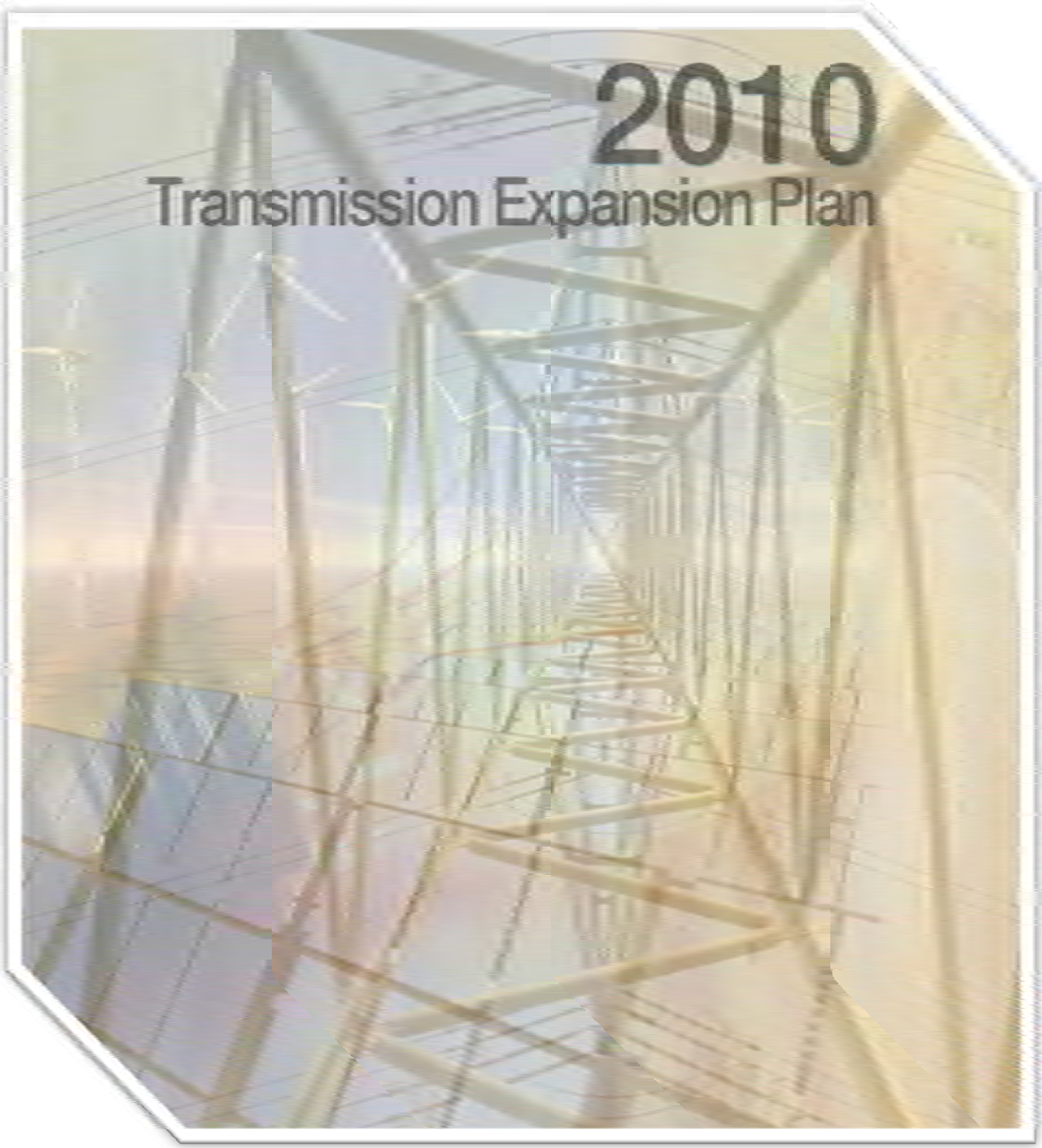

Midwest ISO
Energizing the Heartland

Contents

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1 Executive Summary

The annual Midwest ISO Transmission Expansion Plan (MTEP) identifies solutions to meet transmission needs and to create value opportunities over the next decade and beyond via the implementation of a comprehensive planning approach. The projects listed and described in MTEP10 Appendix A[1] constitute recommendations of essential transmission projects to the Midwest ISO Board of Directors (BOD) for review and subsequent approval. MTEP10, the seventh edition of this publication, is the culmination of more than 18 months of collaboration between Midwest ISO planning staff and stakeholders. Each report cycle focuses efforts on identifying issues and opportunities, developing alternatives for consideration, and evaluating those options to determine effective solutions. The primary purpose of this and other MTEP iterations is to identify transmission projects that:

- Ensure the reliability of the transmission system.
- Provide economic benefits such as increased market efficiency.
- Facilitate public policy objectives such as integrating renewable energy.
- Address other issues or goals identified through the stakeholder process.

MTEP10 recommends $1.2[2] billion in new transmission expansion through the year 2020 for inclusion in Appendix A. This is part of a continuing effort to ensure a reliable and efficient electric grid that keeps pace with energy demands. Key findings and activities from the MTEP10 planning cycle include:

- **Recommendation of 230 New Projects Totaling $680 Million for Approval by the Midwest ISO Board of Directors (BOD):** These projects, together with proposed projects listed in MTEP Appendix B, ensure compliance with all reliability standards and requirements through 2020. Further, although these projects are primarily premised on reliability needs, analysis of a subset of approximately $4 billion of the planned and proposed projects expected to be in service by 2015 indicates these projects will deliver $825 million in annual market efficiency benefits beginning in 2015.[3]
- **Approval by the Midwest ISO BOD of One (1) Project Totaling $510 million Targeted at Integrating Renewable Energy.** This project, intended to address renewable requirements in Michigan, will be the first project whose cost will be shared under the new Multi-Value Project (MVP) cost methodology, assuming MVP cost allocation methodology is approved by the Federal Energy Regulatory Commission (FERC).
- **Development of a Value Maximizing Wind Siting Methodology:** During the Regional Generation Outlet Study (RGOS), analyses showed locating wind zones in a distributed manner throughout the system with a slight skew to the strongest wind regions in the west—as opposed to only siting wind local to load where less transmission is required or only regionally where the wind is the strongest—results in a set of high-value wind zones that meet the objective function of achieving the lowest delivered dollar per MWh cost for wind capacity and its associated transmission.
- **Completion of the RGOS Effort:** RGOS concluded with the identification of three (3) transmission scenarios that would meet the renewable mandates and goals of the states within the Midwest ISO footprint. Transmission from these scenarios was included in MTEP10 Appendix B and will be studied in 2011 Candidate MVP Portfolio analysis. These transmission portfolios

[1] Projects in Appendix A reflect planned projects approved 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] $1.2 billion figure includes the $510 million Michigan Thumb Loop project approved by the Board of Directors on August 19, 2010.

[3] This subset does **not** include projects that cannot, by their nature, drive incremental economic benefits due to their lack of an impact on the system impedance and topology. These excluded projects include capacitor banks, circuit breaker upgrade, rebuilds of existing lines and substations, and control room upgrades.

and the wind generation enabled by these portfolios showed widespread Adjusted Production Cost benefits in excess of the transmission cost required to integrate the wind, both within the Midwest SO footprint and throughout the Eastern Interconnect.

- **Identification of a 2011 Candidate MVP Portfolio:** This portfolio of projects, sourced from the Regional Generation Outlet Study and other transmission studies, represents a major step towards implementing a regional plan to meet Renewable Portfolio Standards and provide economic and reliability benefits. It will be thoroughly studied in the MTEP11 process, with a goal of including any appropriate Candidate MVPs into Appendix A in 2011.
- **Development of a New Cost Allocation Methodology:** Midwest ISO concluded over 18 months of cost allocation discussions with the submission of the public policy-driven and benefits-based cost allocation Multi-Value Project (MVP) methodology to FERC on July 15, 2010.
- **Confirmation of Long-Term Generation Resource Adequacy:** Reserve margin requirements and a risk assessment were conducted to determine the resource adequacy needs of the system. Under no tested scenario did the system fail to meet its reserve requirement or Loss of Load Expectation (LOLE) industry standards through 2019. These calculations do not take into account any potential capacity retirements due to proposed EPA regulations. Rigorous analysis will be performed in 2011 to determine the impacts of the draft regulations on resource adequacy in the Midwest ISO footprint.
- **Assessment of Chronic System Congestion and Potential Mitigation:** The Midwest ISO Top Congested Flowgate Study and The Cross Border Top Congested Flowgate Study evaluated the impact of potential transmission upgrades on critically congested areas in the Midwest ISO system and on neighboring areas. Although no transmission projects from these studies were deemed eligible for inclusion into Appendix A as cost-shared projects under the current Market Efficiency Project (RECB II) protocols, (and no project sponsors volunteered to construct the transmission without cost allocation) study efforts are ongoing, including evaluation of the effectiveness of the Candidate MVP Portfolio at mitigating identified congestion. Also, the appropriateness of the RECB II protocols will be evaluated by stakeholders in 2011.
- **Investigation into Technological and Policy Impacts:** Midwest ISO actively investigated the electrical and economic impacts of several potential technologies and policy statements. These investigations included development of future policy scenarios as well as analyses surrounding the potential rate impacts of those scenarios, carbon reduction strategies, demand response and energy efficiency implementation, and energy storage technologies. Efforts also included the investigation of wind integration and operational impacts through the Wind Integration Initiative.
- **Participation in the Eastern Interconnection Planning Cooperative (EIPC):** Midwest ISO, as a Principal Investigator, will continue to be actively involved in the EIPC study throughout its completion.

In MTEP10, the Midwest ISO completed many analyses which showed the near and long term impacts of proposed transmission lines. In the coming years, the Midwest ISO, through the continued integration of reliability, economic, and public policy projects, will continue to drive grid efficiencies by ensuring near-term projects support long-term goals.

1.1 The Midwest ISO Planning Approach

Midwest ISO is guided in its planning efforts by a set of principles established by the Midwest ISO Board of Directors (BOD), initially adopted on August 18, 2005. These 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 Midwest ISO transmission planning process. These principles, reconfirmed in August 2009, are as follows:

- **Guiding Principle 1:** Make the benefits of a competitive energy market available to all customers by providing access to the lowest possible delivered 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 renewable energy objectives by planning for access to all such resources such as wind, biomass, and demand-side management.
- **Guiding Principle 4:** Provide an appropriate cost allocation mechanism.
- **Guiding Principle 5:** Develop a transmission system scenario model and make the model available to state and federal energy policy makers to provide context and inform the choices they face.

To support these Guiding Principles, a transmission planning process has been implemented reflecting a fully integrated view of project value inclusive of reliability, market efficiency, public policy, and other value drivers across all planning horizons. Now that the fundamental shift in support of the planning principles has been achieved, continuous improvement will increasingly drive the identification of longer-term solutions that provide greater benefits to address reliability or market efficiency issues instead of the series of shorter-term and often less valuable mitigation steps employed today.

A number of conditions must be met in order to build longer-term transmission able to support future generation growth and accommodate new energy policy imperatives. These conditions are intertwined with the planning principles put forth by the Midwest ISO Board of Directors (BOD) and supported by the integrated, inclusive transmission planning approach described above. The conditions that must be met in order to build transmission 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

These conditions are met through the efforts and studies conducted throughout the Midwest ISO planning process. Specifically, the activities listed and described below were undertaken to fulfill these conditions and—through them—the planning principles enunciated by the Midwest ISO BOD:

- **Responding to Evolving Energy Policy:** To address the uncertainties related to Renewable Portfolio Standards, carbon caps or taxes, and other policies, Midwest ISO examines multiple future scenarios through its long-term planning process in order to more fully and realistically capture a wide array of potential policy outcomes, and—more immediately—has conducted the Regional Generation Outlet Study (RGOS), to identify a sub-set of transmission projects as renewable energy transmission solutions. Midwest ISO believes an informal consensus has been reached regarding appropriate planning for energy policies. This belief is based on the work of many stakeholders—spearheaded by the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI), and the Organization of Midwest ISO States Cost Allocation and Regional Planning (OMS CARP)—to develop appropriate planning assumptions. It is also supported by the increasing number of states within the Midwest ISO footprint which have enacted Renewable Portfolio Standards or goals. Moving forward, Midwest ISO staff will continue to work to ensure consensus is maintained.

- **Executing Value-based Planning:** Throughout 2010, Midwest ISO continued to execute the full value-based study process first implemented in 2006 to support business case development for future transmission plans. This value-based approach was included as part of the RGOS and Michigan out-of-cycle analyses and captured a more comprehensive view of project benefits than would be the case with a more traditional approach. Further progress has also been made towards the implementation of robustness testing, as a sample set of results, based on RGOS portfolios, was run to show the potential comparative benefits of the transmission alternatives.
- **Implementation of a New Cost Allocation Methodology:** After considering feedback from stakeholders, Midwest ISO filed its Multi-Value Project (MVP) Cost Allocation methodology with FERC on July 15, 2010 to address the appropriate match of beneficiaries and costs over time. The MVP Regional Transmission Cost Allocation Proposal creates a new class of transmission expansion projects (referred to as MVPs), whose costs are recovered on a Midwest ISO system-wide basis. MVPs are network upgrades that provide regional benefit in response to documented public policy such as renewable energy standards, and/or by providing multiple regional benefits such as reliability and/or economic value, to transmission customers on a regional basis. As of this writing, this new cost allocation methodology is pending FERC approval.

1.2 Key Findings

MTEP10 study efforts included a number of technical findings and policy implications that warrant careful review. Additional information on these findings may be found in the following sections of the Executive Summary, as well as in the body of the report.

1.2.1 Investment in System Reliability and Efficiency

MTEP10 recommends 231 new projects for inclusion in Appendix A, representing an incremental $1.2[4] billion in transmission infrastructure investment within the Midwest ISO footprint. These projects fall into the following five (5) categories:

- **Multi-Value[5] Projects (One [1] project, $510.0 million):** Projects providing regional public policy and/or economic benefits. This project was reviewed and approved by the Board of Directors on August 19, 2010.
- **Baseline Reliability Projects (37 projects, $94.3 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 Midwest ISO's footprint.
- **Generator Interconnection Projects (Six [6] projects, $6.9 million[6]):** Projects required to reliably connect new generation to the transmission grid.
- **Transmission Service Delivery Projects (Two [2] projects, $3.9 million):** Projects required to satisfy a Transmission Service Request. The costs of these projects are always direct assigned to the requestor.
- **Other Projects (185 projects, $574.9 million):** A wide range of projects, such as those designed to provide local economic or similar benefit but not meeting the threshold requirements for qualification as Regionally Beneficial Project (RBPs), and projects required to support the lower voltage (less than 100 kV) transmission system.

The addition of new transmission projects in MTEP10 brings the total number of projects in Appendix A to 614, representing an expected investment of $4.7 billion through 2020. When completed, the projects will result in approximately 4,100 miles of new or upgraded transmission lines. Since the first MTEP cycle closed in 2003, transmission projects recommended for approval total $8.6 billion, of which $3.5 billion is associated with projects already in service and $0.5 billion is associated with projects that have been withdrawn.

MTEP10 contains 10 new Appendix A projects meeting cost-sharing eligibility criteria under the Baseline Reliability Project or Generator Interconnection provisions of the Midwest ISO tariff. This report also features the first project meeting new Multi-Value Project (MVP) cost sharing methodology criteria, subject to final approval by the Federal Energy Regulatory Commission.

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[4] $1.2 billion figure includes the $510 million Michigan Thumb Loop project approved by the Board of Directors on August 19,2010.

[5] New project type effective July 16, 2010 subject to final approval by the Federal Energy Regulatory Commission. MVP cost allocation will be calculated on a formula that adjusts based on the annual revenue requirements reported by each Midwest ISO Transmission Owner for projects meeting MVP criteria.

[6] Project cost shown is the total cost, not just the cost shared or Transmission Owner contribution.

1.2.2 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
- Load Cost Savings
- Reduced Energy And Capacity Losses
- Reduced Reserve Margins

For example, refer to Table 1.2-1, which shows an estimated Market Congestion benefit of $825 million against a modeled transmission portfolio cost of approximately $4 billion[7], leading to an economic benefit-to-cost ratio of approximately 1.03 for this portfolio[8]. Again, these economic benefits are in addition to the benefits derived from increased system reliability considerations initially driving the need for these projects.

Table 1.2-1: 2015 Economic Benefits

Region	Load Cost Savings ($M)[9]	Adjusted Production Cost Savings ($M)[10]	Market Congestion Benefits ($M)[11]
Midwest ISO East (Michigan, Northern Ohio, and Northern Indiana)	127	211	186
Midwest ISO Central (Central and Southern Indiana, Illinois, Missouri)	108	253	209
Midwest ISO West (Wisconsin, Iowa, Minnesota, North Dakota, and Montana)	760	288	430
Midwest ISO (Excludes portions of states in other RTOs)	**995**	**752**	**825**

[7] Please note this $4 billion figure is the sum of project investment in Appendices A and B projected to be in-service by 2015, excluding any projects that would not impact the system dispatch and—as such—do not have incremental economic benefits. It also does not include any candidate MVPs.

[8] Assuming a fixed charge rate of 20%

[9] Load Cost savings are due to lower Locational Marginal Prices (LMPs) at the load centers.

[10] Production cost savings result from lower cost generation being able to deliver its power to load.

[11] The Market Congestion Benefit is a weighted sum of the production and load cost savings (70% and 30%, respectively).

1.2.3 Wind Siting Methodology

Several different wind generation siting options were analyzed during the RGOS work. This analysis focused on the relative benefits of local wind generation, which typically requires less transmission to be delivered to major load centers, and regional wind generation, which can be located where wind energy is the strongest. Capital costs for a variety of wind generation siting options, including the associated high-level transmission overlays created for each option, were calculated and plotted against each other to determine the relative cost of each generation siting approach.

The least-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 on Figure 1.2-1. This approach was affirmed by the Midwest Governors' Association as the best method for wind zone selection.

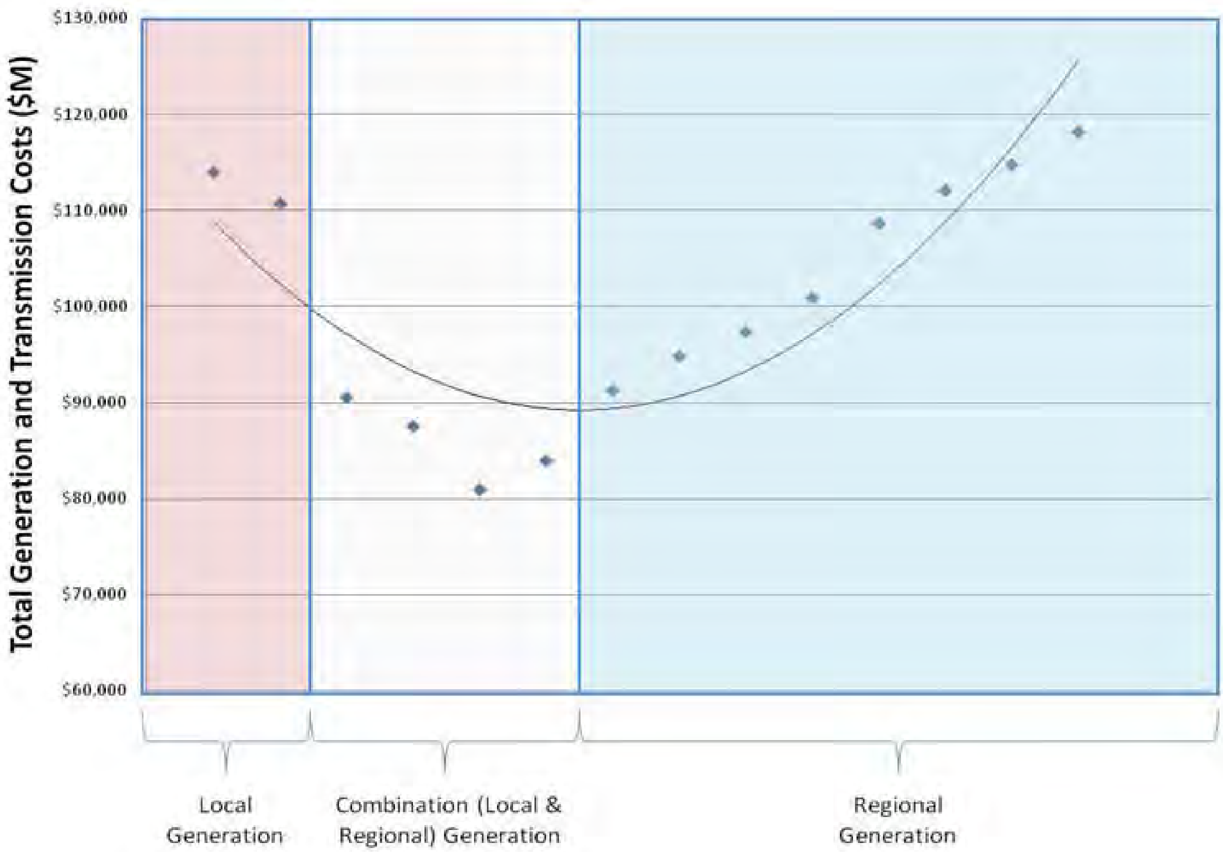

Figure 1.2-1: Wind Generation Siting Cost Comparison

1.2.4 2011 Candidate Multi-Value Project Portfolio Selection

In MTEP10, Midwest ISO identified a portfolio of Candidate Multi-Value Projects (MVPs), from a variety of different studies including RGOS, multiple congestion studies, and numerous generator interconnection studies. In MTEP11, this Candidate MVP portfolio will undergo rigorous analysis as a first step towards a regional transmission portfolio enabling the states in the Midwest ISO footprint to meet their respective near-term Renewable Portfolio Standards (RPS). Refer to Figure 1.2-2.

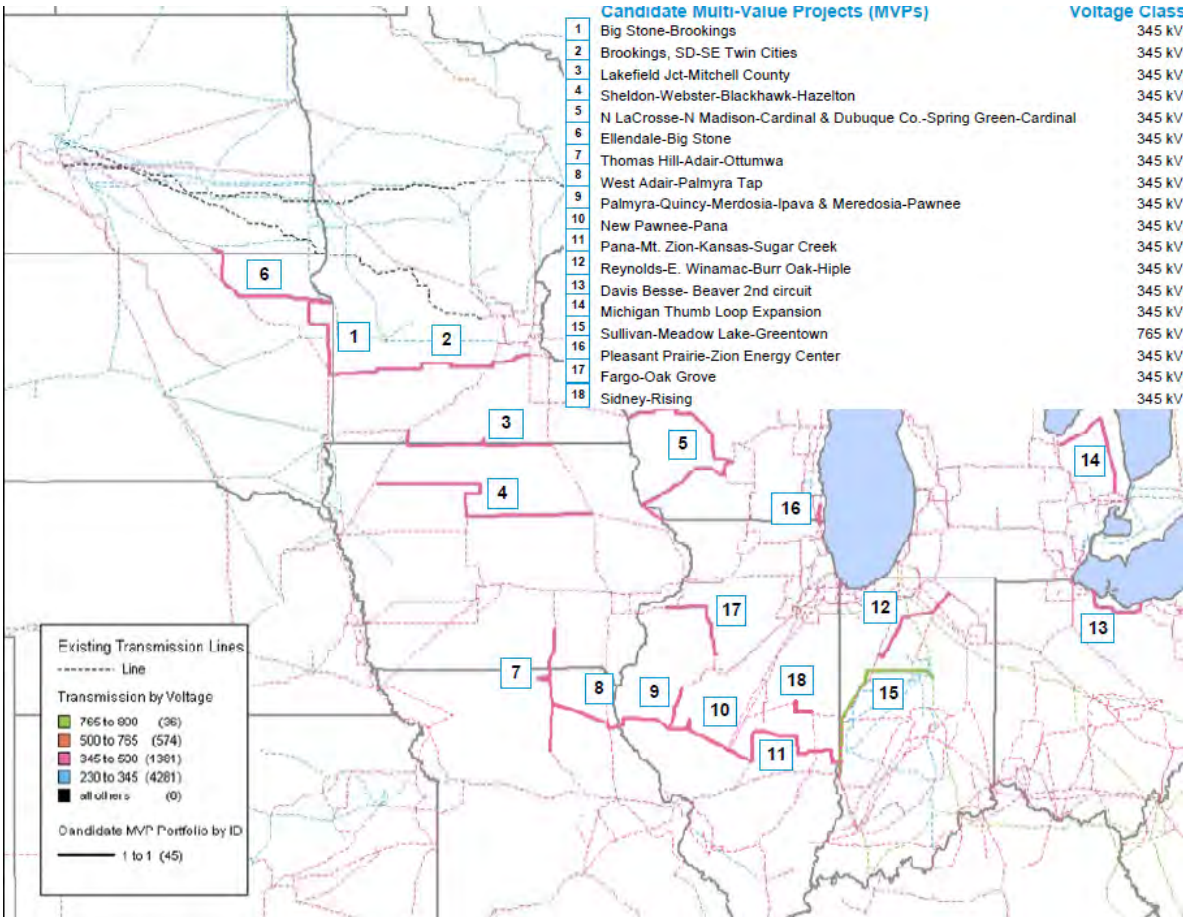

Figure 1.2-2: Proposed Midwest ISO Candidate Multi-Value Project Portfolio #1

MVP portfolio analysis is a methodology designed to provide a high level of benefits relative to project cost under a number of different future possibilities—a fluid, adaptable, and dynamic planning approach—culminating in a regional plan that reliably and efficiently delivers value to load. In the MTEP11 study cycle, this portfolio will be thoroughly evaluated to ensure project value and to confirm system reliability with all the Candidate MVPs included, with a goal of moving any applicable projects to Appendix A as MVPs. In 2012 and subsequent years, MVP portfolio analyses will continue to develop portfolios addressing long-term system value drivers and needs.

1.2.5 Cost Allocation

The construction of the transmission required to enable the states to meet their RPS mandates is dependent upon the allocation of transmission costs to those who benefit from them. To ensure fair allocation of the cost of the transmission investment, in a manner generally commensurate with the benefits realized by stakeholders, Midwest ISO filed a Multi-Value Project (MVP) cost allocation methodology at FERC on July 15, 2010. This cost allocation methodology was developed through a lengthy process of stakeholder review, with input from the Organization of Midwest ISO States (OMS).

The MVP Regional Transmission Cost Allocation Proposal creates a new class of transmission expansion projects and an associated rate design to recover revenue requirements on a Midwest ISO system-wide basis. This new class of regional transmission expansion projects is referred to as MVPs. MVPs are network upgrades that provide regional benefit in response to documented public policy such as renewable energy standards, and/or create value by enhancing the reliable and economic deliverability of generation to load on a regional basis. Multi-Value Projects will also ease the burden of interconnection costs for new generators in the queue due to the development of a regional transmission plan.

1.2.6 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 all 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.

