs between local wind generation, which typically requires less transmission expansion but a larger amount of wind turbines to deliver a given amount of wind energy; versus regional wind generation, which requires fewer wind turbines at the cost of higher levels of transmission expansion.

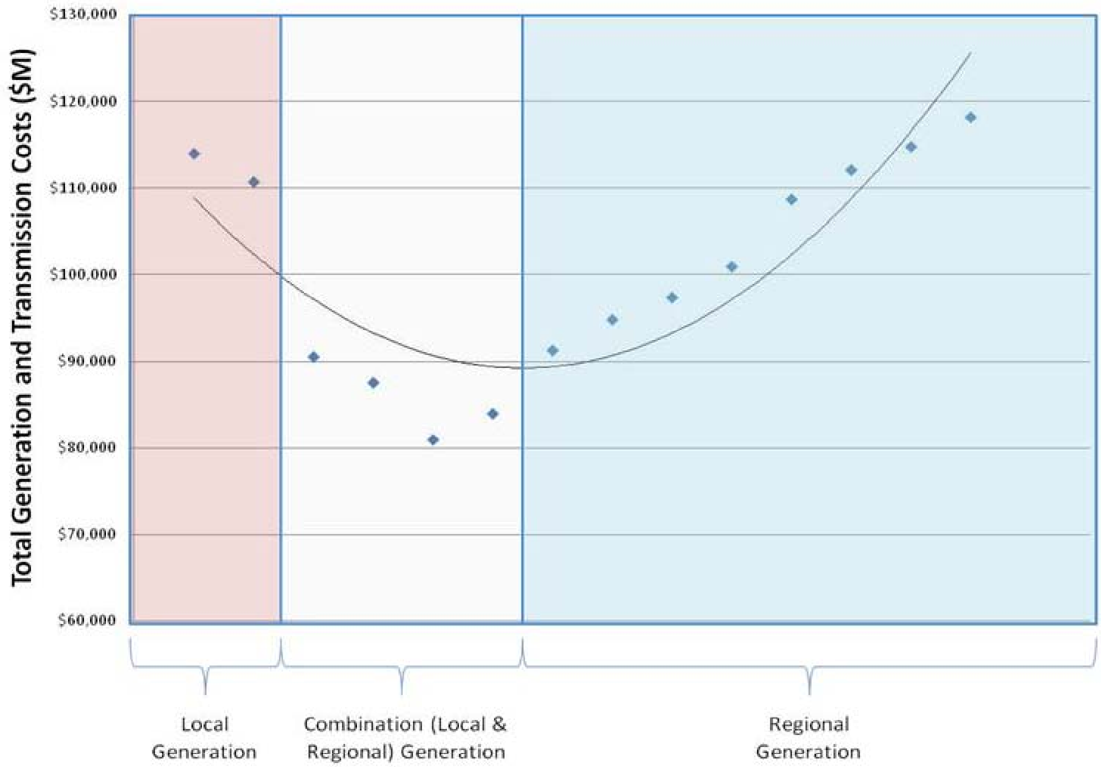


Figure 4.1-9: Capital costs of transmission and generation

[28] More information on the zone development may be found in the RGOS report at http://www.midwestiso.org/Library/Repository/Study/RGOS/Regional percent20Generation percent20Outlet percent20Study.pdf.

The study results demonstrated that the low cost approach to wind generation siting, when both generation and transmission capital costs are considered, is a combination of local and regional wind generation locations, as shown by the white area in Figure 4.1-9. This approach was affirmed by the Midwest Governors' Association as the best method for wind zone selection and used as the basis for the final phase of the RGOS analysis in 2010. It was also used as the basis for the wind siting approach for the Candidate MVP Portfolio Analysis. The set of energy zones chosen for the Candidate MVP Portfolio Analysis are shown below in Figure 4.1-10 as blue ovals.

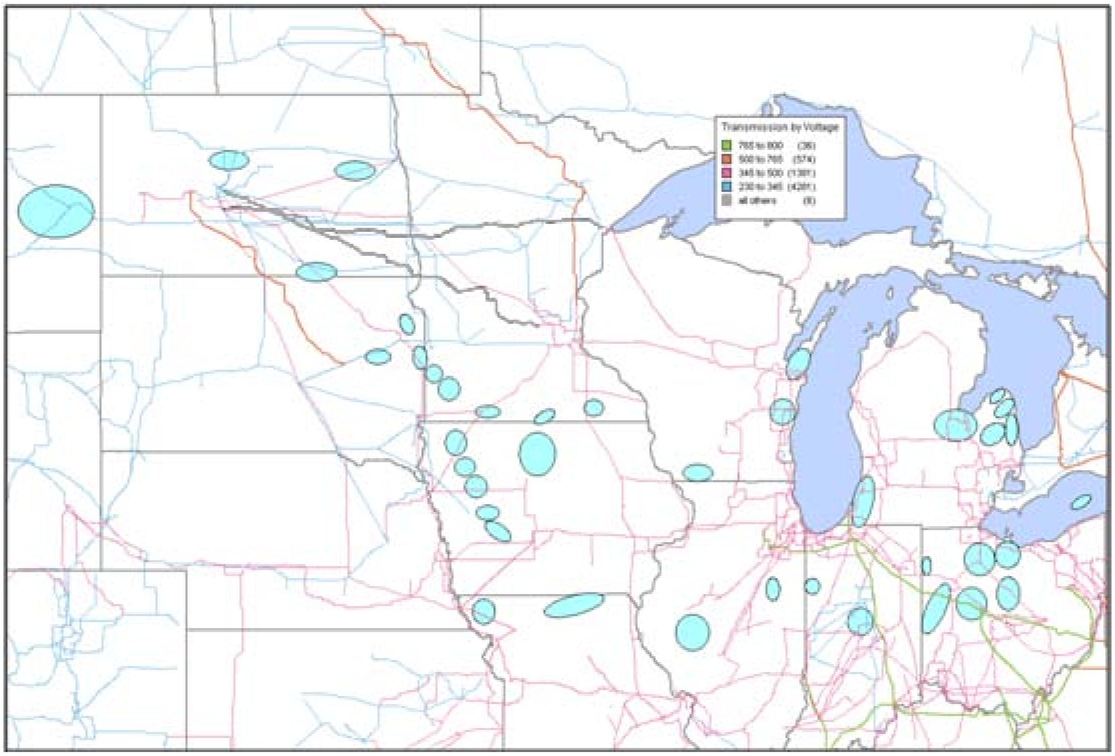


Figure 4.1-10: Candidate MVP Incremental Energy Zones[29]

[29] Zones shown represent the rough geographic area of each energy zone.

Candidate MVP Portfolio Analysis study scope

The Candidate MVP Portfolio Analysis combined the MISO Board of Director Planning Principles and the conditions precedent to transmission construction to develop a transmission portfolio that meets public policy, economic and reliability requirements. The analysis built a robust business case for the recommended transmission, using the newly created Multi Value Project (MVP) cost allocation methodology approved by FERC. The candidate transmission was tested against a variety of potential policy futures. This maximized the value of the transmission portfolio and reduced potential negative risks associated with its construction due to changes in future demand and energy growth. The output of the study was a justified portfolio of proposed MVPs for inclusion in MTEP11 Appendix A and, if approved by the MISO Board of Directors, subsequent construction.

The MVP cost allocation criterion requires the evaluation of the portfolio on a reliability, economic and energy delivery basis.

The MVP cost allocation criteria requires the evaluation of the portfolio on a reliability, economic and energy delivery basis. The analyses were designed to demonstrate this value, both on a project and portfolio basis. To this end, the Candidate MVP Portfolio Analysis included the studies and output shown in table 4.1-2.

These analyses focused on three main areas. The project valuation analyses focused on justifying each individual MVP project against the MVP criteria. The portfolio valuation analyses determined the benefits of the portfolio in aggregate, quantifying additional reliability and economic benefits. Finally, a series of system performance analyses were performed to ensure that the system reliability will be maintained with the proposed MVP portfolio in service.

Analysis Type	Analysis Output	Purpose
Steady state	List of thermal overloads mitigated by the proposed MVP portfolio transmission projects	Project valuation
Alternatives	Relative value of the candidate MVP projects against a stakeholder or MISO identified alternative Can include steady state and production cost analyses	Project valuation
Underbuild requirements	Document any incremental transmission required to mitigate constraints created by the addition of the proposed MVP portfolio	System performance
Short circuit	Document any incremental upgrades required to mitigate any short circuit / breaker duty violations	System performance
Stability	List of violations mitigated by the proposed MVP portfolio transmission projects Includes both transient and voltage stability analysis	System performance / Portfolio valuation
Generation enabled	Document wind curtailed, and additional wind that is enabled by the proposed MVP portfolio	Portfolio valuation
Production cost	Adjusted Production Cost (APC) benefits of the entire proposed MVP portfolio	Portfolio valuation
Robustness testing	Quantification of portfolio benefits under various policy futures or transmission conditions	Portfolio valuation
Operating reserves Impact	Impact of the proposed MVP portfolio on existing operating reserve zones and quantification of this benefit	Portfolio valuation
Planning Reserve Margin (PRM) benefits	Capacity savings due to reductions in the system wide Planning Reserve Margin caused by the addition of the proposed MVP portfolio to the transmission system	Portfolio valuation
Transmission loss reductions	Capacity losses savings, where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour	Portfolio valuation
Wind generation capital investment	Quantification of the incremental wind generator capital cost savings enabled by the wind siting methodology supported by the proposed MVP portfolio	Portfolio valuation
Avoided capital investment (transmission)	Document the future baseline transmission investment that may be avoided due to the installation of the proposed MVP portfolio	Portfolio valuation

Table 4.1-2: Candidate MVP Portfolio Analyses and Output

Proposed MVP portfolio overview

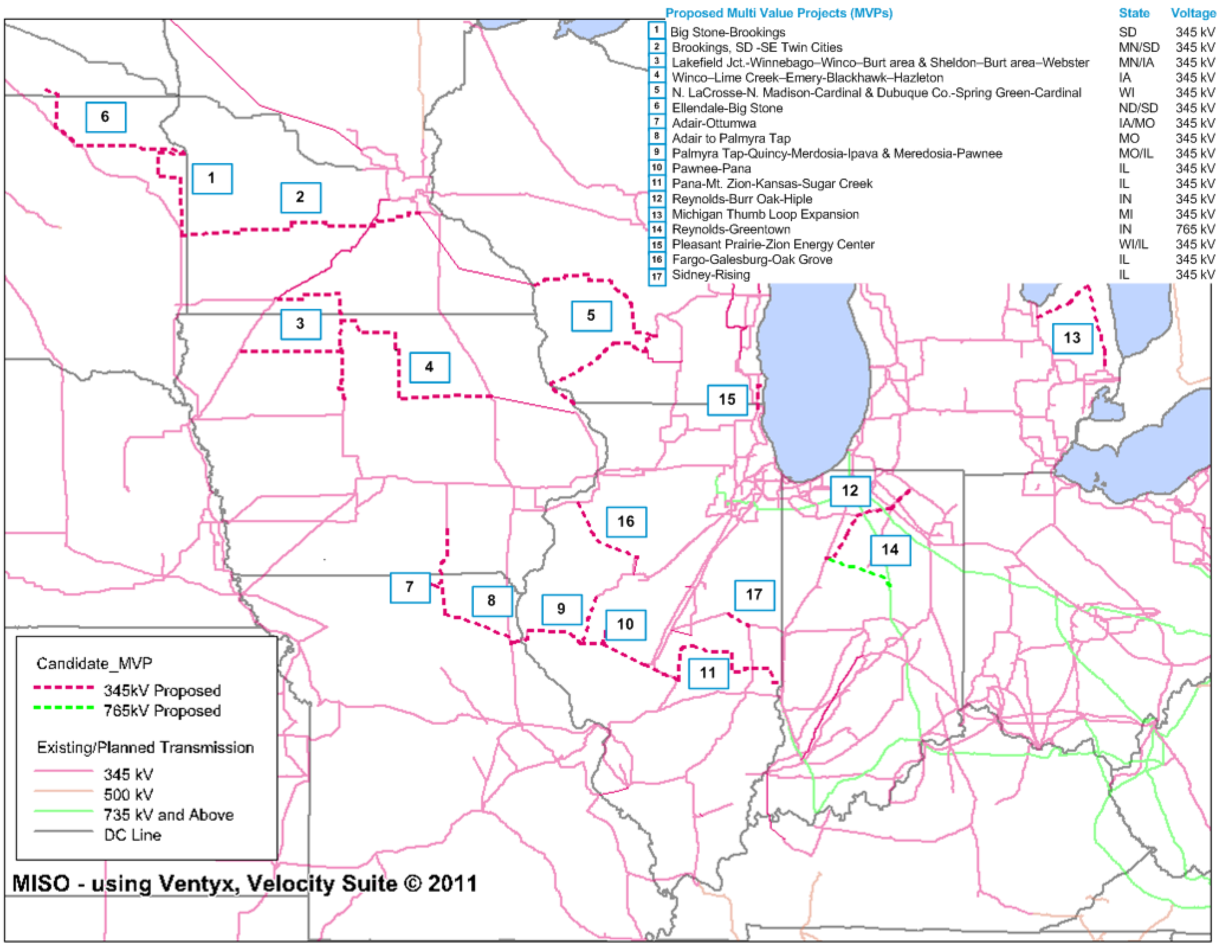


Figure 4.1-11: 2011 proposed MVP portfolio

The proposed MVP portfolio consists of 17 projects spread across the MISO footprint. These projects work together with the existing transmission network to enhance the reliability of the system, support public policy goals and enable the more efficient dispatch of market resources. Table 4.1-3 below describes the projects that make up the proposed MVP portfolio.

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Blackhawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co. –Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2018	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop Expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo-Galesburg–Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 4.1-3: Proposed MVP portfolio

Reliability benefits and analyses

The proposed MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions. It also mitigates 31 system instability conditions. More information on these constraints can be found in Appendix E4, and a full write up of the analyses will be included in the full MVP portfolio report. A description of the reliability analysis results follows in the next section.

Steady state

A series of steady state analyses were conducted to determine the transmission line overloads and system voltage constraints mitigated by the proposed MVP portfolio. The primary steady state analysis was performed on a set of 2021 shoulder peak models, with both 2021 and 2026 mandated wind levels considered. Shoulder peak models were chosen for the primary analysis, as the high wind levels required by the renewable portfolio mandates are more likely to create system constraints under these conditions. A 2021 peak analysis was also conducted to ensure the full reliability benefits of the proposed portfolio were captured. Each set of analyses were performed on: 1) a model with the RPS mandated wind, without any incremental transmission; 2) a model with the RPS mandated wind and the MVP portfolio. The results from the two analyses were compared to determine what constraints were mitigated by the proposed MVP portfolio.

The proposed MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions.

A total of 384 thermal overloads were mitigated by the proposed MVP portfolio under shoulder peak conditions, for approximately 4,600 system conditions. In addition, approximately 100 additional thermal overloads and 150 voltage violations were mitigated by the proposed MVP portfolio in the summer peak analysis.

Stability

<u>Transient Stability</u>

MISO performed a set of transient stability analyses to ensure the ability of existing and proposed generation to remain synchronous with other system generation under severe fault conditions, as required by NERC and regional reliability standards. Two scenarios were studied to evaluate the impact of major fault conditions without any voltage or damping criteria violations. The first scenario included all the incremental wind zones with none of the proposed MVPs portfolio modeled, and the second scenario included incremental wind zones and the proposed MVP portfolio.

Based on the comparative analysis involving simulation of approximately 650 fault conditions under both scenarios, there were 31 fault conditions that without the proposed MVP portfolio would cause the system to experience undamped oscillations, causing generators to trip offline or incur damage due to high speed rotation, creating safety risks for plant personnel and potentially causing a large scale loss of load. These conditions were resolved by the addition of the proposed MVP portfolio to the system, and no additional stability violations were determined with the MVP portfolio in service.

Voltage Stability Analysis

MISO performed voltage stability analyses to identify voltage collapse conditions under high energy transfer conditions from major generation resources to major load sinks. Such transfers may occur during critical dispatch scenarios, such as when local area generation near large load centers are offline and remote generation resources are supplying energy to the load centers. Two scenarios were studied to evaluate the incremental energy transfer capability. The first scenario included all the incremental wind zones with none of the proposed MVP portfolio modeled, and the second scenario included all the incremental wind zones and the proposed MVP portfolio.

MISO did not observe any voltage stability issues with the proposed MVP portfolio in place, and with the high energy transfers corresponding to the highest wind resource output levels. Additionally, the comparative transfer analysis simulated high transfer conditions from the wind rich West Region of the MISO footprint to major load centers such as Minneapolis-St. Paul, Madison, St Louis and Des Moines. The results, shown in Appendix E4, illustrate that the addition of the proposed MVP portfolio causes an increase in transfer capability from wind rich regions to major load centers that ranges from 960 to 1,841 MW. This additional transfer capacity will increase system reliability and robustness, allowing additional energy sources to be dispatched to serve load centers as needed.

Short circuit

The addition of significant amounts of new high voltage transmission to the grid can increase the system connectivity, resulting in lowered impedance for short circuit currents. This can cause available fault currents throughout the system to exceed circuit breaker interrupting capabilities. MISO staff and Transmission Owners performed a series of high level short circuit analyses to identify any breaker or substation equipment needing to be upgraded after the addition of the proposed MVP portfolio to the transmission system. These analyses were performed directly by the affected Transmission Owners, with MISO staff providing modeling information for the proposed MVP projects. Any identified circuit breaker upgrades were verified through independent analysis by MISO staff, and their costs were included in the portfolio. Overall, nine circuit breakers were identified for replacement, at a total cost of $2.2 million.

Underbuild requirements

To ensure that the proposed MVP portfolio works well with the existing system to maintain reliability, MISO conducted analyses to determine any constraints that are present with the proposed MVP Portfolio and not present without the proposed portfolio. Any new constraints were identified for mitigations, and the appropriate mitigation was determined in coordination with the impacted Transmission Owners.

Below is a full list of the underbuild upgrades. Overall, approximately $70 million of transmission investment is associated with such underbuild.

Underbuild requirements
Burr Oak to East Winamac 138 kV line uprate
Lake Marian 115/69 kV transformer replacement
Arlington to Green Isle 69 kV line uprate
Columbus 69 kV transformer replacement
Casey to Kansas 345 kV line uprate
Lake Marian to NW Market Tap 69 kV line uprate
Franklin 115/69 kV transformer replacements
Castle Rock to ACEC Quincy 69 kV line uprate
Kokomo Delco to Maple 138 kV line uprate
Wabash to Wabash Container 69 kV line uprate
Spring Green 138/69 kV transformer replacement
Davenport to Sub 85 161 kV line uprate
West Middleton West Towne 69 kV line uprate
Ottumwa Montezuma 345 kV line uprate

Table 4.1-4: Proposed MVP portfolio underbuild requirements

Alternatives assessment

To ensure the proposed MVP portfolio provides cost-effective benefits to the MISO system, MISO considered alternatives to the Candidate MVP portfolio. In addition, similar alternatives were also considered in the prior studies which led to the selection of the initial Candidate MVP portfolio.

A “do-nothing” alternative was first considered. This alternative was used as a baseline to determine the system performance in delivering future generation requirements to load. It was demonstrated that, without major additions to the regional transmission system, significant generation curtailment would be required to maintain system reliability. Such a system would lead to heavy system loading conditions, potential instabilities, reduced reliability margins and would limit the ability of the states in the MISO footprint to meet their renewable energy mandates. As such, it was determined that significant system enhancements would be needed to meet renewable energy mandates and maintain system reliability.

An alternative build-out based on a piecemeal resolution of each facility experiencing an overload was considered. Such a plan would build incremental local upgrades to mitigate the reliability issues directly caused by the injection of the mandated wind into the transmission system. This would result in a minimum of 650 transmission projects, as compared to the 17 larger projects that comprise the proposed

MVP portfolio. MISO does not believe that 650 projects on the existing system could be completed in the same reliable or timely manner as the construction of the proposed MVP portfolio.

Also, this alternative would cost approximately $4.7 billion, based only upon the constraints found in the steady state reliability analysis. Additional investment would most likely be required to mitigate the constraints found in the stability analyses. This alternative would provide much lower benefits to the MISO system, as it does not provide long term solutions that increase the regional transmission capability. This solution would enable less wind to be delivered, endangering the ability of the states in the MISO footprint to meet their renewable energy mandates. It would provide significantly less economic benefits, as the regional values quantified below would be reduced or eliminated.