MTEP10 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** 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 High Demand and Energy Growth Rates** is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections.
- **The 20% Federal Renewable Portfolio Standard (RPS)** requires 20% of the energy consumption in the Eastern Interconnect to come from wind by 2025.
- **The Carbon Cap with Nuclear** models a declining cap on future CO_2 emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO_2 emissions from a 2005 baseline by the year 2050.
- **The Federal RPS + Carbon Cap + Smart Grid + Electric Vehicles ("Kitchen Sink" Future)** includes a 20% federal RPS, a carbon cap modeled after the Waxman-Markey bill, a "smart" transmission grid, and electric vehicles.

1.2.6.1 Potential Retail Rate Impacts for Future Policy Scenarios

To measure the potential impact to rate payers under each of the future scenarios, Midwest ISO projected a potential 2025 retail rate by calculating the impact of generation capital investment, generation production costs, transmission capital investment, and distribution costs across the forecasted 2025 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. For example, the 20% Federal RPS future scenario has a lower ongoing generation production cost when compared to the BAU with High Demand and Energy Growth Rate future scenario, but the Federal 20% RPS scenario also requires a larger upfront generation capital investment. Refer to Figure 1.2-3, which provides additional detail on theoretical impacts under various futures.

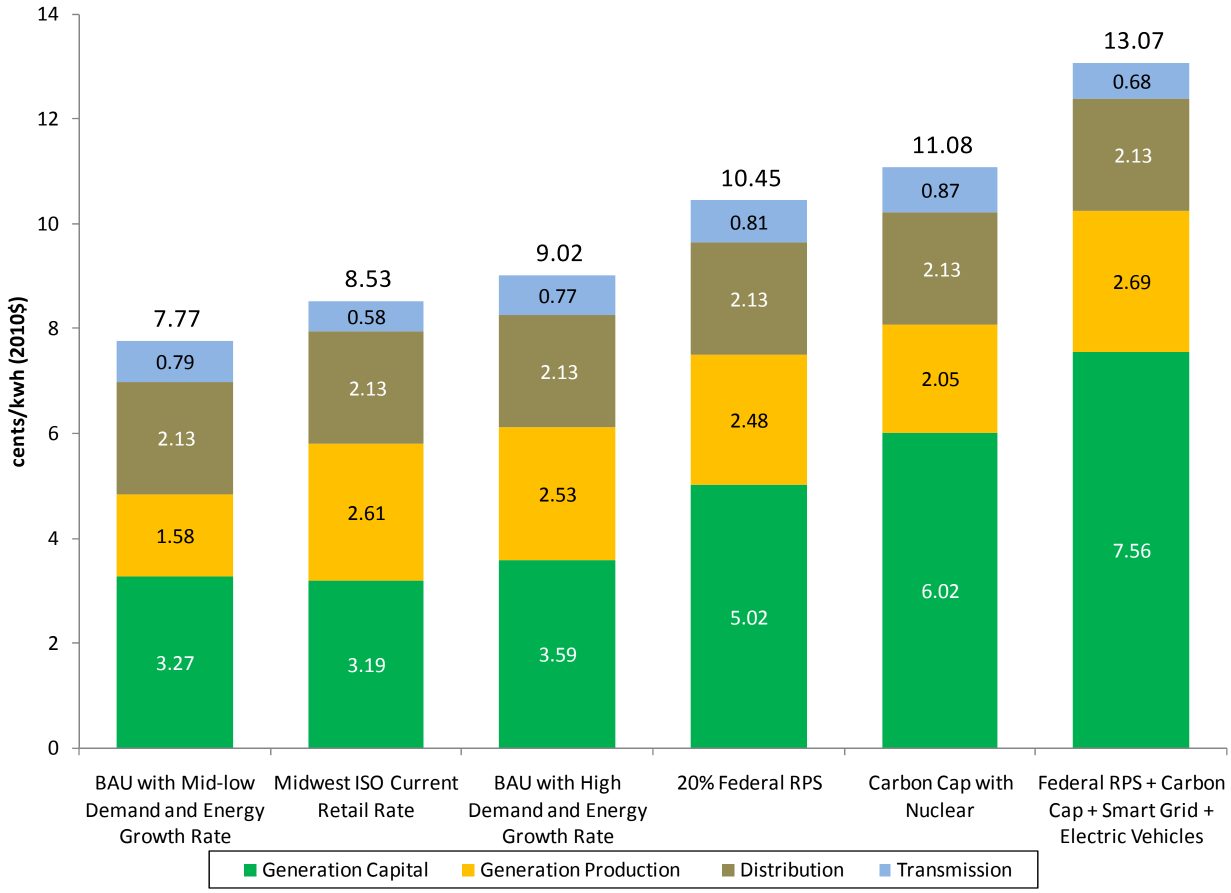

Figure 1.2-3: Comparison of Estimated 2025 Retail Rates for Each Future Scenario (cts per KWh in 2010 Dollars)

Rates for retail customers are projected to increase in all but one (1) 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 9% for the Business as Usual with Mid-low Demand and Energy Growth Rate Future to an increase of 53% for the "Kitchen Sink" Future.

1.2.7 Resource Adequacy & Risk Assessment

In addition to an assessment of the transmission system, MTEP10 includes a forecast of resource adequacy based on projections of future generation and load. The results of a study of the period 2010–2019 indicate that Midwest ISO will have ample generating capacity to meet demand. Based on projections provided by Midwest ISO stakeholders responsible for serving load, forecasted peak demand is 100,578 MW in 2010, an increase from the prior year's analysis. The forecasted peak is expected to grow slowly but consistently over the ten-year period to 111,727 MW in 2019. 141,993 MW of nameplate capacity is expected to be available in 2010 for the Midwest ISO region, increasing to 148,036 MW in 2019[12]. Refer to Figure 1.2-2.

In Figure 1.2-4 below, the 90/10 and 10/90 bands are industry standards for high and low load conditions, respectively. They represent a set of load levels in which there is a 90% chance that the peak load will exceed the 10/90 level and a 90% change that the peak load will be less than the 90/10 value. The 50/50 forecast lines represent the median load forecast for each year.

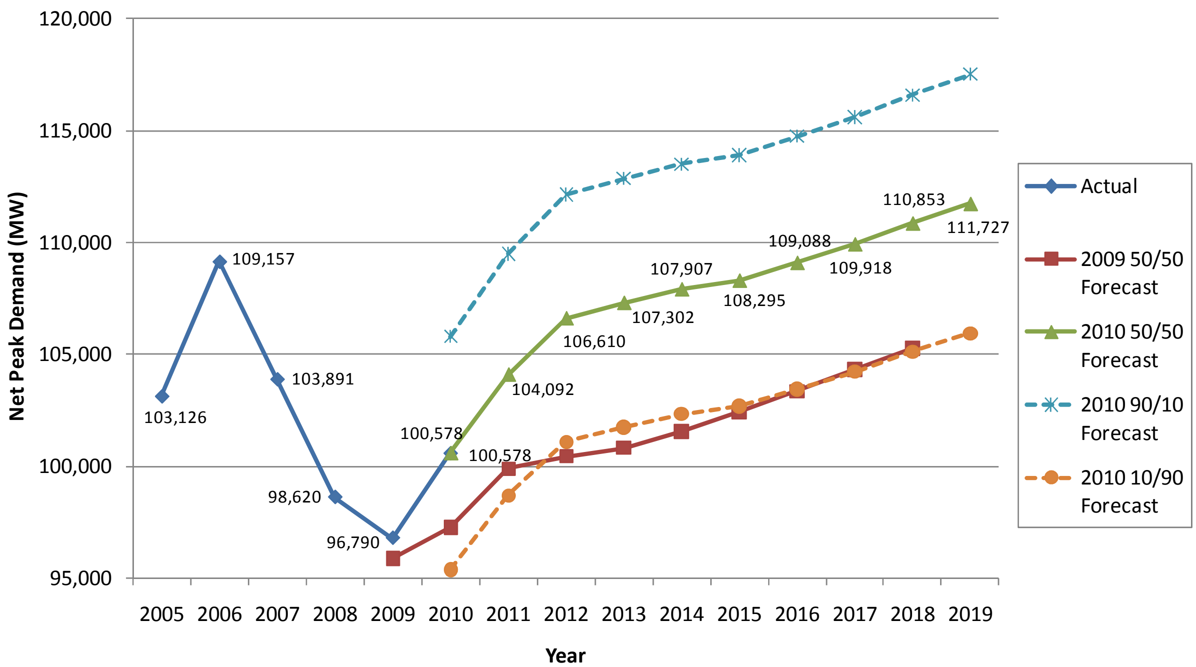

Figure 1.2-4: Historical and Forecasted Peak Demands

Currently, the Midwest ISO reserve margin stands at 25.4%. By 2019, the reserve margin is projected to fall to 16.1%. Due to new member integration and new generation from the Generator Interconnection Queue (GIQ), reserve levels are projected to remain above Midwest ISO-established minimum of 15.4% throughout the next ten (10) years. This reserve margin is calculated with both First Energy and Duke in the Midwest ISO footprint; their removal increases the reserve margin.

Current load forecasts predict sufficient generating capacity during the next ten (10) years. However, various factors representing uncertainties inherent to the industry could contribute to increased risk of a capacity shortfall within the planning period. These factors include a lack of capacity expansion, an increased amount of unit retirements, uncertainty around load forecasts, an aging generation infrastructure, and possible lack of external transmission and generation support. To evaluate the risk of these scenarios, a series of Loss of Load Expectation (LOLE) analyses were performed. In no scenario did the LOLE violate the industry standard of one (1) day in ten (10) years.

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[12] Future statistics reflect Midwest ISO membership as it existed July 2010.

1.2.8 Congestion Management

As part of the MTEP cycle, Midwest ISO conducts an annual assessment of market efficiency by reviewing heavily congested flowgates. Flowgates are chronically congested points in the Midwest ISO and on neighboring systems monitored to ensure the reliable delivery of electricity. Midwest ISO has undertaken several studies in recent years seeking to identify possible economic transmission solutions to both historic and projected congestion. In 2010, Midwest ISO continued the Top Congested Flowgate Study, designed to identify transmission projects where market efficiency impacts exceed project costs, and enlisted neighboring areas and stakeholders to participate in the Cross Border Congested Flowgate Study, a crucial effort given the inherently dynamic nature of the congestion problem. Through these studies and the annual reliability efforts, significant transmission upgrades have been identified which may help to relieve the top congested flowgates on the system.

Refer to Table 1.2-2 below, which summarizes the impacts of previous and current studies on these top congested flowgates. Please note several of these flowgates have no solutions identified. A non-identified solution may occur for several reasons, including—but not limited to—the following:

- It is not necessary to react to acute but short-lived congestion; instead, care must be taken to identify transmission investments required to address chronic congestion.
- Congestion on a particular flowgate may have only taken place part of the time in the relatively short five-year span of the market historically captured so far. It may not yet be possible to identify whether this congestion is chronic or short lived.

It is worthwhile to note that none of the transmission projects evaluated in the 2010 Midwest ISO Top Congested Flowgate Study or the Cross Border Top Congested Flowgate Study were included in Appendix A. Additional transmission alternatives, as well as the appropriateness of the RECB II protocols which would allow the costs of these projects to be shared, will be evaluated by stakeholders in 2011.

Table 1.2-2: Status of Related Activity Regarding 44 Most Congested Flowgates

# of Flowgates	Status Description
15	Solution(s) identified through annual planning cycles
6	Evaluated in Top Congested Flowgate Study(s)
3	Evaluated in Cross Border Congested Flowgate Study
1	Evaluated in both Top Congested Flowgate and Cross Border Congested Flowgate Studies
13	Coordinated flowgate: No solution(s) identified
6	Midwest ISO flowgate: No solution(s) identified

1.2.9 Eastern Interconnection Planning Cooperative (EIPC)

Midwest ISO is taking part in the Eastern Interconnection Planning Collaborative (EIPC), which is seeking to conduct analyses of transmission requirements under a broad range of future scenarios and develop Eastern Interconnection-wide transmission expansion plans. The EIPC is comprised of 26 Planning Authorities across the Eastern Interconnection (EI) and will report directly to the US Department of Energy. To fulfill its purpose, the EIPC will:

- Integrate regional plans.
- Coordinate with the other interconnections.
- Solicit stakeholder input.

- Analyze alternatives against policy objectives.
- Identify gaps for further study.

1.3 Planning to Meet Policy Objectives

The Midwest ISO footprint includes eleven (11) states that currently have either a Renewable Portfolio Standard (RPS) goal or mandate. As of July 1st, 2010, these requirements represent an estimated 25,000 MW of total installed wind generation capacity. State requirements are diverse in the amount, location, and, type of generation required, as well as in the time given to achieve the mandates. Discussions at the federal level encompass a broader set of objectives, including carbon reduction, the development of a smart grid, and energy efficiency initiatives, along with integration of renewable generation. Any federal renewable mandate would likely have a large impact on the Midwest ISO planning efforts, as it is expected that a portion renewable energy requirements in other regions would be fulfilled by generation within the Midwest ISO footprint. Specific efforts include the following:

- **The Michigan Loop Out Of Cycle Review Project:** Initiated in response to the implementation of a near-term Renewable Portfolio Standard (RPS), the Michigan Out of Cycle project investigated the transmission required to integrate wind into the thumb region of Michigan and meet the state's renewable mandate. This project was approved by the Midwest ISO Board of Directors on August 19, 2010 for inclusion in MTEP10 Appendix A.
- **Cost Allocation Regional Planning (CARP):** This initiative, developed by the Organization of Midwest ISO States (OMS), is focused on developing recommendations for a cost allocation methodology that will enable the development of transmission to meet existing and potential future energy and environmental policies. It used the value based planning methodology to develop future scenarios.
- **The Two-Phase Regional Generation Outlet Study (RGOS):** Initiated in response to the growing focus on the use of renewable energy, this study developed three separate transmission portfolios that enable Midwest ISO members to meet the current state Renewable Portfolio Standards. Two of these portfolios and the DC lines from the third have been included in Appendix B of the MTEP10 report[13].
- **Upper Midwest Transmission Development Initiative (UMTDI):** Comprised of the governors and regulators of North and South Dakota, Iowa, Minnesota, and Wisconsin, UMTDI achieved a number of goals in planning and cost allocation. Most importantly, they achieved the following: [14]
  - The identification of six renewable transmission corridors as potential primary paths for the next buildout of transmission in the region in order to support the region's economic, energy, and environmental goals[15]
  - The identification of regional renewable energy zones as the areas within the region most likely to support substantial wind development
  - The development of a set of cost allocation principles that can serve as a foundation for ongoing cost allocation discussions in the region and the country

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[13] For more information, please refer to section 9.1.

[14] Achievements taken from UMTDI Executive Committee Final Report published September 29, 2010.

[15] The UMTDI was also instrumental in the development of the first set of Candidate MVPs that should be constructed to meet the RPS mandates for their respective states.

1.4 Future Implications

The Midwest ISO is proud to have an independent, transparent, and inclusive planning process that is well positioned to study and address future transmission needs in the region. The organization's understanding of the complexities of the national transmission infrastructure, as well as its in-depth knowledge of the unique challenges and issues facing the industry, such as renewable energy integration, cost allocation and emerging energy policies, allow it to successfully energize the heartland. The Midwest ISO welcomes feedback and comments from stakeholders, regulators, and interested parties on the evolving electric transmission power system. For detailed information about the Midwest ISO, MTEP10, renewable energy integration, cost allocation, and other planning efforts, please visit www.midwestiso.org.

2 MTEP10 Overview

2.1 System and Planning Region Information

Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit, member-based organization committed to electricity market leadership by providing its customers with valued service; reliable, cost effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

Midwest ISO has members in thirteen (13) states and one (1) Canadian province. Midwest ISO member systems have 56,600 miles of transmission operated at 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, and 69kV under Midwest ISO functional control. Members also have 18,050 miles of transmission under agency agreements, mostly at 69 kV. Refer to Figure 2.1-1, which depicts the geographic location of the Midwest ISO and the other Independent System Operators (ISO) and Regional Transmission Organizations (RTO) in the United States and Canada.

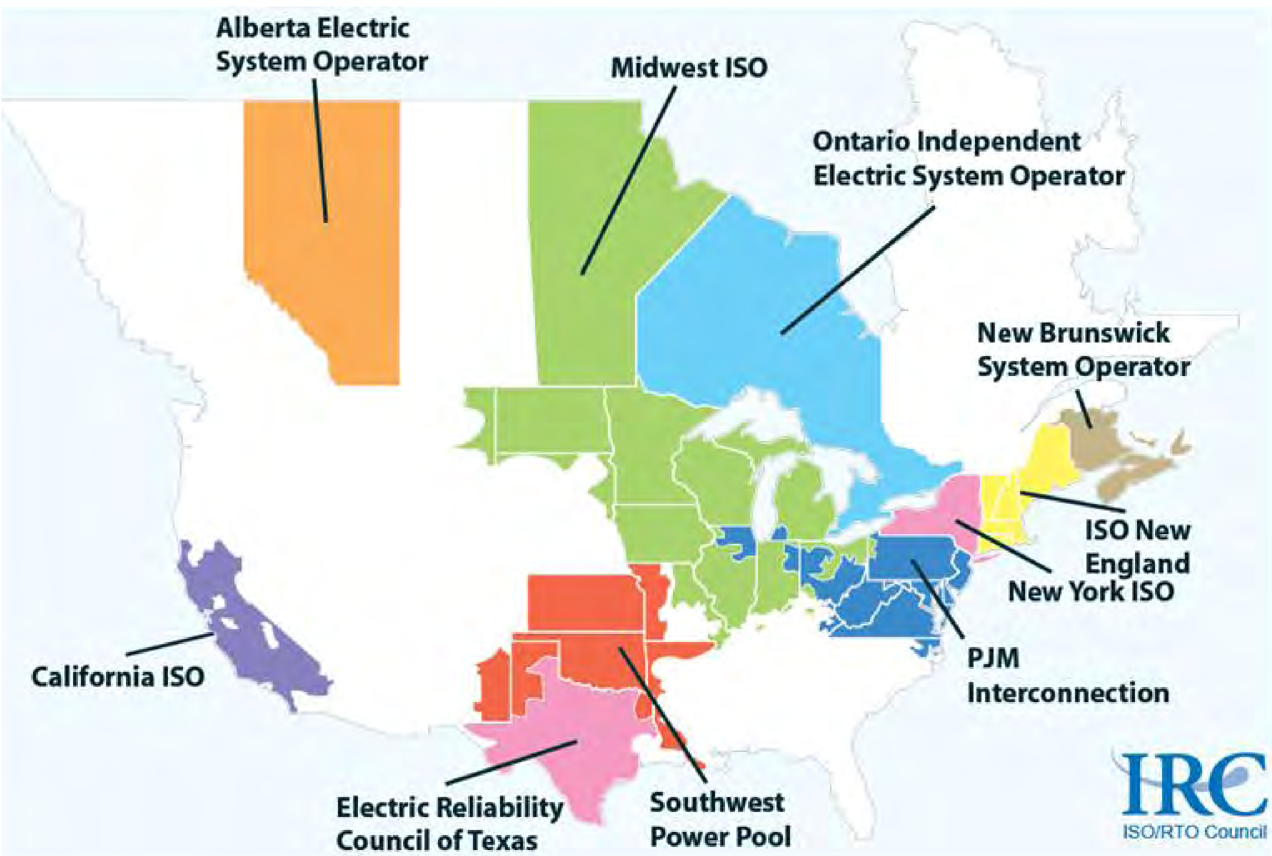

Figure 2.1-1: Midwest ISO Geographical Footprint

2.2 Midwest ISO Members

The following Transmission Owners are Midwest ISO members, categorized by planning region.

2.2.1 West Planning Region

- American Transmission Company
- Central Minnesota Municipal Power Agency
- Dairyland Power Cooperative[16]
- Great River Energy
- ITC Midwest
- Midamerican Energy
- Minnesota Power & Light Company
- Montana-Dakota Utilities
- Muscatine Power and Water
- Northwestern Wisconsin Electric
- Otter Tail Power Company
- Southern MN Municipal Power Association
- Xcel Energy–North

2.2.2 Central Planning Region

- Ameren MO
- Ameren IL
- Big Rivers Electric Corporation[17]
- Duke Energy Midwest (Cinergy)
- Columbia MO Water & Light
- City Water Light & Power (Springfield, IL)
- Hoosier Energy Rural Electric
- Indianapolis Power & Light
- Indiana Municipal Power Agency
- Southern Illinois Power Cooperative
- Vectren (Southern Indiana Gas & Electric)
- Wabash Valley Power Association

[16] Dairyland Power Cooperative is Midwest ISO Transmission Owner, effective June 1, 2010 and, as such, did not participate in the MTEP10 planning cycle.

[17] Big Rivers Electric Corporation was not a Midwest ISO Transmission Owner as of August 1, 2010 and, as such, did not participate in the MTEP10 planning cycle.

2.2.3 East Planning Region

- First Energy (ATSI)
- International Transmission Company
- Michigan Electric Transmission Company
- Michigan Public Power Agency
- Michigan South Central Power Agency
- Northern Indiana Public Service Company
- Wolverine Power Supply Cooperative

Refer to Figure 2.2-1, which depicts the Midwest ISO Planning Regions used in the MTEP study process. The planning region is also indicated for each project in MTEP Appendices A, B, and C.

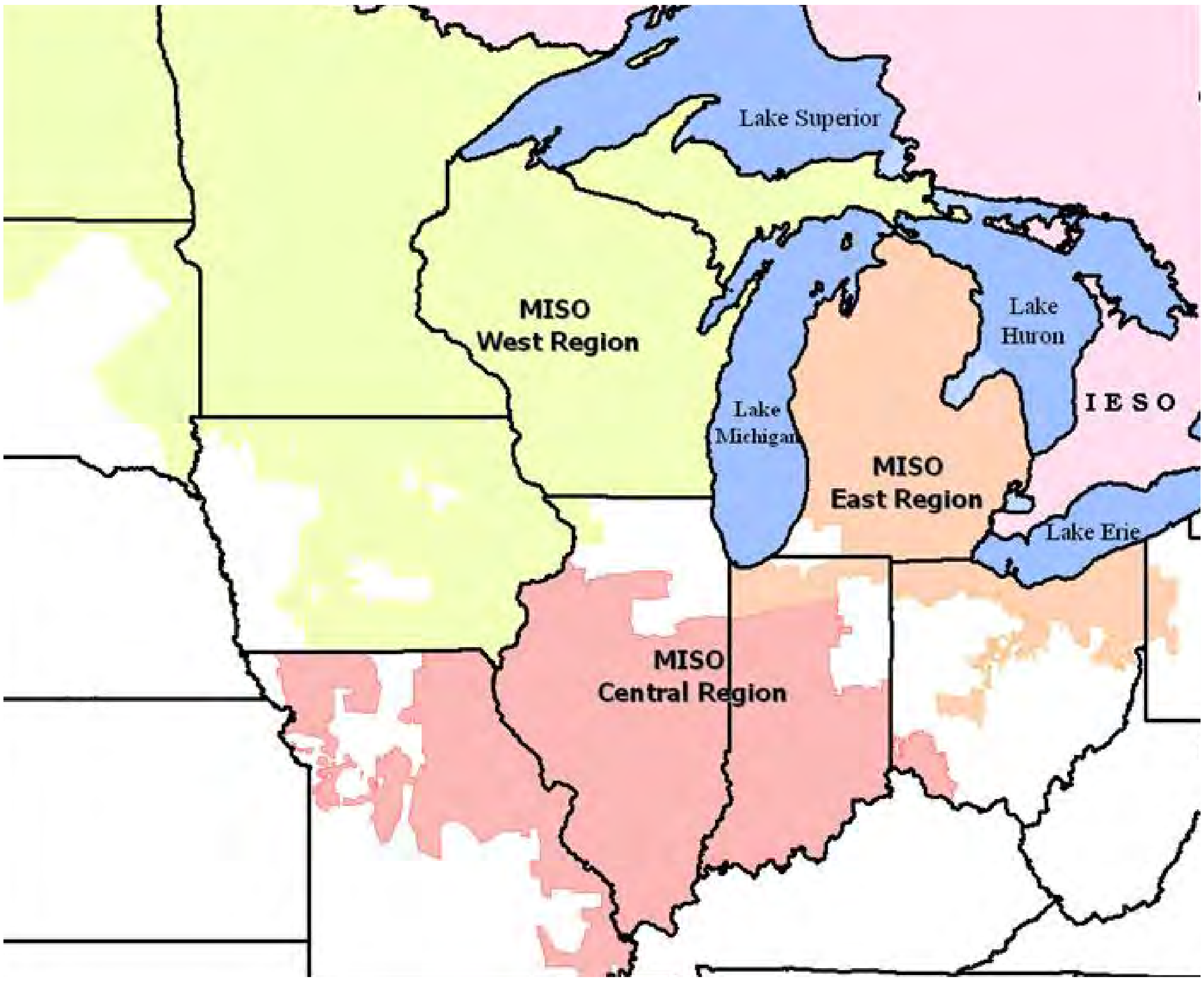

Figure 2.2-1: Midwest ISO Planning Regions

2.3 MTEP Project Types and Appendix Overview

MTEP Appendices A, B and C indicate the status of a given project in the Midwest ISO Transmission Expansion Plan (MTEP) planning process. Projects start in Appendix C when submitted into the MTEP process, transition to Appendix B when Midwest ISO has documented project need and effectiveness, and then move to Appendix A when approved by the Midwest ISO 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 planning cycle.

MTEP10 Appendix A lists projects approved by the Midwest ISO Board of Directors, and also lists projects and associated facilities recommended to the Midwest ISO Board of Directors to be approved in this planning cycle. The new projects are indicated as "A in MTEP10" in the Target Appendix field in the appendix listing. The Appendix 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 (BRPs)** are those transmission projects required to meet North American Electric Reliability Corp. (NERC) standards. A BRP may be cost shared if voltage and project cost meet the designated thresholds.
- **Generator Interconnection Projects (GIPs)** are network upgrades required to ensure the reliability of the system when new generators interconnect. The Interconnection Customer may share the costs of this upgrade under the current tariff if a contract for sale of capacity or energy is in place or if the generator is designated as a Network Resource.
- **Transmission Service Delivery Projects (TSDPs)** are those transmission projects required to satisfy a Transmission Service Request (TSR). The costs of these projects are always directly assigned to the requestor.
- **Market Efficiency Projects (MEPs)**, formerly referred to as Regionally Beneficial Projects (RBP), are those projects meeting Attachment FF requirements for reduction in market congestion. MEPs are shared, based on cost and voltage thresholds.
- **Multi-Value Projects (MVPs)** are a new project type effective July 16, 2010, subject to final approval by the Federal Energy Regulatory Commission. MVPs comprise those projects meeting Attachment FF requirements to provide regional public policy and/or economic benefits and are cost-shared with loads and export transactions in proportion to metered MWh consumption or export schedules.

A project not meeting any of these classifications is designated as 'Other.' The 'Other' category incorporates a wide range of projects, from projects designed to provide local reliability, economic, or similar benefits but not meeting threshold requirements for qualification as Market Efficiency Projects or Multi-Value Projects (MVPs), to those projects required on a lower voltage transmission system outside Midwest ISO functional control.

2.3.1 MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by Midwest ISO staff and approved by the Midwest ISO Board of Directors (BOD) for implementation by Transmission Owners (TO).

Projects in Appendix A have a variety of system-need drivers. Many of the projects are required for maintaining system reliability in accordance with North American Electric Reliability Corporation (NERC) Planning Standards. Other projects may be required for generator interconnection or transmission service. Some projects may be required for Regional Reliability Organization standards due to filed TO local criteria. Yet other projects may be required to provide distribution interconnections for Load Serving Entities (LSEs). Appendix A Projects may also be required for economic reasons, such as to reduce market congestion or losses in a particular area of the footprint or to reduce overall resource adequacy requirements via reduced losses during system peak or reduced planning reserve margins. Finally, projects may be required to enable public policy requirements such as the current state renewable portfolio standards. All projects in Appendix A address one or more Midwest ISO documented Transmission Issues.

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

- Midwest ISO staff has independently validated the project addresses one or more Transmission Issues.
- Midwest ISO staff has considered and reviewed alternatives with the TO.
- Midwest ISO staff has considered and reviewed cost estimates with the TO.
- Midwest ISO staff has endorsed the project.
- Midwest ISO staff has verified that the project is qualified for cost-sharing as a Baseline Reliability Project, Market Efficiency Project, or Multi-Value Project per provisions of Attachment FF.
- Midwest ISO staff has scheduled and held a stakeholder meeting to review any such project or group of projects to be cost shared, or other major projects for zones where 100% of costs are recovered under Tariff.
- Midwest ISO staff has taken the new recommended project to the BOD for approval. Projects are moved to Appendix A following a presentation at any regularly scheduled BOD meeting.

Appendix A is periodically updated. Although projects are generally moved to Appendix A in conjunction with the annual review of the MTEP report, recommended projects need not wait for completion of the next MTEP for BOD approval and inclusion in Appendix A should circumstances dictate the need for approval at a different juncture. Appendix A will be periodically updated and posted as projects go through the process and are approved.

2.3.2 MTEP Appendix B

In general, MTEP Appendix B contains projects still in the Transmission Owners planning process or still in the Midwest ISO review and recommendation process. Appendix B may contain multiple solutions to a common set of Transmission Issues. Projects in Appendix B are not yet recommended or approved by Midwest ISO; therefore, projects in Appendix B are not considered for cost sharing. There may be some potential Baseline Reliability Projects, Market Efficiency Projects (MEPs) or Multi-Value Projects (MVPs)[18] for which Transmission Owners have completed their analyses but for which Midwest ISO staff has not been able to validate the need or reasonableness of the solution against alternatives. Thus, while some projects may become eligible for cost-sharing at an as-yet-undetermined future point in time, the required target date for the project is such that a final recommendation is not yet required, and the project will likely be held in Appendix B until the Midwest ISO review process is complete and the project needs to be moved to Appendix A to ensure implementation by the target date. All projects in Appendix B have been analyzed to ensure they effectively address one or more documented Transmission Issues.

2.3.3 MTEP Appendix C

Appendix C may contain projects still in the early stages of the Transmission Owner (TO) planning process or have just entered the MTEP study process and have *not* been reviewed for need or effectiveness. Like those in Appendix B, these projects are not considered for cost sharing. Appendix C may contain some long-term conceptual projects. There are some long-term conceptual projects in Appendix C which will require significant amounts of planning before being considered ready to go through the MTEP process and moved into Appendix B or Appendix A. Appendix C may contain project alternatives to the best alternative presently in Appendix B. Therefore, a project could revert from B to C if a better alternative is determined yet the TO is not ready to withdraw the previous best alternative. Appendix C projects were not included in the MTEP initial Power Flow models used to perform baseline reliability studies due to a high degree of uncertainty surrounding project decision outcome.

2.4 Investment Summary

This section provides investment summaries of transmission system upgrades identified in MTEP10 and past MTEP studies that are still in the construction planning or execution processes. Therefore, these statistics do not include past MTEP investments which have since gone into service.[19]

- The total estimated investment of the projects in MTEP10 Appendix A and Appendix B for 2010–2015 is $7.88 billion.
- Appendix A contains $4.64 billion in investment through 2015.
- Appendix B contains $3.24 billion of investment through 2015.
- Appendix B also contains $33 billion in investment for 2016–2025, which is primarily comprised of two alternate Regional Generation Outlet Study (RGOS) plans[20].
- Appendix C contains $5.52 billion in investment through 2015 and an additional $32.5 billion in investment for 2016–2020.

Included in Appendix C is the Reference Future Extra High Voltage (EHV) conceptual transmission overlay in 2018. Portions of the MTEP08 EHV plan have been moved to the RGOS planning effort. Additionally, there are also a number of large transmission proposals to address the renewable energy mandates in the region with a $12 billion proposal in 2020. Therefore, there are many alternative and competing plans for renewable energy integration still working their way through the planning process.

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[18] The MVP cost allocation method was filed at FERC on July 15, 2010. The final designation of this cost allocation methodology is subject to FERC order in response to the filing.

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

[20] More details on the RGOS transmission plans may be found in section 9.1.

Not all these proposals will reach Appendix A. For additional information, refer to section 9 for a summary of RGOS findings pertaining to renewable energy transmission development.

The cumulative expected project spending by year and appendix over the 2010-2020 period, is depicted in Figure 2.4-1. Investment totals by year assume that 100% of the project investment occurs when the entire project goes into service. Since a project may require capital investment over multiple years, this assumption causes these numbers to appear ‘lumpier’ than the actual expenditures are expected to be.

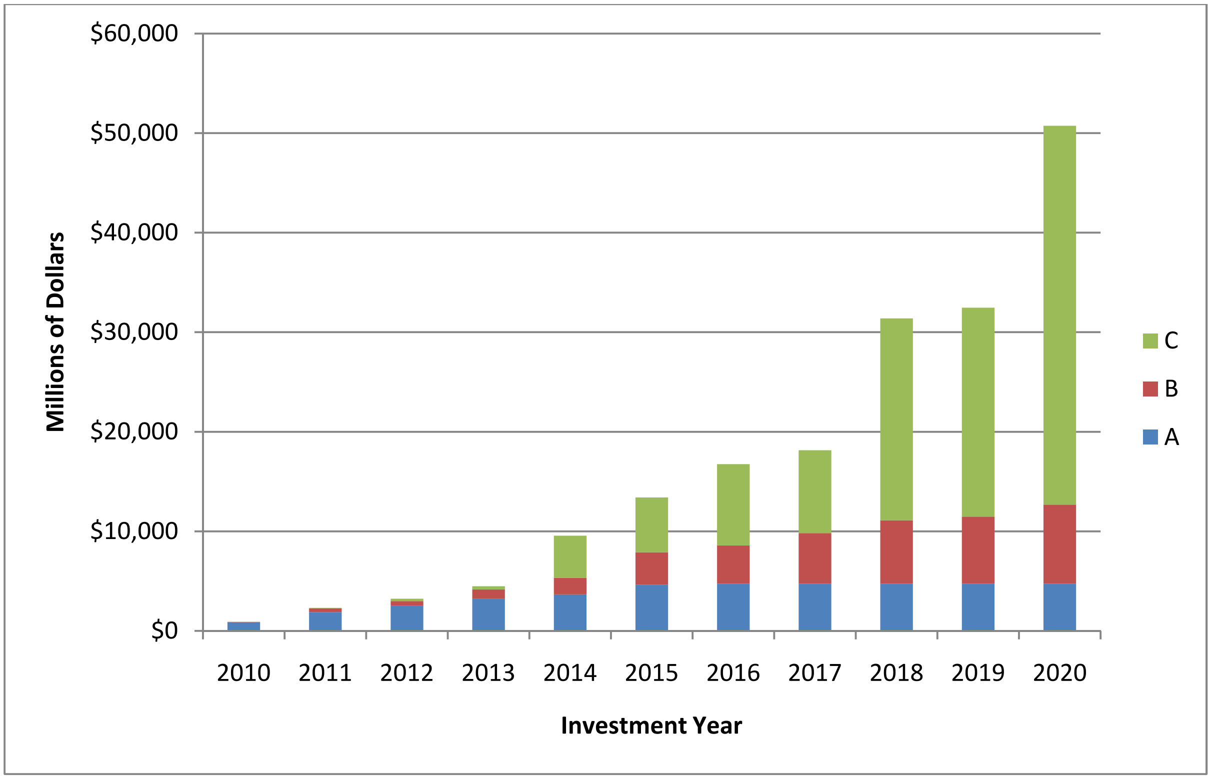

Figure 2.4-1: MTEP10 Cumulative Projected Investment by Year and Appendix

Transmission investment by Planning Region through 2020 is shown in Table 2.4-1.

Table 2.4-1: Projected Transmission Investment by Planning Region through 2020

Region	Appendix A	Appendix B	Appendix C
Central	$757,887,000	$2,127,494,000	$10,564,225,000
East	$1,297,840,000	$322,136,000	$7,002,929,000
West	$2,686,097,000	$5,491,131,000	$20,484,627,000
Total	$4,741,824,000	$7,940,761,000	$38,051,781,000

Table 2.4-2 shows investment in 2010 Appendix A projects by preliminary cost allocation category and eligibility for cost sharing. The categories are: Baseline Reliability Project (BRP), Generator Interconnection Project (GIP), Transmission Service Delivery Project (TDSP), Multi-Value Projects (MVP), Market Efficiency Project (MEP), and Other. The numbers in Table 2.4-2 are a subset of Appendix A values shown in Table 2.4-1. These have a Target Appendix of 'A in MTEP10' and are new to Appendix A in this planning cycle. Approximately $1.2 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 sharing. Not all costs of shared projects are eligible for sharing. For example, some BRP projects costs are not shared and only 50% of GIP costs are shared to pricing zones.

Table 2.4-2: 2010 Appendix A Investment by Allocation Category & Planning Region

Region	Share Status	BRP	GIP	TDSP	MVP[21]	Other
Central	Not Shared	$22,407,900				$133,474,007
	Shared	$12,700,000				
Central Total		**$35,107,900**				**$133,474,007**
East	Not Shared	$8,685,053				$81,572,439
	Shared	$18,063,000			$510,000,000	
East Total		**$26,748,053**			**$510,000,000**	**$81,572,439**
West	Direct Assigned			$3,940,000		
	Not Shared	$20,775,030				$359,840,098
	Shared	$11,699,000	$6,850,498			
West Total		**$32,474,030**	**$6,850,498**	**$3,940,000**		**$359,840,098**
Grand Total		**$94,329,983**	**$6,850,498**	**$3,940,000**	**$510,000,000**	**$574,886,544**

[21] The MVP cost allocation method was filed at FERC on July 15, 2010. The final designation of this cost allocation methodology is subject to FERC order in response to the filing.

Refer to Figure 2.4-2. Further breakdown of new Appendix A project data reveals new transmission build is largely concentrated in a few states, specifically Michigan, Minnesota, Iowa, Wisconsin, Indiana, and Illinois. These geographic trends change over time as existing capacity in other parts of the system are consumed and new build becomes similarly necessary in those areas.

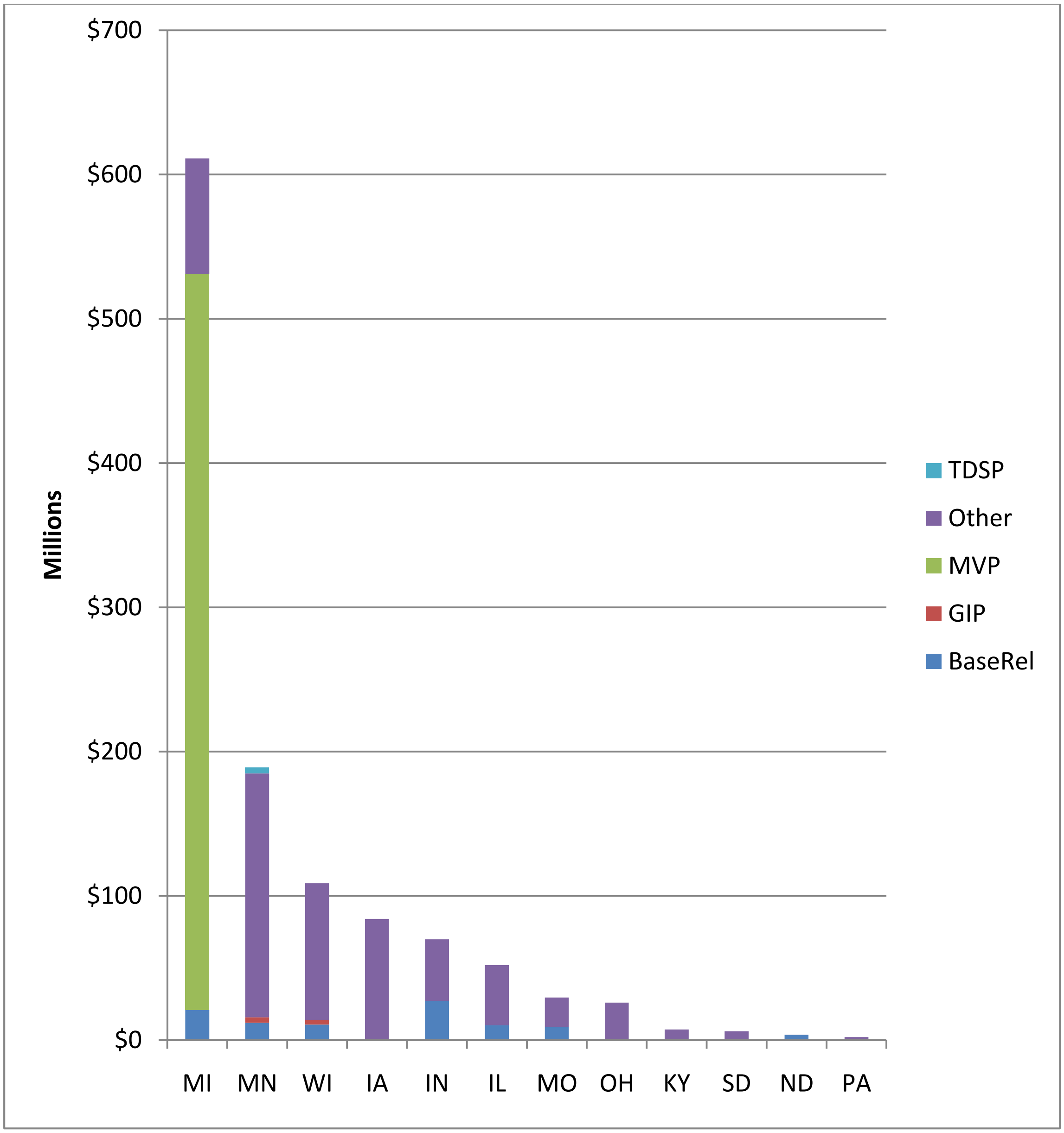

Figure 2.4-2: New Appendix A Investment with Allocation Categorized by State

2.5 Cost Sharing Summary

A total of $559.3 million of costs associated with new MTEP10 Appendix A projects are eligible for sharing.[22] The total project cost number includes the $6.85 million from Generator Interconnection Projects, where half is paid by generation developers. Additional details on new MTEP10 cost allocations are in Appendix A-1 and A-2. Since the Regional Expansion Criteria and Benefits (RECB) cost sharing methodology was implemented in MTEP06, there have been 116 projects eligible for cost-sharing representing $3.2 billion of transmission investment, including 52 Generator Interconnection Projects at approximately $372.8 million, of which 50% is paid by generation developers; 62 Baseline Reliability Projects at $2.3 billion; one (1) Market Efficiency Project at $6 million; and one (1) Multi Value Project (MVP) at $510 million. [23] Note a total of eleven (11) projects at $253 million have been withdrawn of the $3.2 billion in transmission investment approved since MTEP06. Generator Interconnection Projects represent nine (9) of the projects at $53.2 million with the remaining 2 projects at $200 million representing Baseline Reliability Projects.

Refer to Figure 2-5.1, which provides the breakdown by pricing zone of all project costs assigned to the zone after cost allocation per Attachment FF, which includes one (1) Multi-Value Project eligible for cost sharing, pending FERC approval of the MVP cost allocation method. Distribution of project costs is largely driven by non-allocated project costs rather than by costs allocated from others.

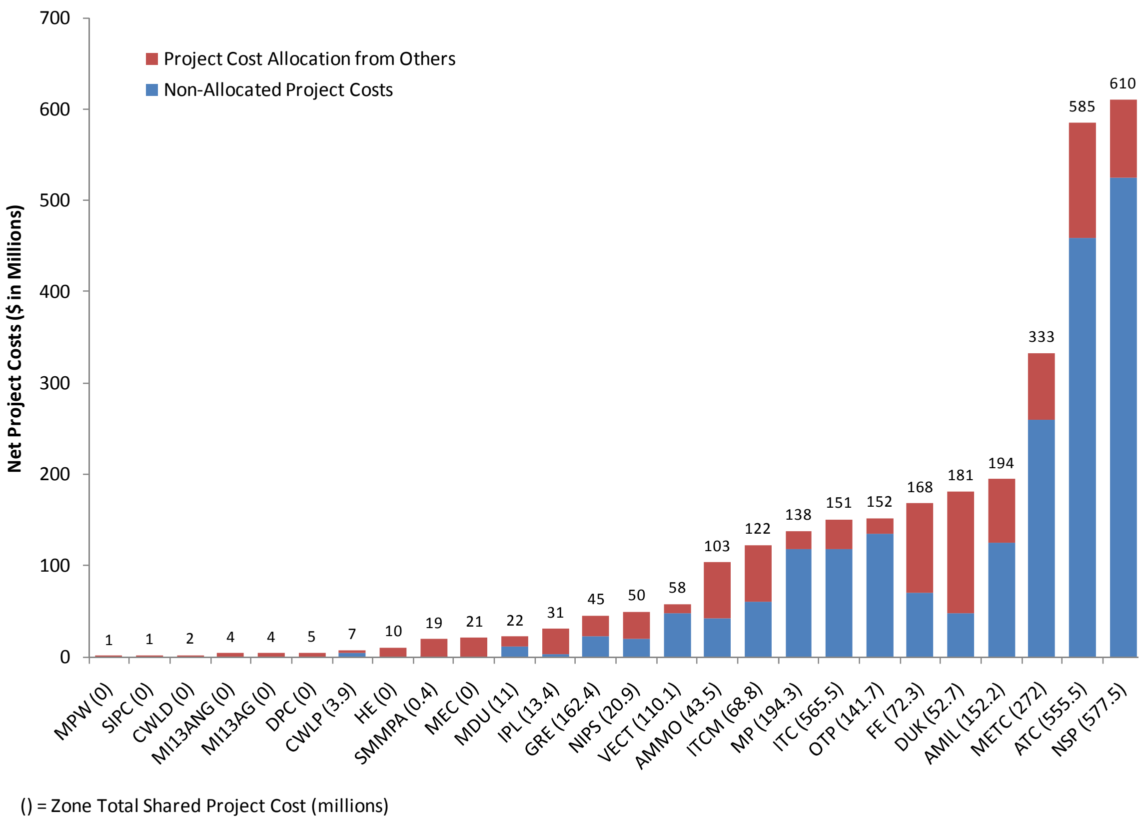

Figure 2-5.1: Net Project Costs by Pricing Zone from MTEP 06 through MTEP10 Appendix A Projects

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[22] Based on preliminary MTEP 10 Appendix A cost shared projects as of September 1, 2010–subject to change as cost allocations are finalized. Note that this includes the $510 million Michigan Thumb Loop Expansion that was approved by the Midwest ISO Board of Directors in its August meeting.

[23] Note cost allocation estimates provided for the Multi-Value Project are *indicative* based on 2009 Midwest ISO net withdrawals, export schedules, and through schedules.

Costs are included for all cost-shared-eligible projects from MTEP06 to MTEP10. Project costs allocated to each zone from prior MTEP report cycles have been updated to reflect the most up-to-date estimates of the project cost and expected in-service date, and excludes those projects that have been withdrawn.

- The blue bar in Figure 2-5.1 denotes non-allocated project costs for that zone, representing $2.1 billion for all pricing zones. This is the total shared project cost for that zone less the portion of the cost allocated to other zones.
- The maroon bar in Figure 2-5.1 represents the portion of zonal costs due to project cost allocation from others outside that zone, which is approximately $951 million for all pricing zones.

Note Figure 2.5-1 excludes the portion assigned directly to generation developers. Refer to Appendix A.3, which offers additional details on MTEP06–MTEP10 cost allocations.

Figure 2-5.2 shows the net cost sharing impact by zone. Net impact is calculated by subtracting costs allocated to a zone by projects outside the zone from the costs of projects within the given zone eligible to be shared outside the zone.

Supporting detail is available in Appendix A.3.2. The distribution of cost impact, which shows many zones being allocated a greater level of costs than they are sharing with other zones, reflects the differing timing of transmission build-out in different zones. A positive net cost sharing impact is accruing in zones where the Transmission Owners are most actively building. However, this disparity would be expected to change over time as build-out in other areas increases. It is also important to note this chart represents only cost impact, not the associated benefits expected to offset allocated costs.

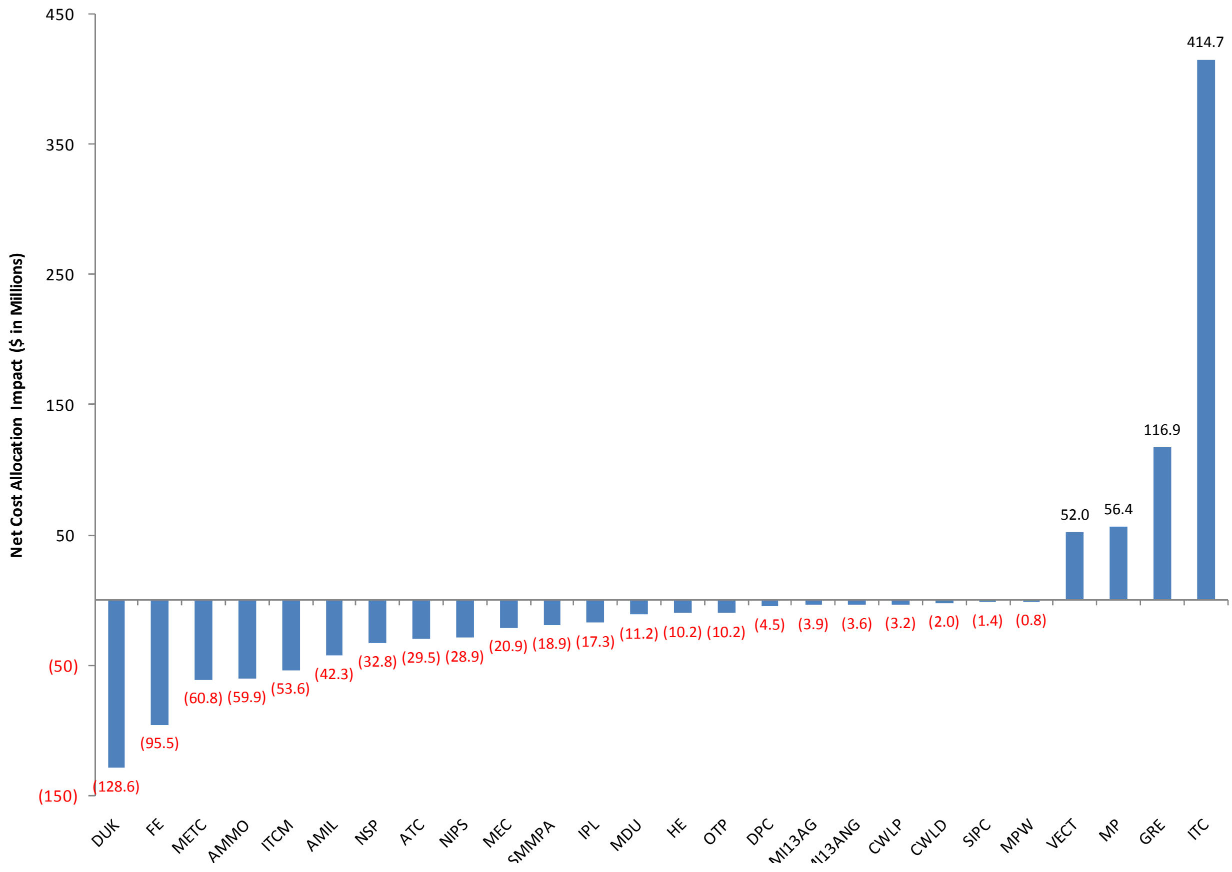

Figure 2-5.2: Net Cost Impact on Pricing Zones of Cost Sharing for MTEP 06 through MTEP10 Projects

Figure 2.5-3 places project costs in greater context by representing them as a percentage of the current net transmission plant in service per Attachment O within the pricing zone. For additional detail, refer to Appendix A.3.2.

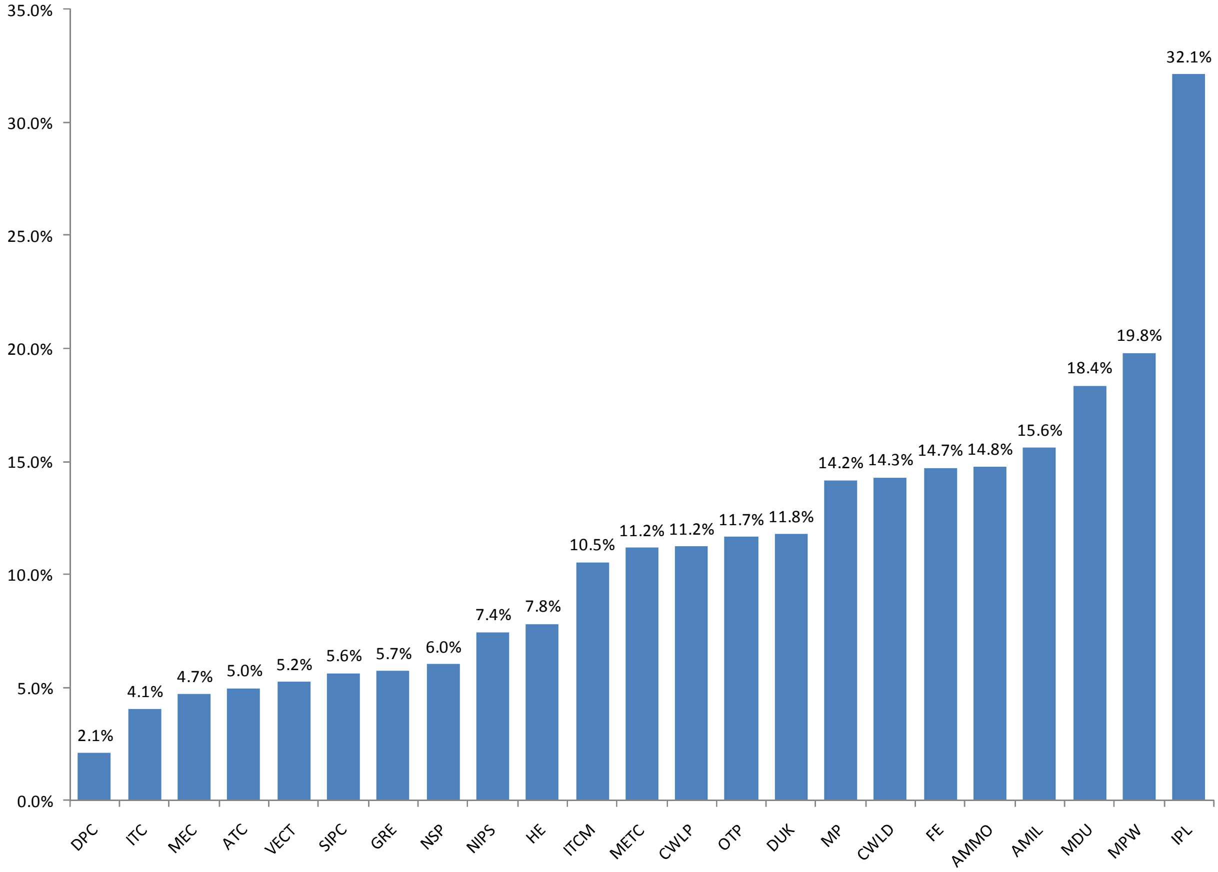

Figure 2-5.3: MTEP06 through MTEP10 Appendix A Project Costs Allocated from Other Pricing Zones as a Percent of Net Transmission Plant in Service (as of June 2010)

2.6 Appendix Overview

2.6.1 Appendix A and B Line Summary

There are approximately 7,870 miles of new or upgraded transmission lines projected in the 2010–2020 timeframe in MTEP10 Appendices A and B.