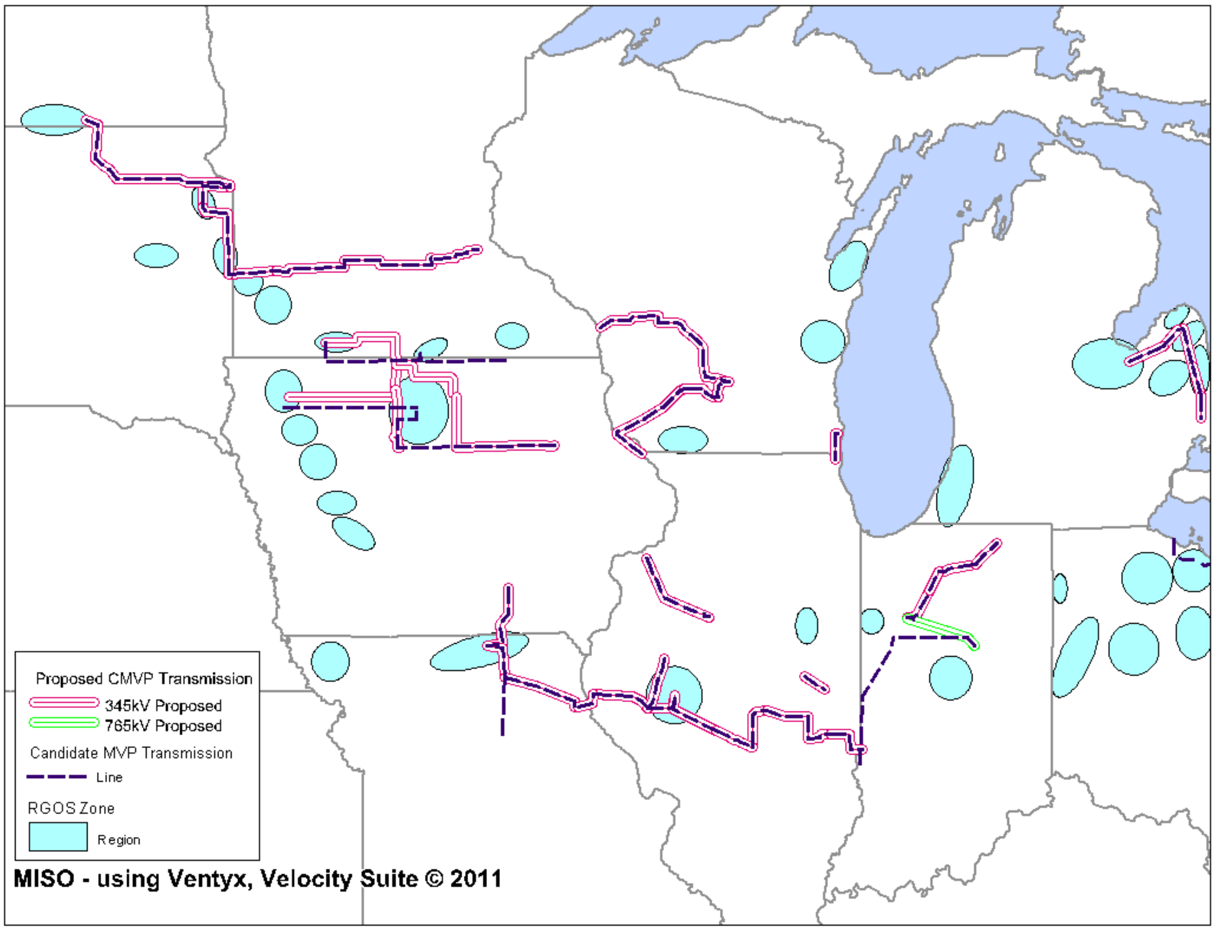


Figure 4.1-12: Candidate versus proposed MVP portfolio

The final alternative considered was the optimization of a regional transmission solution. Analysis surrounding this alternative began with the creation of the Candidate MVP portfolio, a derivative of the highest value transmission solutions from studies beginning in 2003 and continuing to the present. This candidate portfolio was optimized by evaluating each transmission line separately and in the context of other lines in the portfolio. This optimization included analyses of a different transmission configuration in Iowa, the removal of the Adair to Thomas Hill line, an option to reconfigure the transmission lines across southern Illinois and the removal of the Reynolds to Sullivan 765 kV line segment from the candidate portfolio. Although not all these changes were found to be justified, the investigations into the proper portfolio configuration increased the reliability, economic and public policy benefits of the final, proposed MVP portfolio.

Public policy benefits

The proposed MVP portfolio was built upon a set of energy zones that, although they can be used for alternative forms of generation, were premised upon a low cost approach to wind generation siting. Through resolving reliability constraints that would otherwise result in the curtailment of wind generation, the proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy annually to support the renewable energy mandates of the MISO states through at least 2026.

Through resolving reliability constraints that would otherwise result in the curtailment of wind generation, the proposed MVP portfolio enables the delivery of 41 million MWh of renewable energy annually.

Economic benefits

Multi Value Projects represent the next step in the evolution of the MISO transmission system: a regional network that, when combined with the existing system, provides value in excess of its costs under a variety of future policy and economic conditions. These benefits are quantified below. More information on the method used to quantify the values can be found in Appendix E5, and a more detailed analysis will be included in the full MVP portfolio report, which will be published later in 2011.

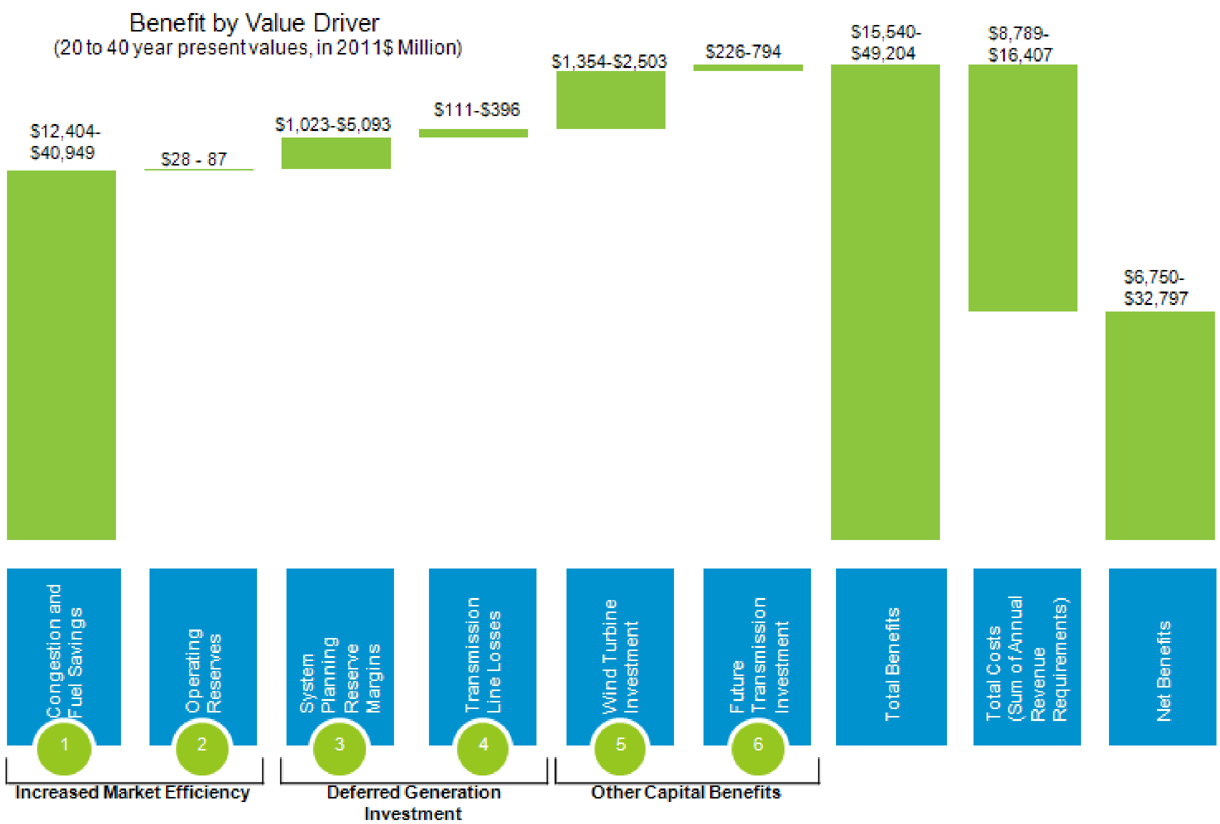


Figure 4.1-13: Proposed MVP portfolio economic benefits

Congestion and fuel savings

The proposed MVP portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low cost generation throughout the footprint. These benefits were quantified through a series of production cost analyses, which captured the economic benefits of the proposed MVP transmission and the wind it enables. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient generation resource utilization.

In order to show the economic benefits of the portfolio under a variety of different potential policy based futures, MISO calculated four sets of Adjusted Production Cost (APC) benefits. The futures analyzed were designed to 'bookend' the range of potential future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts were within the range bounded by the results. The futures analyzed are described below.

- Business As Usual with Continue Low Demand and Energy Growth assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.
- Business As Usual with High Demand and Energy Growth assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates
- Carbon Constrained assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- Combined Energy Policy assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.

More information on these futures may be found in Appendix E2.

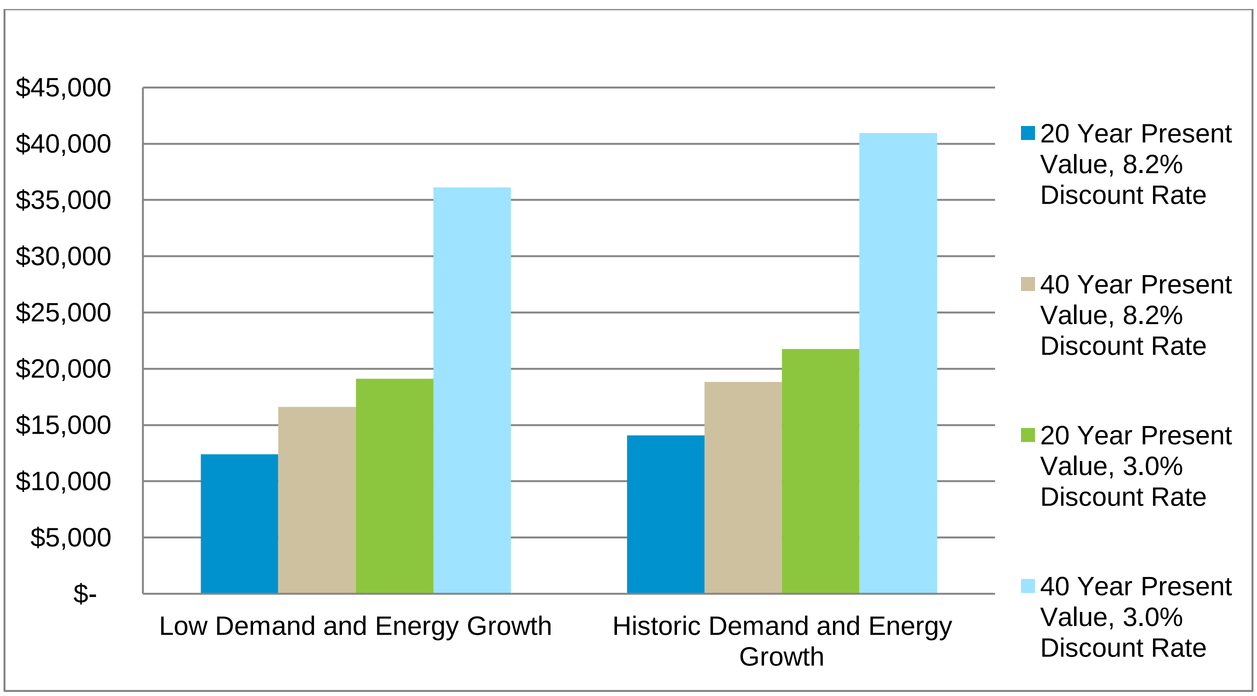


Figure 4.1-14: Proposed MVP portfolio Adjusted Production Cost Benefits

The future scenarios without any new energy policy mandates provide a baseline of the proposed MVP portfolio's benefits under current policy conditions. Additionally, the evaluation of the Carbon Constrained and Combined Policy future scenarios provide 'bookends' which help show the full range of benefits that may be provided by the portfolio. When the 'Business as Usual' future scenarios with no new energy policies were analyzed, the proposed MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year Present Value (PV) Adjusted Production Cost (APC) benefits, depending on the timeframe, discount rate, energy growth rates and demand growth rates considered. This benefit would increase to a maximum present value of $91.7 billion under the Combined Policy future scenario.

Operating reserves

In addition to the energy benefits quantified in production cost analyses, the proposed MVP portfolio will also reduce operating reserve costs. The MVPs decrease congestion on the system, increasing the transfer capability into several key areas that would otherwise have to hold additional operating reserves under certain system conditions.

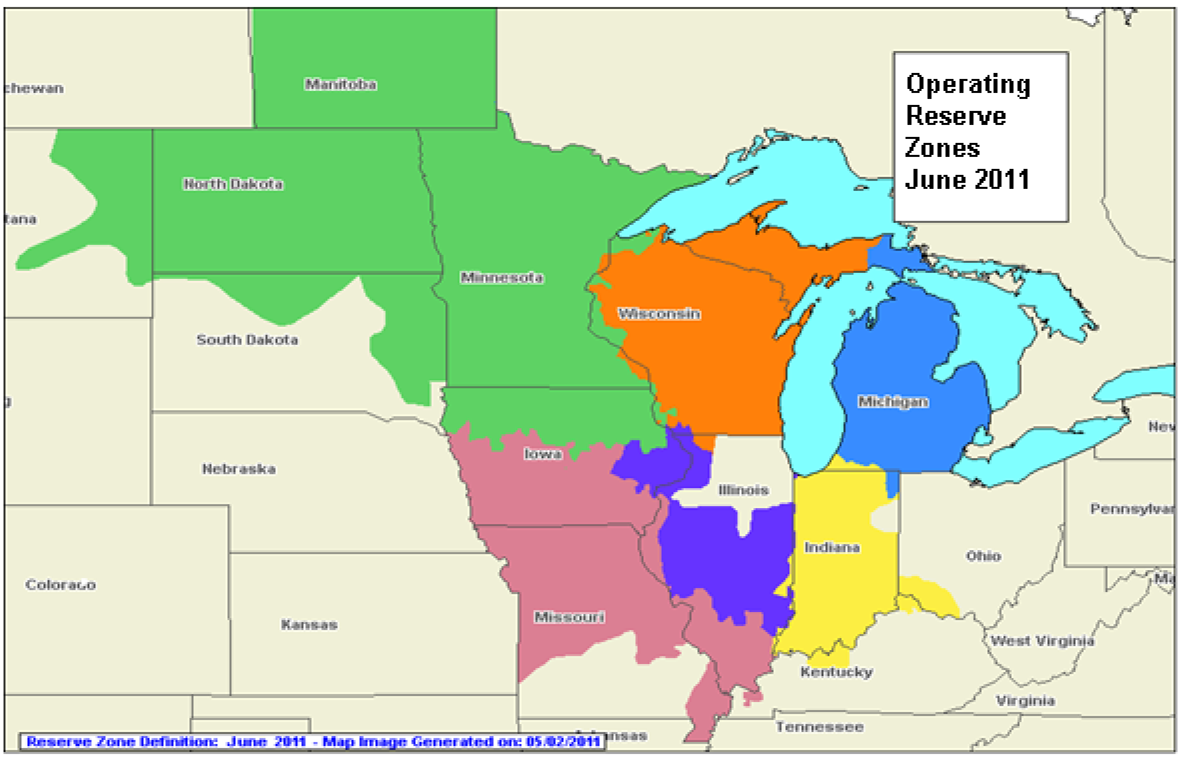


Figure 4.1-15: Operating reserve zones

MISO determined that the addition of the proposed MVP portfolio will eliminate the need for the Indiana operating reserve zone, and the need for additional system reserves to be held in other zones across the footprint would be reduced by half. This creates the opportunity to locate an average of 690,000 MWh of operating reserves annually where it would be most economical to do so, as opposed to holding these reserves in prescribed zones, creating benefits of $28 to $87 million in 20 to 40 year present value terms.

System planning reserve margin

The system planning reserve is calculated by determining the amount of generation required to meet a one day in 10 year Loss of Load Expectation (LOLE). It has two components: the unconstrained system Planning Reserve Margin (PRM), and the congestion contribution. The proposed MVP portfolio reduces transmission congestion across MISO, thereby reducing the system PRM and decreasing the amount of generation needed to maintain the PRM.

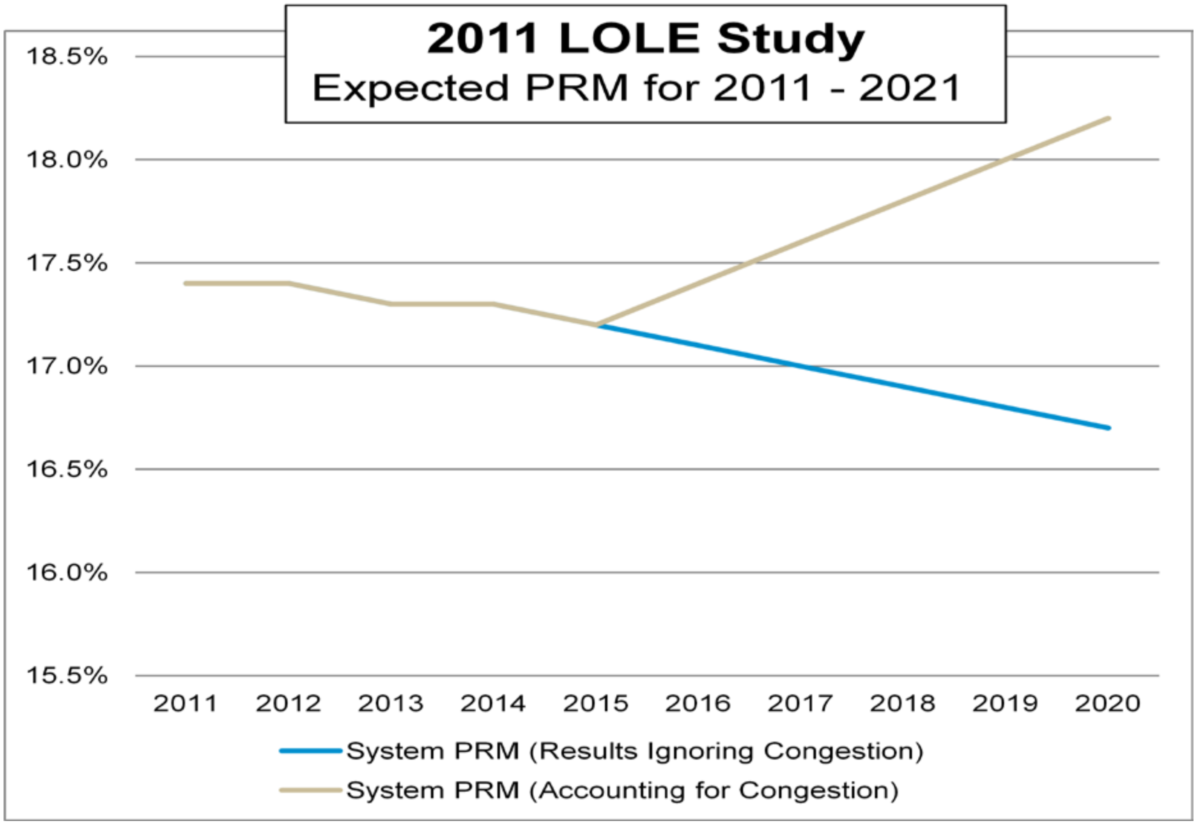


Figure 4.1-16: Expected planning reserve margin, with and without congestion

Through reducing the PRM, the proposed MVP portfolio allows the deferral of new generation, creating \$1.0 to \$5.1 billion in present value benefits, depending on whether a 20 or 40 year present value is considered, as well as the future growth and discount rates.

Transmission line losses

The addition of the proposed MVP portfolio to the transmission network reduces overall system losses, reducing the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs. Specifically, when installed generation capacity is only just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses creates benefits through reducing the amount of generation that must be built. This creates \$111 million to \$396 million in present value savings, depending on the timeline of the present value calculations, the discount rate and energy/demand growth rates.

Wind turbine investment

As discussed previously, MISO determined a wind siting approach that results in a low cost solution, when transmission and generation capital costs are considered. This approach sources generation in a combination of local and regional locations, placing wind local to load, where less transmission is required; and regionally, where the wind is the strongest. However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation would have to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

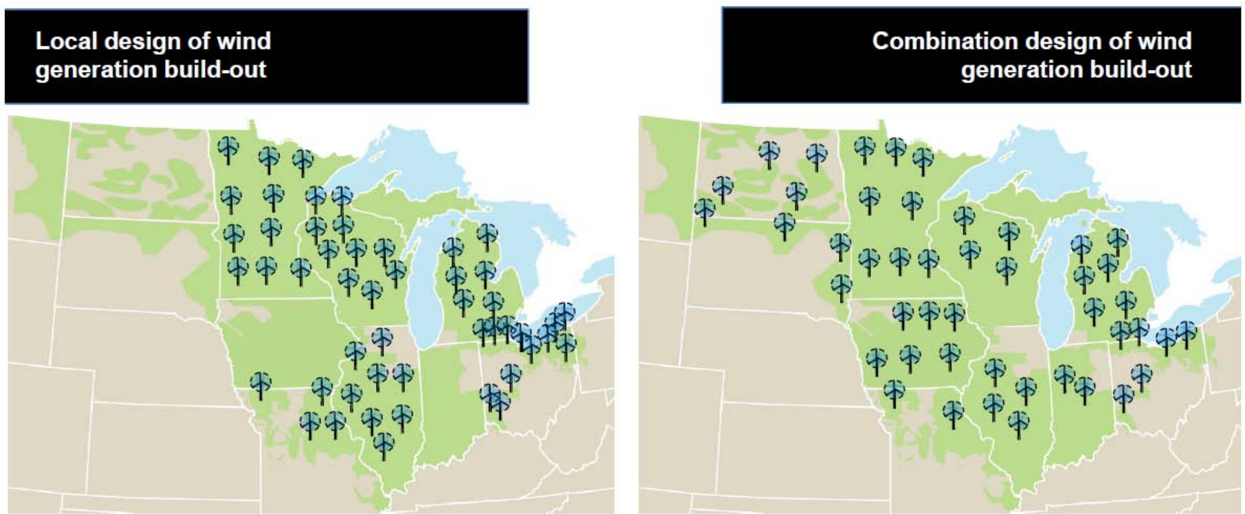


Figure 4.1-17: Local versus combination wind siting

In the RGOS study, it was determined that 11 percent less wind would need to be built to meet renewable energy mandates in a combination local/regional methodology relative to a local only approach. Approximately 2.9 GW less generation capacity is required for the combination siting approach, creating present value benefits of $1.4 billion to $2.5 billion.