- About 3,220 miles of transmission line upgrades are projected through 2020 of the approximately 56,600 miles of line under Midwest ISO functional control.
- About 4,650 miles of transmission involving lines on new transmission corridors is projected through 2020.

Miles of lines by voltage class identified in Appendices A and B are depicted in Figure 2.6-1. Line miles for projects in Appendix C are discussed in section 2.6.2.

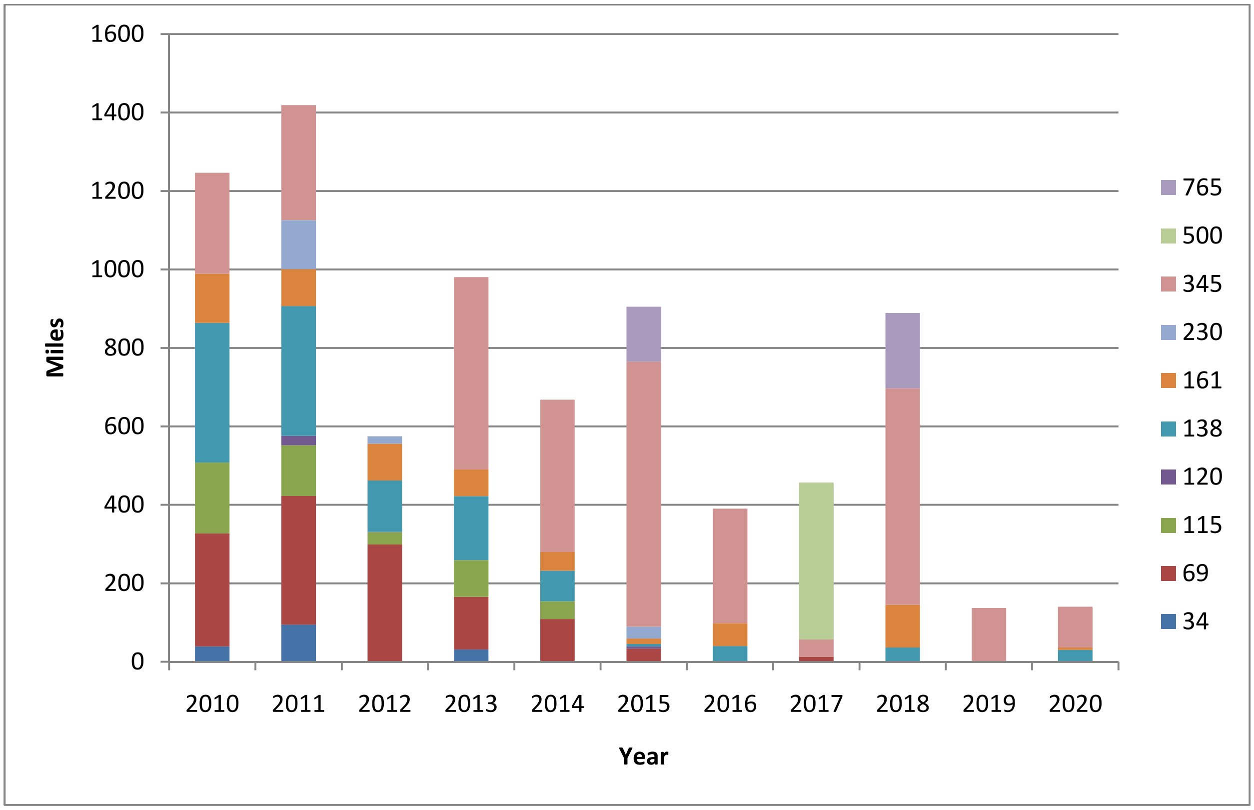

Figure 2.6-1: New or Upgraded Line Miles by Voltage Class in Appendix A & B through 2020

Refer to Figure 2.6-2, which delineates new transmission line mileage by state for Appendices A and B.

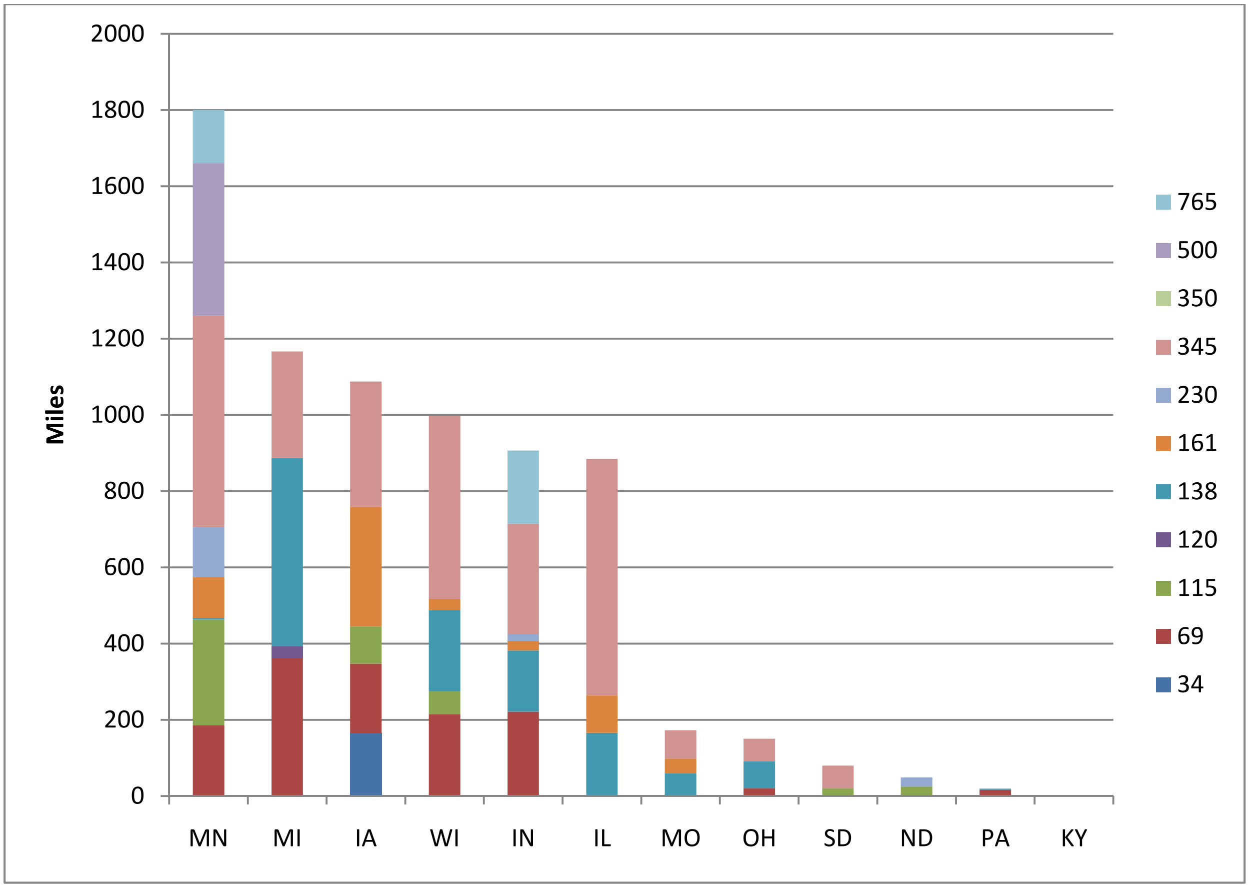

Figure 2.6-2: New or Upgraded Line Miles by State in Appendix A & B

2.6.2 Appendix C Summary

MTEP10 Appendix C lists and describes $38.5 billion of conceptual and proposed transmission investment. The MTEP08 Reference Future 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 (RGOS) effort and are now in Appendix B. Notably, there are multiple proposals to enable integration and delivery of large amounts of renewable energy. One 765 kV proposal is $12 billion in 2020. In addition, there are two Direct Current (DC) line proposals for renewable energy—respectively $1.9 billion and $1.6 billion—in 2014. Also included is a proposal for 765 kV backbone transmission in lower Michigan for $2.5 billion in 2016. However, some of these are competing proposals; therefore, not all of the investment is expected. Approximately 71 projects worth $34.6 billion have been loosely categorized as potential Multi-Value Projects (MVPs). The remaining 435 project proposals, at $3.9 billion, were added in order to address traditional reliability needs in future years. These projects have just entered the planning process or represent needs being revisited due to changes in the system such as load forecast adjustments caused by the economic downturn.

2.7 Economic Assessment of Recommended and Proposed Expansion

Midwest ISO MTEP10 Appendix A/B contains planned/proposed projects primarily designed to address reliability needs. However, these projects may provide economic benefits in addition to expected reliability benefits. Economic benefits include:[24]

- Adjusted Production Cost saving
- Load Cost saving
- Lower CO2 emission costs in some scenarios
- Energy loss benefit
- Capacity loss benefit

2.7.1 Study Methodology and Assumptions

Underlying data for economic benefit assessment comes from two PROMOD® case runs: one case without the Appendix A and B projects and one case with these projects. In order to provide a more accurate analysis, note only those projects are excluded that—by nature—will not drive economic benefits. Examples of those not included are capacitor banks, circuit breaker upgrades, rebuilds of existing lines or substations, and control room upgrades. These types of projects will not result in significant impedance and rating changes to existing lines and will not impact system topology; thus, these types of projects have no impact on the creation of economic benefits. The results from these two cases are compared in order to calculate the economic benefit.

2.7.1.1 PROMOD® Cases

The MTEP10 2015 summer peak Power Flow case, reviewed by Midwest ISO stakeholders and incorporating the latest PJM system update, was used as the starting point for this study. Two (2) 2015 PROMOD® cases were developed for this study:

- 2015 PROMOD® case with Appendix A/B transmission projects
- 2015 PROMOD® case without Appendix A/B transmission projects

Both cases utilize the same MTEP10 PAC Business as Usual with Medium-Low Demand and Energy Growth Rate Future, the scenario containing all generator, load, fuel, and environmental information. The detailed information associated with the Reference Future can be found in Appendix E2. Power Flow cases comprise the difference between the two; i.e., different transmission topologies were used.

2.7.1.2 Power Flow Case

To develop these two PROMOD® cases, two (2) Power Flow cases are required:

- One (1) Power Flow case with Appendix A/B projects
- One (1) Power Flow case without Appendix A/B projects

For both Power Flow cases, the transmission system outside Midwest ISO is identical, originating from the Eastern Interconnection Regional Reliability Organization (ERAG) 2015 summer peak Power Flow case. The Midwest ISO portion, in the Power Flow case with Appendix A/B projects, is from MTEP10 2015 summer peak Power Flow case, which includes all Appendix A/B projects. The Midwest ISO portion in the Power Flow case without Appendix A/B projects is from the ERAG 2010 summer peak Power Flow case, which represents the current transmission topology in Midwest ISO.

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[24] Midwest ISO benefits only, with the assumption First Energy Ohio, Duke Ohio, and Duke Kentucky are still included in Midwest ISO.

Refer to Table 2.7-1, which summarizes the differences of these two Power Flow cases.

Table 2.7-1: Power Flow Cases Difference

Transmission Source	Power Flow Case with Appendix A/B	Power Flow Case without Appendix A/B
MIDWEST ISO Transmission	MTEP10 2015 Summer Peak (ERAG 2010 Summer Peak + Appendix A/B)	ERAG 2010 Summer Peak
Non-MIDWEST ISO Transmission	ERAG 2015 Summer Peak	ERAG 2015 Summer Peak
Generation/Load/Interchange	The Power Flow model values used for these variables were not used in PROMOD.	The Power Flow model values used for these variables were not used in PROMOD.

2.7.1.3 New Generators

New generators, identified in the MTEP10 PAC Business as Usual with Medium-Low Demand and Energy Growth Rate Future, are included in this study. More details on these generators can be found in section 7.

2.7.1.4 Event File

An event file includes the list of flowgates treated as transmission constraints in security constrained unit commitment and economic dispatch. The quality of the event file has a large impact on the quality of study results. Not all N 1 or N 2 contingencies can be included in the event file since PROMOD® establishes a limit on total number of events. The event file for this 2015 PROMOD® case includes flowgates derived from:

- The Midwest ISO master flowgates file
- *The NERC Book of Flowgates*
- Critical monitored line/contingencies provided by the Expansion Planning group, which identified these contingencies while conducting a reliability study of Appendix A/B projects
- Appendix A/B projects, which involve 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.

2.7.2 Benefits Calculation

2.7.2.1 Economic Benefits

From each PROMOD® case, the following economic indices are calculated:

- **Adjusted Production Cost (APC):** Production Cost +/- (Net Purchase)/(Net Sale) *(Load Weighted Locational Marginal Price (LMP))/(Generation Weighted LMP) Note the formula is dependent on whether there is a net purchase or net sale; for net purchase use the items before "/", for net sale use the items after "/".
- **Load Cost:** Load * Load Weighted LMP

Comparison of the economic indices from two PROMOD® cases (with Appendix A/B case, and without Appendix A/B case) yields the following economic benefits:

- **Adjusted Production Cost Savings:** The annual Adjusted Production Cost savings for the case with the Appendix A/B projects relative to the case without Appendix A/B projects
- **Load Cost Savings:** The annual Load Cost savings for the case with the Appendix A/B projects relative to the case with Appendix A/B projects

These values are used to calculate the following benefit:

- **Market Congestion Benefit:** 70% * Adjusted Production Cost Savings + 30% * Load Cost Savings

The Market Congestion Benefit formula is identical to the formula used to calculate benefits for Regionally Beneficial Projects (RBP), also known as RECB II projects. While the projects evaluated in Appendix A and B do not necessarily meet RECB II eligibility criteria independently, market congestion is consistent with a methodology already outlined in the RECB II tariff, familiar to Midwest ISO stakeholders, and provides a basis of common understanding for a discussion about portfolio benefits other than reliability.

2.7.2.2 Loss Benefit Definitions

The following are commonly used loss benefit definitions:

- **Energy Loss Benefit (MWH):** This is the annual total energy savings (MWH) for the 'with Appendix A/B' case relative to the 'without Appendix A/B' case.
- **Capacity Loss Benefit (MW):** Capacity loss benefit for MISO is the loss decrease (MW) for the 'with Appendix A/B' case relative to the 'without Appendix A/B' case for Midwest ISO's peak load hour.
- **Dollar Value of Energy Loss Benefit:** Quantification of the dollar value of the energy loss benefit, for each hour, requires calculating the hourly company loss costs. This is calculated by multiplying a company's hourly losses by its load- weighted LMP for the same hour. The aggregate of these values for all Midwest ISO companies and for all hours of the year gives the dollar loss cost. The difference in lost costs between, for example, the 'with Appendix A/B' case and the 'without Appendix A/B' case results in the Energy Loss Benefit.
- **Dollar Value of Capacity Loss Benefit:** Dollar value of the capacity loss benefit represents the value of deferring additional generation construction. It is calculated using $650/kW-$1200/kW cost range for the construction of different types of generators in 2008 dollars, and assuming a 2% inflation rate. Thus, the corresponding dollar value of capacity loss benefits is the Capacity Loss Benefit times these costs.
- **Maximum Hourly Loss Decrease (MW):** This is the maximum hourly loss decrease (MW) for the 'with Appendix A/B' case relative to the 'without Appendix A/B' case.

2.7.2.3 Other Impacts

To determine other impacts such as generation, capacity factor, and CO_2 emission change requires a comparison of the changes in generation and capacity factors of different unit types and changes in CO_2 emissions between the 'with' and 'without' Appendix A/B projects case PROMOD runs.

2.7.3 Study Results

2.7.3.1 Economic Benefits

Table 2.7-2 shows Adjusted Production Cost savings, Load Cost savings and Market Congestion benefit for the MTEP10 Appendix A/B projects.

Table 2.7-2: Economic Benefits in 2015

Region	Load Cost Savings ($M)	Adjusted Production Cost Savings ($M)	Market Congestion Benefits ($M)
Midwest ISO East	127-	211-	186-
Midwest ISO Central	108-	253-	209-
Midwest ISO West	760-	288-	430-
Midwest ISO	995-	752-	825-

MTEP10 Appendix A/B projects can save Midwest ISO $752 million in Adjusted Production Costs and $995 million in Load Costs. Market Congestion benefits are $825 million.

As previously noted, the full portfolio of MTEP10 Appendix A and B projects is not modeled because some projects do not impact the economic metrics. Thus, total cost of the MTEP10 Appendix A/B projects influencing the economic metrics in the MTEP09 2015 Power Flow case is $4 billion. Refer to Table 2.7-3, which shows the Benefit to Cost (B/C) Ratio of the Appendix A/B projects, based on the Economic Benefits shown in Table 2.7-2 and $4 billion in project cost, under different fixed charge rates. The fixed charge rate varies by pricing zone, but—on average—comprises approximately 20% for the Midwest ISO footprint.

Table 2.7-3: B/C ratio of MTEP10 Appendix A/B projects in 2015

Fixed Charge Rate	Total Project Cost–$4 billion		B/C Ratio
	Annual Project Cost ($M)	Market Congestion Benefits ($M)	
14%	560	825	1.47
16%	640	825	1.29
18%	720	825	1.15
20%	800	825	1.03
22%	880	825	0.94
24%	960	825	0.86
26%	1,040	825	0.79
28%	1,120	825	0.74

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

- Higher load growth: load is 5% higher than the load in the base case.
- Lower load growth: load is 5% lower than the load in the base case.
- Higher gas price: gas prices are 40% higher than those in the base case.
- Lower gas price: gas prices are 40% lower than those in the base case.

Table 2.7-4 shows the Adjusted Production Cost savings, Load Cost savings and Market Congestion benefits of the MTEP10 Appendix A/B project relative to not having the projects for Midwest ISO for the various sensitivities.

Table 2.7-4: 2015 Economic Benefits of Sensitivity Runs

Savings/Benefits Type	Base Case ($M)	5% Higher Load ($M)	5% Lower Load ($M)	40% Higher Gas Price ($M)	40% Lower Gas Price ($M)
Adjusted Production Cost Savings (million $)	752	965	619	1078	591
Load Cost Savings (million $)	995	1732	547	1342	845
Market Congestion Benefits (million $)	825	1195	597	1158	667

Table 2.7-5 shows the B/C ratio of the Appendix A/B projects under different fixed charge rates under different sensitivities. Market Congestion benefits are used to determine the ratios in this table.

Table 2.7-5: B/C ratio of MTEP10 Appendix A/B projects in 2015

Fixed Charge Rate	Annual Project Cost ($M)	Base Case	5% Higher Load	5% Lower Load	40% Higher Gas Price	40% Lower Gas Price
14%	560	1.47	2.13	1.07	2.07	1.19
16%	640	1.29	1.87	0.93	1.81	1.04
18%	720	1.15	1.66	0.83	1.61	0.93
20%	800	1.03	1.49	0.75	1.45	0.83
22%	880	0.94	1.36	0.68	1.32	0.76
24%	960	0.86	1.24	0.62	1.21	0.69
26%	1,040	0.79	1.15	0.57	1.11	0.64
28%	1,120	0.74	1.07	0.53	1.03	0.60

2.7.3.2 Loss Benefits

Loss benefits attributed to the Appendix A/B projects relative to not having these projects are summarized in Table 2.7-6. The Appendix A/B projects enable Midwest ISO generation to sell more energy to non-Midwest ISO entities since the total generation has increased more than 7,000 GWH in the Midwest ISO footprint. As a result of this generation increase, the annual (2015) energy loss increases by 638,470 MWH. Using each company's hourly load-weighted LMP to price this energy loss, the dollar value of the energy losses increases to approximately $2.6 million in 2015. The energy loss increase is offset by increased revenue from exported generation. The capacity loss benefit is based on a loss decrease for the Midwest ISO peak hour, which permits delaying the installation of additional generation capacity. It is equal to approximately 57.3 MW in this case. If $650/kW–$1200/kW (the range of construction cost of different type units, in 2008 dollars) is used to price the capacity, the savings range is $43–$79 million (in 2015 dollars, assuming 2% inflation rate)[25].

Table 2.7-6: MIDWEST ISO Loss Benefits with Appendix A/B Project in 2015

Energy Loss Benefit	Value of Energy Loss Benefit	Capacity of Loss (Peak) Benefit	Value of Capacity Loss Benefit	Maximum Hourly Loss Decrease
-638,470 MWH	-$2.6 million	57.3 MW	$43 -$79 million	301 MW

2.7.3.3 Other Benefits

Refer to Table 2.7-7, which shows annual generation and capacity factor changes for different types of Midwest ISO units. After adding Appendix A/B projects, some types of units have slight capacity factor increases while others have slight capacity factor decreases; but the capacity factors changes overall are very small (from -0.99% to 0.88%). Total Midwest ISO generation (excluding wind) increases by about 4,568 GWH. Adding the Appendix A/B projects results in less wind energy being curtailed (2,389GWH), and increases sales to non-Midwest ISO loads. Table 2.7-7 also indicates coal units generate more in the case including Appendix A/B projects. This causes annual CO_2 emission to increase by approximately 3 million tons as shown in Table 2.7-8. With Appendix A/B projects added, congestion is relieved and low-cost generation such as coal increases while higher cost, combined cycle generation decreases.

Table 2.7-7: 2015 Generation and Capacity Factor Change for Different Type Units

Unit Type	Status	Generation (MWh)	Capacity Factor
Combined Cycle	No Appendix Projects	24,382,356	19.34%
	With Appendix Projects	23,127,179	18.35%
	Change	-1,255,177	-0.99%
CT Gas	No Appendix Projects	6,231,861	3.04%
	With Appendix Projects	6,324,293	3.09%
	Change	92,432	0.05%
CT Oil	No Appendix Projects	71,195	0.17%
	With Appendix Projects	352	0.00%
	Change	-70,843	-0.17%

25 Capacity deferred does not account for reserve margin requirement; assuming a 15% reserve margin, this would increase the deferred generation to 65.9 MW, with a cost savings of $50 - $91 million.

Table 2.7-7: 2015 Generation and Capacity Factor Change for Different Type Units

Unit Type	Status	Generation (MWh)	Capacity Factor
Hydro (existing)	No Appendix Projects	4,738,966	33.81%
	With Appendix Projects	4,738,966	33.81%
	Change	0	0.00%
IGCC	No Appendix Projects	51,886	0.94%
	With Appendix Projects	80,770	1.46%
	Change	28,884	0.52%
Internal Combu	No Appendix Projects	38,886	1.15%
	With Appendix Projects	21,370	0.63%
	Change	-17,516	-0.52%
Nuclear	No Appendix Projects	84,503,051	86.52%
	With Appendix Projects	84,587,616	86.60%
	Change	84,565	0.08%
ST Coal	No Appendix Projects	45,995,963	68.84%
	With Appendix Projects	46,585,925	69.72%
	Change	5,899,627	0.88%
ST Gas	No Appendix Projects	212,242	1.14%
	With Appendix Projects	52,784	0.28%
	Change	-159,458	-0.86%
ST Oil	No Appendix Projects	16,001	0.12%
	With Appendix Projects	4,102	0.03%
	Change	-11,899	-0.09%
ST Other	No Appendix Projects	2,533,407	53.65%
	With Appendix Projects	2,510,510	53.16%
	Change	-22,897	-0.49%

Table 2.7-8: 2015 Annual CO_2 Emission Change for Different Type Units

Status	CO_2 Emission (Ton)
No Appendix Projects	440,432,174
With Appendix Projects	443,713,614
Emission Increase	3,281,440

2.7.4 Conclusions

PROMOD® simulations and economic analysis demonstrate MTEP10 Appendix A/B projects will provide reliability benefits and substantial economic benefits to Midwest ISO.

- In the 2015 study year, Midwest ISO will save approximately $995 million in Load Costs and $752 million in Adjusted Production Costs.
- The corresponding total project cost will be about $4 billion.
- Using a 20% fixed charge rate, the Benefit/Cost ratio of these projects is about 1.03%.
- Sensitivity runs show these projects can realize even greater economic benefits with the inclusion of higher load growth or higher natural gas prices.

Appendix A/B projects relieve constraints and congestion in the Midwest ISO system. Increased transmission capacity will allow more sales from Midwest ISO to the outside world, which will in turn lead to a forecasted increase in coal unit generation and therefore an increase in CO_2. Increased transmission capacity also leads to less wind curtailment in Midwest ISO. Increased coal and wind generations cause more energy to flow across the Midwest ISO system, thus slightly increasing energy losses on the Midwest ISO transmission system. But for the 2015 peak hour Midwest ISO losses decrease by about 57.3MW, which means the Midwest ISO footprint can defer installation of 57.3[26] MW of new generation at a cost of $43–$79 million, depending on type of generation built.

[26] Capacity deferred does not account for reserve margin requirement; assuming a 15% reserve margin, this would increase the deferred generation to 65.9 MW, with a cost savings of $50 - $91 million.

3 MTEP Plan Status

This section provides an update on the implementation of projects featured in the Midwest ISO Transmission Expansion Plan (MTEP) and approved by the Midwest ISO Board of Directors. Any given MTEP Appendix A contains newly approved projects, along with previously approved projects not in service when the MTEP appendices were set. Section 3.2 on the following page furnishes a historical perspective of all past MTEP-approved plans.

3.1 MTEP09 Status Report

Midwest ISO transmission planning responsibilities include monitoring progress and implementation of necessary system expansions identified in the MTEP. The Midwest ISO Board of Directors approved the last MTEP (MTEP09) in December 2009. This section provides a review of the status of the approved project facilities contained in the MTEP and listed in MTEP 09 Appendix A. The Midwest ISO Board of Directors has been receiving quarterly updates on the status of active MTEP plans since December 2006. The information in this report reflects the 2nd Quarter of 2010 status report to the Board of Directors, which included status on MTEP09 projects through June 30, 2010.