Transmission investment

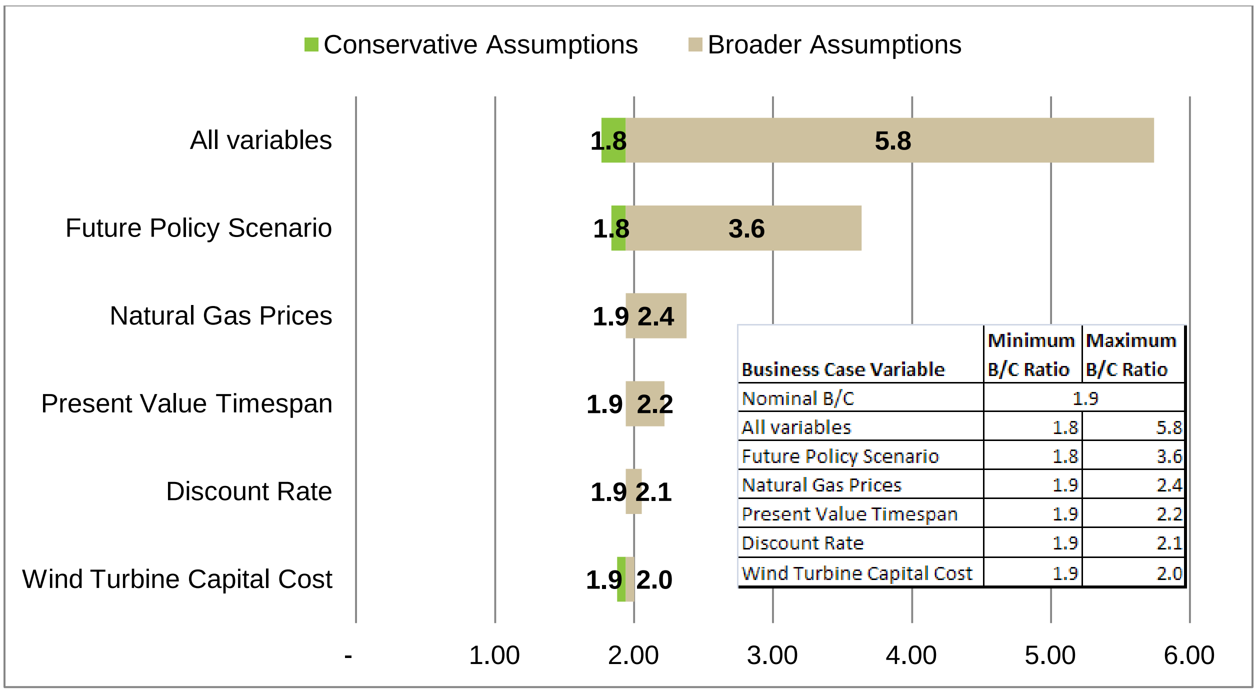
In addition to relieving constraints under shoulder peak conditions, the proposed MVP portfolio will eliminate some future baseline reliability upgrades. A modeling simulating 2031 summer peak load conditions was created to determine what future baseline reliability upgrades would not be needed, and this model was run both with and without the proposed MVP portfolio. The proposed MVP portfolio eliminates the need for baseline reliability upgrades on 23 lines between 2026 and 2031. This creates benefits which have 20 and 40 year present values of $268 and $1,058 million, respectively.

Business case variables and impacts

The projected benefits created by the proposed MVP portfolio are dependent on projections of future policy and economic variables.

The most critical variables considered were:

- Future energy policies
    - Includes a range of policy, demand and energy growth assumptions
    - Sensitivities were conducted to determine the impact of a legislated cost of carbon or national renewable energy mandate
- Length of Present Value Calculations: 20 or 40 years from the portfolio's in service date
- Discount Rate: 3 percent to 8.2 percent
- Natural gas prices: $5-$8 (Business as Usual Scenarios)
  $8-$10 (Combination Policy and Carbon Constrained Futures)
- Wind turbine capital cost: 2.0 to 2.9 $M/MW



Business Case Variable	Minimum B/C Ratio	Maximum B/C Ratio
Nominal B/C	1.9	
All variables	1.8	5.8
Future Policy Scenario	1.8	3.6
Natural Gas Prices	1.9	2.4
Present Value Timespan	1.9	2.2
Discount Rate	1.9	2.1
Wind Turbine Capital Cost	1.9	2.0

Figure 4.1-18: Benefit – cost variations due to business case assumptions

> Under existing energy policies, the proposed MVP portfolio creates benefits that are at least 1.8 times its cost.

Depending on which variables are assumed, the present value of the benefits created by the entire portfolio can vary between $18.5 and $126.0 billion in 20 to 40 year present value terms. This savings yield benefits ranging from 1.8 to 5.7 times the portfolio cost.

It should be noted that the benefits of the portfolio do not depend upon the implementation of any particular future energy policy to exceed the portfolio costs. Under existing energy policies, a conservative discount rate of 8.2 percent and 20 year present value terms, the portfolio produces benefits that are 1.8 times its cost. However, if other energy policies or enacted, or a lower discount rate is used, this benefit has the potential to greatly increase.

Portfolio benefits and cost spread

A key principle of the MISO planning process is that the benefits from a given transmission project must be spread commensurate with its costs. The MVP cost allocation methodology distributes the costs of the portfolio on a load ratio share across the MISO footprint, so the proposed MVP portfolio must be shown to deliver a similar spread of benefits.

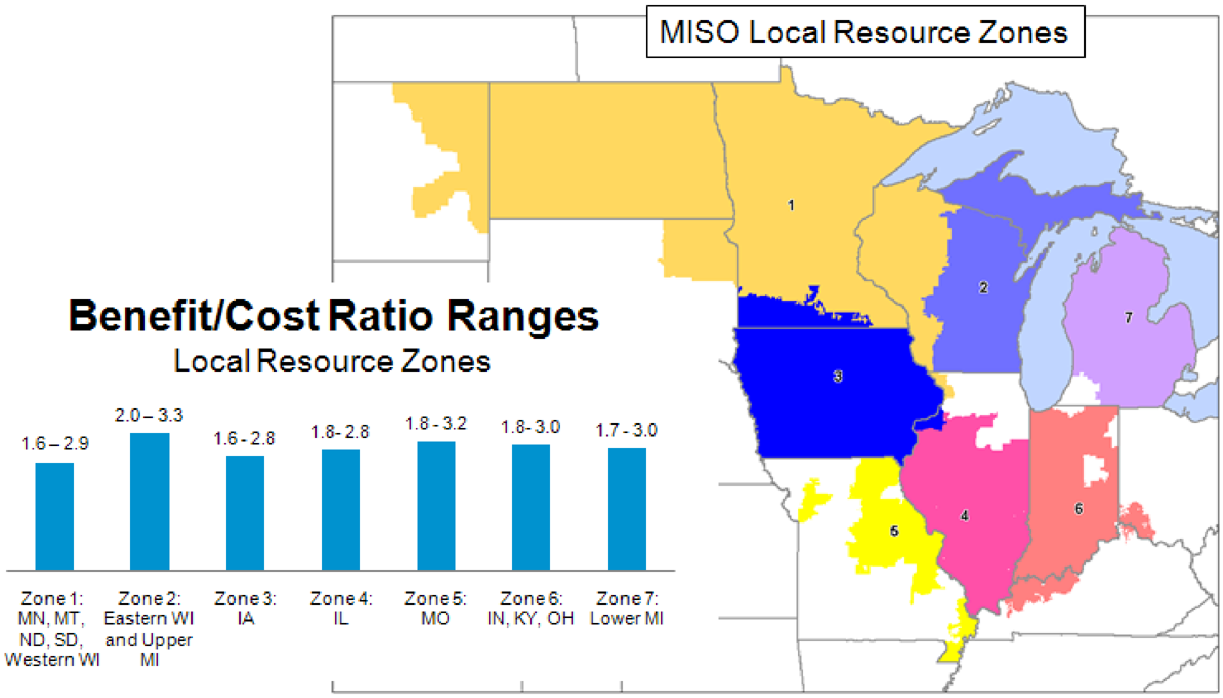


Figure 4.1-19: Proposed MVP portfolio production cost benefits spread

The proposed MVP portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to its costs allocation. For each of the local resource zones, as shown in Figure 4.1-19 above, the portfolio's benefits are at least 1.6 to 2.9 times the cost allocated to the zone.

Qualitative and social benefits

The previous sections demonstrated that the proposed MVP portfolio provides widespread economic benefits across the MISO system. However, these metrics do not fully quantify the benefits of the portfolio. Other benefits, based on qualitative or social values, are discussed in the next sections. These sections suggest that the quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the portfolio.

Enhanced generation policy flexibility

Although the proposed Multi Value Project portfolio was primarily evaluated on its ability to reliably deliver energy required by the renewable energy mandates, the portfolio will provide value under a variety of different generation policies. The energy zones, which were a key input into the Candidate MVP portfolio Analysis, were created to support multiple generation fuel types. For example, the correlation of the energy zones to the existing transmission lines and natural gas pipelines were a major factor considered in the design of the zones. This can be seen in Figure 4.1-20, which shows the correlation between the energy zones and natural gas pipelines.

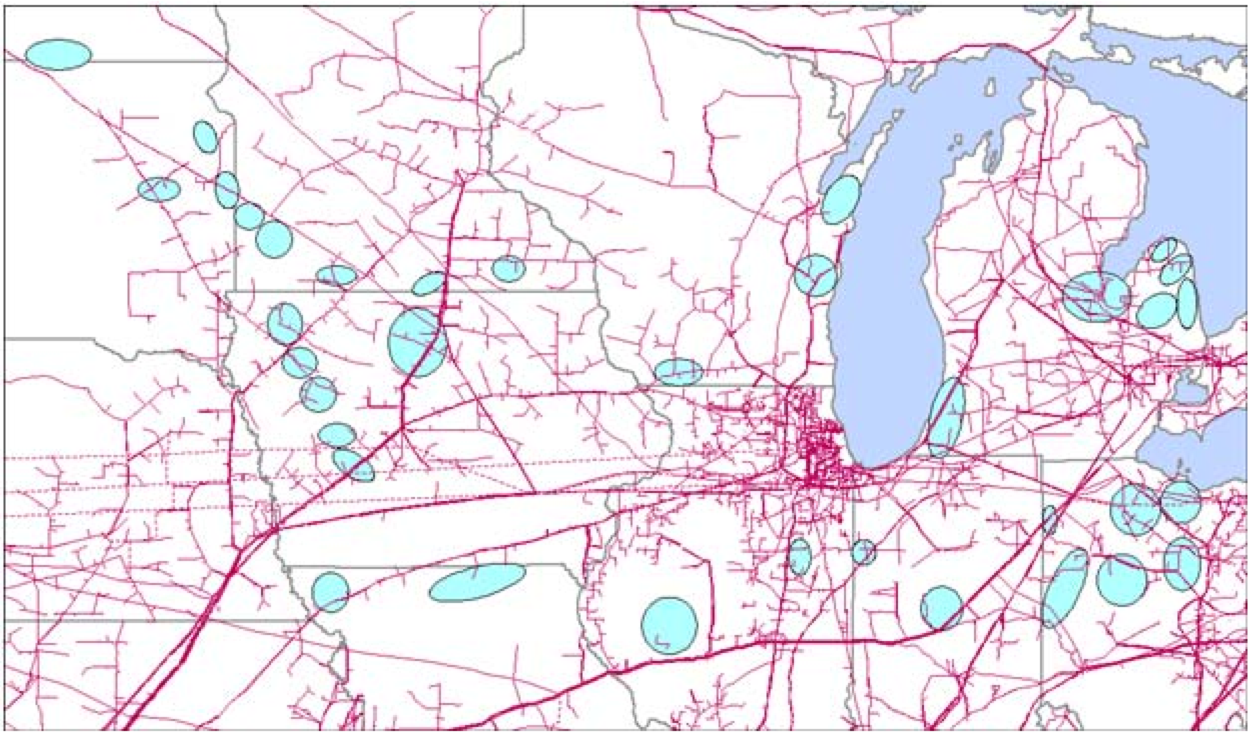


Figure 4.1-20: Energy zone correlation with natural gas pipelines

Increased system robustness

A transmission system blackout, or similar event, can have wide spread repercussions, resulting in billions of dollars of damage. The blackout of the Eastern and Midwestern U.S. during August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.[30]

The proposed MVP portfolio creates a more robust regional transmission system which decreases the likelihood of future blackouts by:

- Strengthening the overall transmission system by decreasing the impacts of transmission outages.
- Increasing access to additional generation under contingent events.
- Enabling additional transfers of energy across the system during severe conditions.

[30] Data sourced from: *The Economic Impacts of the August 2003 Blackout*, The Electricity Consumers Resource Council (ELCON)

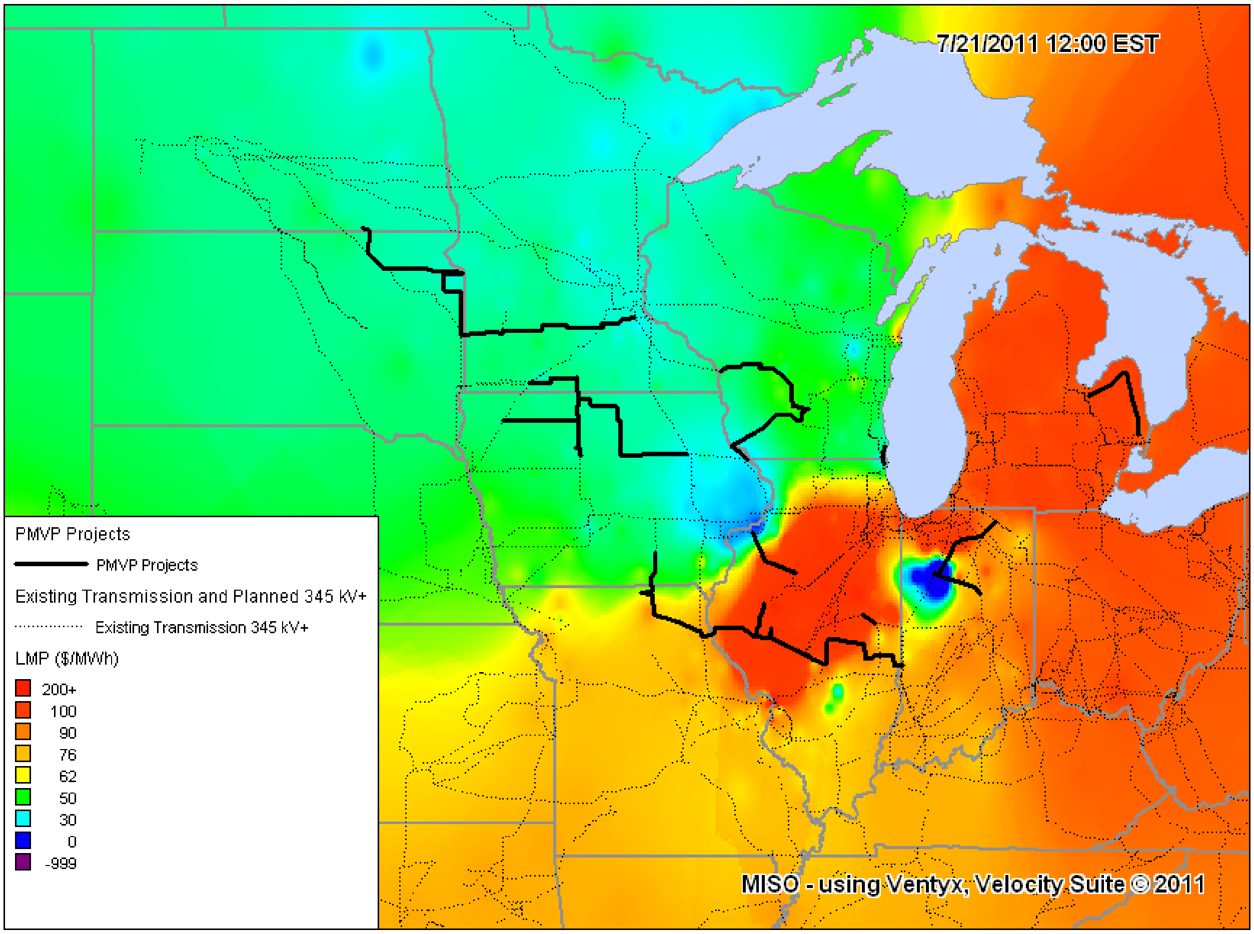


Figure 4.1-21: June 2011 LMP map with proposed MVP portfolio overlay

The proposed MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

For example, the proposed MVP portfolio will allow the system to respond more efficiently during high load periods. During the week of July 17, 2011, high load conditions existed in the eastern portion of the MISO footprint, while the western portion of the footprint experienced lower temperatures and loads. Thermal limitations on west to east transfers across the system limited the ability of low cost generation from the west to serve the high load needs in the east, as shown in Figure 4.1-21. The proposed MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

Decreased natural gas risk

Natural gas prices have historically varied widely, causing corresponding fluctuations in the cost of energy from natural gas fueled generation. Also, recent Environmental Protection Agency (EPA) regulations and proposed regulations limiting the emissions permissible from power plants will likely lead to more natural gas fired generation. This may put additional upward pressure on natural gas costs as demand increases. However, the proposed MVP portfolio can help partially offset the associated natural gas price risk by providing additional access to generation that uses fuels other than natural gas (e.g. nuclear, wind, solar and coal) during periods with high natural gas prices.

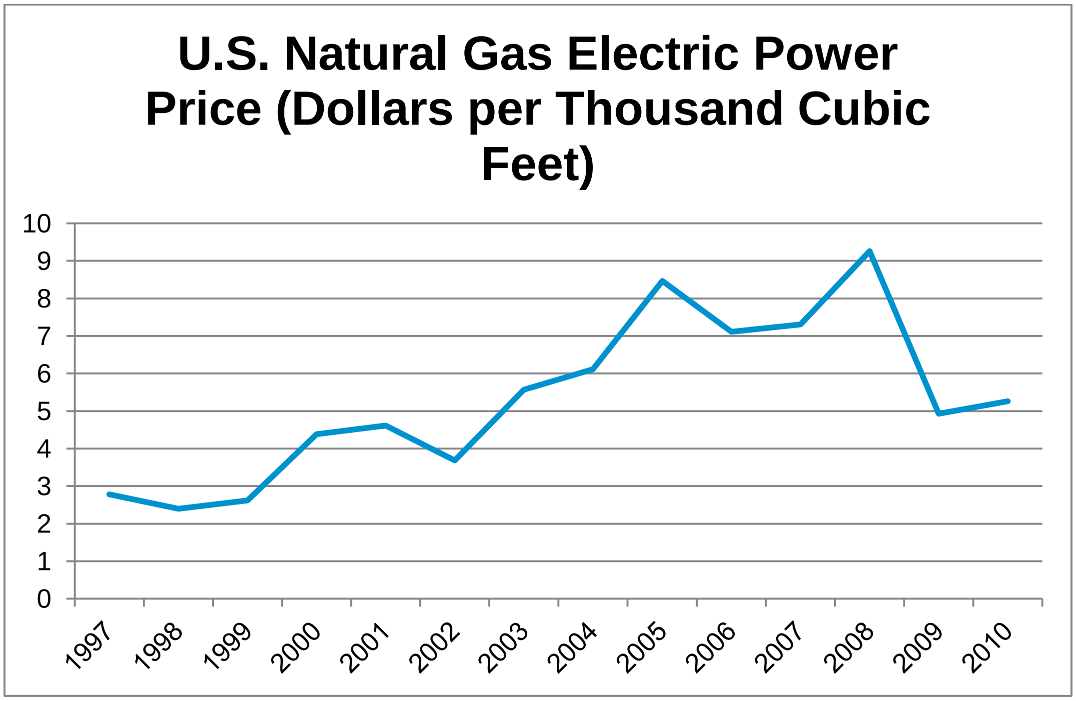


Figure 4.1-22: Historic U.S. natural gas electric power prices

Assuming a natural gas price increase of 25 percent to 60 percent, the proposed MVP portfolio provides 5 percent to 40 percent higher production cost benefits.

Decreased wind generation volatility

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a geographically diverse set of wind plants, relative to a closely clustered group of wind plants. The proposed MVP portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

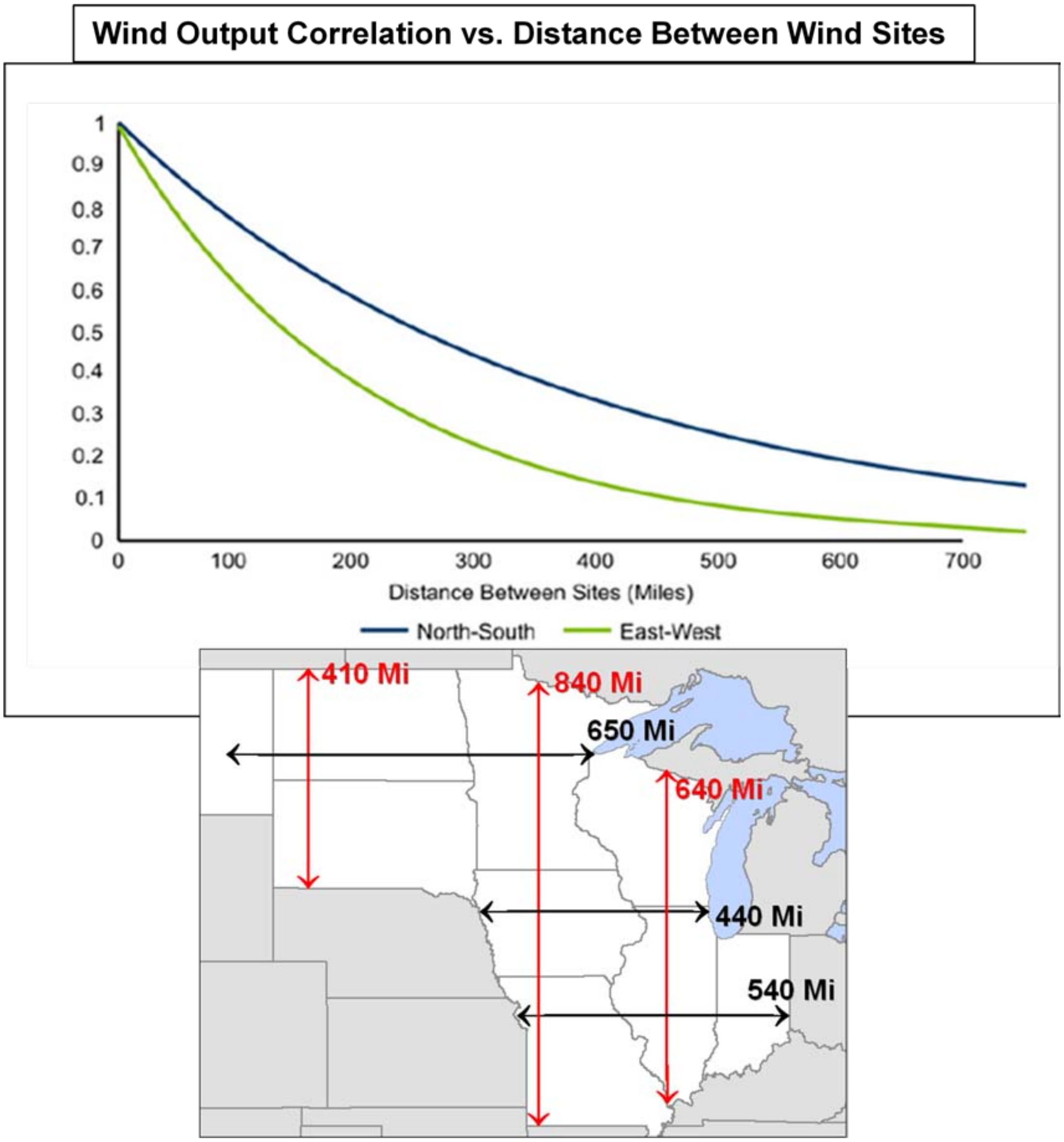


Figure 4.1-23: Wind Output correlation to distance between wind sites

Local investment and job creation

In addition to the direct benefits of the proposed MVP portfolio, studies have shown the indirect economic benefits of transmission investment. They estimated that, for each million dollars of transmission investment:

- Between $0.2 and $2.9 million of local investment is created.
- Between 2 and 18 employment years are created.[31]

The wide variations in these numbers are primarily due to the extent to which materials, equipment and workers can be sourced from a 'local' region. For example, each million dollars of local investment supports 11 to 14 employment years of local employment, as compared to 2 to 18 employment years which are created for non-location specific transmission investment.

The proposed MVP portfolio supports the creation of between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. This calculation is based upon a creation of $0.3 to $1.9 million local investment and 3 to 7 employment years per million of transmission investment.

Carbon reductions

The proposed MVP portfolio enables the more economical dispatch of generation, as low cost wind resources displace higher cost generation. This redispatch creates a reduction in the total carbon output produced by MISO generation of between 8.3 to 17.8 million tons annually.

Some of the future policy scenarios included a cost of carbon. This carbon cost is additive to the overall system production cost, and it was based upon a carbon cost of $50 per ton.

If such a carbon cost was to occur, benefits would increase by between $3.8 and $15.4 billion in 20 and 40 year present value terms, respectively.

Conclusions and recommendations

MISO staff recommends the proposed MVP portfolio to the MISO Board of Directors for their review and approval. This recommendation is premised on the ability of the portfolio to meet MVP criterion 1, as each project in the portfolio was shown to more reliably enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

The recommendation is also supported by the strong economic benefits of the portfolio, which delivers a large amount of value in excess of costs under all conditions and policy scenarios studied. Furthermore, these benefits are spread across the MISO footprint, in a manner commensurate with the allocation of the portfolio's costs.

The proposed MVP portfolio reliably enables the delivery of wind generation in support of public policy needs, while delivering value in excess of its cost in all scenarios studied.

[31] Source: *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, The Brattle Group

4.2 EPA Regulation Impact Analysis

Study disclaimer

The objective of the MISO EPA Regulation Impact Analysis is to inform stakeholders. MISO has no intention or authority to direct generation unit strategies. 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.

The detailed results of the analysis were derived from a limited set of economic assumptions that included low demand and energy growth, low gas prices and variation of carbon prices with sensitivities performed on gas and carbon prices. Retirement impacts can change with different assumptions for these variables. The study also assumes that the natural gas Transmission System is sufficient to accommodate the increased dependence on the natural gas fleet. This addresses some of those issues, but can't capture all future outcomes. To better understand the affects of changing inputs and risks of the uncertainty of carbon, additional analysis needs to be performed.

An additional caveat - since completion of this analysis - the EPA finalized the Cross State Air Pollution Rule (CSAPR). In general, the final regulation mandated more restrictive emission limits for some states than was modeled in this analysis. The final CSAPR has stronger state limitations in most cases but allows for a national trading program, which may allow for more flexibility in meeting the limits. In general, the rule appears to have the greatest impact in the near-term (1-3 years) operation of the generation fleet due to the reduction in the number and availability of both SO_2 and NO_X allowances. The magnitude of this change on the MISO system is being evaluated in a follow-up study.

The EPA Regulation Impact Analysis was based on assumptions for *proposed* EPA regulations. Finalization of the remaining three regulations has the potential to introduce the risk of additional change and uncertainty, similar to what occurred with the CSAPR regulation. Any of the final regulations could differ from what was modeled in this analysis.

EPA impact results summary

Over the last two years the U.S. Environmental Protection Agency (EPA) issued four proposed regulations that will affect the MISO system. One of the rules was finalized in July while the other three are still in draft form. The regulations will impact unit operations in the near-term (1-3 years) in addition to requiring utilities retrofit their generators with environmental controls or retire them in the 2015 timeframe. At the direction of its members, stakeholders and Board of Directors, MISO evaluated the impacts of the new regulations, including carbon requirements. This study evaluated the impacts on capacity cost, Resource Adequacy, cost of energy and transmission reliability.

MISO evaluated the four proposed regulations separately and in combination with each other over a nine month study period. This report focuses on the four rules as they were developed in draft form. The impact of the finalized Clean Air Transport Rule/Cross State Air Pollution Rule will be undertaken in an exhaustive follow-on study that is currently underway.

A survey of the current fleet within MISO revealed a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs to comply outweigh the benefits of continued operation.

The four proposed EPA regulations are:

- Cooling Water Intake Structures (CWIS) – section 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS), formerly known as EGU Maximum Achievable Control Technology (MACT).

A survey of MISO's current fleet revealed that a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs outweigh the benefits of continued operation. Figure 4.2-1 shows that there are 298 coal units affected by these four proposed regulations and that the majority of the units (63 percent) are affected by three or all four regulations.

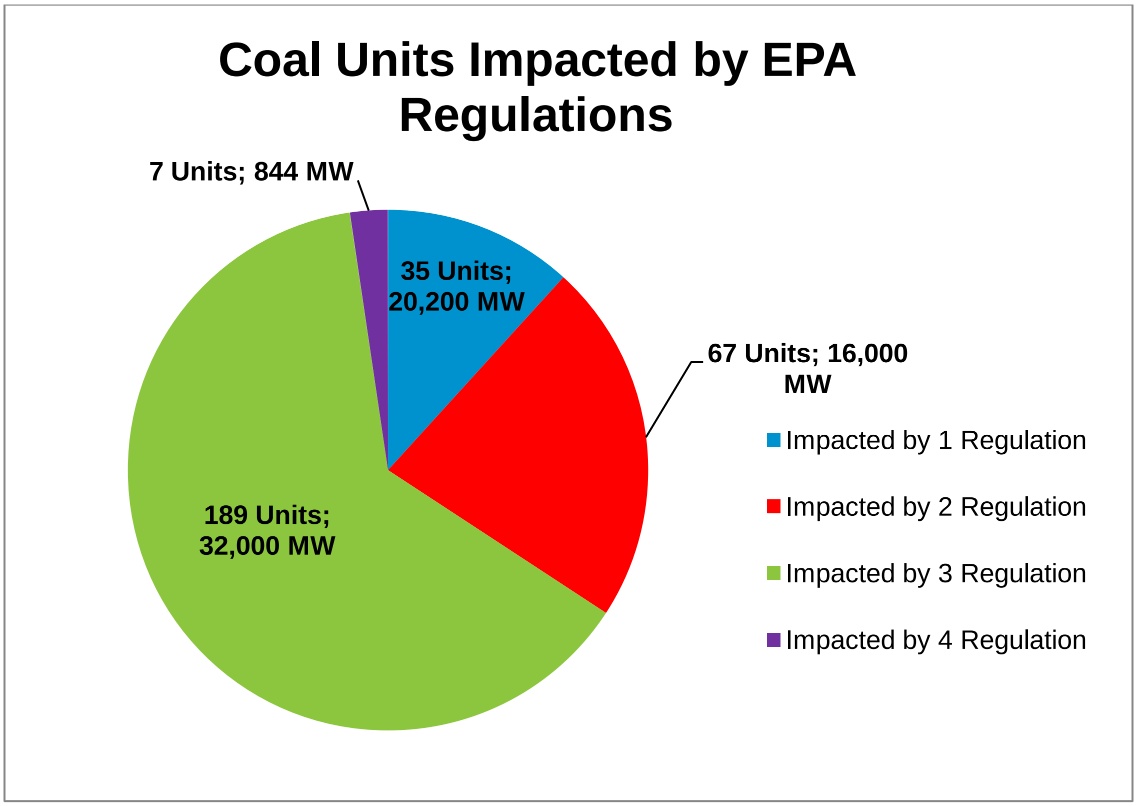


Figure 4.2-1: Number of coal units affected by EPA regulations.

The studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) commonly used by utility generation planners. MISO performed more than 400 sensitivity screens using the EGEAS capacity expansion model to identify the units most at-risk for retirement. The sensitivities consisted of variation in costs for natural gas, cost uncertainty risk and retrofit compliance.

MISO identified nearly 13,000 MW of units at risk for retirement. Those units were offered to the EGEAS model as an economic choice to retrofit for compliance or retirement. The model makes this decision by comparing alternatives and selecting an expansion forecast that minimizes costs, capital investment, production, emissions and annual fixed operations and maintenance.

Nearly 13GW of generation is at risk of retiring.

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis evaluated increased compliance costs on the system. These increased costs are represented through a production cost adder coupled with the production of carbon on the system and is proxy for costs associated with the uncertainty around rules not finalized, additional life extension costs needed for balance of plant as well as the considered risk around the uncertainty of the treatment of green-house gases. It is expected that one or all are within the assumption error bounds for this analysis and the impacts will be considered in the fleet strategies of the asset owners. The results of the EGEAS analysis produced:

- 2,919 MW of coal fleet capacity at-risk for retirement under all likely scenarios. As of the publishing of this study, retirement requests of the coal fleet have amounted to 2,500 MW in the MISO Attachment Y process.
- 12,652 MW of coal fleet capacity at-risk for retirement identified to be within prudence considerations and error bounds for the assumptions of the MISO study.

The EGEAS retirement analysis minimizes the total system net present value costs over a twenty year planning period plus a forty year extension period. When the 2,919 MW and 12,652 MW of retired capacity were forced into the model, it was shown that the overall net present value of system costs varied by approximately 1 percent. This value is within the tolerance of assumption error. Additionally, MISO did not consider unit life extension costs in its evaluation. Because of these two considerations, it is expected that the higher value of nearly 13,000 MW is more realistic of the potential retirements on the system.

Using a suite of planning products, MISO's evaluation on the range of potential impacts indicates the following:

- Total 20-year net present value capital cost of compliance may range from $31.6 billion for 2,919 MW of retirement to $33.0 billion for 12,652 MW of retirement. Both values are in 2011 dollars and include the cost of retrofits on the system, replacement capacity, fixed operations and maintenance and transmission upgrades. The perceived balance in total system capital investment occurs because the average cost for installation of control technologies for a unit is approximately equivalent to the cost of a new combustion turbine that represents an alternative solution to compliance with the rules.
    - Capital costs for retrofits are $28.2 billion and $22.5 billion, respectively.
    - Maintenance of the Planning Reserve Margin (PRM) is obligated under the MISO tariff. So it is expected that any capacity retirements would eventually be matched with replacement capacity to support PRM requirements. To maintain this requirement, it is estimated that the replacement costs would be $1.7 billion and $9.6 billion.

It will cost MISO approximately $30 billion to comply with the new regulations, regardless of compliance strategy, increasing rates by more than 7 percent.

- The bulk of the capital investment for the generation fleet is expected to occur in the 2014/2015 time frame to meet 2015/2016 requirements established through the proposed MATS regulation. This includes potential need for replacement resources as 12,652 MW of capacity retirements would erode the current installed reserves to below planning reserve margin values by 6 to 7 percentage points, Table 4.2-1.

- The annual fixed operations and maintenance impacts the total cost impact by $1.1 billion and $0.0, respectively.

- Retirement of units will have an impact on localized Transmission System reliability. To ensure voltage and transmission thermal support on the system, an estimated $580 million and $880 million, respectively, of additional transmission upgrades could be necessary to maintain system reliability. The transmission numbers depend on location and any change from the study assumptions could result in different costs. This assumes that no replacement capacity is at the retired units. If it is, the transmission upgrade costs will decrease.

- By replacing traditionally less reliable capacity with new resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by having a more reliable fleet. Loss of Load Expectation (LOLE) analysis showed reductions of 0.2 to 1.0 percent. However, if no replacement capacity is identified for Resource Adequacy purposes, then analysis shows that the LOLE on the system could be on the order of 0.21 to 1.028 days/year. The current target is 0.1 days/year. Refer to Chapter 5.2 for more information on EPA impacts on resource adequacy.

- There will also be an increase in the MISO load-weighted LMP of between $1.2/MWh to $4.8/MWh (2011 dollars). This is driven by two key factors: (1) newly retrofitted units are less efficient because of the emission controls, and (2) retired coal facilities are replaced with natural gas fired capacity resulting in a greater dependence on the higher cost energy.

- Identifying all the costs to maintain regulation compliance and system reliability, retail rates could increase 7.0 to 7.6 percent.

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
No retirements	Reserve Margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
	Reserve Margin (percent)	27.0%	24.8%	24.2%	23.3%	22.5%	21.5%	20.5%	21.0%	19.9%	18.6%
2.9 GW Retirements (impacts adjusted for expected derates)	Reserve Margin (MW)	21,603	20,111	19,737	19,041	18,433	17,738	16,960	17,623	16,704	15,705
	Reserve Margin (percent)	24.3%	22.2%	21.7%	20.8%	19.9%	19.0%	18.1%	18.6%	17.5%	16.2%
12.6 GW Retirements (impacts adjusted for expected derates)	Reserve Margin (MW)	12,544	11,052	10,678	9,982	9,374	8,679	7,901	8,564	7,645	6,646
	Reserve Margin (percent)	14.1%	12.2%	11.7%	10.9%	10.1%	9.3%	8.4%	9.0%	8.0%	6.6%

Table 4.2-1 Potential system reserve margin impacts of retirements compared to the MISO 2011 Long Term Resource Assessment

The generation capacity cost components include both the costs to retrofit and to build new capacity to eventually replace that which is retired. From the previous information, this twenty year net present value cost for 12,652 MW of retirement is approximately $32.1 billion. Table 4.2-2 shows where those costs are incurred in reference to the fleet to meet the proposed regulations. The investment identified is expected to occur prior to implementation of the MATS regulation and the lead time for the addition of control technology or new resources will include planning, regulatory approval, engineering, procurement, construction and installation that may require three to five years to implement on the system.

Technology	Impacted Capacity (MW)	Average Costs ($/kW)
No Action Required	9,569	0
Require Fabric Filters (Baghouse)	27,921	150
Require DSI and ACI or FGD	20,427	478
Replacement Greenfield Combustion Turbine Capacity for Retirement	12,652	663

Table 4.2-2 Average overnight construction costs to comply with the proposed regulations.

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 not addressed directly that must be recognized is the time in which units must be compliant. Figure 4.2-2 demonstrates a high level timetable of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace it. Also, if Transmission System reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time from final regulation to compliance may be difficult for some situations throughout the system.

Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed compliance equipment. Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy.

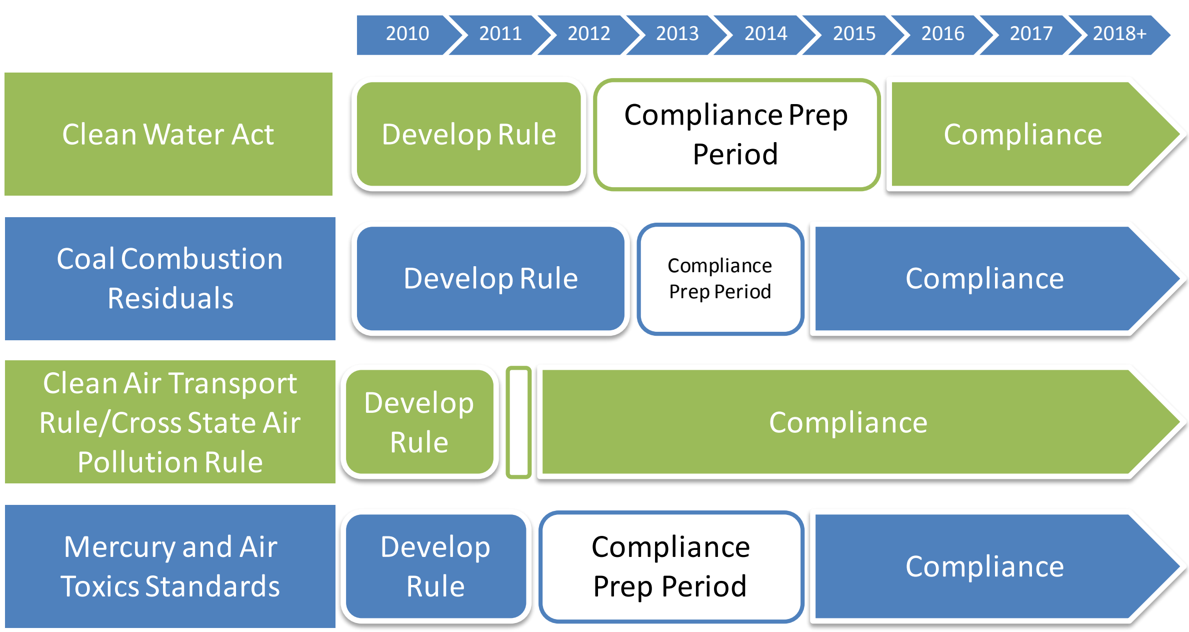


Figure 4.2-2: **Estimated timeline for regulation development and implementation**

Sensitivities impact

Just as in the MISO Transmission Expansion Plan (MTEP), MISO uses a scenario planning process in the analysis and evaluation of these EPA regulations. Evaluating the impact requires that many conditions be considered separately and in combination. MISO evaluated six scenarios with 77 sensitivities for each of the scenarios.

- Base conditions, no new regulations.
- Cooling Water Intake Structures section – 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT).
- Combination of all four regulations.

Figure 4.2-3 demonstrates the sensitivities evaluated for each analysis. Since there are six regulation scenarios there would be six branches to this decision tree. Only the first branch is shown in Figure 4.2-3.

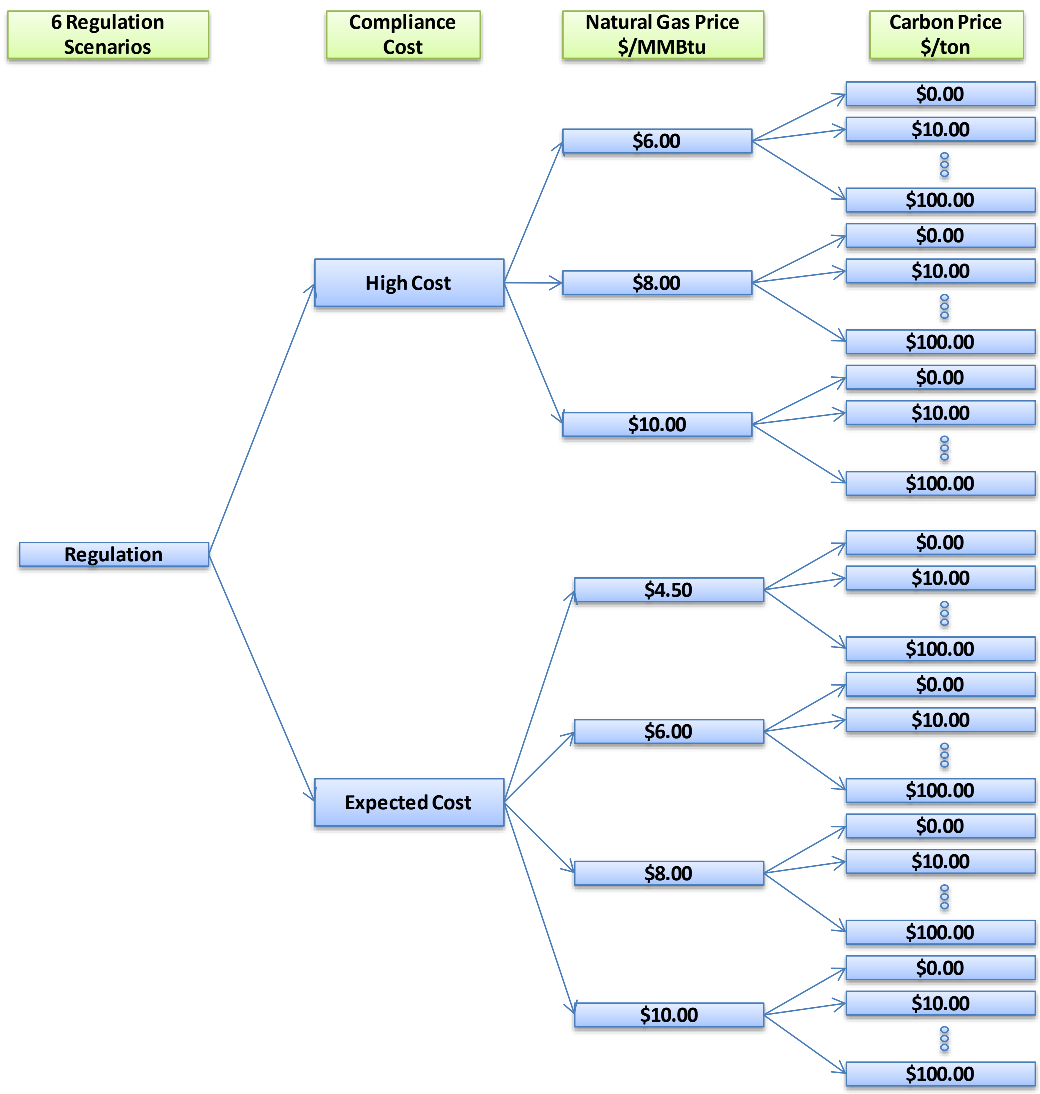


Figure 4.2-3: **Decision tree of EPA cases**

For each of the scenarios, 77 sensitivity cases consisting of two variations in compliance costs, natural gas costs and uncertainty risk costs represented as a cost to carbon production were modeled to produce a combined total of more than 400 sensitivity cases. The results indicated that up to 23,000 MW of coal capacity could be at-risk because of regulation compliance.

From these sensitivity cases, a few general conclusions can be made.

- EPA regulation impacts: Compliance associated with the Mercury and Air Toxics Standards (MATS) produces the most at-risk units, since its compliance costs and emission reductions have the greatest impact of the proposed regulations.

- Stringent Rule Application: Higher compliance costs to meet more stringent rules result in more at risk units. Evaluating all natural gas and carbon sensitivities for the stringent rule application cases resulted in up to 23,000 MW of at-risk capacity. However, running the same sensitivities at the more expected compliance costs as recommended and reviewed through the MISO stakeholder process, up to 13,000 MW of capacity was considered to be at risk.