Tracking the progress of projects ensures a good faith effort to actively move necessary projects forward to completion, as prescribed in the Transmission Owner's agreement. Most projects planned and approved for construction move forward in a timely manner towards the desired in-service date—despite the variety of reasons why a project may be delayed, including such issues as equipment procurement delays, construction difficulties, and regulatory processes taking longer than anticipated by the Transmission Owner (TO) at the time of the original service date estimate. A project is only considered 'off-track' if Midwest ISO cannot ascertain a reasonable cause for expected project delays such as the considerations described above. These approved MTEP projects have completed the planning process and are the recommended solution to identified transmission system issues. These projects may be driven by reliability issues, transmission service requests, generator interconnection requests, or by market flow constraints. A transmission system upgrade project may be comprised of multiple facilities. Multiple facilities comprise over half of MTEP Appendix A projects.

3.1.1 MTEP09 Planned Facilities Status

MTEP09 Appendix A has 565 projects comprised of 1004 facilities. MTEP09 Appendix A includes expansion facilities through 2019 plan year. As a whole, $4.330 billion of the $4.365 billion in MTEP09 Appendix A or 99.2% of the approved facilities included in MTEP09 are in service, on track, or have encountered reasonable delays. There were 109 in-service date adjustments to projects. Little or no impact on reliability is expected because schedule adjustments were primarily driven by economic slowdown. Therefore, it is reasonable and prudent for Transmission Owners to adjust project schedules to match project drivers. It is also prudent to examine withdrawn projects to ensure the planning process of Midwest ISO and its members not only addresses needed system additions, but ensures either good cause or that a different project covers the need of the withdrawn project when a project is withdrawn. MTEP09 Appendix A contains projects approved in MTEP09 and past MTEPs but not yet in service, so withdrawn facilities may have been approved in prior MTEPs but withdrawn after MTEP09 was approved. There were 68 facilities (7% of 1004) 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.
- There was no longer a need.

All withdrawn facilities were withdrawn for valid reasons. The majority of withdrawn facilities were cancelled due to service requests being withdrawn or changes in need due to reduction in load forecast. Transmission Owners are clearly making a good faith effort to construct approved projects.

3.2 MTEP Plan Implementation History

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

Refer to Figure 3.2-1, which depicts cumulative transmission investment dollars for projects, categorized by plan status, for all past MTEPs from MTEP03 through the current MTEP10 cycle. MTEP10 data depicted in Figure 3.2-1, subject to Board approval, is from the current MTEP study and will be added to the data set tracked by the Midwest ISO Board of Directors. The steady increase in planned facilities testifies to the coordinated planning efforts of Midwest ISO and its Transmission Owning members. Note these statistics do not include a number of new Midwest ISO members who did not participate in this planning cycle.

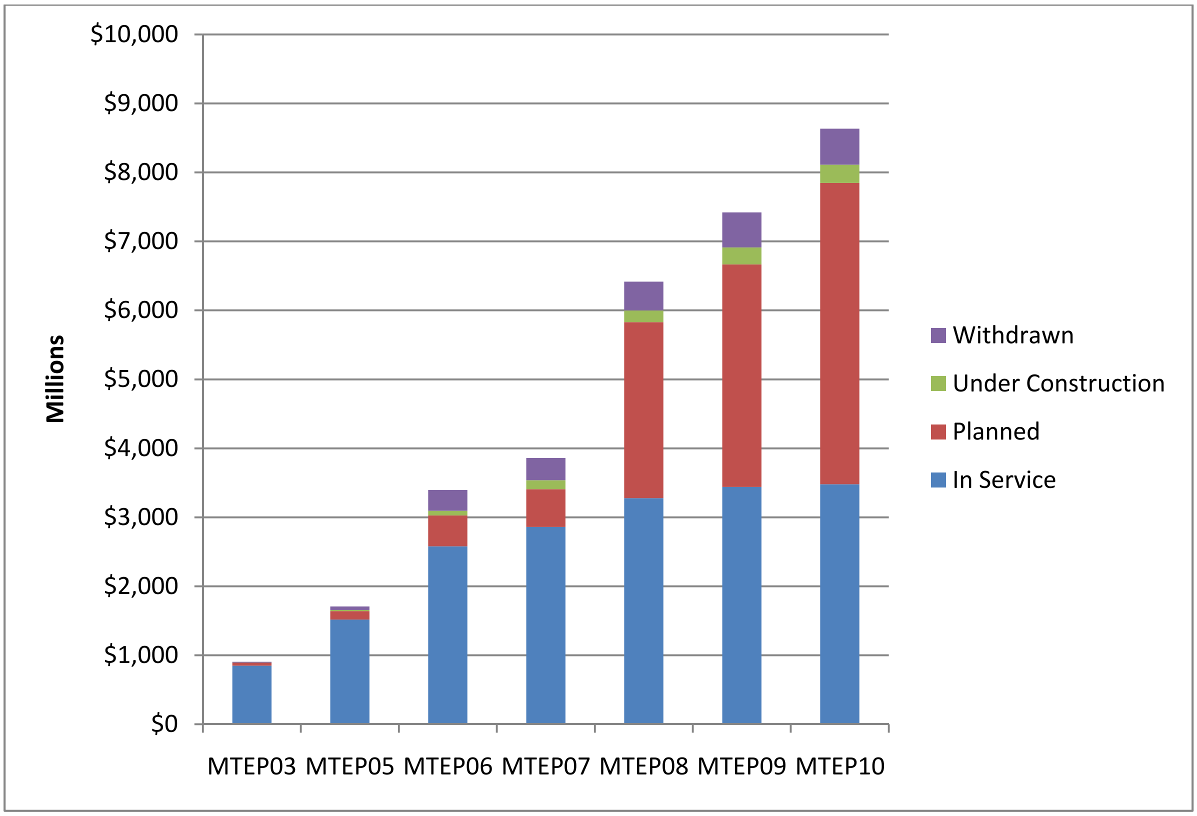


Figure 3.2-1: Cumulative Approved Investment by Facility Status

Figure 3.2-2 depicts MTEP project investment by Facility Status for each MTEP iteration. The historical perspective shows extensive variability in transmission plan development. This variability is normal, due to the long development time of transmission plans and the life cycle of a transmission plant. The irregular shape of the graph represents the maturation of the MTEP process, and demonstrates the good faith effort of Midwest ISO 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 planned projects increased due to developing transmission needs, including several large sized transmission 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 constructed.
- MTEP10 contains significant planning adjustments for reduced load forecasts and presents a transmission planning approach driven by Candidate Multi-Value Projects (MVPs), an adaptable rather than fixed methodology which takes into account market and policy uncertainties and defines an array of multiple possible future scenarios capable of adapting to outcome, integrating mandated renewable energy sources, and providing market benefits.

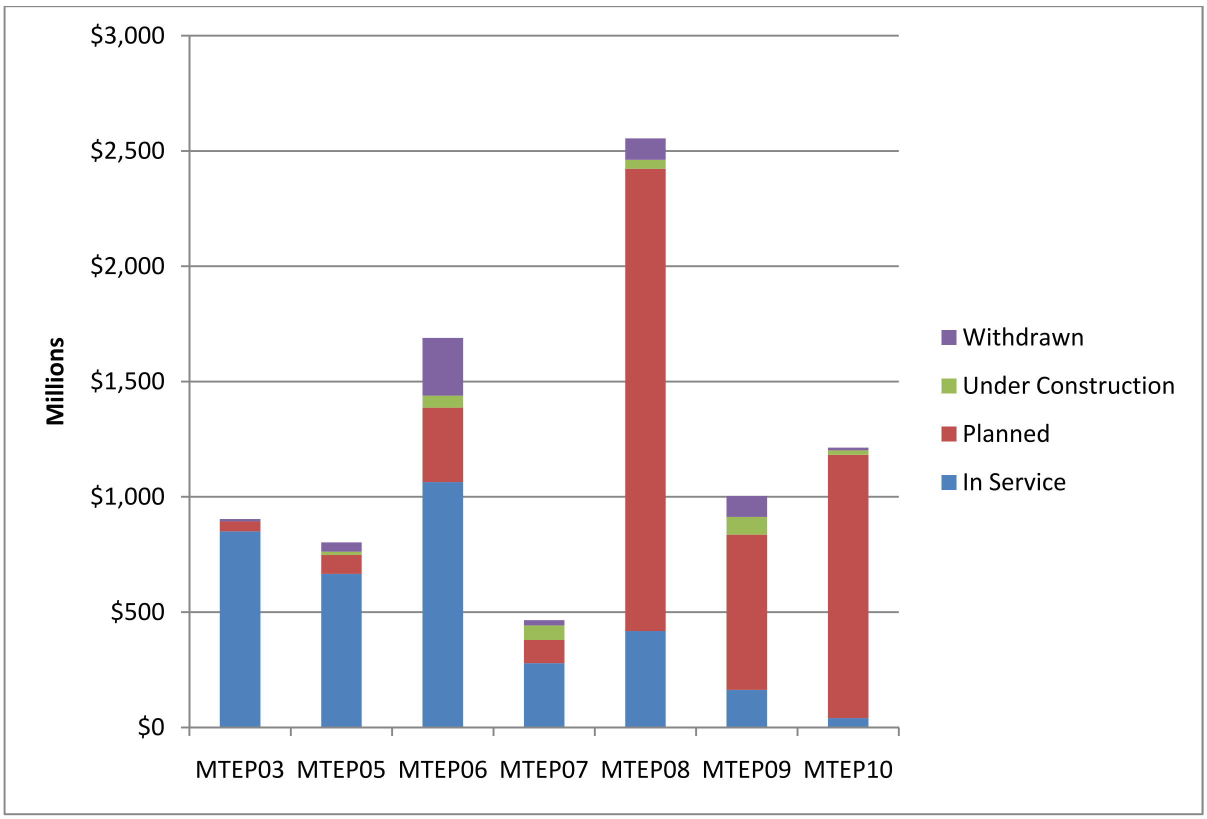


Figure 3.2-2: Approved MTEP Investment by Facility Status

Midwest ISO Energizing the Heartland

4 Planning Approach Evolution

In 2010, Midwest ISO furthered its efforts to develop a comprehensive planning approach meeting reliability and economic expansion planning needs. From the implementation of renewable energy mandates to the introduction of a real-time energy and ancillary services market, the energy industry is undergoing rapid changes. These changes have necessarily influenced and enhanced planning methodologies used by Midwest ISO to ensure long-term reliability of the transmission network, resulting in the adoption of a comprehensive, integrated expansion planning process employing both traditional reliability planning and more economically oriented value-based planning, allowing Midwest ISO to realize greater short- and long-term benefits for its members.

Key issues and questions confronting Midwest ISO in its role as Regional Planning Authority (PA) include introduction and implementation of new renewable energy policies, reduction of grid congestion, and incorporation of new generation and demand response programs—all while still meeting load growth requirements. Overlying these newer challenges are an aging transmission infrastructure, as well as the need to keep cost allocation fair. New challenges with new variables require not only a longer time horizon for study but also a more hypothesis-based approach to planning—planning bounded by likely outcomes addressing all underlying issues. Thus, adoption of a more comprehensive planning approach addresses the following questions when considering transmission expansion issues:

- Is there a business case for increased transmission build?
- From an operational perspective, what type and location of transmission is required to effectively integrate wind?
- Does the cost sharing methodology employed reflect all primary value drivers?

Midwest ISO completed several efforts in 2010 which helped to clarify the answers to these questions. These efforts, which included the Regional Generation Outlet Study (RGOS) and the Regional Expansion Criteria & Benefits (RECB) Task Force, determined the magnitude of transmission needed to be built in order to meet the policy goals of Midwest ISO stakeholders, as well as how to fairly allocate costs associated with these projects. These efforts also included further refinement of future generation and load scenarios, more fully establishing the value of transmission scenarios under a multitude of situations capturing the full range of future possibilities.

Next year, Midwest ISO will continue to work to provide its stakeholders with an increased level of value from its transmission expansion planning process. This work will include the first step towards a truly regional transmission solution to integrate wind resources into the Midwest ISO footprint. This step will involve evaluating a portfolio of Candidate Multi-Value Projects (MVPs) or near-term, robust transmission solutions that fulfill multiple transmission and reliability needs. These projects would then be moved to Appendix A in 2011, providing a solid next step towards the ultimate goal of implementing a value-adding regional plan.

4.1 Guiding Principles

Midwest ISO is guided in its planning efforts by a set of principles established by the Midwest ISO Board of Directors. These guidelines serve to ensure transmission system expansion plans established by Midwest ISO, in collaboration with its stakeholders, will support national energy policy goals and enable a competitive energy market benefiting all customers. These guidelines also ensure the plan identifies and supports the development of a delivery infrastructure sufficiently robust to meet local reliability standards and to enable competition among wholesale energy suppliers. The desire to ensure achievement of this broad range of objectives underlies guidance given in 2005 by the Midwest ISO Board to Midwest ISO community and staff in an effort to improve transmission investment in the region and furnish an element of strategic direction to the Midwest ISO transmission planning process. These principles, reconfirmed in August 2009, are as follows:

- **Guiding Principle 1:** Make the benefits of a competitive energy market available to all customers by providing access to the lowest possible delivered 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 renewable energy objectives by planning for access to all such resources such as wind, biomass, demand-side management.
- **Guiding Principle 4:** Provide an appropriate cost allocation mechanism.
- **Guiding Principle 5:** Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and inform the choices they face.

4.2 Application of Principles

Supporting the Guiding Principles listed and defined above requires implementation of a transmission planning process reflecting a fully integrated view of project value inclusive of reliability, market efficiency, public policy, and other value drivers across all planning horizons. As this process is enacted, longer-term solutions providing greater benefits will increasingly become alternative solutions to address reliability or market efficiency issues that are today solved through a series of shorter-term and often less valuable mitigation steps. The Regional Generation Outlet Study (RGOS), which seeks to address the renewable portfolio mandates in effect in the Midwest ISO through 2025, is an example of a transmission study that takes a regional view to develop longer-term solutions that can begin to be implemented in the present. However, this is not to say discrete analyses with shorter-term focus will disappear. Studies over each of the time-frames are still required to meet the planning needs of the region with efficiency and expedience. Nearer-term transmission solutions can be developed in such a way to support future goals by means of more efficient plan development, including considerations such as the preservation of future right-of-way requirements.

A number of conditions must be met in order to build transmission able to support future generation growth and accommodate new energy policy imperatives. These conditions are intertwined with the planning principles of the Midwest ISO Board of Directors and supported by the transmission planning approach discussed above. A robust business case for the transmission plan is premised on Guiding Principles 1, 2, and 3, since a robust business case, by necessity, would include an evaluation of wide ranging value drivers including reliability, market, and public policy impacts. The value-based planning process discussed further in Section 4.4 uses a future scenario-based approach which is useful to both inform and demonstrate the technical implications of policy decisions. Making this approach and information available to policy makers not only directly reflects attention to Guiding Principle 5, but also provides the basis on which increased consensus can be achieved—if not on the policies themselves–then at least on the appropriate way to address the energy policies on a region-wide basis. Finally, the last two (2) conditions are based upon Guiding Principle 4, the requirement to provide an appropriate cost allocation methodology.

These conditions that must be met in order to build transmission are as follows:

- **A robust business case for the plan:** First, the hypothesized benefits of any given plan must be justified; potential benefits must be proven to exist. Building a business case involves the thorough understanding of value drivers and underlying assumptions and the complete evaluation of alternatives, including an alternative in which a significant transmission infrastructure build-out is not able to occur. It is not expected a stakeholder such as a Transmission Owner would sponsor a transmission plan without a benefits justification. Nor would state regulators, the ultimate arbiters of project justification, approve such a plan.
- **Increased consensus around regional energy policies:** Across the Midwest ISO, different states have different views regarding which benefits have the highest importance. Differences in regional policies exacerbate this divide, which can be a barrier to the development of large-scale transmission projects that provide benefits of various types to users across multiple states or other entities. Public policy differences lead to differing goals and transmission level requirements. Prior to undertaking any given region-encompassing transmission expansion project, these differences must be reconciled to the greatest extent possible.
- **A regional tariff matching who benefits with who pays over time:** To feel satisfied with a given investment, those paying for increased transmission must derive proportional benefits over time. This is particularly true in an RTO, where participation is voluntary. Determining beneficiaries becomes increasingly complex as Midwest ISO seeks to incorporate a more complete set of value drivers, such as those drivers reflecting public policy, into the transmission assessment process. Thus, Midwest ISO has just completed a year-long, stakeholder-driven process to revise its tariff to more accurately link costs to beneficiaries.
- **Cost recovery mechanisms to reduce financial risk:** Investors in transmission projects must have a reasonable expectation of returns commensurate with the risks faced and—in the case of regulated utilities—be assured shareholders will not subsidize rate payers.

It may be possible to proceed with some level of increased transmission build-out after satisfying a subset of these conditions. However, meeting policy goals—especially those goals related to the renewable energy requirements of Midwest ISO member states—will require the construction of a transmission overlay similar in breadth and complexity to the construction of the interstate highway system. Accomplishing an engineering task of this magnitude requires satisfying *all* of the precedents listed above. The steps Midwest ISO is undertaking to meet these precedents are described in greater detail in subsequent sections of this document.

4.3 Responding to Evolving Energy Policy

Midwest ISO's approach to planning is influenced by the decisions and actions of policy makers. There are currently efforts underway at all levels of government aimed at reducing the environmental impacts of energy generation and enabling the more effective and efficient use of energy supplies. As a result, the impacts of the electric industry are currently being scrutinized more than at any time in recent history. Topics currently being discussed and analyzed include renewable energy, carbon reduction, energy efficiency, and smart grid implementation.

Uncertainty regarding the direction of future policy decisions creates difficulty for those involved in the planning function and causes hesitancy among those with the resources to undertake transmission expansion projects. To minimize the risk involved with building a system bearing the weight of such uncertainty, the process must consider projects in the context of all potential outcomes. Thus, Midwest ISO and its stakeholders must strive to identify transmission plans that provide the best fit to an array of multiple, possible future scenarios.

4.3.1 State Regulatory Policies

Refer to Figure 4.3-1. The Midwest ISO footprint includes eleven (11) states that currently have either a Renewable Portfolio Standards (RPS) goal or mandate. In total, the requirements of these states represent approximately 22,000–27,000 MW[27] of generation, based on stakeholder surveys focusing on expected renewable energy needs for the next 30 years. In addition, seven (7) states in the Midwest ISO footprint have also enacted on-going demand response and energy efficiency program goals or requirements. These state requirements are very diverse in their details, adding an additional level complexity to an already complex regulatory schema.

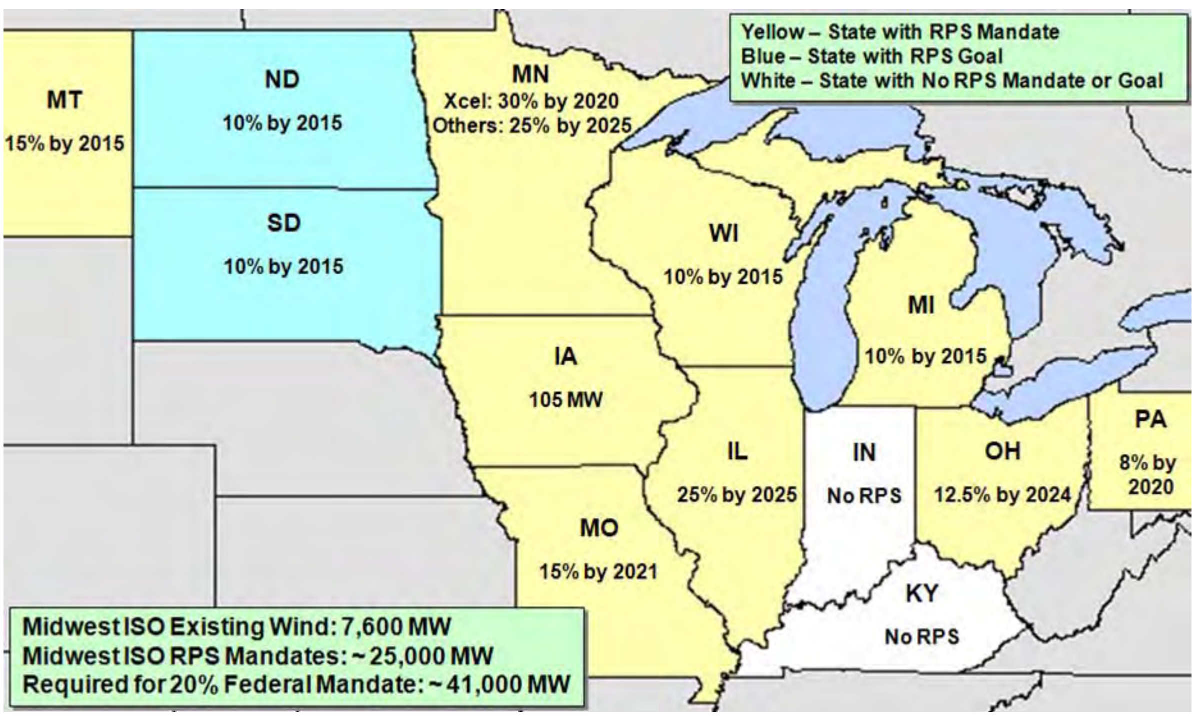


Figure 4.3-1: RPS Requirements within the Midwest ISO Footprint[28]

[27] This value is based upon RPS requirements of the states in the Midwest ISO as of July 1st, 2010. The actual amount of generation required to meet the mandates is dependent upon the energy growth rate and capacity factors of the installed wind turbines. Please see the RGOS report for more details.

[28] As of 2/10/2010

It should be emphasized the states within the Midwest ISO footprint have achieved a compromise consensus regarding the renewable resource policies with the greatest impact on transmission. This consensus has been achieved through the work of many stakeholders and spearheaded by several regulatory groups. The Organization of Midwest ISO States Cost Allocation and Regional Planning (OMS CARP) was instrumental in developing a new cost allocation policy for the Midwest ISO footprint. Further, the Midwest Governor's Association (MGA) affirmed the best approach to the selection of wind resources for inclusion into studies. These aspects of policy, which create receptiveness to new transmission construction, are vital to the success of the set of first mover projects, as determined by the Candidate MVPs portfolio analysis discussed in section 4.4.9, which must be constructed to meet the energy policy mandates and goals of the various states within the Midwest ISO footprint.

4.3.2 Federal Regulatory Policies

Discussions at the federal level encompass a broader set of objectives but include a focus on integration of renewable generation consistent with state efforts. This focus includes discussions of a federal renewable energy portfolio, a carbon cap-and-trade program, implementation of a smart grid, and other, various ways to achieve increased energy efficiency. Each of these programs would independently have a significant impact upon generation utilization, load growth, and transmission planning. The possibility many or all of them will be incorporated into future legislation further complicates system planning. In addition, transmission siting and cost allocation hurdles must be overcome to realize the Extra High Voltage (EHV) grid overlay currently under consideration in both the US Senate and House of Representatives. The planning process is also influenced by federal support for interconnection-wide planning. The Department of Energy has released a Funding Opportunity Announcement (FOA) awarding financial assistance to chosen entities who undertake interconnection-level analyses and plans. Projects under this FOA will be funded in whole or in part by the American Recovery and Reinvestment Act of 2009 (ARRA 2009), which included funds to facilitate regional transmission planning. As this evolves, it will be critical that planning entities continue to enhance the level of collaboration and cooperation taking place with one another.

4.4 Creating a Robust (Best-Fit) Business Case

Midwest ISO continues to further its value-based planning efforts to address longer-term system needs under a wide range of potential policy decisions. For the MTEP10 cycle, the focus of value-based planning is shifting away from the design of conceptual transmission plans to the development of a robust business case to assess the value of the plans. As discussed in section 4.2, the first condition precedent to transmission investment is to develop a robust business case for the plan. It must be demonstrated the hypothesized benefits of any plan exist, including a fully developed transmission overlay. Capturing the total value of transmission plans is a major, requisite challenge. Developing a list of appropriate value measures will enable a more complete value assessment of transmission plans and result in an improved business case for proposed plans.

The following broad steps outline the value-based planning process Midwest ISO has been implementing and will continue to evolve in accordance with the guiding principles described in Section 4.1. To meet both economic and reliability needs, the value-based planning process starts with an analysis of value drivers and ends with a reliability assessment, as follows:

- **Step 1:** Create a regional generation resource forecast.
- **Step 2:** Site the new generation resources into both 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:** Consolidate and sequence transmission plans
- **Step 6:** Evaluate conceptual transmission for reliability
- **Step 7:** Perform cost allocation.

The Midwest ISO value-based planning process has been focused upon developing and implementing the first three (3) steps in the past few planning cycles. As analytical methodologies have matured, robustness testing of transmission portfolios has become the primary focus of MTEP10. Given the increasing level of future-focused policy discussions, continued evolution of the current planning approach necessarily entails using robustness analysis when making transmission plans. Robustness testing is intended to identify the best-fit transmission plan both maximizing the value of transmission system under a wide range of future scenarios and resulting in least future regrets regardless of policy decisions.

The flow of the process is outlined in Figure 4.4-1 and described in greater detail in following subsections. Midwest ISO will continue to work with stakeholders to evolve the value-based planning methodology and implement the remaining steps of the process.

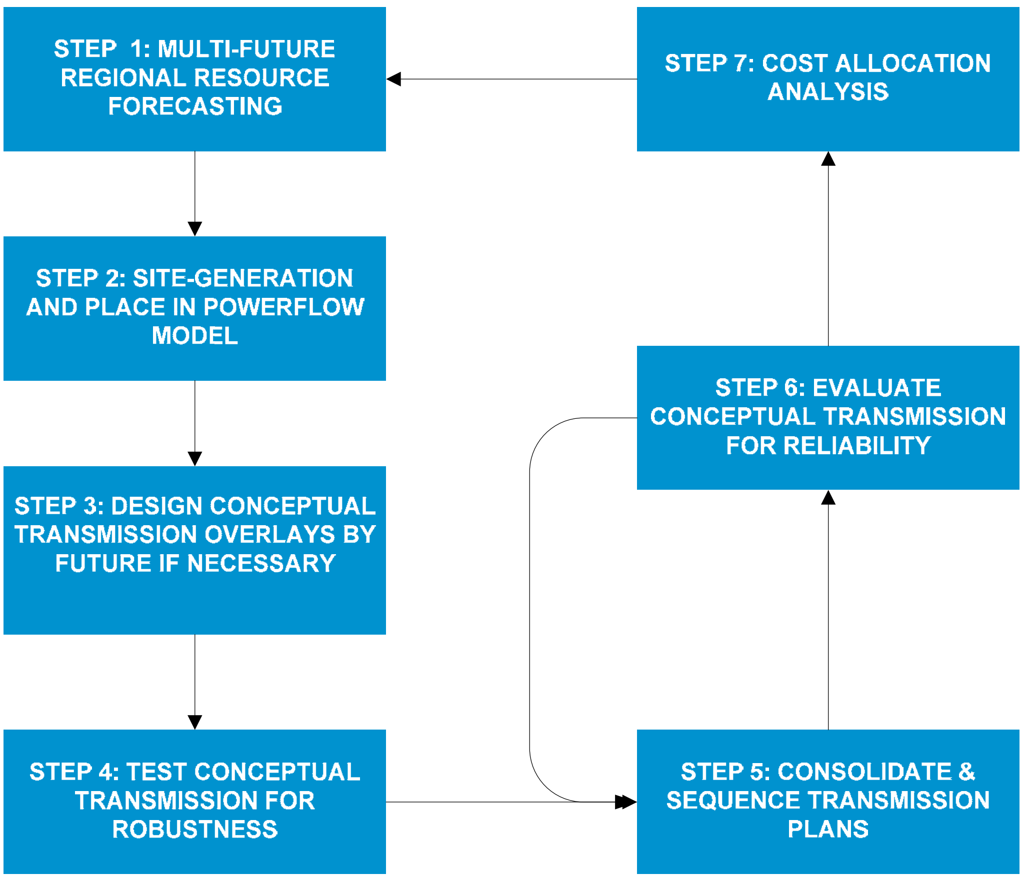


Figure 4.4-1: MTEP10 Process–Economic Transmission Planning

4.4.1 Step 1: Create a Generation Portfolio Forecast and Assessment Process

Effectively designing and evaluating the impact of new transmission development requires multi-dimensional analysis of future generation. The existing Generation Interconnection Queue (GIQ) provides initial insight into the new generation being proposed within the footprint, but does not provide the extended time horizon required. To supplement GIQ proposed capacity, a resource forecasting model is required to determine the total resource needs driven by energy policies and other long-term integrated resource plans not reflected in the current queue.