- Natural gas costs: Lower natural gas prices produced more at-risk capacity than higher gas prices. The lower natural gas prices provide more incentive to retire capacity as the alternative resources provide competitive energy costs for the system. Conversely, when gas prices are high, the coal units find enough revenue on the system to cover compliance costs and keep general energy prices lower.

- Risk costs: MISO evaluated the risks associated with uncertainty in regulation compliance through costs added to megawatt-hour production. This cost was represented by adding a price to carbon. Because of this, higher compliance costs put more economic pressure on the coal units within the system, and the economics favor natural gas and carbon neutral capacity. So more coal units are at-risk for retirement with the higher compliance costs applied.

The units at-risk for retirement range from 0 MW to 23,000 MW based on the economic assumptions within the sensitivities. Cases where no units were identified to be at-risk for retirement include low compliance costs, higher gas prices and no risk costs applied. This occurs because it minimizes cost for compliance while increasing potential revenue within the energy market through higher natural gas prices. Cases that produce at-risk generation of up to 23,000 MW include stringent rule application, low gas prices and varying levels of risk costs.

Figure 4.2-4 depicts an example of the impacts of the cost of compliance, gas and risk from the identified potential retirements of 2,919 MW with all four EPA regulations.

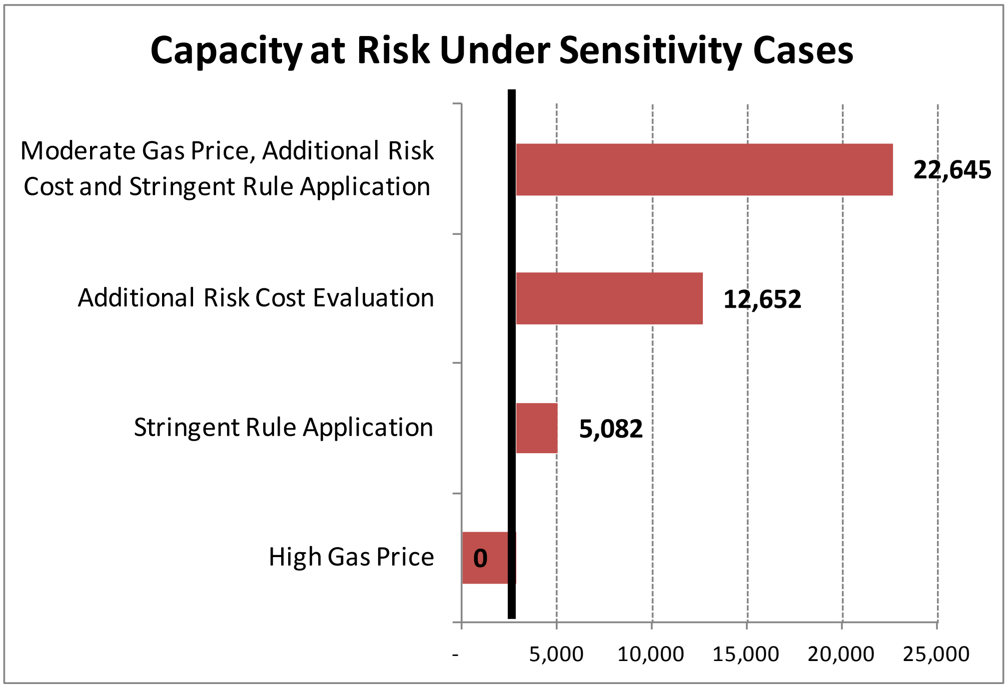


Figure 4.2-4: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements

Rate impact

In general, the retail rates on the system are driven by the costs of generation production, generation capital, transmission capital and distribution capital. The MISO EPA regulation analysis identifies costs that impact three of the four components of the rates.

The greatest impact on the rates comes from the capital cost component. The capital cost increase comes in two forms, the EPA capital compliance cost and the capital cost for replacement capacity. Figure 4.2-5 demonstrates the comparison of the rate impact of the two retirement scenarios with the current average system rate. The overall increase in the rates because of compliance with the EPA regulations is approximately 7.0 to 7.6 percent.

The relatively small rate increase difference between the two scenarios is due to the balance of capital cost configurations. The total EPA regulation related capital cost comes in three forms - 1) control equipment, 2) capital cost for replacement capacity and 3) transmission capital cost needed for retired capacity. The relationship between the three costs is a balance between retired capacity to forgo costs for control equipment while adding replacement capacity and transmission costs for the forgone capacity, versus more control costs to retrofit generation. In other words, as retirements increase, the total control equipment cost decrease, while replacement capacity and transmission costs increase – and vice versa. A balance of all three costs occurs to end up with the least cost strategy.

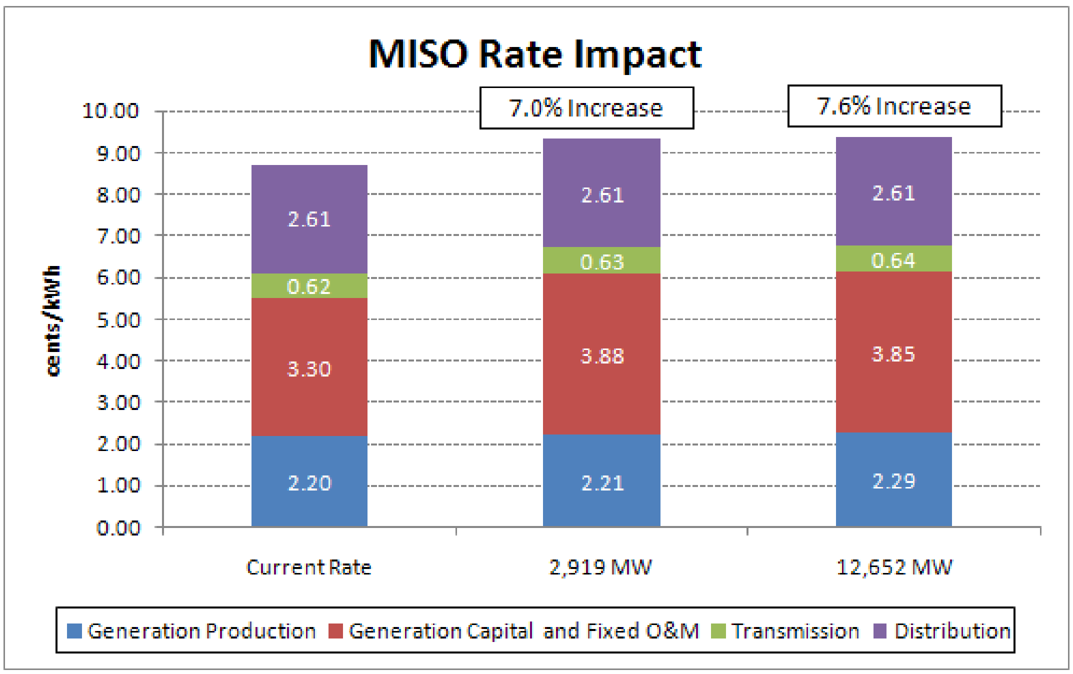


Figure 4.2-5: MISO rate impact

4.3 Generation portfolio analysis

MISO performed regional assessments using the Electric Generation Expansion Analysis System (EGEAS) on the MISO footprint as of June 1, 2011. Using assumed projected demand, energy for each company and common assumptions for resource forecasting, MISO developed models to identify least cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

Future scenario definitions

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. MTEP11 has examined multiple future scenarios:

MISO developed models to identify least cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

1. Business As Usual with Low Demand and Energy Growth Rates
2. Business As Usual with Historical Demand and Energy Growth Rates
3. Combined Energy Policy
4. Carbon Constraint

A more detailed discussion of the assumptions and methodology around these scenarios is presented later in Section 4.3 and in Appendix E.2.

Figure 4.3-1 on the following page represents capacity expansions for each defined future scenario through the 2026 PROMOD® study year. The capacity added is required to maintain stated reliability targets for each region. Stated targets for MISO are defined by means of the Module E Resource Adequacy Assessment.

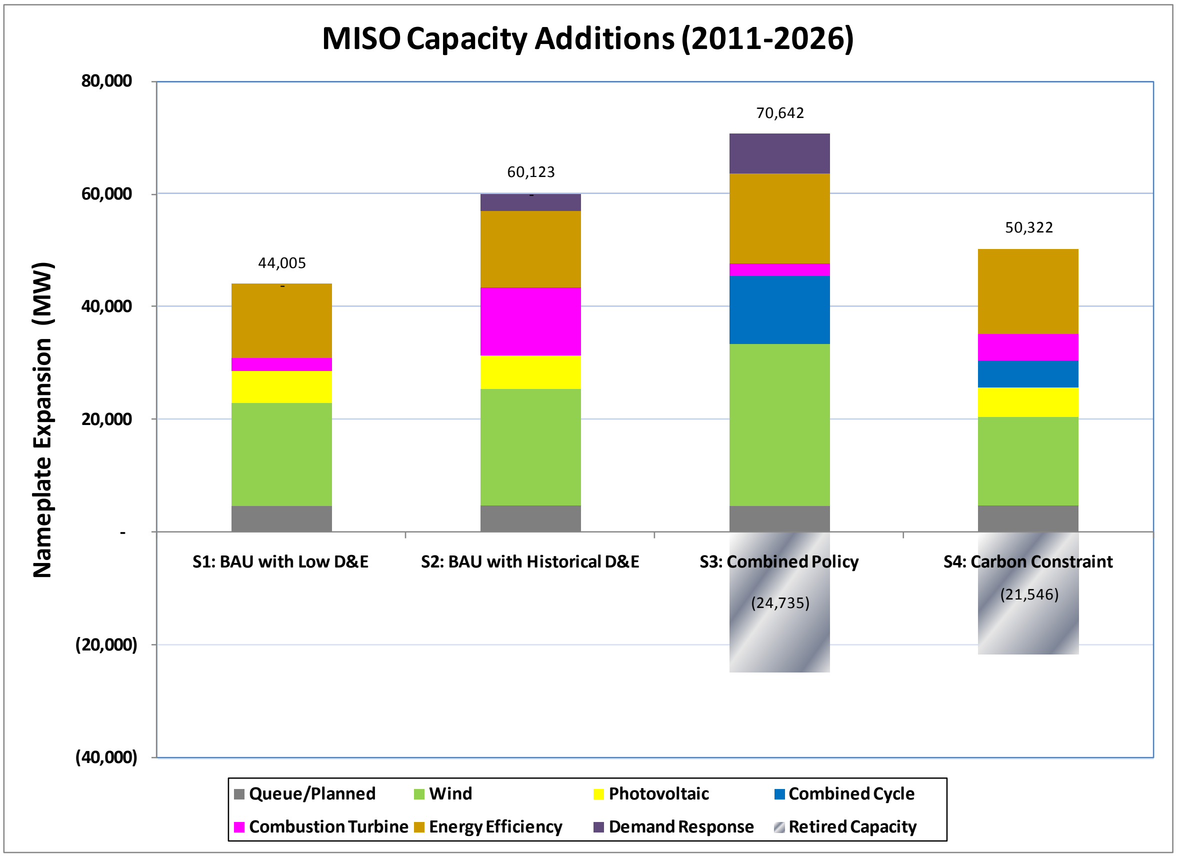


Figure 4.3-1: MISO modeled system aggregate nameplate installed MW from 2026 PROMOD Model.

Recognizing that redundancies across the existing MTEP10 future scenarios and assumptions did not provide any additional information, MISO staff, along with the planning advisory committee, narrowed down to four the scenarios for analysis in MTEP11. A diverse set of generation scenarios emerges when examining the MTEP11 future. While making comparisons across futures with different growth rates for demand and energy can be difficult, some observations can be made when studying future scenarios as a group or when comparing one to another.

Traditionally, most base load capacity needs have been met with coal and nuclear generation. Gas-fired combined cycle units have taken over some of the base load generation role thanks to the discovery of large quantities of shale gas and subsequent lower prices. Rising construction costs, pending EPA regulations and many uncertainties surrounding the future of nuclear generation are also factors. In the combined energy policy and Carbon Constraint scenarios coal units are retired in order to achieve the 42 percent carbon reduction cap. To achieve these targets within the specified time, 55 percent (~44,000 MW) of the oldest and least efficient coal units were retired in the analyses for the combined energy policy scenario and 50 percent (~40,000 MW) were retired in the Carbon Constraint scenario. Much of this base load generation capacity was replaced with natural gas-fired combined cycles and energy efficiency programs.

In all future scenarios, the addition of state-mandated renewable energy capacity overshadows thermal capacity, because most states within the MISO footprint have renewable energy standards and an abundance of existing capacity. The presence of lower demand and energy starting points and growth rates during the study are also factors. A large portion of capacity needs are being met through demand response and energy efficiency programs, which are allowed to compete against traditional supply-side resources in the EGEAS program for the first time in MTEP11. The Global Energy Partners study conducted for MISO in 2010 provided the demand response and energy efficiency estimates.

Figure 4.3-2 demonstrates the value of costs for the study period through 2026. Production and capital costs are provided. Production costs include fuel, variable and fixed operations and maintenance and emissions costs (where applicable). Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and RPS requirements, which drive the future capacity expansion capital investments and total production costs.

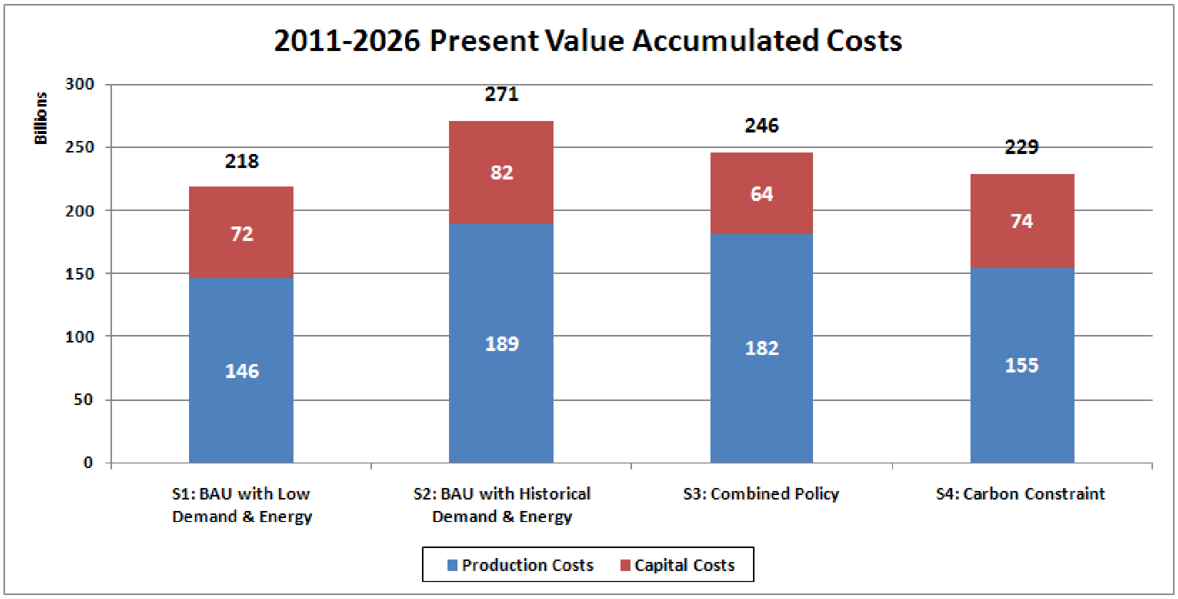


Figure 4.3-2: MISO present value of cumulative costs in 2011 U.S. dollars

Each of the future scenarios has a different impact on carbon dioxide output. Refer to Figure 4.3-3, which demonstrates the varying impact for each of the defined future scenarios. Figure 4.3-3 compares 2005 carbon production provided by the dispatch of a 2005 EGEAS model and year-end 2030 carbon production associated with the capacity expansion for each future scenario.

Continued demand and energy growth at levels close to historic trends will result in the need for additional generating capacity. If this capacity is dominated by coal or natural gas, carbon output will increase on an annual basis. The increased penetration of renewable resources and energy efficiency will result in a system reduction in carbon dioxide.

The increased penetration of renewable resources and energy efficiency will result in a system reduction in carbon dioxide.

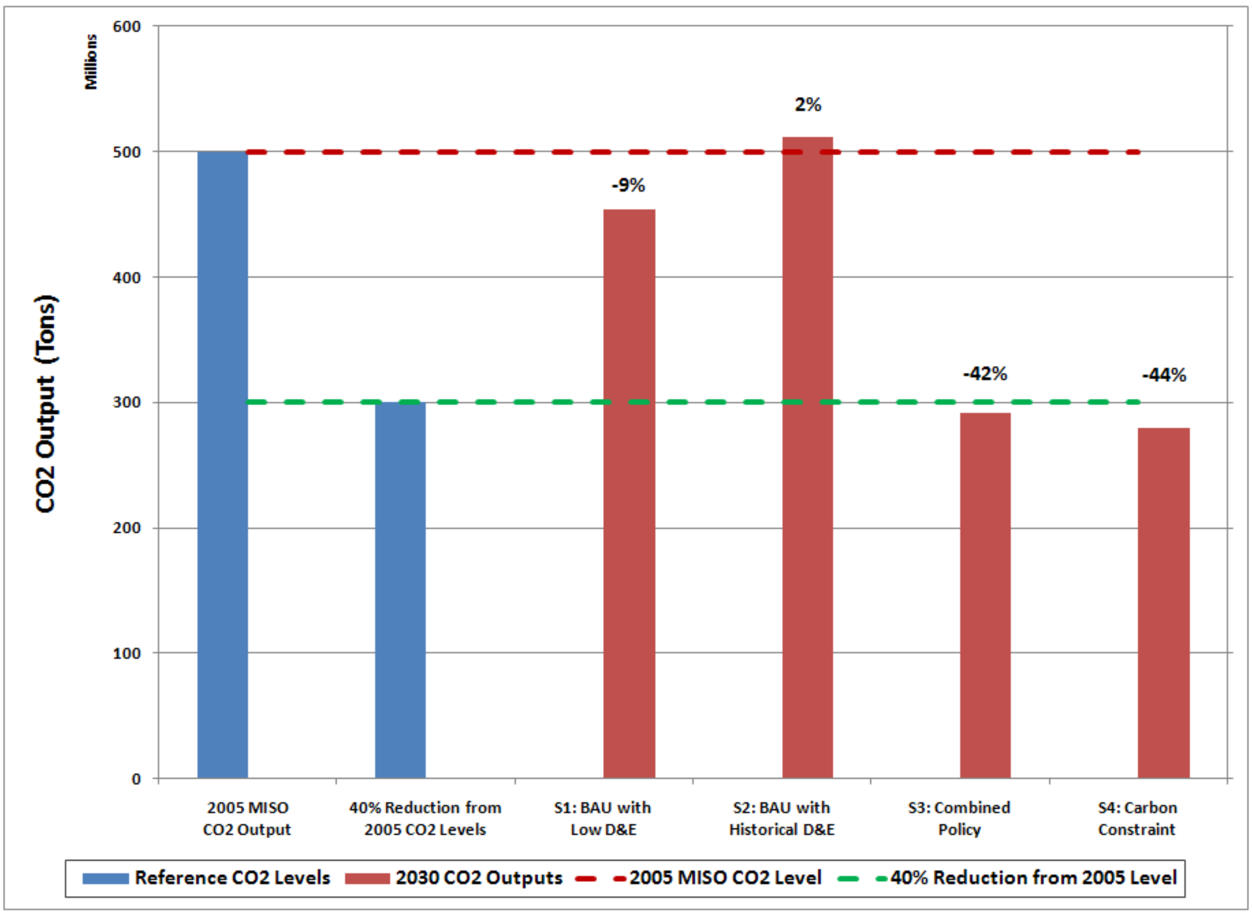


Figure 4.3-3: MISO carbon production

Siting of capacity

Generation resources forecasted from the expansion model for each of the scenarios are specified by fuel type and timing, but these resources are not site-specific. Completing the process requires a siting methodology tying each resource to a specific bus in the power flow model. A guiding philosophy and rule-based methodology, in conjunction with industry expertise, was used to site forecasted generation. Refer to Figure 4.3-4, which depicts capacity siting associated with the Business As Usual with Historical Demand and Energy Growth Rates scenario. Likewise, Figure 4.3-5 shows the associated demand response siting for the BAU with Historical Demand and Energy Growth Rates scenario. The siting methodology used for this and the other future scenarios is explained further in Appendix E2.

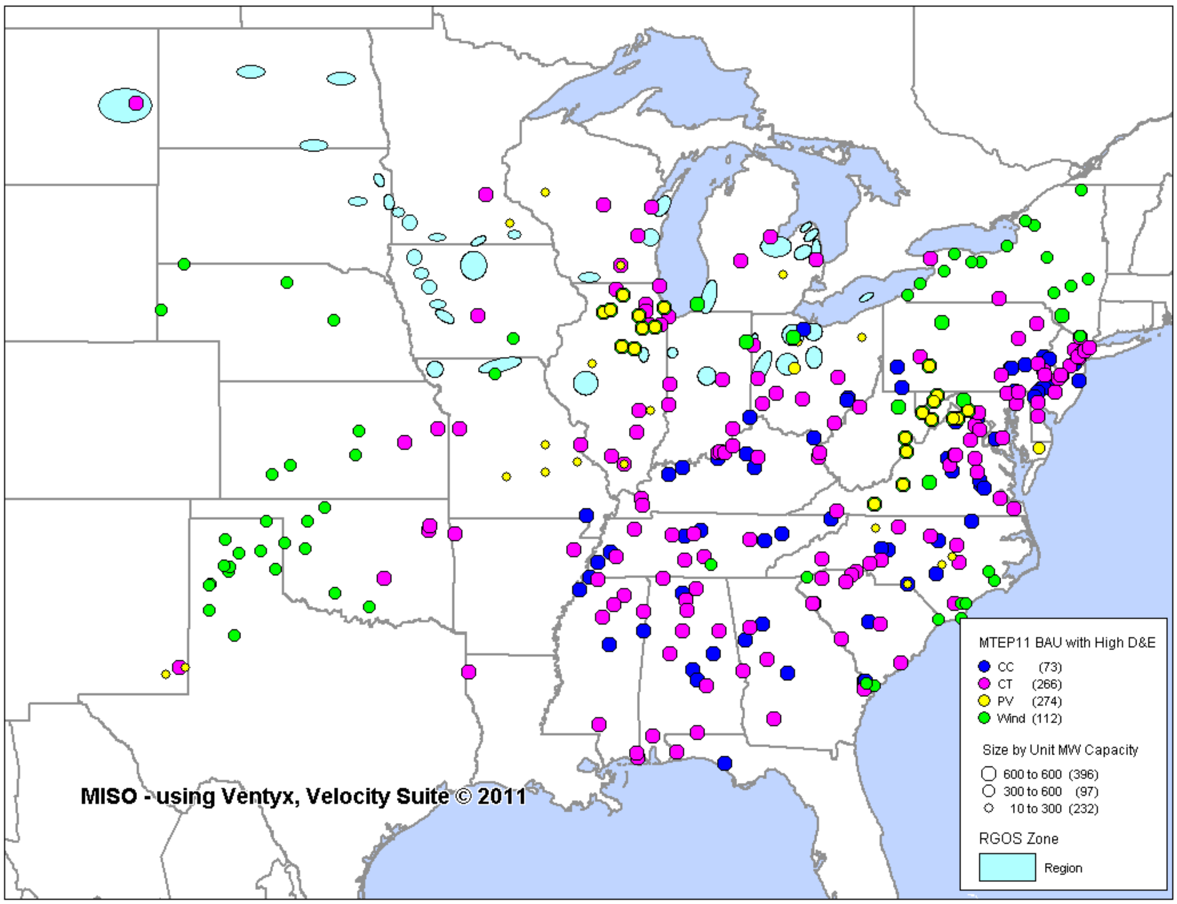


Figure 4.3-4: Future capacity sites for MISO BAU with historical demand and energy growth rates scenario

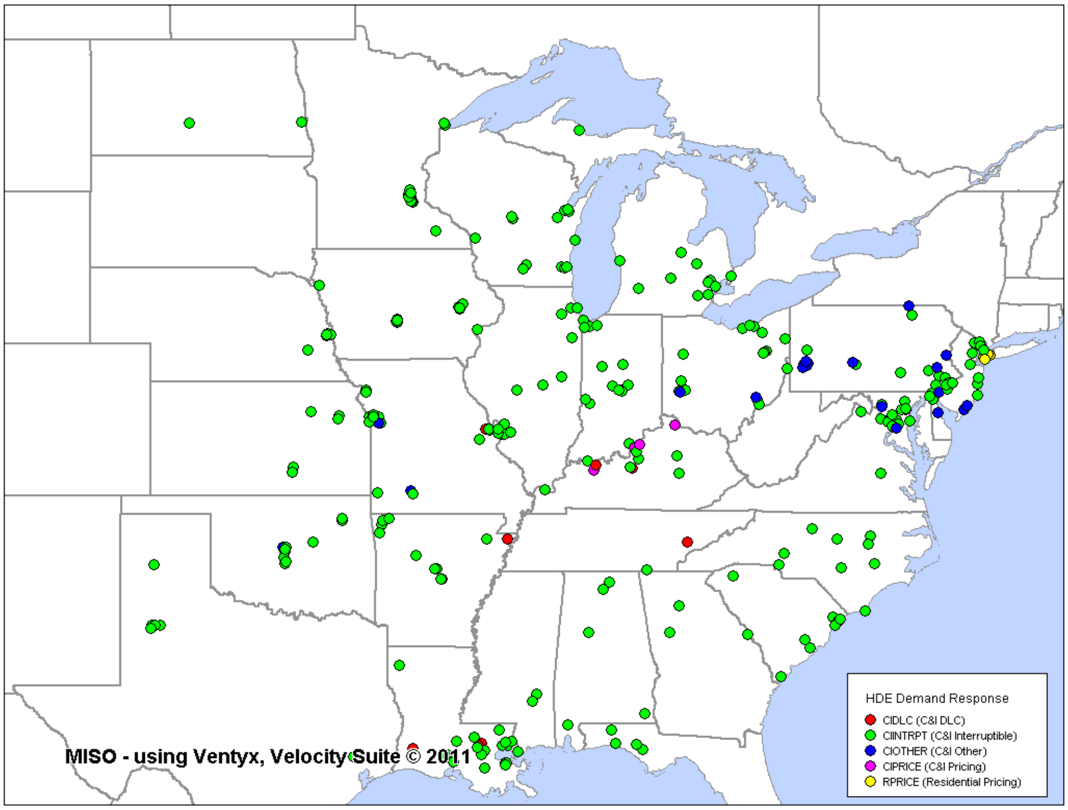


Figure 4.3-5 Future DR sites for MISO BAU with historical demand and energy scenario

Generation futures development

A planning horizon of at least 15 years is needed to accomplish long range economic transmission development, since large projects normally take 10 years to complete. Performing a credible economic assessment over this time is challenging. Long-range resource forecasting, power flow 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, a value-based planning process is developed by integrating the best models available. This allows the evaluation of the long-term transmission requirements to proceed.

The following broad steps outline the value-based planning process that MISO has been implementing. It starts with the analysis of value drivers and ends with a reliability assessment to meet both economic and reliability needs.

- Step 1: Create a regional generation resource forecast.
- Step 2: Site the new generation resources into the power flow and economic models for each future scenario.
- Step 3: Design preliminary transmission plans for each future scenario, if needed.
- Step 4: Test for robustness.
- Step 5: Perform reliability assessment, consolidation and sequencing.
- Step 6: Final design of integrated plan**.**
- Step 7: Cost allocation.

MISO's planning approach continues to evolve to integrate its planning. One focus of the MTEP 11 planning effort is to refresh a set of available future scenarios to capture potential energy policy outcomes.

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

This section summarizes Steps 1 and 2 of the integrated transmission planning process, where regional resource forecasting is performed using scenario-based analysis to identify and site generation for several potential future scenarios. With the increasingly interconnected nature of organizations and federal interests, forecasting greatly enhances the planning process for electricity infrastructure. The futures analysis provides information on the cost and effects of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios which can be postulated and performed.

Future scenarios and assumptions for the models for Steps 1 and 2 were developed with stakeholder involvement. The MISO Planning Advisory Committee (PAC) provided the opportunity for stakeholder input necessary to comply with FERC Order 890 planning protocols. Scenarios have been developed and subsequently refreshed to reflect shifts in energy policies in the last few years, in coordination with the committee, through efforts in MTEP09, MTEP10, the Joint Coordinated System Planning and the Eastern Wind Integration and Transmission Study.

In MTEP11, four primary future scenarios were used for robustness (best-fit) testing of proposed transmission plans associated with major studies, such as the 2011 Candidate MVP Portfolio study and transmission project evaluation under various market efficiency studies. New to MTEP 11 future scenario development is the inclusion of Global energy study estimated DSM projections, which are offered as demand side resources to compete against conventional supply-side resources based on economics. A notable portion of capacity needs are being met through demand side programs which are economically chosen for each of the MTEP11 futures.

MISO consulted with Global Energy Partners LLC (Global) in 2010 to perform an evaluation of Demand Response (DR) and Energy Efficiency (EE) potential in the MISO footprint. This effort developed a 20-year forecast for the MISO region and the rest of the Eastern Interconnection. This study demonstrated the enhanced modeling capabilities of DSM programs in the Electric Power Research Institute's (EPRI) Electric Generation Expansion Analysis System (EGEAS), the regional resource forecasting software tool used to assist in long term resource planning as part of Step 1 of the MTEP seven-step process. The study found DR and EE programs could significantly affect the load growth and future generation needs of the system. In MTEP11, Global provided DR and EE estimates for EGEAS to perform regional resource forecasting. An associated siting methodology for chosen demand response programs was also developed to facilitate business case development of proposed transmission plans. See the links below for more complete study results:

Volume 1: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78818

Volume 2: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=78819

The assumptions for the models and the results presented in this document reflect the prices and policies leading to publication. MISO recognizes changes have occurred in many of these assumptions and will continue to update.

A full discussion of the assumptions and results of Steps 1 and 2 of the economic analysis process can be found in Appendix E2 of this document.

The following describes the various future scenarios in greater detail:

- The Business As Usual with Low Demand and Energy Growth Rates future scenario is considered the status quo scenario and continues the impact of the economic downturn on demand, energy and inflation rates. This scenario models the power system as it exists today with reference values and trends, with the exception of demand, energy and inflation growth rates. The demand, energy and inflation growth rates are based on recent historical data and assume existing standards for resource adequacy, renewable mandates and that environmental legislation remains unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply.
- The Business As Usual with Historical Demand and Energy Growth Rates future scenario is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This scenario models the power system as it exists today with reference values and trends—with the exception of demand and energy growth rates—and is based on recent historical data prior to the economic downturn. This scenario assumes existing standards for resource adequacy renewable mandates and that environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state and have many potential renewable resources that can apply.
- The Combined Energy Policy future scenario was developed to capture the effects of multiple future policy scenarios into one future. This scenario includes a federal Renewable Portfolio Standard, a carbon cap and trade, smart grid and electric vehicles. The RPS is modeled assuming all states are required to meet a 20 percent federal RPS mandate by 2025. The carbon cap is modeled after the Waxman-Markey bill, which requires an 83 percent reduction of CO2 emissions from a 2005 baseline by the year 2050. That is achieved through a linear reduction from 2011 to 2050 with mid point goals of 3 percent in 2015, 17 percent in 2023 and 42 percent in 2033. This future employs coal retirements, with the oldest and least efficient coal units retired first. Smart grid is modeled by reducing the demand growth rate, assuming that a higher penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled by increasing the energy growth rate. They are assumed to increase off-peak energy usage and—increase the overall energy growth rate.
- The Carbon Constraint future scenario models a declining cap on future CO2 emissions. It is modeled in the same way as in the Combined Energy Policy future scenario. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential renewable resources that can apply.

Refer to Table 4.3-1, which illustrates the key input variables for each future scenario. Each future has a unique set of input assumptions driven by a range of policy decisions. With extensive stakeholder involvement under the Planning Advisory Committee, the consensus has been reached with respect to the methodology for determining baseline demand and energy growth rates for each of MTEP11 futures. The demand and energy growth rates were then adjusted to reflect the economically chosen DSM programs during the EGEAS capacity expansion analyses, which offer Global energy study estimated DSM projections as demand side resource options for each scenario. The resulted effective demand and energy growth rates for the four MTEP 11 futures are tabulated as follows:

Future scenarios	MISO wind penetration (GW)	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas price	Carbon Cost / reduction target
Business As Usual with Low Demand & Energy	29	0.78%	0.79%	$5.00	None
Business As Usual With Historical Demand & Energy	32	1.28%	1.42%	$5.00	None
Combined Energy Policy	40	0.52%	0.68%	$8.00	$50/ton (42 percent by 2033)
Carbon Constraint	27	0.03%	0.05%	$8.00	$50/ton (42 percent by 2033)

Table 4.3-1: Future scenario input assumptions

5. MISO resource assessment

5.1 Reserve margin requirements

As directed under Module E of the MISO Tariff, the system planning reserve is calculated by determining the amount of generation required to meet a 1 day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRM), based on the system-wide MISO concident load peak and resources based on their installed capacity rating (that is, PRMSYSIGEN), for the 2011/2012 Planning Year (PY) is 17.40 percent, increasing 2 percentage points from the 2010/2011's 15.40 percent. The Planning Reserve Margin based on Unforced Capacity (PRM_UCAP) declined from 4.50 percent to 3.81 percent, and applies to the non-coincident peak of each Load Serving Entity (LSE).

The system planning reserve is calculated by determining the amount of generation required to meet a 1 day in 10 years (0.1 day per year) Loss of Load Expectation (LOLE). The MISO Planning Reserve Margin (PRMSYSIGEN) for the 2011/2012 Planning Year (PY) is 17.40 percent.

The majority of the 2 percent PRMSYSIGEN increase can be attributed to three factors. In approximate values: The increased uncertainty of forecasting the load contributed to 0.8 percent of the increase; the forced outage rates of resources were up and contributed to 0.7 percent of the increase; and the external system support was found less effective and contributed to 0.6 percent of the increase. While these three factors contributed a total increase of 2.1 percent, other factors contributed an offsetting decrease of about 0.1 percent.

Unlike previous years, the 2011 PRM reflects no component due to transmission congestion. For example, had there been no congestion in the two previous years, the PY 2009 value would have been 0.6 percent marginally lower than its 15.4 percent, and the PY 2010 value would have been lower by 0.4 percent. All previous congestion was due to effects of bottled-up resources that could not likely be counted as available to serve system wide load. Like previous studies, the 2011 MISO LOLE found no evidence of load pockets where the lack of resources would require importing more than the Transmission System's ability to deliver.

Benefits associated with system-wide diversity must be considered since compliance with Module E Resource Adequacy Requirements is based on representing each Load Serving Entity's (LSE) non-coincident monthly peak demand on the appropriate individual CPnodes. MISO has determined that a diversity factor of 4.55 percent will be used for the 2011/12 Planning Year. This is an increase from the 3.00 percent diversity factor used last year. MISO believes the 1.55 percent increase in diversity factor is appropriate in order to appropriately capture the diversity of all LSEs within the MISO BA without significantly increasing the loss of load risk to the MISO system. After consideration for load diversity, the PRM is based on the Load Serving Entity's non-coincident peak and resources based on their installed capacity rating (that is, PRMLSEIGEN), and the value is 12.06 percent.

Projected planning reserve margin requirements for 2012 through 2020 are also calculated in the LOLE Study and are utilized in Section 5.2 as a comparison to the projected reserves. The complete 2011 report on MISO Loss of Load Expectation (LOLE) study can be found at the following link:

https://www.midwestiso.org/Library/Repository/Meeting percent20Material/Stakeholder/LOLEWG/2011/2011 percent20LOLE percent20Report.pdf

5.2 Long term resource assessment

Although current load and resource forecasts do not predict insufficient capacity within the next 10 years, various uncertainties could change that forecast. Less capacity expansion than expected, increased level of generation unit retirements, uncertainty around load forecast, increased forced outage rates due to an aging generation infrastructure and possible lack of external support - are all uncertainties which may negatively affect future Resource Adequacy. The risk of these uncertainties on reliability is assessed through Loss of Load Expectation (LOLE) analysis and the results summarized in this section.

Absent EPA regulations, MISO projects sufficient capacity relative to demand over the next 10 years ……

With EPA regulations and no replacement capacity, the system reserve margin could decrease to 6.9 percent in 2021

Of specific interest is the uncertainty around the pending EPA regulations, one of which has been finalized. The passage of these regulations could lead to increased unit retirements throughout the MISO region; quickly eroding reserve margins from their projected levels.

Recent proposals from the Environmental Protection Agency (EPA) and the uncertainty around carbon control may force retirements of generation within the MISO footprint, which would quickly erode reserve margins from their projected levels. With the anticipated decline of coal generation due to EPA regulations, environmental and economic trends; approximately 3,000 MW of coal generation could be retired in the MISO system by 2015, for a natural gas cost of $4.5/MMBtu and no carbon cost applied. These coal retirements could grow to 12.6 GW of generation, at a carbon cost of $50/ton. If no replacement capacity is identified for Resource Adequacy purposes, then the system reserve margin could decrease to 6.9 percent in 2021. Table 5.2-1 below shows the impact of these scenarios on 2016 and 2021 reserve margins. Refer to MTEP11 chapter 4.2 for more information about the EPA Regulation Impact Study.

Reserve margin	3 GW coal generation retirements		12.6 GW coal generation retirements	
	2016	2021	2016	2021
Projected reserve margin (percent)	19.9	16.2	10.1	6.9
Planning reserve margin requirements (percent)	17.4	18.2	17.4	18.2

Table 5.2-1: Potential EPA impacts on resource adequacy

Absent EPA regulations, MISO projects sufficient capacity relative to demand over the next 10 years. The following section summarizes this situation, and provides forecasts of future demand, capacity, and reserves through 2021. Risks, such as the proposed EPA regulations, are also examined to gauge the potential affect on resource adequacy.

The MISO 2011 Long Term Resource Assessment report will be posted at: https://www.misoenergy.org/Planning/SeasonalAssessments/Pages/SeasonalAssessments.aspx

Refer to Appendix E6 for a more detailed discussion and breakdown of the data presented below.

Forecasted demand

MISO Load Serving Entities are required by current resource adequacy practices to report their non-coincident peak forecasted demand to MISO out 10 years. These demands were collected from the Module E Capacity Tracking (MECT) tool and aggregated to a MISO level. MISO's total internal demand and net internal demand for the 10th-year peak are expected to be approximately 101 GW and 97 GW, respectively. The forecasted MISO annual growth rate from 2012-2021 is approximately 1.0 percent, a slight increase from the 2010 LTRA.

Demand (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Unrestricted non-coincident	97,206	99,149	99,560	100,313	101,034	101,761	102,574	103,515	104,475	105,520
Estimated diversity	4,230	4,315	4,333	4,366	4,397	4,429	4,464	4,505	4,547	4,592
Total internal	92,976	94,834	95,227	95,947	96,637	97,332	98,110	99,010	99,929	100,928
Direct control load management	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118
Interruptible load	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093
Net internal demand	88,765	90,623	91,016	91,736	92,426	93,121	93,899	94,799	95,718	96,717

Table 5.2-2: 2012-2021 forecasted demand

Forecasted capacity

MISO's total designated capacity for the 10th year peak is expected to be approximately 115 GW. A total of 2,549 MW of Generation Interconnection queue projects[32] are expected to be available for the 10th year peak based on a thorough study of the queue. Behind-the-Meter Generation (BTMG) is treated as a capacity resource and not a load modifier to align with the current resource adequacy practices outlined within Module E and standard industry practice.

Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Internal designated capacity resources	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698	103,698
External designated capacity resources	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894	4,894
Behind-the-meter generation	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608
Future planned resources	495	862	881	904	986	986	986	2,549	2,549	2,549
Total designated capacity	112,695	113,062	113,081	113,104	113,186	113,186	113,186	114,749	114,749	114,749

Table 5.2-3: 2012-2021 forecasted capacity

Forecasted reserves

The target reserve margin requirement varies throughout the 10-year period, from 17.4 percent in 2012 to 18.2 percent in 2021. The reserve margins projected through the assessment time vary from 27.0 percent to 18.6 percent for 2012-2021. This is in excess of the MISO target reserve margins through 2019.

Reserve margin	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reserve margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065	19,287	19,950	19,031	18,032
Reserve margin (percent)	27.0	24.8	24.2	23.3	22.5	21.5	20.5	21.0	19.9	18.6
Planning reserve margin requirement (percent)	17.4	17.3	17.3	17.2	17.4	17.8	17.8	18	18.2	18.2

Table 5.2-4: 2012-2021 forecasted reserves

[32] Generator Interconnection Queue data as of March 28th, 2011

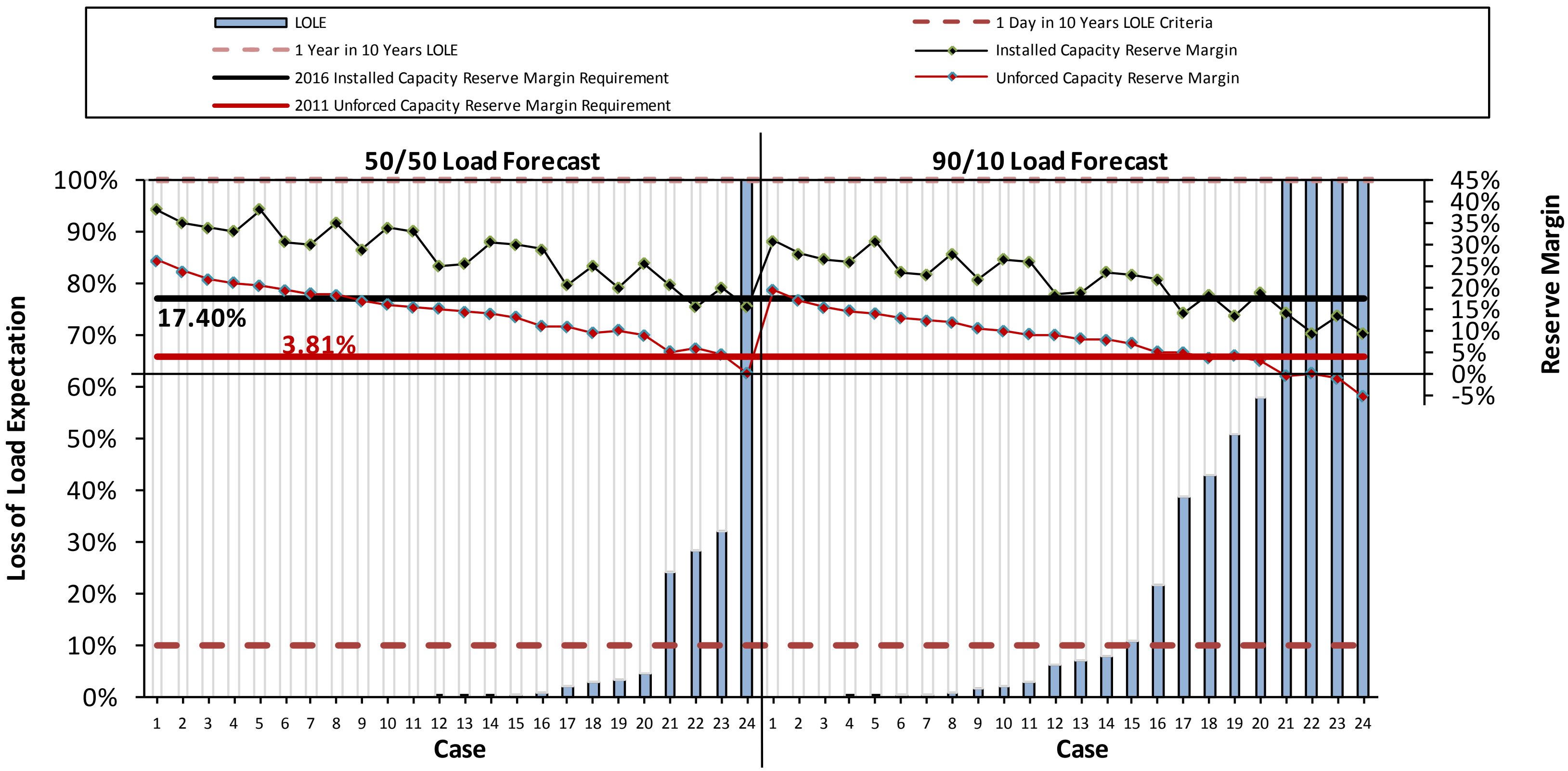
Forecasted risk

To quantify effects each future uncertainty has on the 50/50 and 90/10 load level scenarios, 48 sensitivities were run. The various sensitivities simulate increased forced outage rates across the footprint, no load modifying resources, no external support and increased unit retirements due to the pending EPA regulations (3 GW of coal retirements and 12.6 GW) for both 2016 and 2021. In each case, variables were changed to observe the effects on Loss of Load Expectation (LOLE).