As part of its MTEP10 value-based planning effort, Midwest ISO collaborated with stakeholders to refresh a set of available future scenarios developed in the course of the last few years and to identify a number of additional new future scenarios to provide further variation in potential energy policy outcomes. In recognition of the uncertainty level around future policy discussions, the overall objective was to develop a broad set of future scenarios capturing what could happen as a result of various policy decisions. The process to create these future scenarios—and the detailed assumptions underlying them—are discussed further in section 7.2.

4.4.2 Step 2: Incorporate Generation from Futures into Models

Once future generation from the regional resource forecast process is developed, generation type and timing required to meet future load growth requirements must be sited within all the planning models to provide an initial reference condition. The indicative siting of generation is likely to be controversial; however, the tariff-driven queuing system has not provided the time horizons required and—absent the generation assumption—transmission line benefit analyses have no economic underpinning. A philosophy and rule-based siting methodology, in conjunction with industry expertise, is used to provide reasonable assumptions on the siting locations of forecasted resources.

Using fixed-in-place generation as a starting point, the development of the transmission plan around fixed generation can proceed to provide integrated reliability and economic enhancements. Future generation is needed for the development of the long-term transmission models and production cost models, and this process must be developed and completed as an input into those models.

4.4.3 Step 3: Design Preliminary Transmission Plans for Each Future If Needed

Long-term transmission development is driven primarily by evolving energy policy decisions. To alleviate the impact of uncertainties surrounding future outcomes, a broad set of future scenarios are defined to meet a wide range of key policy goals. For each planning cycle, future scenarios are refreshed to better align with potential policy outcomes taking place at the time. Transmission expansion plans developed for prior planning cycles will remain sufficient if there are no significant energy policy shifts. However, new transmission plan development is necessary to capture the variation if the future diverges from current policy discussions. This process is collaboratively performed with stakeholders in an open planning process.

Driven by discussions at both state and federal levels, renewable energy policy has been a primary focus of Midwest ISO planning efforts in recent years. No conceptual transmission plans were developed for MTEP10 future scenarios. Instead, the Regional Generation Outlet Study (RGOS) was created in response to the growing focus on enabling the integration of renewable generation. A summary of the RGOS effort may be found in section 4.4.8.1, below. For a more detailed discussion of the RGOS effort, refer to section 9 of this document.

4.4.4 Step 4: Test Transmission for Robustness

The outcome of the Step 3 process is the development of transmission plans for each future scenario being studied or the equivalent plans developed through major transmission studies. Up to this point, preliminary plans are developed in isolation of other future scenarios or plans. As the primary focus of the MTEP10 value-based planning process, the ultimate goal of robustness testing is to develop one (1) transmission plan capable of accommodating the various uncertainties inherent to potential policy outcomes and that can perform reasonably well under a broad set of different future scenarios. Since the planning process is often fraught with uncertainty, the objective is to manage the uncertainty as much as possible. Therefore, each preliminary transmission plan must be analyzed under the conditions associated with the development of each of the other plans.

To perform robustness tests, each preliminary transmission plan is assessed against a set of metrics across multiple future scenarios. The plan emerging from this assessment with the highest value, most flexibility, and lowest risk will be selected to move forward as the best-fit solution. Identifying and incorporating appropriate value measures in the assessment is critical since value comparisons can be made only when the complete value of transmission plans is captured. Such value measures could include—but are not necessarily limited to—the following:

- Production Cost Savings/LMP Reduction
- Losses Reduction (Energy and Capacity)
- LOLE/Reserve Margin Impact
- Emission Reduction
- Reducing Wind Generation Curtailment
- Project Cost
- Right of Way Usage
- Avoidance of Other Transmission Investment
- Operational Impact
- Project Risk Measures

An expanded value measure analysis that refines and adds to current RECB II measures allows more thorough evaluation of transmission plans and helps create a more robust business case.

4.4.5 Step 5: Consolidate and Sequence Transmission Plans

Once robustness testing has been conducted, it is necessary to develop appropriate portfolios of transmission projects comprising the overall, long-term plan. One key consideration in consolidating plans is the need to maintain flexibility in adapting to future changes in energy policies. By selecting the best performing preliminary plan components to develop a comprehensive plan that furnishes the most benefit under all outcomes, the transmission infrastructure will support changes to generation and market requirements with the least incremental investment and rework. As an additional advantage, evaluating multiple future scenarios shows which configurations produce value. If the same group of projects is proposed in multiple solutions, it is a good indication that a given portfolio is robust and would result in a less future regrets than a portfolio that does not.

Long-term planning focuses on robust business case development and provides long-term strategy to minimize the risk involved in the planning process under future uncertainties. Long-term plans have to be implemented in phases over a period of time (at least 15 years) by executing a series of shorter-term solutions. Given the timing of shorter-term solutions, the overall plan can be organized into first movers, intermediate or next movers, and long-term movers. Additional considerations are necessary in the process of transmission sequencing, including but not limited to the solutions identified from existing studies, timing needs of RPS requirements, transmission constructability, and portfolio efficiency. In 2010, Midwest ISO has taken the first step towards sequencing long-term plans by identifying immediate Candidate MVPs compatible with all potential transmission plan strategies meeting near-term reliability and policy needs. Candidate MVPs and related analyses are discussed in more detail in section 4.4.8.2.

4.4.6 Step 6: Evaluation of Conceptual Transmission for Reliability

The fundamental goal of the Midwest ISO planning process is to develop a comprehensive expansion plan that provides least-cost energy delivery and meets reliability, policy, and economic needs. Detailed Power Flow studies are required to identify additional reliability issues that may be introduced by the long-term transmission plans developed through economic assessment and to adjust the plans as needed to ensure system reliability. On the other hand, the reliability assessment is necessary to determine the reliability-based value contribution of the long-term plans. As value-driven regional expansions are justified, traditionally developed intermediate-term reliability plans may be affected. The combined impact of both reliability and value-based planning strategies must be fully understood in order to further the development of an integrated transmission plan.

4.4.7 Step 7: Cost Allocation

Cost allocation may be the single most important issue impacting the development of regional and multi-regional high voltage transmission. In recognition of the importance of an appropriate cost allocation mechanism for regional transmission development, the Upper Midwest Transmission Development Initiative (UMTDI), the Cost Allocation Regional Planning (CARP) Initiative and the Midwest ISO RECB Task Force have developed a new cost allocation methodology which addresses the needs of policy-based, regional transmission development. Further discussion of cost allocation issues can be found in section 4.5 of this document.

4.4.8 Value-based Approach Application

Midwest ISO does not (and is not authorized to) construct transmission facilities. That responsibility, along with presenting the business case for transmission expansions to state regulators, lies with the Transmission Owners (TO) of the Midwest ISO, per the Transmission Owners Agreement, under the regulation of state and federal authorities. The Transmission Owners Agreement requires TOs to "…make a good faith effort to design, certify and build" the facilities included in the MTEP approved by the Midwest ISO Board of Directors. However, given the lack of authority of any other party with respect to the obligation to construct, this implicitly requires approval of the TO for the project before submission to the Midwest ISO Board. Although Midwest ISO may, in its regional planning role, identify alternative or even incremental plans to those identified by stakeholders, responsibility for a transmission project to be approved and built ultimately requires the acceptance and approval of those who must build the facility.

The value-based planning approach can be used to expand upon this business case. It can also be used to inform and guide new targeted studies. For example, the value-driven transmission plans developed through prior MTEP cycles, the Joint Coordinated System Plan (JCSP) and the Eastern Wind Integration and Transmission Study (EWITS), addressed a broader set of policy decisions and created the roadmaps to guide RGOS transmission development. An example of the application of the value-based planning approach in the context of a larger planning study is described in Regional Generation Outlet Study (RGOS). This study, which was conducted as part of the MTEP10 study process, combined traditional reliability work with a value-based approach to business case development. The RGOS analysis, along with stakeholder alternatives and the US Department of Energy's commissioned EWITS, are discussed in more detail below.

4.4.8.1 Regional Generation Outlet Study

The Regional Generation Outlet Study (RGOS) was initiated in response to the growing focus on renewable sources of energy. As more states created Renewable Portfolio Standards (RPS) goals or mandates, it became necessary to identify areas rich in renewable sources of generation and to develop plans for connecting those resources to load centers. RGOS (discussed in detail in Section 9 of this document) began in 2008 with the identification of transmission scenarios that could be used to meet state-mandated renewable energy standards and the goals of utilities in the states of Illinois, Iowa, Minnesota, and Wisconsin. The 2009 RGOS effort also recommends a mix of renewable energy generation consisting of a blend of wind zones distributed across the Midwest ISO's geographical footprint, an approach affirmed as the best means of wind zone selection by the Midwest Governor's Association. These wind zones included both high-wind potential zones located further from load centers and low capacity wind zones located closer to load.

The 2010 iteration of the RGOS effort determined a total of three (3) transmission portfolios that could be used to meet renewable energy standards and goals of all states in the Midwest ISO footprint. While none of the three portfolios emerged as the definitive renewable energy transmission solution, it is important to note a set of projects demonstrating compatibility with all three strategic pathways. Those projects compatible with all three transmission portfolios were identified as the next, most immediate step to transmission investment: a set of projects meeting current renewable energy mandates and the regional reliability needs of its members. These projects, along with similar projects determined through other studies in the MTEP process, serve as inputs into the 2011 Candidate MVP portfolio and are discussed further in section 4.4.9.

4.4.8.2 Eastern Wind Integration and Transmission Study (EWITS)

The Eastern Wind Integration and Transmission Study (EWITS) was commissioned by the US Department of Energy (DOE) through its National Renewable Energy Laboratory (NREL). EWITS was designed to analyze technical issues (identified by a wide group of stakeholders) surrounding a scenario in which the United States obtains 20% of its electricity from wind by 2030. Four (4) different wind generation scenarios, as well as a status quo Reference Future, were created for the study. Three (3) of the scenarios were devoted to investigating a 20% wind energy penetration future while the fourth scenario explored a wind energy penetration future of 30%. The scenarios also differed in their respective treatment of offshore wind and the geographical placement of wind generation in the Eastern Interconnect. The study reached the following conclusions:

- High levels of wind generation may be developed in the Eastern Interconnection if supported by a significant expansion of the transmission infrastructure.
- New transmission will be required in all future scenarios, including the status quo Reference future.
- Without new transmission, wind generation would be highly curtailed.
- Significant market, tariff, and operational changes would be required to successfully accommodate interconnection-wide costs of large amounts of wind generation.
- An increased transmission build-out reduces the impact of wind variability, reducing wind integration costs and increasing system reliability and efficiency.
- An increased level of wind generation displaces coal generation, resulting in reduction of carbon emissions.

4.4.8.3 Stakeholder Alternatives

A number of specific transmission proposals, designed with the purpose of integrating wind energy into the transmission grid, have been proposed by individuals or groups of stakeholders. Consistent with the overall Midwest ISO planning approach, these transmission projects were considered as transmission alternatives—in whole or in part—in the value-based Regional Generation Outlet Study (RGOS). A few of these studies are listed below.

- **SMARTransmission Study:** The Strategic Midwest Area Transmission Study (SMARTransmission Study) is a study of the transmission required in the upper Midwest to support renewable energy development and delivery while addressing the Midwest ISO and PJM seams. More information may be found at http://www.smartstudy.biz/default.aspx.
- **Green Power Express (ITC):** This proposal is a series of 765 kV lines intended to move power from the upper Midwest to load centers in the east. It includes lines which cross North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, and Indiana. More information may be found at: http://www.itctransco.com/projects/thegreenpowerexpress.html.
- **Pioneer Project:** The Pioneer Project was initiated to investigate ways to strengthen the area around the Rockport and Greentown 765 kV stations in Indiana, and provided suggested line additions to the RGOS effort. More information may be found at http://www.pnrtransmission.com/.

4.4.9 Value-based Approach Future Application

A Candidate Multi-Value Project (MVP) portfolio has been identified by analyzing transmission needs from multiple transmission and economic studies. These studies included the Regional Generation Outlet Study (RGOS), studies conducted in the generation interconnection process, congestion studies (such as the Top Congested Flowgate Study and the Cross Border Congested Flowgate Study), and MTEP reliability studies. Transmission solutions from these studies were evaluated for comparability and the ability to be built within the near-term. These projects will continue to be evaluated in more detail into 2011, both to ensure project robustness and to confirm system reliability with the MVP Candidate portfolio included. This analysis was previously referred to as “Starter Project” analysis, but the analysis title was modified to further align its evaluation with the August 15th cost allocation filing at FERC. Refer to Figure 4.4-2.

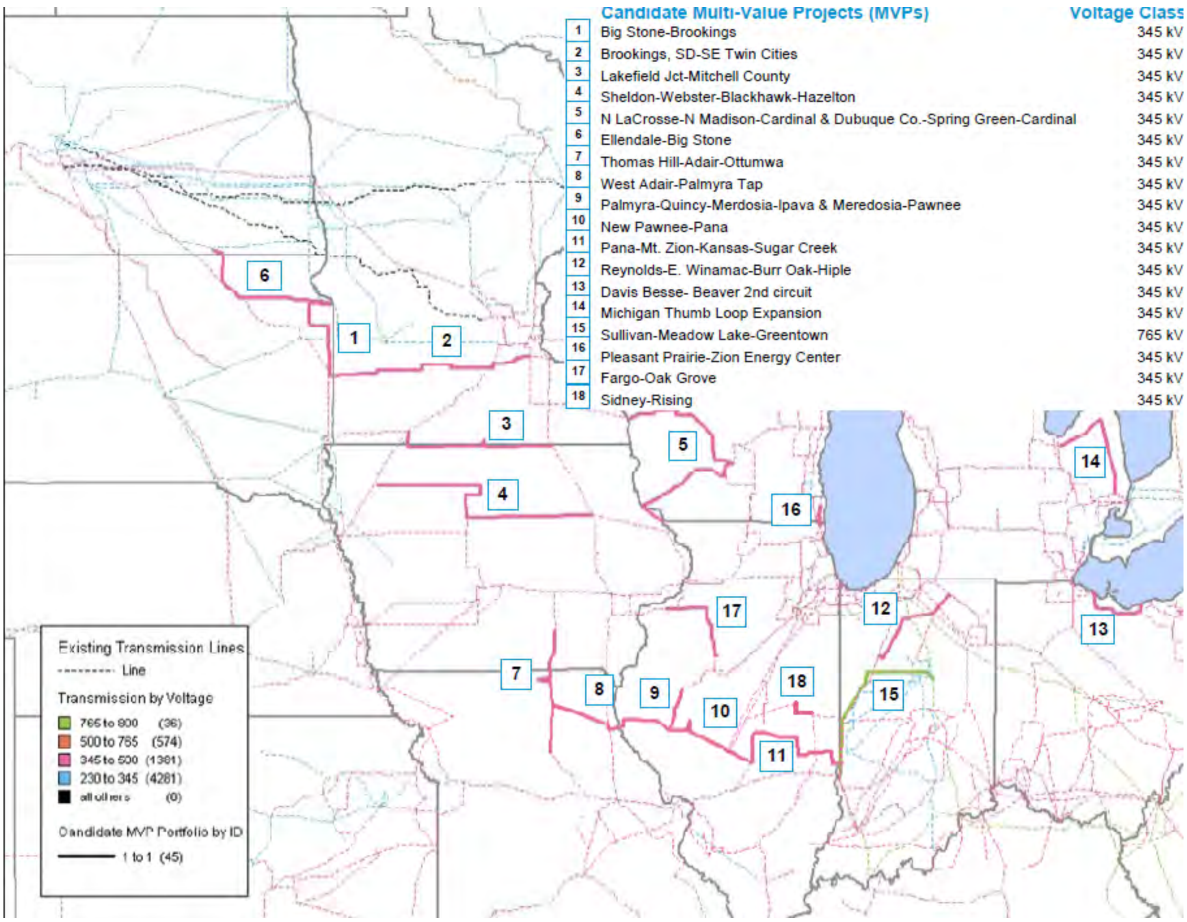


Figure 4.4-2: 2011 Midwest ISO Candidate Multi-Value Portfolio

Table 4.4-1: Midwest ISO 2010 Candidate Multi-Value Portfolio #1 Details

	Project	Description
1	Big Stone to Brookings	Part of West sub region wind collection and outlet
2	Brookings to Twin Cities	Part of West sub region wind collection and outlet
3	Lakefield to Mitchell County	Part of West sub region wind collection and outlet
4	Sheldon to Webster to Blackhawk to Hazelton 345 kV line	Part of West sub region wind collection and outlet
5	Dubuque to Spring Green to Cardinal La Crosse to North Madison to West Middleton	Part of West sub region wind collection and outlet
6	Ellendale to Big Stone	Part of West sub region wind collection and outlet
7	Thomas Hill to Adair to Ottumwa	Outlet path to Central and East sub region load centers
8	Adair to Palmyra	Outlet path to Central and East sub region load centers
9	Palmyra to Quincy to Meredosia to Ipava Ipava to Meredosia to Pawnee	Outlet path to Central and East sub region load centers
10	Pawnee to Pana	Outlet path to Central and East sub region load centers
11	Pana to Mt. Zion to Kansas to Sugar Creek	Outlet path to Central and East sub region load centers
12	Reynolds to E. Winamac to Burr Oak to Hiple	Northern Indian wind outlet, relieves congestion
13	Davis Besse to Beaver 2nd circuit	North Ohio wind outlet
14	Michigan Thumb Loop expansion	Michigan wind outlet
15	Sullivan to Meadow Lake to Greentown	Northern Indian wind outlet, relieves congestion
16	Pleasant Prairie to Zion Energy Center	Part of West sub region wind collection and outlet, relieves congestion
17	Fargo to Oak Grove	Outlet path to Central and East sub region load centers, part of West sub region wind collection and outlet
18	Sidney to Rising	Outlet path to Central and East sub region load centers

2011 Candidate MVP portfolio analysis will be used to determine the total value of the proposed project portfolio and—by means of reliability and economic analyses—decide if these projects are eligible for MVP cost allocation. To ensure total value of the projects is captured as accurately as possible, Midwest ISO will continue to refine and develop the set of metrics and methodology used to evaluate the total value of a portfolio of projects in the robustness testing step discussed in section 4.4.4, above. This refinement will take place with heavy stakeholder involvement through such forums as the Planning Advisory Committee (PAC) and the Planning Subcommittee (PS). It should also be stressed that 2011 Candidate MVP portfolio analysis is only the beginning of a cyclical set of Candidate MVP portfolio analyses that will determine the policy-based transmission needs of the Midwest ISO system and analyze portfolios to meet these needs.

4.5 Matching Who Benefits with Who Pays

Midwest ISO currently employs a cost allocation methodology for reliability-based projects (RECB I criteria), economically based projects (RECB II criteria), and generator interconnection-based projects (Attachment FF criteria). These methodologies, however, fail to encompass projects that provide benefits not solely driven by reliability, economic, or generator interconnection needs. Midwest ISO and stakeholders explored alternative cost allocation solutions, a process which resulted in the development of the Multi-Value Project (MVP) cost allocation method. When formulating the MVP cost allocation methodology, the Midwest ISO and stakeholders sought to find a cost allocation solution that would:

- Enable investment in the regional transmission infrastructure necessary to ensure a reliable and robust transmission system supporting the public policy requirements while maximizing stakeholder value in the long-term.
- Allocate the costs of such investment fairly, in a way roughly commensurate with benefits realized by stakeholders. In addition, Midwest ISO and its stakeholders sought to address—to the extent feasible—free rider and late comer issues, the changing use of the system over time, cost allocation issues regarding regional versus local use of the Transmission System, and the ability of the transmission system to facilitate both energy- and capacity-based requirements. Additional goals of the process included ensuring unintended consequences—such as those associated with the generator interconnection cost allocation method in place prior to July 9, 2009—did not reoccur, and avoiding additional unforeseen consequences.

With these principles in mind, Midwest ISO worked very closely with stakeholders to evaluate cost allocation alternatives. There were two primary groups of stakeholders working on the development of a transmission cost allocation methodology. The Organization of MISO States (OMS) identified regional transmission planning and transmission cost allocation as two of the three key strategic areas on which it planned to focus and provide leadership on during the 2009-2010 time period. As a result, OMS formed an internal group known as the Cost Allocation and Regional Planning (CARP) group, to study and develop long-term solutions for transmission cost allocation and regional transmission planning issues. Working in parallel to the OMS CARP, the Midwest ISO RECB TF also focused on cost allocation during 2009–2010. The work of the RECB TF was coordinated very closely with the OMS CARP effort. Stakeholders from each of these two groups closely monitored the activities of the other group and exchanged feedback and ideas.

After considering feedback from stakeholders, Midwest ISO filed its MVP Cost Allocation methodology with FERC on July 15th, 2010. The MVP Regional Transmission Cost Allocation Proposal creates a new class of transmission expansion projects and associated rate design to recover revenue requirements on a Midwest ISO system-wide basis. This new class of regional transmission expansion projects is referred to as MVPs. MVPs are network upgrades that provide regional benefit in response to documented public policy (such as renewable energy standards) and/or by providing multiple regional benefits (such as reliability and/or economic value) to Transmission Customers on a regional basis.

MVPs will help advance the integration of renewable resources to meet state public policy requirements. These projects will also alleviate major areas of congestion on the Midwest ISO system by allowing more efficient delivery of energy to load. This enhanced deliverability of energy will help loads meet respective state public policy requirements because it will reduce the amount of wind energy that must be curtailed due to trapped generation. MVP development will also ease the burden of interconnection costs for new generators in the queue as MVP project costs are allocated through the Midwest ISO under the MVP cost allocation methodology, rather than similar projects being proposed and cost shared as part of the generator interconnection process.

It is important to note both Order 890 and the October 23 Order indicate state support is important to FERC when it comes to transmission cost allocation. For this reason, Midwest ISO relied heavily on feedback from the OMS CARP group as well as the RECB TF. While Midwest ISO did not ultimately adopt the OMS proposal, key aspects of the OMS proposal are included in the MVP proposal. For example, important concepts such as increased regional sharing, maintaining a siting signal for new generators interconnecting to the grid, and addressing free riders through a charge to exports and wheel-throughs are all part of the final Midwest ISO proposal.

4.6 Reducing Financial Risk

As discussed in sections 4.3.1 and 4.3.2, the electricity industry is facing a number of impending policy changes from both state and federal levels that generate a great deal of industry uncertainty, including potential rate increases to retail customers. At the state level, as shown in Figure 4.3-1, all but two (2) of the thirteen (13) states in the Midwest ISO footprint have enacted a Renewable Portfolio Standard (RPS) mandate or goal. There is a great deal of uncertainty around how these mandates will be met, including the location of future renewable generation and the required transmission to enable renewable integration. In addition to state policies, there is discussion at the federal level on implementation of a federal RPS, a carbon cap-and-trade program, a smart grid, and others. To address these uncertainties, Midwest ISO examines multiple future scenarios through its long-term planning process in order to capture the wide spectrum of potential policy outcomes.

4.6.1 Future Policy Scenarios

Midwest ISO has examined a number of policy-driven future generation expansion scenarios to develop an array of “best plans” for a range of possible outcomes. These future scenarios result from policy discussions taking place during a given time, meaning these scenarios will evolve depending on the direction of current and future legislation. The following future policy scenarios have been developed to estimate potential impacts to retail rate payers in the Midwest ISO footprint.[29]

- **Business as Usual with High Demand and Energy Growth Rate** assumes a quick recovery from the economic downturn in demand and energy projections and models the power system as it exists today, using current reference values and trends and projecting demand and energy growth rates based on recent historical data. This future scenario assumes existing standards for resource adequacy, renewable mandates, and environmental legislation will remain essentially unchanged.
- **Business as Usual with Mid-low Demand and Energy Growth Rate** predicts a continuation of the economic downturn, and its impact on growth in demand, energy consumption, and the inflation rate.
- **Carbon Cap and Trade with Nuclear** models a declining cap on future CO2 emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO2 emissions from a 2005 baseline by the year 2050. For the purposes of analysis, a 30% reduction by 2025 is assumed from the 2005 baseline.
- **Federal RPS** requires 20% of the energy consumption in the Eastern Interconnect come from wind by 2025. State mandates are the same as those modeled in the Business as Usual Future. Any additional renewable energy is met with wind.
- **Federal RPS, Carbon Cap and Trade, Smart Grid, and Electric Car; i.e., the “Kitchen Sink” future scenario** combines the impact of multiple future policy scenarios into one future. Smart grid is modeled within the demand growth rate. It is assumed the increased penetration of smart grid will lower overall growth of demand. Electric vehicles are modeled within the energy growth rate and are assumed to increase off-peak energy usage and the overall energy growth rate.

To meet various policy objectives, all of the future scenarios included in this rate impact analysis require significant investment in both generation and transmission expansion across the 15-year study horizon. This increased investment is expected to have an impact on retail electricity rate, especially since a large share of current generation and transmission assets have or soon will reach the end of their recoverable book life. For example, more than 50% of the generating capacity in the Midwest ISO footprint is at least 30 years old. As shown in this rate impact analysis, all but one (1) of the scenarios examined show consumer retail rates increasing at a rate faster than inflation.

[29] For additional, detailed description of the MTEP10 Futures refer to section 7.2 and Appendix F.1.

4.6.2 Current Retail Electricity Rates

Current cost of electricity to the retail customer must be considered before examining the potential impact of the future scenarios. The current Midwest ISO retail rate, weighted by state average retail electricity rate for the residential, commercial, and industrial sector, is 8.5 ¢/kWh, which is about 11% lower than the national average of 9.6 ¢/kWh.[30] Refer to Figure 4.6-1, which provides the average retail rate in cents per kWh for each state in the Midwest ISO footprint, and shows the retail rate paid by consumers varies greatly across the Midwest ISO footprint. Based on information provided by the Energy Information Administration (EIA) in the Annual Energy Outlook 2010, the generation, transmission, and distribution cost components of the retail electricity rate in 2010 are estimated to average 68.1%, 6.9%, and 25.0%, respectively.[31] This equates to approximately 5.8 ¢/kWh for generation, 0.6 ¢/kWh for transmission, and 2.1 ¢/kWh for distribution.[32] For the purposes of this rate impact analysis, it is assumed the average Midwest ISO residential customer uses approximately 1 MWh of electricity each month, equal to an annual electricity bill of approximately $1,020, based on an 8.5 ¢/kWh retail rate.