Both 2016 and 2021 had 48 identical cases created to observe its effect on LOLE. An additional eight cases were run for 2021 based on the premise that Generation Interconnection gas-fired projects, approximately 5,000 MW, would have a 100 percent chance of being built, if MISO experiences 12.6 GW of early coal retirement due to EPA regulations.

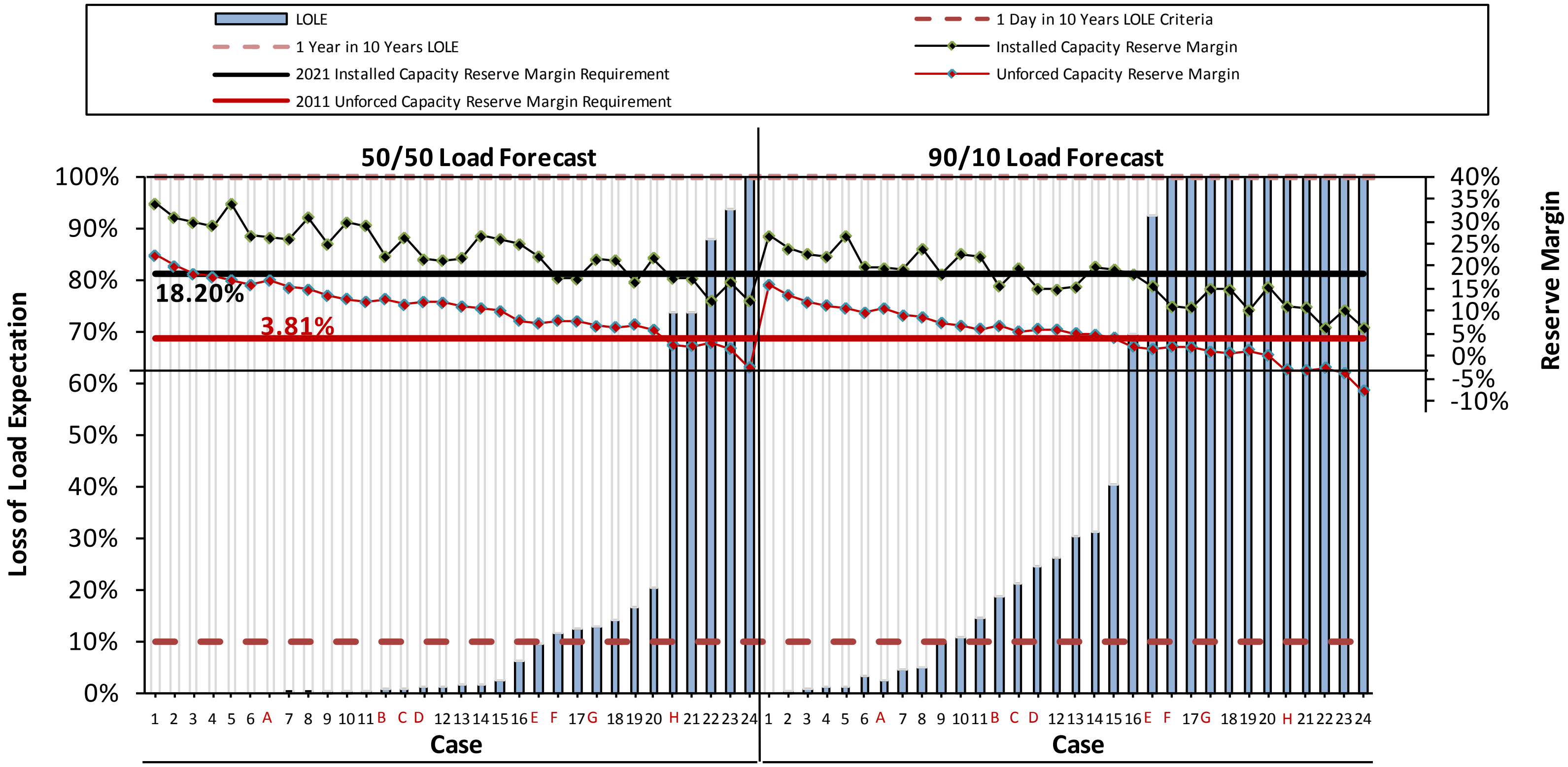
An LOLE of one day in 10 years is an industry standard benchmark for minimum system reliability. When studying the 2016 and 2021 systems, with no early coal facility retirements due to environmental regulations, the analysis shows only a few cases exceeding this benchmark for each year. It should be noted that this is only when unlikely significant impacts occur to the system, such as a 90/10 load forecast with either combination of no external support, no load modifying resources, or 50 percent higher forced outage rates.

A summary of results for 2016 and 2021 is given in figures 5.2-1 and 5.2-2, respectively. The summary shows the LOLE and corresponding reserve margin for each case run in the analysis. Uncertainty exists given the potential effect of pending environmental legislation on MISO’s system. The results indicate risk exponentially exceeding one day in 10 years given increased early retirement of MISO base generation, combined with current future generation resources expected to be built in the Generation Interconnection Queue.



1	Base	9	(EXT), (LMR)	17	(12.6 GW), (LMR)
2	3 GW EPA Retire (3 GW)	10	(FOR), (LMR)	18	(12.6 GW), (FOR)
3	No Load Modifying Resources (LMR)	11	(FOR), (EXT)	19	(12.6 GW), (EXT)
4	No External Resources (EXT)	12	12.6 GW EPA Retire (12.6 GW)	20	(3 GW), (FOR), (LMR), (EXT)
5	50% Increased Forced Outage Rates (FOR)	13	(3 GW), (EXT), (LMR)	21	(12.6 GW), (FOR), (LMR)
6	(3 GW), (LMR)	14	(3 GW), (FOR), (LMR)	22	(12.6 GW), (EXT), (LMR)
7	(3 GW), (EXT)	15	(3 GW), (FOR), (EXT)	23	(12.6 GW), (FOR), (EXT)
8	(3 GW), (FOR)	16	(FOR), (LMR), (EXT)	24	(12.6 GW), (FOR), (LMR), (EXT)

Figure 5.2-1: Year 2016 LOLE sensitivity to variable adjustment



1	Base	B	(12.6 GW) (Gas), (LMR)	18	(12.6 GW), (FOR)
2	3 GW EPA Retire (3 GW)	C	(12.6 GW) (Gas), (FOR)	19	(12.6 GW), (EXT)
3	No Load Modifying Resources (LMR)	D	(12.6 GW) (Gas), (EXT)	20	(3 GW), (FOR), (LMR), (EXT)
4	No External Resources (EXT)	12	(12.6 GW)	H	(12.6 GW) (Gas), (FOR), (LMR), (EXT)
5	50% Increased Forced Outage Rates (FOR)	13	(3 GW), (EXT), (LMR)	21	(12.6 GW), (FOR), (LMR)
6	(3 GW), (LMR)	14	(3 GW), (FOR), (LMR)	22	(12.6 GW), (EXT), (LMR)
A	12.6 GW EPA Retire (12.6 GW) w/Partial Gas Replacement (Gas)	15	(3 GW), (FOR), (EXT)	23	(12.6 GW), (FOR), (EXT)
7	(3 GW), (EXT)	16	(FOR), (LMR), (EXT)	24	(12.6 GW), (FOR), (LMR), (EXT)
8	(3 GW), (FOR)	E	(12.6 GW) (Gas), (FOR), (LMR)		
9	(EXT), (LMR)	F	(12.6 GW) (Gas), (EXT), (LMR)		
10	(FOR), (LMR)	17	(12.6 GW), (LMR)		
11	(FOR), (EXT)	G	(12.6 GW) (Gas), (FOR), (EXT)		

Figure 5.2-2: Year 2021 LOLE sensitivity to variable adjustment

6. Near and long-term reliability analyses

MISO performs an annual Reliability Assessment through its MISO Transmission Expansion Plan (MTEP).

MISO also conducts Baseline Reliability studies in support of MTEP to ensure the Transmission System is in compliance with two entities: applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations applicable within the Transmission Provider region. MISO's studies typically include simulations to assess transmission reliability in the near and long term, using power flow models representing conditions two, five and 10 years out.

MISO identified various transmission issues through the studies. Planned and proposed transmission upgrades needed to mitigate identified issues are included in the 2011 MISO Transmission Expansion Plan. Planned transmission upgrades are in MTEP Appendix A following MISO Board of Directors approval. Proposed transmission upgrades are in MTEP Appendix B.

In MTEP 2011, MISO conducted regional studies using the following base models:

- 2013 Summer Peak
- 2016 Summer Peak
- 2016 Shoulder Peak
- 2016 Light Load
- 2021 Summer Peak
- 2021 Shoulder Peak

MISO member companies and external RTO companies use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2011 series Multi-Area Modeling Working Group (MMWG) interchange. MISO determines total generation necessary to be dispatched for each of the models after aggregating 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:

- 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

Scenario	West Sub Region		Central Sub Region		East Sub Region		Total Load (MW)	Total Generation (MW)	Total MISO Interchange (MW)
	Load (MW)	Generation (MW)	Load (MW)	Generation (MW)	Load (MW)	Generation (MW)			
2013 Summer Peak	41,515	40,065	42,004	39,356	24,906	25,896	108,425	105,317	-3,108
2016 Summer Peak	43,271	41,183	42,736	40,931	25,559	27,809	111,567	109,923	-1,644
2016 Shoulder Peak	31,529	32,945	33,467	32,659	21,294	20,847	86,289	86,451	162
2016 Light Load	22,262	20,778	28,185	29,264	9,883	9,511	60,330	59,553	-777
2021 Summer Peak	45,921	41,378	41,126	41,595	26,768	26,816	113,815	109,788	-4,027
2021 Shoulder Peak	34,557	37,749	33,876	30,757	19,932	18,630	88,365	87,136	-1,229

Table 6-1: MTEP11 models summary

Associated power flow models in MISO Planning Regions are modeled above. Loads are received directly from members. Generation dispatched by MISO in each region is derived from a number of factors, such as modeling of wind. The 5- and 10-year out models have wind zones dispatched in wind integration studies (Regional Generation Outlet Study and proposed Multi Value Project study). Wind zone modeling is based on wind generation required to meet state renewable portfolio standards. Wind projects required to meet state renewable portfolio standards are incrementally needed beyond existing and planned wind with signed interconnection agreements. These wind zones are spread throughout the MISO footprint. The size of these wind zones is determined in two ways: 1) consideration of existing and planned wind near the region and 2) aggregate MISO renewable portfolio standards requirements in 5- and 10-year scenarios. MISO models all planned and incremental wind-existing required to meet state mandates at 20 percent of capacity in summer peak and 90 percent of capacity in shoulder and light load scenarios.

A total of 38 Baseline Reliability Projects (6-MISO East, 6-MISO Central and 26-MISO West Region) and 27 Generation Interconnection projects (3-MISO East, 8-MISO Central and 16-MISO West Region), adding up to $702 million, are being recommended in the current planning cycle. More than $676 million in sub-transmission investment is also planned.

Near term assessment

Near term assessment involves study of the MTEP 2- and 5-year out models. A total of 38 Baseline Reliability Projects (6-MISO East, 6-MISO Central and 26-MISO West Region) and 27 Generation Interconnection Projects (3-MISO East, 8-MISO Central and 16-MISO West Region), adding up to $693 million, are recommended in the planning cycle. More than $685 million in sub-transmission investment is also planned. Detailed documentation of these plans is included in Appendix D1.

Straits power flow control – back to back HVDC voltage source converter

A notable near term Baseline Reliability plan in MTEP11 is the Straits HVDC project. Through the years, power transfers through transmission in the Upper Peninsula (UP) of Michigan have increased so much that re-dispatching local generation around the area's constraints is now a formidable task. The peninsula's system has been split for extended periods in the past few years. The split was created by opening the electrical connections between Indian Lake and Hiawatha 138 kV stations. Consequently, the Transmission System east of Hiawatha is supplied by local generation and lower Michigan through two Straits 138 kV cables. While operating in this mode for extended periods has effectively trapped through flows, performing maintenance on METC lines in lower Michigan has become harder because of the eastern Upper Peninsula's reliance on METC tie lines.

The planned addition of 200 MW Straits back-to-back DC Voltage Source Converter (VSC) will eliminate the need to split the system to prevent overloads. This improves reliability by keeping the system intact. This will improve system reliability. Modern voltage source converter HVDC technology, unlike line commutated converter HVDC technology, provides dynamic reactive power to improve system voltages. It can also be tuned to improve system damping during system swings. This VSC is expected to be able to produce approximately 100 MVARs of reactive power.

All transmission plans in the final NERC Reliability Assessment include additional planned and proposed transmission projects or operating steps. They are necessary to meet system performance requirements of applicable standards. Noteworthy MISO near term issues within the RFC footprint have been documented below and grouped into the local regions:

Minnesota

Most constraints in Minnesota are on the 115 kV transmission lines. In most cases, use of existing Special Protection Schemes (SPS) and Operating Guides (Op-Guide) alleviate thermal issues. Coal Creek runback, Taconite Harbor special protection schemes and Ramsey special protection schemes are notable SPS and Operating Guides used in the constraint mitigation.

Iowa

Generation re-dispatch mitigates most identified Iowa constraints. In almost all cases, these constraints are driven by wind. While in the long term, proposed Multi Value Projects will provide needed outlet for these wind resources, in the near term they will need to be curtailed to alleviate thermal constraints.

Southeast Wisconsin

Category C events (See Appendix E1 for descriptions of NERC TPL standards) drive a number of southeast Wisconsin generator outlet issues. Generation curtailment associated with outages local to the generators will be used to relieve these constraints.

Marquette County-Michigan

Thermal loading issues in Marquette County in the Upper Peninsula of Michigan driven by Category C events were identified in both 2- and 5-year-out models. Local mining load curtailment will be used to mitigate these constraints.

Illinois

A few 138 kV constraints in the Mount Vernon and St. Louis metropolitan areas are thermal constraints driven by Category C events. These conditions will be mitigated by reconductoring of a few sections and load curtailment at some stations. Constraints electrically tied closely to the Taum Sauk Pumping Station are identified in the shoulder scenario with Taum Sauk operating in a pumping mode. The situation will be mitigated by a curtailment of interruptible pumping load. Generation redispatch will mitigate a majority of the remaining constraints.

Tippecanoe County-Indiana

A number of 138 kV loadings here are driven by wind. Proposed Multi Value projects, when approved, will alleviate loadings in the long term planning horizon. Use of wind curtailment through established Operating Guides will be employed to alleviate issues in the near term

Cincinnati-Ohio

A couple of 138 kV circuits on the east side of the metropolitan area are overloaded for various category C events. Operating guides involving load switching and operating lines radially will alleviate the thermal constraints in the near term. A proposed project to reconductor circuits is being evaluated for the long term.

Long term assessment

Long term assessment primarily focuses on reliability issues driven by renewable generation. In addition to existing and planned wind, an incremental 8.5 GW of nameplate capacity is needed in the 10-year planning horizon to meet renewable mandates. The mandates grow further to 10.7 GW in the 15-year out horizon. Growth in wind within five years is compelling wind curtailments. These curtailments will be significant in the long term. The proposed Multi Value Project Study (see Chapter 4.1) shows a possible curtailment of more than 34 TWHr wind energy, in lieu of no long term transmission plans to integrate wind. This equates to about 63 percent of the MISO renewable portfolio standards requirement. As part of the MVP Study, significant transmission (about $5 billion) is planned in the current planning cycle. Though primarily intended to alleviate wind driven constraints in MISO, these projects provide long term help by offloading the underlying 100 kV system, and providing increased outlet for conventional generation as well. These CMVP projects mitigate thermal constraints on about 500 branches for more than 6,400 category B and C contingent events, encompassing study of shoulder and summer peak scenarios.

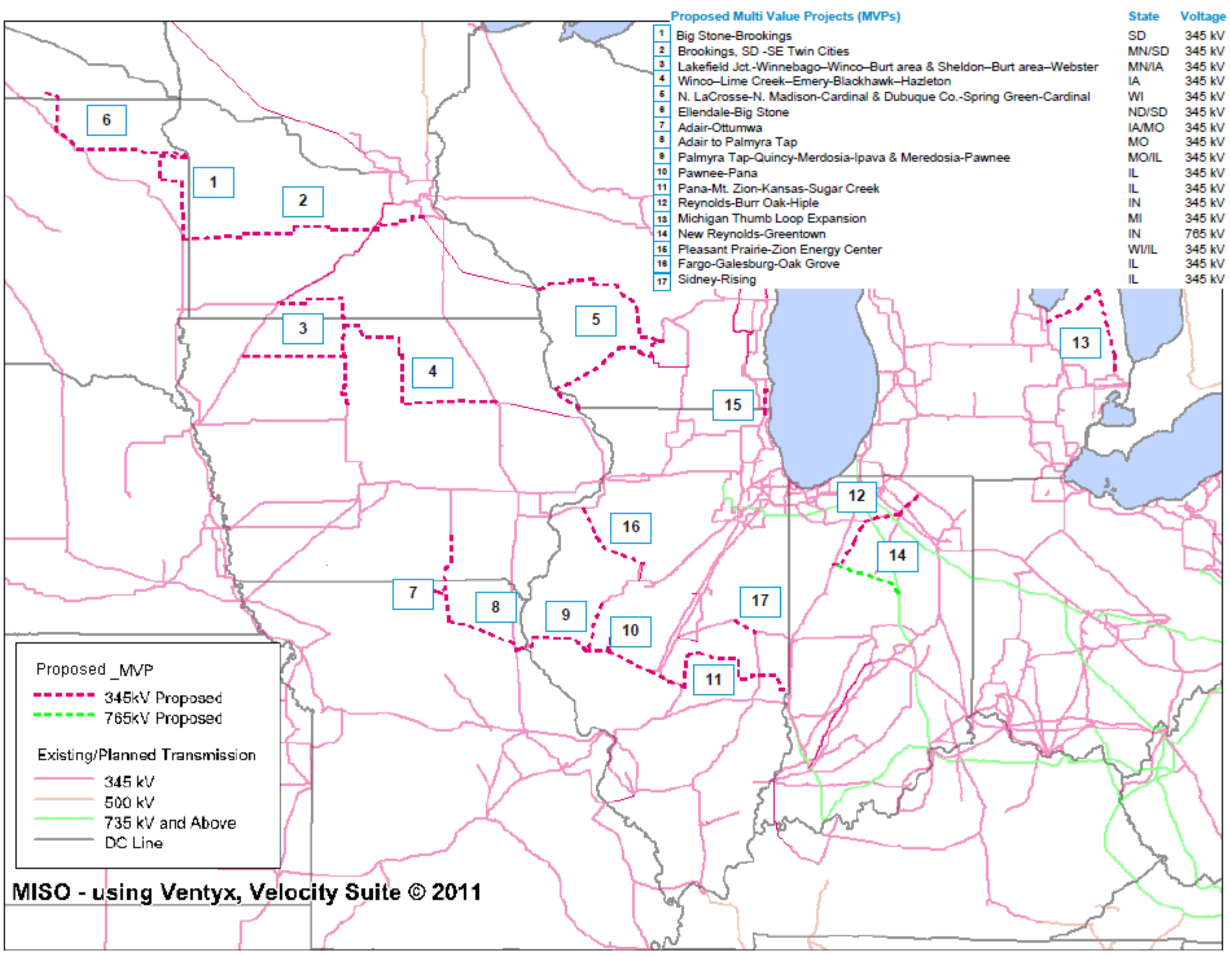


Figure 6-1: 2011 Proposed MVP portfolio

A brief summary of these new plans is documented below:

Ellendale to Big Stone to Brookings

A new line planned from North Dakota into Minnesota provides an outlet to North Dakota wind by directly transferring wind energy at 345 kV, thus offloading the existing 230 kV circuits.

Brookings to Twin Cities

In addition to transferring wind from North Dakota, this new 345 kV line helps transfer additional southwestern Minnesota wind into Minneapolis-St. Paul. Through various transformations throughout the path, this circuit provides on and off ramps for power transfer.

North LaCrosse to North Madison to Cardinal

This new transmission, a continuation of the northern 345 kV path, connects the North Lacrosse station at the Minnesota-Wisconsin border into the Madison load center.

Pleasant Prairie to Zion Energy Center

Creating a new tie line between American Transmission Company (ATC) and Commonwealth Edison (ComEd), this new 345 kV circuit provides an outlet for southeast Wisconsin generation noted in the near term assessment, in addition to allowing wind energy transfer from the Dakotas and Minnesota.

Lakefield to Winnebago to Winco-Burt, Lime Creek to Emery to Blackhawk to Hazleton, Sheldon to Burt to Webster 345kV

These lines facilitate transfer of wind from MISO's West Region closer to large load centers in Illinois and Wisconsin by connecting existing wind heavy areas around Lakefield and Sheldon, and further accessing wind in central Iowa from the Lime Creek area to Hazleton. It provides on and off ramps for power transfer through intermediate transformations.

Dubuque County to Spring Green to Cardinal and Oak Grove to Galesburg to Fargo

Both projects, one connecting to Madison, Wisconsin; and the other to the northern Illinois station at Fargo, provide an outlet for the Western Region wind and connections to load centers. The two projects also help offload transmission constraints out of the Quad Cities Station.

Ottumwa to Adair to Palmyra Tap

This new line provides an outlet for a wind zone in Missouri, and offloads transmission constraints driven through transfers between Iowa and Illinois.

Palmyra Tap to Pawnee to Sugar Creek

This 300 mile line connects Palmyra Tap station at the Missouri-Illinois border to Sugar Creek at the Illinois-Indiana border. The project helps facilitate wind energy transfer between MISO's West and East planning regions.

Sidney to Rising

This new line helps offload underlying transmission and facilitates power transfer between Illinois and Indiana by closing a short electrical distance between two existing 345 stations, providing increased reliability between the states.

Reynolds to Hiple

This new circuit offloads the existing 138 kV parallel circuits by connecting Reynolds station in Indiana's wind heavy Tippecanoe County to Hiple in northeast Indiana.

Reynolds to Greentown

This 765 kV circuit helps further offload existing transmission by creating a new 765 kV station at Reynolds and transferring wind to the closest existing 765 kV station at Greentown. The circuit significantly reduces loadings on 138 kV as well as 345 kV transmission network in Indiana.

6.1 Reliability analysis results

The results of MTEP11 Reliability Analyses are included in Appendix D.2–D.8 and posted at the Midwest ISO File Transfer Protocol (FTP) site at ftp://mtep.midwestiso.org/mtep11/. MISO Planning Regions are separated into West, Central and East. Refer to Table 6.1-1-2 on the following pages, which shows generation, load, losses and interchange modeled in each of the five planning models used in MTEP11 Reliability Analysis.

Planning Region	BA Name	2013 Summer Peak			
		Generation	Load	Loss	Interchange
East	NIPSCO	3,149	3,716	50	-617
	METC	12,730	9,722	317	2,691
	ITCT	10,017	10,883	218	-1,084
Central	HE	1,249	827	34	388
	DEI	6,716	7,980	307	-1,577
	Vectren	1,561	1,708	22	-169
	DEO&K	4,656	5,561	133	-1,042
	IP&L	3,371	3,312	72	-17
	BREC	1,660	1,638	10	11
	CWLD	28	266	1	-239
	AmerenMO	9,350	9,251	148	-49
	AmerenIL	9,948	9,867	186	-104
	CWLP	562	330	3	230
	SIPC	256	345	5	-94
West	WEC	7,208	7,067	142	-9
	XEL	8,704	10,277	267	-1,846
	MP	2,632	1,465	77	1,090
	SMMPA	176	556	1	-381
	GRE	2,960	2,787	87	83

Planning Region	BA Name	2013 Summer Peak			
		Generation	Load	Loss	Interchange
	OTP	1,250	1,702	74	-527
	ALTW	4,056	3,895	73	88
	MPW	242	161	1	80
	MEC	6,294	4,716	93	1,485
	MDU	161	548	9	-395
	DPC	1,215	926	62	228
	ALTE	2,710	2,540	92	75
	WPS	2,164	2,782	71	-691
	MGE	260	795	12	-547
	UPPC	34	224	16	-206

Table 6.1–1: Near term model (2013) generation, load, losses and interchange results by balancing area

Planning Region	BA Name	2016 Summer Peak				2016 Shoulder Peak				2016 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
East	NIPSCO	3,150	3,837	52	-739	1,436	2,953	49	-1,565	2,003	2,092	36	-126
	METC	12,806	9,971	299	2,537	7,827	8,351	231	-756	2,347	3,602	126	-1,381
	ITCT	11,853	11,165	236	452	11,584	9,475	235	1,874	5,161	3,908	119	1,135
Central	HE	1,443	827	40	576	1,207	827	28	352	1,625	827	25	773
	DEI	6,846	8,138	307	-1,606	4,863	5,972	185	-1,301	3,485	3,803	82	-408
	Vectren	1,591	1,708	22	-139	899	1,708	26	-835	1,747	1,708	21	19
	DEO&K	4,656	5,569	130	-1,047	3,946	4,040	76	-174	3,169	2,514	42	609
	IP&L	3,415	3,456	73	-118	2,218	2,417	50	-253	1,179	1,174	16	-15
	BREC	1,719	1,671	12	37	1,259	1,473	12	-225	1,449	1,451	13	-15
	CWLD	30	351	3	-325	30	254	2	-225	24	173	1	-150
	AmerenMO	9,513	9,351	172	-10	6,806	7,510	134	-838	7,258	7,456	113	-312
	AmerenIL	10,905	9,988	221	696	10,623	7,986	168	2,468	8,847	8,170	131	546
	CWLP	561	330	3	228	562	330	3	229	330	330	1	-2
	SIPC	253	362	5	-114	247	262	5	-19	154	133	2	19
West	WEC	7,752	7,300	145	298	6,128	5,300	108	712	2,525	3,281	69	-834
	XEL	8,426	10,602	255	-2,437	6,977	7,471	233	-733	5,005	5,392	221	-614

Planning Region	BA Name	2016 Summer Peak				2016 Shoulder Peak				2016 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
	MP	2,594	1,525	44	1,018	1,907	1,414	39	416	1,742	1,296	82	372
	SMMPA	185	676	1	-492	43	484	1	-436	22	347	1	-325
	GRE	3,001	2,960	39	-51	1,996	2,074	23	-155	997	1,252	26	-285
	OTP	1,241	1,429	81	-270	1,032	1,016	80	-65	1,198	1,037	74	84
	ALTW	4,307	4,048	81	178	4,697	2,950	97	1,649	2,998	2,926	130	-58
	MPW	247	165	1	81	273	127	1	145	63	98	1	-36
	MEC	6,319	5,427	101	791	4,523	3,848	77	591	2,380	2,036	82	262
	MDU	188	575	9	-396	134	410	6	-283	152	292	7	-147
	DPC	1,187	1,027	60	100	561	752	41	-232	319	478	32	-192
	ALTE	2,892	2,654	87	148	2,033	1,940	64	27	1,524	1,233	37	251
	WPS	2,522	2,829	68	-377	2,603	2,143	57	402	1,789	1,328	41	418
	MGE	288	830	12	-555	10	583	11	-585	40	341	6	-308
	UPPC	35	227	14	-207	29	174	8	-152	25	116	2	-94

Table 6.1–2: Generation, load, losses and interchange results by balancing authority

Long term models

Planning Region	BA Name	2021 Summer Peak				2021 Shoulder Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
East	NIPSCO	3,027	4,006	70	-1,049	1,851	4,006	81	-1,206
	METC	12,419	10,368	332	1,720	6,885	10,368	251	-1,074
	ITCT	11,370	11,744	248	-622	9,895	11,744	186	979
Central	HE	1,553	827	32	693	972	827	24	333
	DEI	7,118	6,299	256	557	4,128	6,299	226	-2,257
	Vectren	1,590	1,708	24	-142	1,235	1,708	15	-51
	DEO&K	4,426	5,200	127	-905	3,429	5,200	99	-657
	IP&L	3,247	3,684	70	-511	2,081	3,684	53	-715
	BREC	1,668	1,789	10	-132	1,307	1,789	8	-31
	CWLD	85	266	1	-182	70	266	1	-129
	AmerenMO	9,495	9,042	184	270	6,925	9,042	157	-1,200
	AmerenIL	11,469	10,635	257	577	9,939	10,635	216	1,436
	CWLP	669	330	2	336	444	330	2	197
	SIPC	277	380	6	-109	226	380	5	-62
West	WEC	7,129	7,632	154	-666	5,559	7,632	130	-124
	XEL	8,521	11,186	344	-3,015	7,542	11,186	478	-1,257

Planning Region	BA Name	2021 Summer Peak				2021 Shoulder Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
	MP	2,538	1,643	95	800	2,066	1,643	84	760
	SMMPA	176	754	1	-580	99	754	1	-464
	GRE	2,793	3,199	95	-504	1,951	3,199	82	-511
	OTP	1,595	1,575	80	-61	2,256	1,575	113	966
	ALTW	4,382	4,276	102	4	5,352	4,276	148	2,024
	MPW	273	170	2	102	222	170	1	90
	MEC	6,253	5,670	106	477	6,906	5,670	146	2,516
	MDU	250	618	9	-378	427	618	9	-42
	DPC	1,148	1,105	59	-16	830	1,105	70	-61
	ALTE	3,420	2,833	92	492	1,876	2,833	87	-283
	WPS	2,486	2,910	64	-490	2,538	2,910	77	258
	MGE	385	899	12	-527	96	899	24	-560
	UPPC	30	228	7	-205	29	228	3	-147

Table 6.1–3: Long term model generation, load, losses and interchange results by balancing authority

6.2 Steady state analysis results

MTEP11 Appendix E1.1.4 lists contingencies tested in steady state analysis. Contingencies were simulated in MTEP11 2013 summer peak, 2016 summer peak, shoulder peak and light load, 2021 summer peak and shoulder peak models. All steady state analysis-identified constraints and associated mitigations are tabulated in results tables in MTEP11 Appendix D.3.

6.3 Voltage stability analysis results

MTEP11 Appendix E1.1.1 lists types of transfers tested in voltage stability analysis. The study did not find low voltage areas or voltage collapse points for critical contingencies in transfer scenarios close to the base load levels modeled in the MTEP11 2016 summer peak and shoulder peak models. A summary report with associated p-v plots is documented in MTEP11 Appendix D.4.

6.4 Dynamic stability analysis results

MTEP11 Appendix E1.1.4 lists types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP11 2016 light load and shoulder peak load models. The system was stable. Results tables listing all simulated disturbances along with damping ratios are tabulated in MTEP11 Appendix D.5.

6.5 Generator deliverability analysis results

Generator deliverability analysis was performed in MTEP11 to ensure continued deliverability of aggregate deliverable network resources. A total of 370 MW of deliverability is restricted due to constraints identified in MTEP11. These constraints have not been planned for in the current MTEP cycle and will be investigated in the subsequent MTEP cycle (MTEP12). This compares to more than 900 MW in MTEP10 and more than 3,000 MW of restricted deliverability in MTEP09. This progressive reduction in restricted deliverability has been accomplished through planned upgrades in past MTEP cycles.

MTEP10 Deliverability Constraint	Total Generation Restricted	Percentage of MWs Impacted	Rating (MVA)	Percent Overload	MTEP Project ID	Target Appendix MTEP11
Boone Jct.--Ft. Dodge 161 kV line	226	23 percent	147	115.8	2941	C
East Calamus--Grand Mound 161 kV line	237	24 percent	176	112.8	1619	In Service in MTEP11, A in MTEP08

Table 6.5-1: The list of mitigations for the outstanding constraints from MTEP10 that were proven effective

The description of table 6.5-2 column headings is below.

- An Overload Branch is caused by "bottling-up" of aggregate deliverable generation. Deliverability was tested only up to the granted NR (Network Resource) levels of the existing and future NR units modeled in the MTE11 2016 case.
- Use the Map ID to find an approximate location of the overloaded element on Fig. 6.5-1
- Contingency is the outage created in the overload. In some cases, the system may be system intact, so there is no outage. Detailed contingency definitions are included in the Appendix.
- Rating is the rating of the overloaded element used in the analysis. It's normal if the system is intact, but an emergency for post contingent constrained branches.
- 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
Wilmarth to Swan Lake 115 kV line	XEL	1	Wilmarth to Helena 345 kV line	110	19.19 percent
Wilmarth to Eastwood 115 kV line	XEL	1	Wilmarth to Summit 115 kV line	190.8	4.59 percent
Medford Jct. to Waseca Junction 69 kV line	ALTW	1	Loon Lake to Loon Lake Tap 115 kV line	30	8.23 percent
Turkey Hill 345/138 kV transformer[33]	AMIL	2	C-BLWN-4511 Caokia 345/138 kV transformer Cahokia to Baldwin 345 kV line	672	1.81 percent

Table 6.5-2: The MTEP11 constraints that limit deliverability of about 370 MW of Network Resources. See Appendix D6 for the detailed results with a list of impacted Network Resources.

[33] The Turkey Hill 345/138 kV transformer has a MTEP Appendix C project 3001 that will mitigate the deliverability constraint. Projects targeted as mitigation for deliverability constraints will be moved to Appendix B.

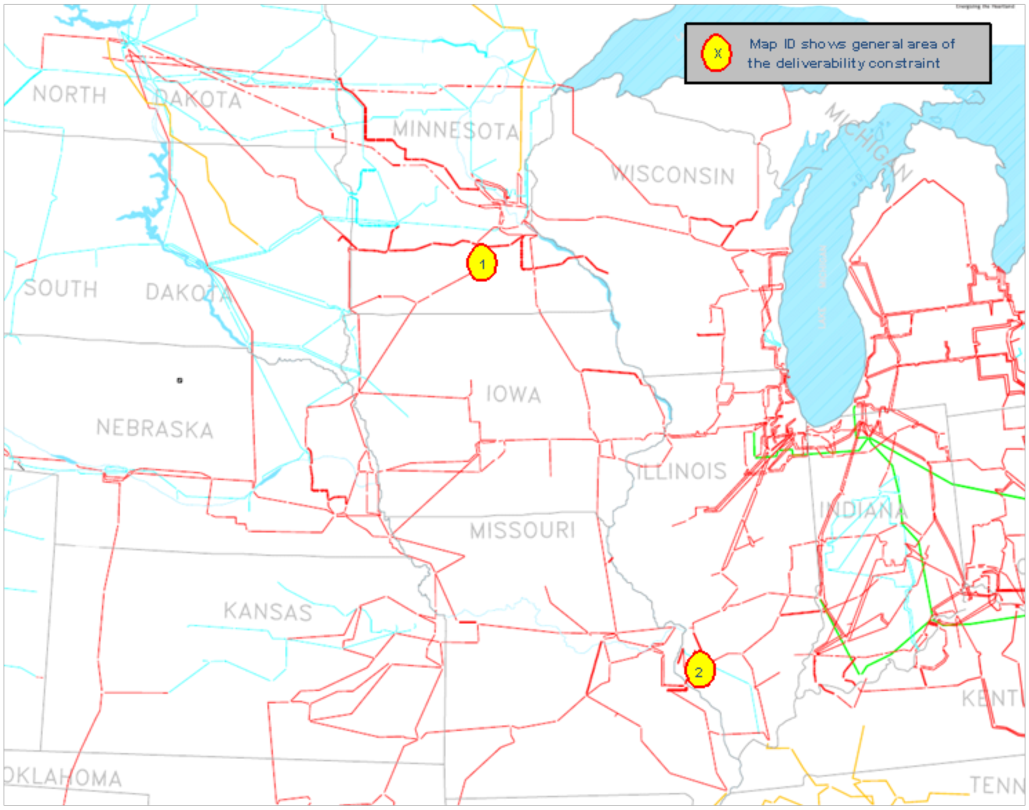


Figure 6.5-1: General location of MTEP11 2016 SUPK baseline generator deliverability constraints

MISO will create a Technical Review Group of stakeholders to address generator deliverability issues in the MTEP12 planning cycle.

6.6 Long Term Transmission Rights (LTTR)

This section documents planned upgrades to address constraints driving infeasibility of Long Term Transmission Rights. Refer to Table 6.6-1, which shows the uplift costs associated with the infeasible LTTRs in the 2011 Annual Allocation.

Year	Total Stage1A (GW)	Total LTTR Payment ($M)	Total Infeasible Uplift ($M)	Uplift Ratio
2011 Allocation	354.3	211.2	7.6	3.60 percent

Table 6.6-1: Uplift costs associated with infeasible LTTR in the 2010 annual allocation

Refer to Table 6.6-2, which further details the infeasible uplift to binding constraints from the annual auction. Binding constraints are filtered for those with values greater than $75,000. Planned mitigations have been documented against constraints where future proposed or planned upgrades have already been identified through other planning studies. MISO constraints with no identified plans in the current planning cycle result in uplift of less than $600 thousand or less than 10 percent. MISO will coordinate with its Transmission Owners on investigation of these constraints in MTEP12 planning cycle. Additionally, MISO will coordinate with adjacent RTOs on seams constraints.

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3442' (Rising 345/138 TR1 (flo) Dresden - Pontiac 345kV)	$0	$1,160,037	$245,685	$0	$1,405,721	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
'3191' (IP Rising 345/138 XFMR 1 (flo) Clinton - Brokaw 345 (IP4535))	$661,750	$0	$0	$0	$661,750	P2239 Rising to Sidney 345kV CMVP Line ISD: 11/15/2016
FOX_LK 500 161 kV to RUTLAND 500 161 kV	$93,517	$362,743	$0	$12,870	$469,130	3205 Lakefield-Burt & Sheldon-Webster 345 kV line 3213 Candidate MVP Portfolio 1 - Winco to Hazleton 345 kV
'3570' (Pleasant Prairie-Zion Energy Center 345 flo Cherry Valley-Silver Lake 345 R)	$8,163	$217,895	$317	$5,725	$232,100	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove Galesburg- Fargo CMVP ISD: 11/15/2018

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3451' (Edwards-Kewanee (CE) 138kV (flo) Powerton-Goodings Gr (R)+Powerton (R)-Powerton (B) 345kV)	$230,959	$0	$0	$0	$230,959	Palmyra Tap – Meredosia – Pawnee + Meredosia – Ipava CMVP Line ISD: 11/15/2016 and 11/15/2017
CEDAR_RG 3 138 kV to OHMSTEAD 1 138 kV	($153)	$211,978	$2,702	($495)	$214,033	no planned upgrade
LUCAS 358 161 kV to LUCAS 369 69.0 kV	$79,263	$47,607	$0	$79,263	$206,134	P3170 CMVP line from Ottumwa – Adair – Palmyra Tap – Thomas Hill ISD: 11/15/2018
'3443' (Coffeen North-Ramsey 345kV (flo) Praire State-W Mt Vernon 345kV + W Mt Vernon 345/138kV TR4)	$0	$197,097	$0	$0	$197,097	P2237, P2238 and P2240 CMVP line from Pana to Mount Zion to Kansas to Sugar Creek 345 kV ISD: 11/15/2018 and 11/15/2019
'3180' (W. Mt. Vernon-E. W. Frankfort 345 (flo) St. Francois-Lutesville 345)	$7,438	$174,845	$0	$0	$182,282	P2295 Upgrade terminal equipment on W. Mt. Vernon-E. W. Frankfort 345 kV ISD: 6/1/2015
'6214' (Bunge-Hastings 161 kV flo Cooper-St. Joe 345 kV)	$58,400	$79,302	$37,151	($264)	$174,589	No MISO planned upgrade
'3771' (Pleasant Prairie - Zion 345kV)	($188)	$172,630	$0	($2,460)	$169,982	P2844 Pleasant Prairie - Zion Energy Center CMVP ISD: 3/6/2014 and P3022 Oak Grove-Galesburg - Fargo CMVP ISD: 11/15/2018
RICH2 4 230 kV to ROSEAUMP 400 230 kV	$22,475	$100,784	$0	$23,259	$146,518	Manitoba Constraint
'3646' (Nucor-Whitestown 345kV (flo) Rockport-Jefferson 765kV)	$0	$107,761	$17,251	$0	$125,012	P3203 Reynolds to Greentown 345kV CMVP ISD: 12/31/2013

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3737' (Alliat Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345 + Tiffin-Hills 345)	$0	$99,826	$22,465	$0	$122,291	P1344 Build a new 345 kV Morgan Valley (Beverly) substation which taps the Arnold - Tiffin 345 kV line ISD: 12/31/2014
'6061' (Richer -- Roseau 230kV line (R50M))	$0	$113,054	$0	$0	$113,054	Manitoba Constraint
'2571' (Marktown - Inland Steel 5 138kV (flo) Burnham - Munster 345kV)	$0	$104,875	$6,743	$0	$111,618	P2792 Northwest Circuit reconfiguration ISD: 12/1/2013
WINBALTW 572 69.0 kV to DELEAST 794 69.0 kV	$8,288	$0	$0	$102,475	$110,762	no planned upgrade
ROSEAUMP 400 230 kV to MORNVLL 400 230 kV	$48,038	$30,945	$9,035	$21,987	$110,005	Manitoba Constraint
KANSAS00 HAB 138 kV to HARBOR01 4 138 kV	$0	$96,544	$5,946	$0	$102,489	Manitoba Constraint
'1613' (Volunteer - Phipps Bend 500)	$14,828	$101,497	($20,853)	$5,282	$100,754	TVA Constraint
'549' (Dresden-Elwood 1222 345 kV l/o Dresden-Electric 1223 345 kV)	$100,293	$0	$434	$0	$100,727	PJM Constraint
'3312' (Lanesville 345/138kV Xfmr (flo) Lanesville - Brokaw - Pontiac 345kV)	$28,717	$31,182	$33,304	$0	$93,203	P2236, P2237, P2238 345kV loop around area including additional 345/138kV transformers.
'2497' (State Line-Wolf Lake 138)	$0	$90,273	$0	$0	$90,273	P2792 Northwest Circuit reconfiguration ISD: 12/1/2013
'6124' (Sub K/Tiffin-Arnold 345kV)	$84,536	$0	$0	$4,922	$89,459	P3022 Oak Grove Galesburg- Fargo 345kV CMVP line ISD: 6/1/2016 and P3127 Dubuque - Cardinal 345kV CMVP line ISD: 12/31/2020

Constraint	Summer 2011	Fall 2011	Winter 2011	Spring 2012	Grand Total	Planned Mitigation
'3353' (Lanesville 345/138 (flo) Kincaid - Pawnee 345 + 2106 SPS)	$81,727	($14,531)	$16,830	$0	$84,026	P2236, P2237, P2238 345kV loop around area including additional 345/138kV transformers.
6007' (GENTLMN3 345 REDWILO3 345 1)	($270)	$96,112	($14,467)	($639)	$80,737	MRO Contraint
'2336' (BentnHrbr-Palisades345/Cook-Palisades345)	$0	$76,971	$0	$0	$76,971	no planned upgrade

Table 6.6-2: Infeasible uplift to binding constraints from the annual auction

Appendices

Most MTEP11 appendices are available and accessible on the MISO public webpage. Confidential appendices, such as D.2 - D.8, are available on the MISO MTEP11 FTP site. Access to the FTP site requires an id and password.

A link to the MTEP11 appendices, on the MISO public website, is below:

https://www.midwestiso.org/Library/Pages/ManagedFileSet.aspx?SetId=694

The confidential appendices are located at:

ftp://mtep.midwestiso.org/mtep11/

Appendix A: Projects recommended for approval
- Section A.1, A.2, A.3: Cost allocations
- Section A.4: MTEP11 Appendix A new projects

Appendix B: Projects with documented need & 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 MTEP11 Study support
- Section E.1: Reliability planning methodology
- Section E.2: Generations futures development
- Section E.3: MTEP11 futures retail rate impact methodology
- Section E.4: Proposed MVP portfolio steady state and stability results
- Section E.5: Proposed MVP portfolio business case presentation
- Section E.6: Resource assessment results

Appendix F: Stakeholder substantive comments