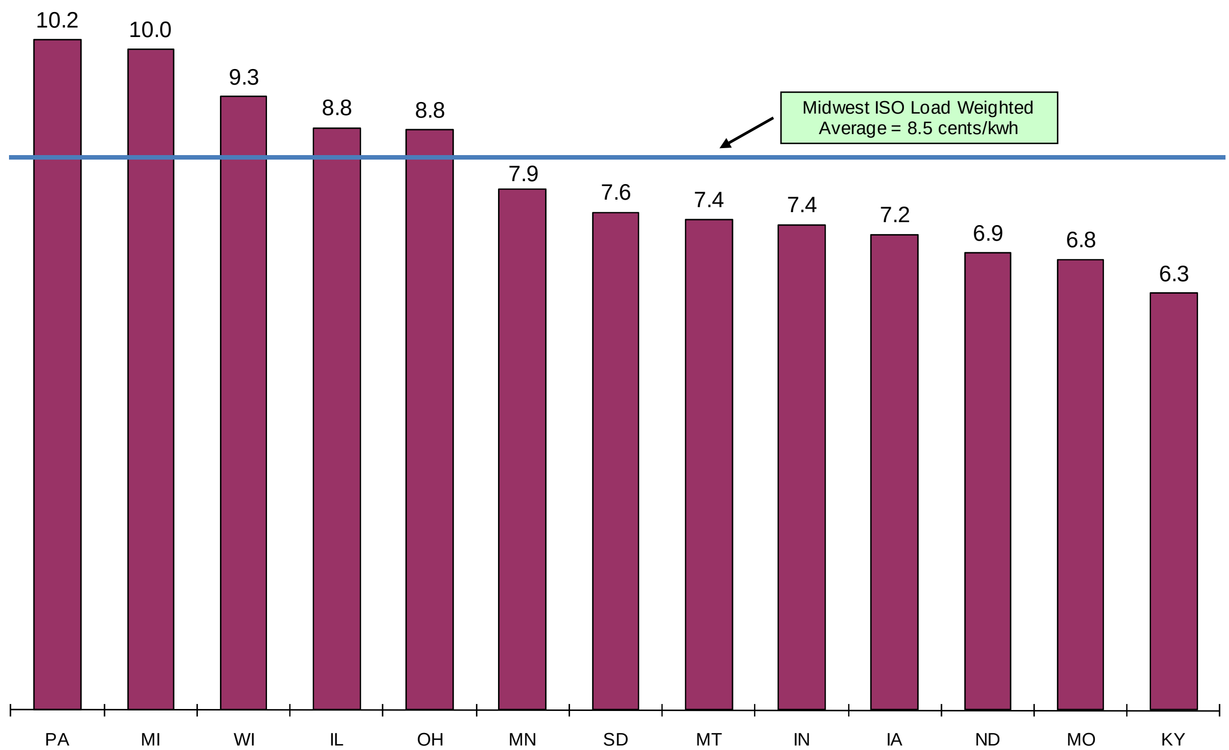


Figure 4.6-1: Midwest ISO Retail Rate for all Sectors in ¢/kWh (2010 Dollars)

[30] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly in April 2010. The Midwest ISO rate was calculated by taking the load weighted average of the thirteen states that compromises the Midwest ISO footprint.

[31] The Midwest ISO average generation, transmission, and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2010 by the following modeling regions East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP). The regions were weighted based on the load ratio share of the ECAR, MAIN, MAPP modeling regions including only those loads in the Midwest ISO footprint.

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

4.6.3 Overview of Rate Impact Methodology and Results

To measure the potential impact to rate payers under each of the future scenarios, Midwest ISO projected a potential 2025 retail rate by estimating the revenue requirements for the following generation, transmission, and distribution rate components:[33]

- **Transmission Component**
  - Transmission overlay investment required to support the generation capacity expansion for each future scenario through 2025[34] (constant across all future scenarios)
  - Additional required reliability transmission investment through 2025 (constant across all future scenarios)
  - Non-depreciated current transmission that would still be recoverable in 2025 (constant across all future scenarios)
- **Generation Component**
  - Production costs for the Midwest ISO generation fleet associated with each future scenario in 2025 and includes fuel, emissions, variable and fixed O&M costs
  - Generation capital investment associated with the capacity expansion for each future scenario through 2025[35]
  - Non-depreciated current generation that would still be recoverable in 2025 (constant across all Futures)
- **Distribution Component**
  - Assumes that the distribution component of the current Midwest ISO retail rate at 2.2 ¢/kWh will grow at the assumed rate of inflation through 2025

To calculate 2025 retail rate, revenue requirements for the generation, transmission, and distribution components described above were distributed across the forecasted 2025 energy usage levels. The 2025 rate was then adjusted for inflation to 2010 dollars for comparison to the current Midwest ISO retail rate.[36] The results of that calculation are shown in Figure 4.6-2 for each of the future scenarios. All but one of the future scenarios show that—based on various economic and policy assumptions—rates for retail customers can be expected to grow at a rate faster than would be experienced if rates simply increased by the inflation rate. However, the magnitude of this impact varies greatly across the five (5) future scenarios, from a 9% decrease for the Business as Usual with Mid-low Demand and Energy Growth Rate Future to a 53% increase for the "Kitchen Sink" Future. Major rate drivers for each future scenario are discussed in more detail in the next section.

[33] Additional detail on the rate calculation methodology is provided in Appendix F4.

[34] Based on the transmission plans identified in the Regional Generation Outlet Study, see Section 9.1. For each of the future retail rate impacts calculated the total cost of the transmission plan is assumed to be $15 billion in 2010 dollars.

[35] Refer to Figure 7.2-2 for details on the capacity expansion, by fuel type, for each Future. Generation Siting maps for each Future are provided in Section 7.2.4.

[36] 2025 energy usage levels are from the Powerbase database utilized in the capacity expansion. The Energy Growth Rates assumed for each Future are available in Appendix F1.

Refer to Figure 4.6-2 and Table 4.6-1, which depict the impact the various future scenarios have on rates for retail customers. Note these rates include costs for generation, transmission and distribution, **not** general and administrative costs.

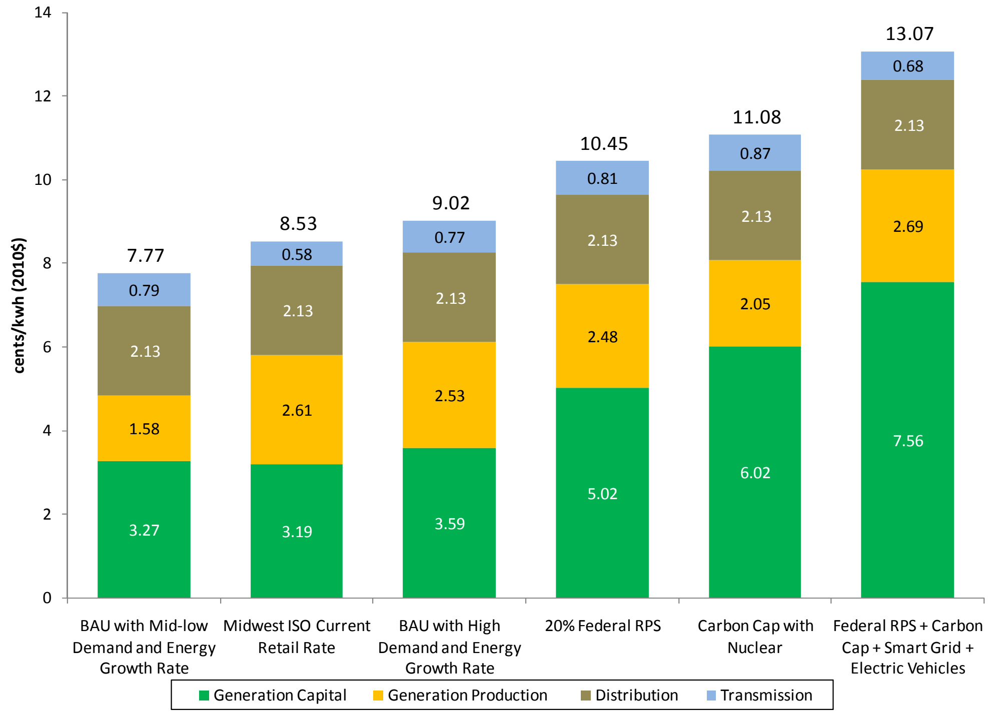


Figure 4.6-2: Comparison of Estimated Retail Rate for Each Future Scenario (cents per KWh in 2010 Dollars)

Table 4.6-1: 2025 Retail Rate Impacts in 2010$ of for Each Future Scenario

Case	Rate (cts/kWh)	Percent (Change from BAU)
BAU with Mid-low Demand and Energy Growth Rate	7.77	-8.9%
Business as Usual (Base Case)	8.53	0.0%
BAU with High Demand and Energy Growth Rate	9.02	+5.7%
20% Federal RPS	10.45	+22.5%
Carbon Cap with Nuclear	11.08	+29.9%
Federal RPS+Carbon Cap+Smart Grid+Electric Vehicles	13.07	+53.3%

4.6.4 Rate Impact Drivers under Future Policy Scenarios

Table 4.6-2 compares the Business as Usual with Mid-Low Demand and Energy Growth Rate (BAUMLDE) future scenario retail rate to the Midwest ISO current retail rate by rate component to illustrate which component is driving the overall estimated decrease of $90 to the average residential ratepayer's annual electricity bill.[37] The BAUMLDE is the only scenario resulting in an estimated retail rate lower than the current retail rate, which is largely driven by the low demand and energy growth rate assumed for this scenario based on the presumption the economic downturn will continue indefinitely.

Table 4.6-2: Comparison of BAUMLDE Future Retail Rate to Current

Business As Usual with Mid-Low Demand and Energy Growth Rate (BAUMLDE) Future Retail Rate	Rate Component				
	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh2009$)	3.19	2.61	0.58	2.13	8.53
BAUMLDE Future Retail Rate (cents per kWh2009$)	3.27	1.58	0.79	2.13	7.77
Percentage Change in Projected Retail Rate	2.4%	-39.6%	34.2%	-	-8.9%
Projected Shift in Avg. Residential Rate Payer's Annual Electricity Bill	$9.03	$(124.26)	24.01	-	$ (91.22)

Table 4.6-3 compares the Business as Usual with High Demand and Energy Growth Rate (BAUHDE) Future retail rate to the Midwest ISO current retail rate by rate component to illustrate which component is driving the overall estimated increase of $60 to the average residential ratepayer's annual electricity bill. The increase in generation capital and transmission investment in the BAUHDE Future is in part being driven by the need to meet the state renewable mandates included in the study. To meet the current state RPS mandates in the Midwest ISO footprint, an additional 21,000 MW of wind capacity is added through 2025, which also drives the need for the $15 billion in regional transmission investment included through 2025. In the BAUHDE Future, the share of energy met by wind increases from 2% in 2010 to approximately 11% in 2025, which results in a decrease in generation production costs.

Table 4.6-3: Comparison of BAUHDE Future Retail Rate to Current

Business as Usual with High Demand and Energy Growth Rate (BAUHDE)	Rate Component				
	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh2009$)	3.19	2.61	0.58	2.13	8.53
BAUHDE Future Retail Rate (cents per kWh2009$)	3.59	2.53	0.77	2.13	9.02
Percentage Change in Projected Retail Rate	12.4%	-3.2%	31.6%	-	5.8%
Projected Shift in Avg. Residential Rate Payer's Annual Electricity Bill**	$47.41	$ (10.09)	$ 22.20	-	$59.52

[37] Based upon an average monthly usage of 1 MWh.

Table 4.6-4 shows that the estimated rate under the 20% Federal RPS Future, designed to have 20% of the energy met by renewable energy in 2025 and approximately 23% higher than the current rate, represents an increase of nearly $230 to the residential ratepayer's annual electricity bill. The generation capital component is the key driver in the increase over the current retail rate, with the addition of 40,000 MW of wind capacity to meet the 20% Federal RPS. Offsetting the increase in generation capital is a reduction in generation production costs with 20% of the energy served by wind generation. Note the transmission assumed for the 20% Federal RPS is the same as in the BAUHDE Future, so the difference in the transmission rate component (in cents/kWh) between these two Futures is due to the lower load (kWh) assumed for the 20% Federal RPS Future.

Table 4.6-4: Comparison of 20% Federal RPS Future Scenario Retail Rate to Current

20% Federal RPS Future Scenario Retail Rate	Rate Component				
	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh2009$)	3.19	2.61	0.58	2.13	8.53
20% Federal RPS Future Scenario Retail Rate Future Retail Rate (cents per kWh2009$)	5.02	2.48	0.81	2.13	10.45
Percentage Change in Projected Retail Rate	57.1%	-5.0%	38.8%	-	22.5%
Projected Shift in Avg. Residential Rate Payer's Annual Electricity Bill**	$218.94	(15.78)	$27.21	-	$230.37

Table 4.6-5 shows the Carbon Cap with Nuclear Future, which targets a 30% reduction in CO2 emissions by 2025 from 2005 levels, results in a projected 30% increase over the current retail rate, representing nearly a $306 increase to the residential ratepayer's annual electricity bill. The main driver of the rate increase is due to the generation capital expenditures associated with the 8,400 MW of nuclear capacity added in this Future to achieve the 30% reduction in CO2 emissions. Offsetting the increase in generation capital expenditures is a reduction in generation production costs as energy met from nuclear generation nearly doubles from 9% in 2010 to 16% in 2025.

Table 4.6-5: Comparison of Carbon Cap with Nuclear Future Scenario Retail Rate to Current

Carbon Cap with Nuclear Future Scenario	Rate Component				
	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh2009$)	3.19	2.61	0.58	2.13	8.53
Carbon Cap with Nuclear Future Scenario Retail Rate Future Retail Rate (cents per kWh2009$)	6.02	2.05	0.87	2.13	11.08
Percentage Change in Projected Retail Rate	88.5%	-21.4%	48.4%	-	29.9%
Projected Shift in Avg. Residential Rate Payer's Annual Electricity Bill**	$339.23	$ (67.10)	34.01	-	306.14

Table 4.6-6 compares the "Kitchen Sink" future retail rate, which includes a 20% Federal RPS, carbon cap, smart gird investment, and increased electric vehicle usage, to the Midwest ISO current retail rate by rate component in order to illustrate which component is driving the overall estimated increase of $545 to the average residential ratepayer's annual electricity bill. Note for the 'Kitchen Sink' future scenario, 30% carbon reduction by 2025 is met using IGCC and CC generation types with sequestration technology, unlike the Carbon Cap and Trade with Nuclear Future. The 'Kitchen Sink' scenario shows the largest potential impact to retail rates, with a projected increase of over 50%—mainly driven by the amount of total new generation added in this future scenario, which is the highest of the five future scenarios at 82,000 MW.

Table 4.6-6: Comparison of "Kitchen Sink" Future Scenario Retail Rate to Current

"Kitchen Sink" Future	Rate Component				
	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh2009$)	3.19	2.61	0.58	2.13	8.53
"Kitchen Sink" Future Scenario Retail Rate Future Retail Rate (cents per kWh2009$)	7.56	2.69	0.68	2.13	13.07
Percentage Change in Projected Retail Rate	136.7%	2.9%	16.8%	-	53.3%
Projected Shift in Avg. Residential Rate Payer's Annual Electricity Bill**	$524.17	$ 9.02	$11.80	-	$545.00

Potential rate impacts from the five (5) future scenarios demonstrates higher electricity rates are likely; however, the magnitude of the rate increase will vary greatly, depending on actual economic and policy situations. The disparate range of outcomes illustrates the importance of performing long-term scenario analyses in order to provide decision-makers with the information needed to minimize potential impacts (in the form of higher rates) to end-users.

4.7 Ensuring Compliance

Midwest ISO and its stakeholders operate in highly regulated environments where compliance with tariffs, regulations, and standards—including provision of evidence of that compliance—is required; thus, compliance is a foundational focus area, imperative to ongoing success and one in which Midwest ISO must continually excel. The annual MTEP process constitutes a key component of Midwest ISO compliance activities.

4.7.1 Corporate Compliance Overview

Formed in May 2008 to provide high-level oversight for all Midwest ISO compliance activities and support an overarching compliance culture, the Corporate Compliance Oversight Committee (CCOC) identifies and pursues opportunities for continuous improvement to ensure effective compliance management for Midwest ISO. The CCOC directs the activities of a newly-created Corporate Compliance Management Team (CCMT) and oversees the development and implementation of the Midwest ISO Compliance Master Plan addressing framework, processes, and tools for managing compliance activities.

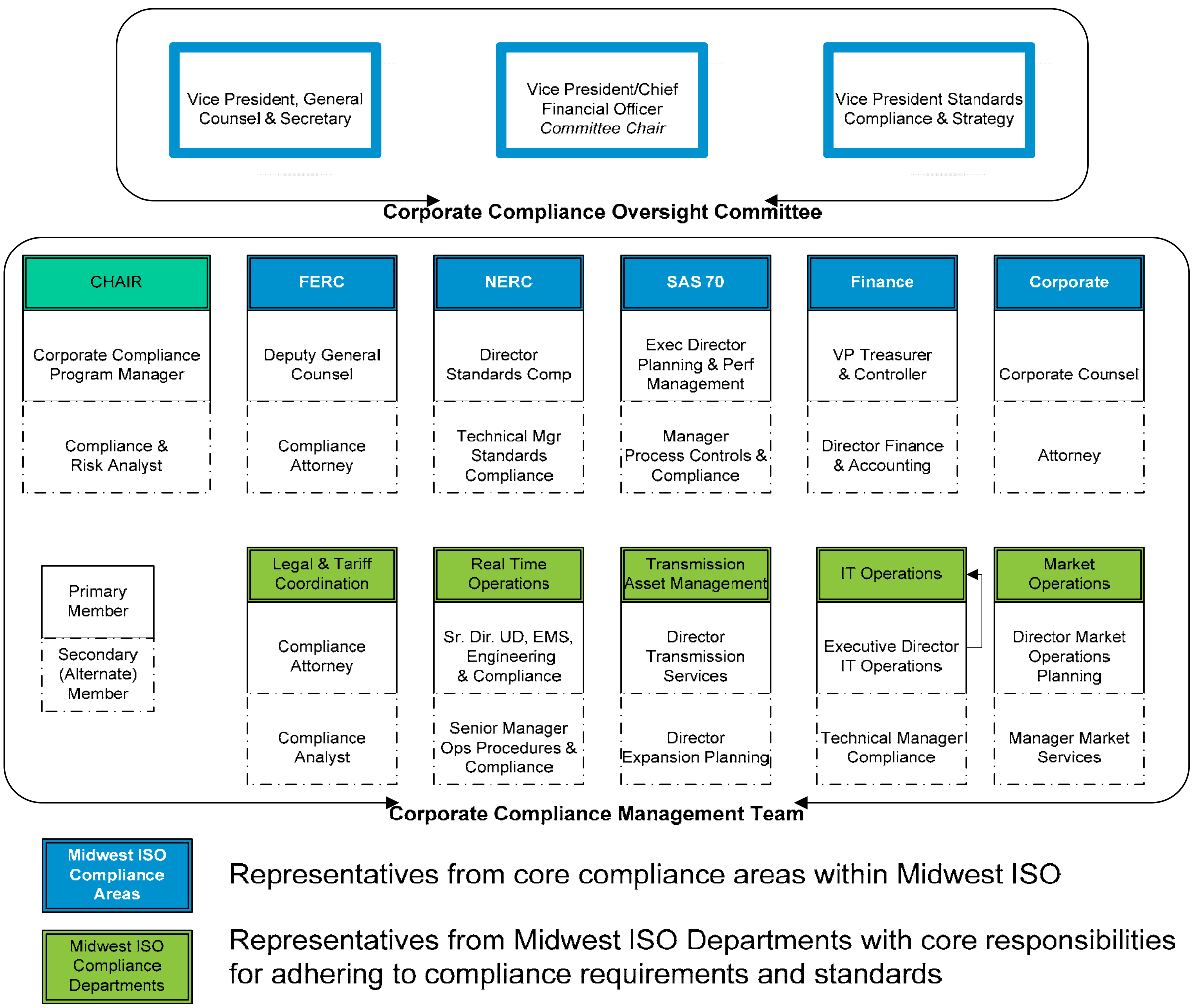


Figure 4.7-1: CCOC and CCMT Organizational Chart

As part of the Corporate Compliance Management Team (CCMT), Transmission Asset Management (TAM) performs a Baseline Reliability Analysis[38] through the annual MTEP studies in support of NERC compliance. The Baseline Reliability Analysis assesses the existing plan against NERC contingency Table 1 events from the TPL-001 through TPL-004 Transmission Planning (TPL) standards. Midwest ISO evaluates whether the system as planned meets NERC TPL standards. Midwest ISO develops and tests additional transmission system upgrades to address any identified issues, and then tests the performance of the corrective action plan for baseline reliability. Interconnection Reliability Operating Limit (IROL) testing in the planning horizon is also accomplished by means of the MTEP process in support of the NERC FAC-014 (Facility Connection Requirements) standard.

This compliance section describes the study process used to make a system reliability assessment. The regulatory approved, NERC-defined standards—as well as proposed Midwest Reliability Organization (MRO) Regional Standards—are listed and referenced in Table 4.7-1, below.

Table 4.7-1: NERC and Regional Standards Applicable to MTEP Study

NERC Standards	Effective Date	NERC Website
FAC-010-2.1	April 19, 2010	http://www.nerc.com/
FAC-014-2	April 29, 2010	http://www.nerc.com/
TPL-001-0.1	May 13, 2010	http://www.nerc.com/
TPL-002-0a	April 23, 2010	http://www.nerc.com/
TPL-003-0a	April 23, 2010	http://www.nerc.com/
TPL-004-0	April 1, 2005	http://www.nerc.com/
MRO Standards	Effective Date	MRO Website
TPL-503-MRO-01	December 6, 2007	http://www.midwestreliabilily.org
PRC-502-MRO-01	December 6, 2007	http://www.midwestreliabilily.org

[38] Midwest ISO's Transmission Planning BPM–Section 4.3.2 Baseline Reliability Analysis Methodology: http://oasis.midwestiso.org/documents/miso/Transmission%20Planning%20BPM.pdf

4.7.2 Areas of Compliance Addressed Through MTEP Process

Midwest ISO has three key areas of compliance addressed through its annual MTEP study:

- **FERC Order 890:** Process steps incorporated within the MTEP cycle to demonstrate compliance are documented in subsequent subsections below.
- **NERC Standards:** A general discussion on Midwest ISO support of NERC compliance is documented below. Specific narratives corresponding to individual NERC TPL requirements and pointers to associated evidence can be found in Appendix E1.
- **Module E:** Process steps incorporated within the MTEP cycle to demonstrate compliance to FERC Order 890 are documented below.

4.7.2.1 FERC Order 890 Planning Principles

On August 13, 2008, Midwest Independent Transmission System Operator, Inc. (Midwest ISO) submitted revisions to Attachment FF (Transmission Expansion Planning Protocol) of its Open Access Transmission and Energy Markets Tariff (TEMT or Third Revised Volume) and its Open Access Transmission, Energy and Operating Reserve Markets Tariff (ASM Tariff or Fourth Revised Volume), in Docket No. OA08-53-001, in compliance with the Commission's directives in the Midwest ISO Planning Order. On May 21, 2009, FERC conditionally accepted Midwest ISO's compliance filing in Docket No. OA08-53-001, subject to further compliance filing. The nine (9) planning principles each transmission provider was directed to address by Order No. 890 in its Attachment K planning process include the following:

1. Coordination
2. Openness
3. Transparency
4. Information exchange
5. Comparability
6. Dispute resolution
7. Regional participation
8. Economic planning studies
9. Cost allocation for new projects

The Commission explained it had adopted a principles-based reform to allow flexibility in implementation of and to build upon transmission planning efforts and processes already underway in many regions of the country. The Commission also explained, however, that although Order No. 890 allows for flexibility, each transmission provider has a clear obligation to address each of the nine principles in its transmission planning process, and all of these principles must be fully addressed in the tariff language filed with the Commission. The Commission emphasized that tariff rules, as supplemented with web-posted business practices when appropriate, must be specific and clear in order to facilitate compliance by transmission providers and place customers on notice of their rights and obligations. In Order No. 890, the Commission reformed the pro forma OATT to clarify and expand the obligations of transmission providers to ensure transmission service is provided on a non-discriminatory basis. One of the Commission's primary reforms was designed to address the lack of specificity regarding how customers and other stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in planning activities, the Commission directed all transmission providers to develop a transmission planning process that satisfies nine principles, and to clearly describe that process in a new attachment to their OATT (Attachment K). Below is a link to the revised Midwest ISO Attachment FF (Transmission Expansion Planning Protocol) of its Open Access Transmission and Energy Markets Tariff:

https://www.midwestiso.org/_layouts/MISO/ECM/Download.aspx?ID=19272

4.7.2.2 Planning Process Steps to Address Order 890

A key element of the principles is the involvement of transmission customers early in the planning process. At the beginning of the MTEP10 planning cycle, Subregional Planning Meetings (SPMs) were held in the West, Central and East planning regions of Midwest ISO. These SPMs provide forums for stakeholders to become engaged early in the process. Newly proposed transmission projects were discussed at the SPM held in December. Additional Subregional planning meetings were held through the course of the MTEP cycle to provide stakeholders with information and an opportunity to provide feedback on transmission projects proposed in the current cycle. In order to accommodate the timely exchange of planning information between Transmission Owners, Transmission Customers, Stakeholders, and Midwest ISO, as required to meet the Order 890 Planning Requirements and based on discussions with stakeholders before and during the December 2009 SPMs, the following schedule and requirements for the SPMs was established:

Table 4.7-1: General MTEP Cycle Planning Process Milestones

Date	Deliverable	Responsible Entity
By September 15th	Per Commission Order on Compliance: Transmission Owner's local plan, which consists of a list of planned and proposed projects, shall be made available on the Midwest ISO (Transmission Provider) website for review by the PAC, the PS, and the SPM participants, subject to CEII and confidentiality provisions in Midwest ISO Attachment FF	Transmission Owner
By November 1st	Transmission Owners submit planning reports, per BPM specifications, for projects to be included in Appendix A, including but not limited to: 1. Planning criteria expected to be violated or other issue to be addressed 2. Load level(s) supporting the project needs, for the area served by the TO 3. Limiting element behind identified expected constraint	Transmission Owner
By December 30th	1st SPM: Presentation of all current cycle MTEP projects and discussion of initial comments by stakeholders	Midwest ISO Staff, Transmission Owners and Stakeholders
By January 31st	Major equipment within scope of work associated with each project such as: a. Transformers b. Breakers c. Major bus work d. New line structures and/or conductor e. Miles of new conductor f. Other major equipment 2. Expected cost of the project 3. Significant milestones in project schedule up to the projected in-service date	Transmission Owner
By February 15th	All information submitted by Transmission Owners posted on Midwest ISO website	Midwest ISO Staff
By March 31st	2nd SPM: Preliminary results of Midwest ISO independent evaluation of transmission proposals by Transmission Owners and discussion of feedback received from staff and Stakeholders on alternatives to TO proposals	Midwest ISO Staff, Transmission Owners and Stakeholders
By April 15th	Feedback on all current MTEP projects including project alternative proposals	Transmission Customers and other MTEP stakeholders
By June 15th	3rd and Final SPM with Midwest ISO independent evaluation of all current MTEP projects and cost allocation calculations of all RECB1 and RECB2 eligible projects and MVPs	Midwest ISO Staff
By July 15th	First Draft of current cycle MTEP report	Midwest ISO Staff

Please note additional, more focused Technical Study Task Forces were formed as necessary in order to carry out sub-regional planning responsibilities. Refer to Table 4.7-2, below.

Table 4.7-2: MTEP10 SPM Schedule

Date	Meeting	Location
2-Dec-09	1st West Sub Regional Planning Meeting	St Paul, MN
7-Dec-09	1st Central Sub Regional Planning Meeting	Carmel, IN
2-Dec-09	1st East Sub Regional Planning Meeting	Livonia, MI
19-Mar-10	Michigan Technical Study Task Force Meeting	Lansing, MI
31-Mar-10	2nd East Sub Regional Planning Meeting	Detroit, MI
1-Apr-10	2nd Central Sub Regional Planning Meeting	Carmel, IN
5-Apr-10	2nd West Sub Regional Planning Meeting	St. Paul, MN
5-May-10	West Region Technical Study Task Force Meeting	St. Paul, MN
20-May-10	Michigan Technical Study Task Force Meeting	Livonia, MI
15-Jun-10	Michigan Technical Study Task Force Meeting	Jackson, MI
17-Jun-10	3rd West Sub Regional Planning Meeting	St. Paul, MN
18-Jun-10	3rd Central Sub Regional Planning Meeting	Carmel, IN
21-Jun-10	3rd East Sub Regional Planning Meeting	Cadillac, MI
9-Jul-10	Michigan Technical Study Task Force Meeting	Conference call
19-Jul-10	Michigan Technical Study Task Force Meeting	Lansing, MI

The Information Requirement and Schedules described above are also posted on the Midwest ISO website at the following links, respectively:

https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP%20Information%20Exchange%20Schedules_Requirements.pdf

https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=89495

4.7.2.3 Other Key Inputs to the Planning Process

The analytical inputs and assumptions for the baseline reliability analysis include the following:

- The transmission system condition to be modeled and analyzed with associated load, generation, and base interchange values
- Contingencies and system events to be analyzed
- Facilities monitored with respect to the Planning Criteria
- Current transmission expansion plans from the planning process

Please note planning criteria, models, contingencies, and mitigation plan development are discussed in Appendix E.1.

4.7.2.4 Economic Planning Requirements of Order 890

The economic planning studies principle of Order No. 890 requires transmission providers to account for economic and reliability considerations in the transmission planning process. The Commission explained in Order No. 890 that good utility practice requires transmission providers to plan not only to maintain reliability but also to consider whether transmission upgrades can reduce the overall cost of serving native load. The economic planning principle is designed to ensure economic considerations are adequately addressed when planning for OATT customers, as well.

The Commission emphasized the scope of economic studies should not just be limited to individual requests for transmission service. Customers must be given the opportunity to obtain studies evaluating potential upgrades or other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis.

The Midwest ISO planning process complies with the economic planning studies principle in many areas of Attachment FF and the Transmission Planning Business Practices Manual (TP BPM) including, for example, provisions concerning Regionally Beneficial Projects in section II.B of Attachment FF, which have been approved by the Commission. Midwest ISO, by means of the Planning Advisory Committee and other Technical Study Groups formed to address Targeted Studies, conducts long-range economic planning with stakeholders. This long-range planning process has been developed with stakeholders, has a planning horizon of up to 20 years, and considers a multitude of economic, policy, and operational factors in seeking to identify an optimal expansion plan for the long-term. The process provides a blueprint for resolving future congestion and reliability needs associated with generation expansion scenarios. The JCSP and RGOS Targeted Studies are examples of this long range planning approach.

In addition to this long-term view, Attachment FF provides an opportunity for stakeholders to provide input concerning near-term congestion issues impacting customers. Through the Sub-regional Planning Meeting (SPM) process, Midwest ISO reviews stakeholder's historical congestion data and evaluates the expected impact of the approved upgrades, and develops prioritized study scopes to address the most significant and persistent congestion or generation integration issues within the Midwest ISO footprint. In this way the most problematic issues, identified and prioritized collectively with all stakeholders, are addressed, rather than by addressing issues on a request-by-request basis. Targeted Studies such as the Top Congested Flowgate Study, as well as ad hoc evaluations to address specific issues raised by stakeholders during SPM discussions, are examples of near term economic studies conducted in compliance with Order No. 890 economic planning requirements. In its Orders accepting Midwest ISO compliance filings, the Commission found that Attachment FF complies with the Order No. 890 economic planning studies principle. The Commission found that this economic planning approach considers the needs of the entire region when it coordinates its stakeholders' routine short-term reliability needs and short to mid-term range congestion and generation integration needs with the long-term developmental needs of the entire Midwest ISO footprint. In addition, the Commission stated the Midwest ISO approach of addressing the most significant congestion or generation integration issues, identified and prioritized collectively with all stakeholders, is consistent with or superior to the Order No. 890 requirement of responding to a select number of economic studies on a request-by-request basis.

4.7.2.5 NERC Standards

The Baseline Reliability Analysis performed in the annual MTEP studies demonstrates the Midwest ISO portion of the interconnected transmission system is planned in accordance with TPL-001 through TPL-004. This is accomplished through a series of evaluations of the system with planned and proposed transmission system upgrades identified in the Midwest ISO TP BPM Section 4.3.1–Steps in the Short-Term Planning Process[39], ensuring transmission system upgrades are sufficient and necessary to meet NERC (TPL and FAC) and Regional planning standards for system reliability. The primary inputs and assumptions[40] for the Baseline Reliability Analysis include the following:

- The transmission system condition to be modeled and analyzed with associated load
- Generation and base interchange values
- Contingencies and system events to be analyzed
- Facilities monitored with respect to planning criteria
- Current transmission expansion plans from the planning process

Midwest ISO performs valid transmission studies up to and beyond the five-year, short-term planning horizon useful in the identification of critical thermal, voltage, and stability issues. All MTEP reports and Appendices list all contingency results both before and after impact of planned/proposed upgrades in order to demonstrate their effectiveness within the project evaluation process. Each annual iteration of the MTEP report includes a list of all existing and planned facilities.

At the end of each valid MTEP assessment, additional analysis is performed to ensure there are no outstanding limits that have not been mitigated. For MTEP studies, Appendices A and B list all planned/proposed upgrades needed to meet system performance. Project completion is closely monitored by Midwest ISO and reported to the Board of Directors on a quarterly basis. MTEP project in-service dates are included in MTEP Appendices A and B, with each project monitored through project tracking in collaboration that project's respective Transmission Owner (TO). Proposed projects in Appendix B are evaluated for lead-time and need date and recommended for Action Date. Project implementation plans are reviewed quarterly and—when revised—evaluated at the time of revision and further reviewed in subsequent MTEP analyses.

In addition to its Baseline Reliability Study, Midwest ISO, in coordination with its TOs, routinely performs additional studies in compliance with the NERC reliability standards. These analyses include evaluations of thermal loading, voltages, and system stability, as well as loss-of-load expectation associated with determining import capabilities needed to support resource adequacy requirements. Typical analyses include the following:

1. Annual system-wide screening analyses to determine system thermal loading performance under system intact, single-element contingency, and multiple-element contingency conditions
2. Regional detailed evaluations of system performance against planning criteria to determine the most effective reinforcement solutions to identified concerns
3. Ongoing evaluations of requests for transmission service that identify upgrades necessary to expand or improve transmission service
4. Periodic evaluations of generator stability under severe fault conditions at existing generating stations
5. Ongoing evaluations of impacts of potential new generator interconnections to Midwest ISO TO systems

[39] Midwest ISO's Transmission Planning BPM–Section 4.3.1 Steps in the Short-Term Planning Process: http://oasis.midwestiso.org/documents/miso/Transmission%20Planning%20BPM.pdf

[40] Midwest ISO's Transmission Planning BPM–Section 4.3.3 Reliability Analysis–Process Overview: http://oasis.midwestiso.org/documents/miso/Transmission%20Planning%20BPM.pdf

6. Periodic evaluations of extreme disturbance impacts in cooperation with the Regional Reliability Organizations study efforts
7. Periodic internally initiated independent evaluations of extreme disturbance impacts

Other studies are performed that have been generated by either internal investigation or at the request of stakeholders and other potential users of the system, including prospective Independent Power Producers (IPPs), interconnections with other control areas, Generation Interconnection and/or Transmission Service Requests (TSRs). In these cases, engineering judgment may be used to determine appropriate contingency scenarios that need to be studied in order to ensure compliance with any applicable individual TO transmission planning criteria and the NERC Planning Standards. TO planning criteria is outlined in Appendix E.1.

4.7.2.6 Module E Compliance

In accordance with Module E of the Tariff, Midwest ISO is required to perform Loss of Load Expectation (LOLE) analysis annually in order to determine a minimum Planning Reserve Margin (PRM) for the upcoming Planning Year (June through May), as well as to perform a ten-year LOLE analysis for informational purposes. The 2009 Planning Year was the first Planning Year in which Midwest ISO performed LOLE analysis for the purpose of establishing a PRM.

In addition, the Midwest Reliability Organization and ReliabilityFirst Corporation have created standards for performing LOLE analysis. These standards will be applicable to Midwest ISO in its capacity as a NERC-registered Planning Authority (PA). The study process described here has been designed to be compliant with the respective standards in the Midwest ISO footprint.

The 2010 Midwest ISO LOLE study report can be found at the following link:

https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/2010%20LOLE%20Study%20Report.pdf

5 Midwest ISO System Information

5.1 Midwest ISO System Overview

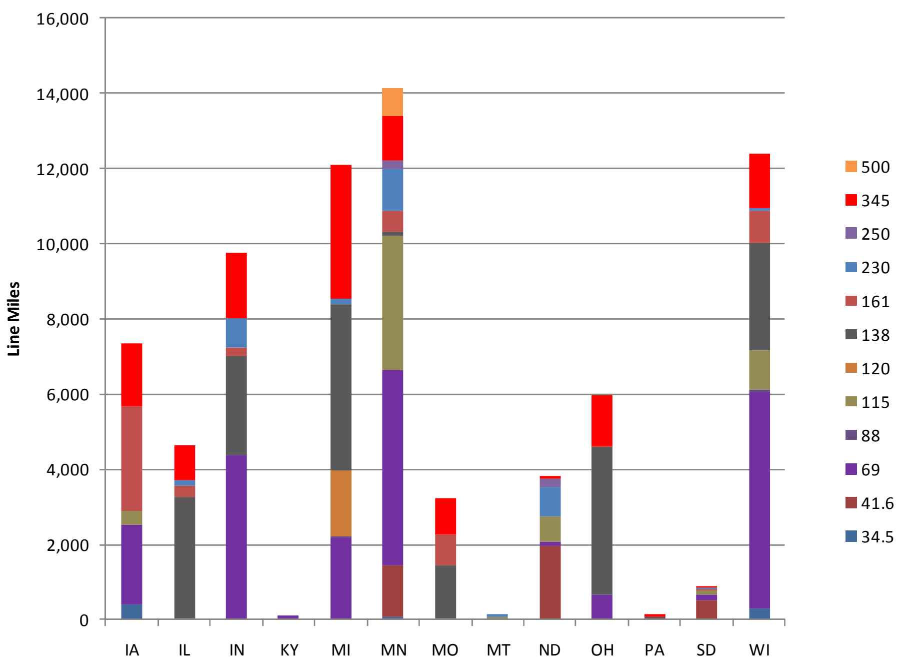
To furnish context to new facility statistics associated with MTEP Appendices A, B, and C, MTEP10 contains statistical data pertaining to the existing transmission system under Midwest ISO functional control (typically facilities >100 kV) and to non-transferred facilities under agency agreement (typically facilities <100 kV), as well as analyses of total load and generation. For ease of reference, Transmission Owner (TO) facility lists are posted online on the Midwest ISO website at https://www.midwestiso.org/StakeholderCenter/Members/Pages/TransmissionFacilities.aspx. Transmission line, substation, and transformer statistics described in subsequent subsections are based on these function control listings.

Further, Transmission system assets and capacity described in this section and in section 5.2 reflect current Midwest ISO membership as of July 31st, 2010. Impacts of future changes in Midwest ISO membership are also captured in section 5.3, which outlines long-term risk assessment strategies.

5.1.1 Existing Transmission System Assets

5.1.1.1 Transmission Lines

Midwest ISO Transmission Owners[41] (TOs) have transmission lines with operating voltages from 500 kV–35 kV. Eight (8) TOs have 69 kV transmission under Midwest ISO functional control. Most utilities have significantly more line miles at the lower voltages (100 kV or less) than higher voltages (230, 345, and 500 kV). There are approximately 31,800 miles at voltages between 115 to 161 kV, and there are approximately 17,370 miles at voltages between 230 to 500 kV. Including non-transferred facilities under agency agreements, there are now over 20,000 miles of 69 kV lines, 3,800 miles of 41.6 kV lines, and 790 miles of 34.5 kV lines. Total line mileages in all voltage classes comprise 74,650 miles. Refer to Figure 5.1-1, which depicts Midwest ISO Transmission Owners' transmission line miles by voltage class and state.



[41] Dairyland Power Cooperative and Big Rivers Electric Corporation are Midwest ISO Transmission Owners, effective June 1, 2010 and September 1, 2010, respectively. These transmission owners did not participate in the MTEP10 planning cycle; however, DPC's facilities *are* included in these statistics.

Figure 5.1-1: Midwest ISO Transmission by Voltage Class

For the purposes of this report, Midwest ISO is divided into three (3) planning regions: Central, East, and West. Figure 5.1-2 shows significantly more line miles in the West planning region, which is geographically larger than the other two regions.

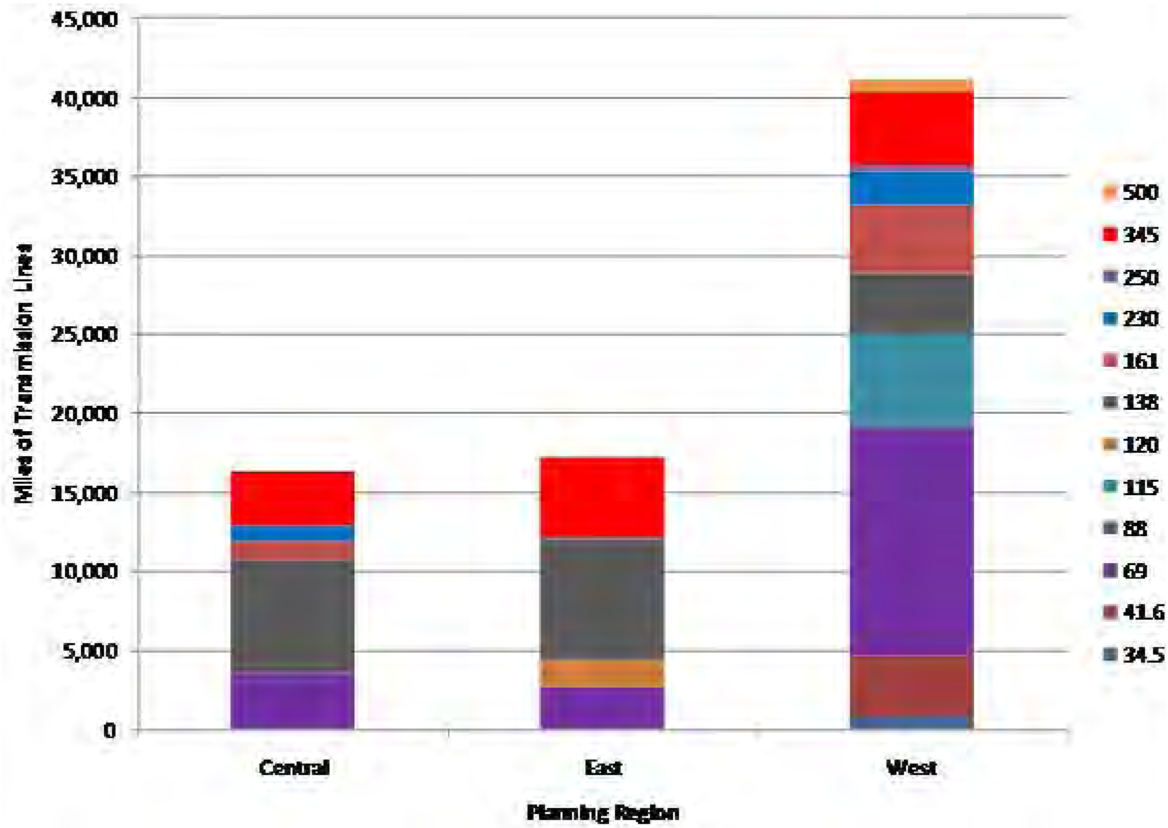


Figure 5.1-2: Transmission under Midwest ISO Functional Control by Planning Region and Voltage Class

5.1.1.2 Transmission Substations

Transmission substations transform voltage from one level to another. Voltage is stepped down as power moves closer to end users. Switching stations are substations that have transmission line terminations but do not have transformers. There are approximately 2,300 transmission substations and switching stations under Midwest ISO functional control and approximately 640 under agency agreements. Refer to Figure 5.1-3, which depicts the number of substations and switching stations by state. In the chart, the color blue denotes equipment under Midwest ISO Functional Control (FC), while red represents Non-Transferred (NT) equipment not under Midwest ISO functional control. Note most utilities in Wisconsin have 69 kV transmission under Midwest ISO functional control, placing many substations and switching stations at the 69 kV voltage level within the Midwest ISO footprint.

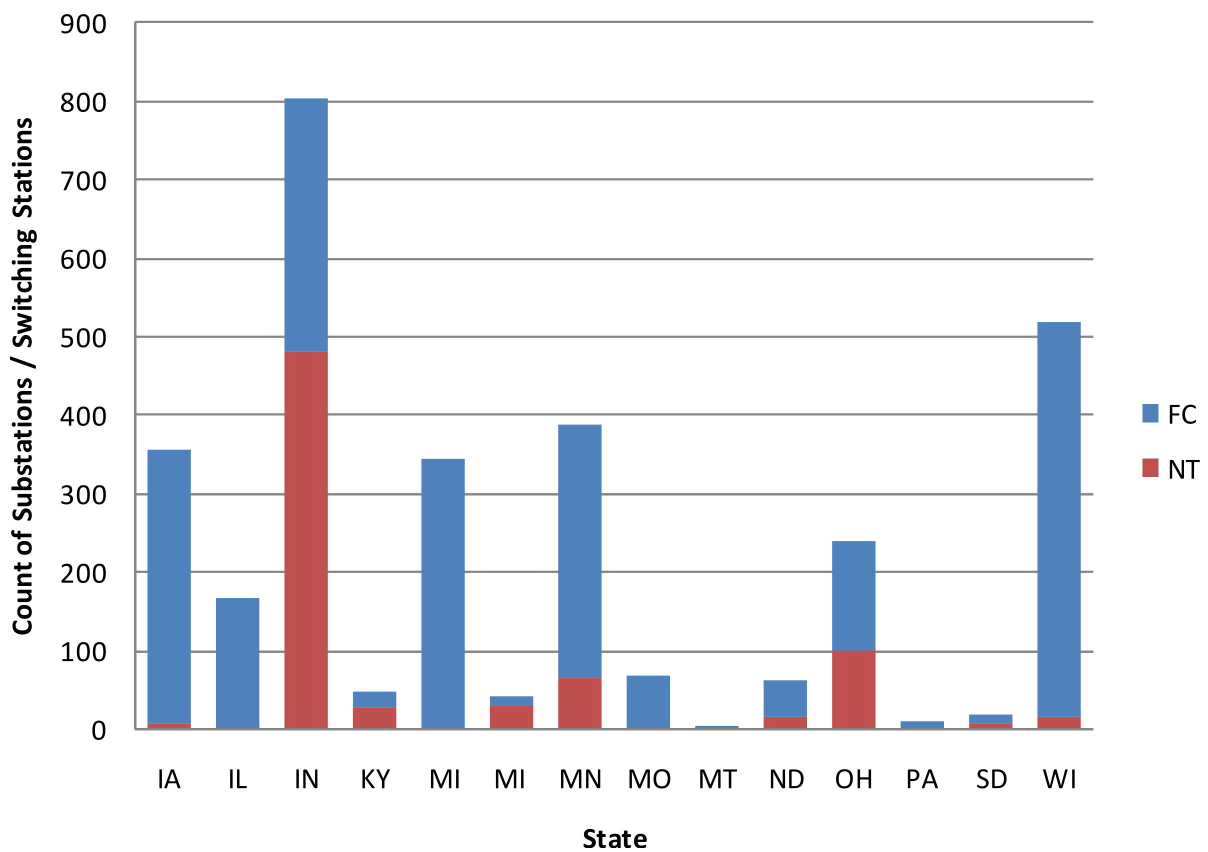


Figure 5.1-3: Substations & Switching Stations Count by State

Typical transmission substations have a high-side voltage of 345 kV and a low-side voltage of 115 kV, 120 kV, 138 kV or 161 kV. There are also 500/345 kV substations, 138/69 kV substations, and many other combinations. Including non-transferred facilities under agency agreements, there are now more transformers with 69 kV and 34.5 kV low-side voltages than in previous MTEP cycles. Refer to Table 5.1-1, which provides information demonstrating the range of transmission transformers in Midwest ISO and the number of transformers at those voltage levels.

Table 5.1-1: Transmission Transformers

High-side kV	Low-side kV	Count	Total MVA
765	138	2	2,073
500	345	2	2,408
500	230	4	672
345	230	30	15,353
345	161	51	23,042
345	138	219	90,187
345	120	26	11,830
345	115	37	15,898
345	69	11	1,972
230	230	1	800
230	161	2	589
230	138	19	4,418
230	120	13	7,335
230	115	41	5,658
230	69	51	5,774
230	41.6	3	86
161	138	18	3,192
161	115	16	2,582
161	69	120	10,204
138	120	3	748
138	115	7	899
138	69	374	33,515
120	120	2	1,120
115	115	2	440
115	88	1	50
115	69	90	6,224
115	41.6	33	923
115	34.5	17	1,380
69	69	1	50
69	41.6	4	28
69	34.5	17	50

5.1.1.3 Generating Plants

There are 492 generating plants in the Midwest ISO system, with 1,210 generating units at those plants. Refer to Figure 5.1-4, which depicts the distribution of those plants and units across the states within the Midwest ISO footprint. Exact number of units will vary since Commercial Pricing Node (CPN) information was used to produce the statistics. Wind plants are counted as a single unit per plant although these plants may have many individual turbines. Further, statistics are approximate since multiple wind plants may be connected to the same location. Please note, too, the large number of plants and units in Iowa and Minnesota is in part attributable to wind plants. There was an increase of 26 plants in Iowa from the number of plants identified in MTEP09 due to wind plant integration and the addition of new members. There have also been 15 plant additions in Minnesota since MTEP09, attributable to interconnection of wind plants. Type and capability of the generation fleet is described in further detail in section 5.1.7 of this document.

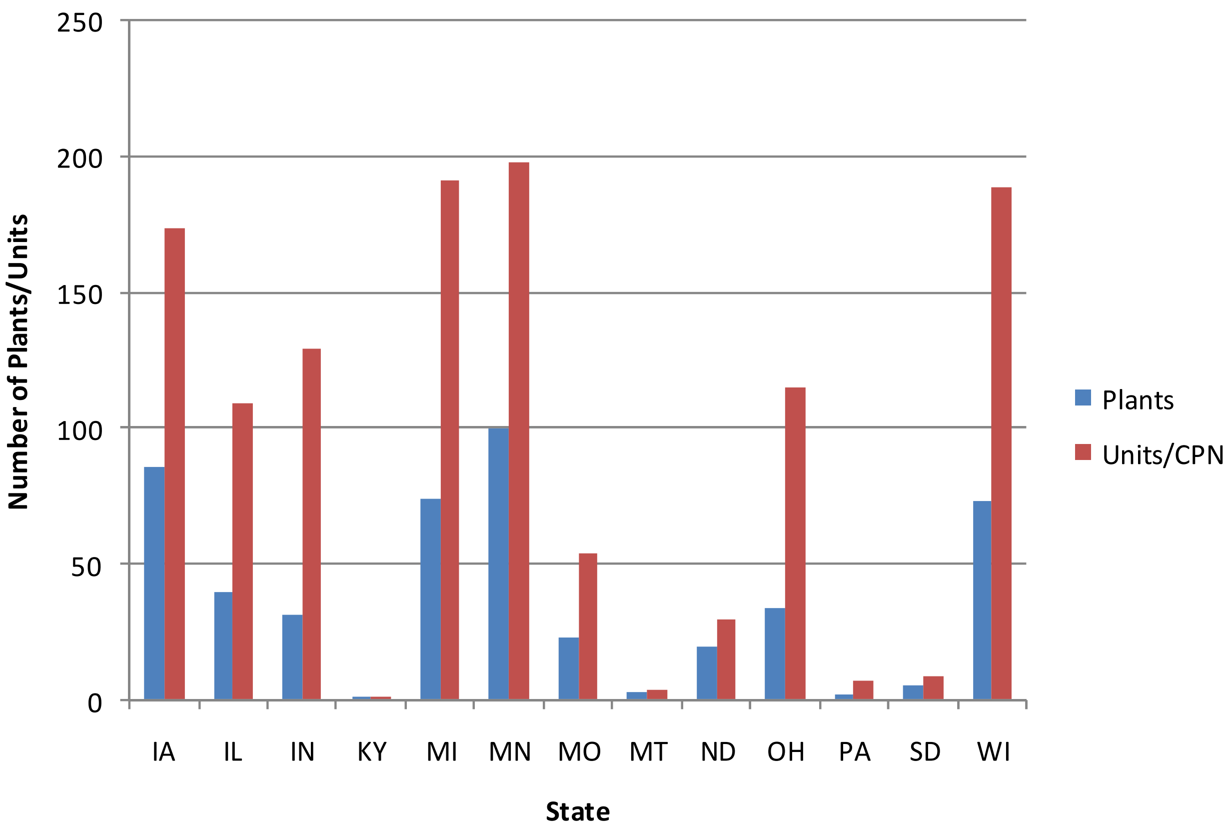


Figure 5.1-4: Generating Plants and Units

5.1.1.4 Reactive Resources

To maintain system voltage levels, there are other sources of reactive power on the transmission system in addition to reactive supplies provided by generating plants and transmission line capacitance. Switched capacitors and reactors provide voltage control. There are approximately 1,200 devices on the system at many voltage levels. Devices are often put on tertiary windings of transformers; hence, a large proportion of the devices are at lower voltages.

Table 5.1-2: Switched Shunts

kV	Capacitor (MVAR)	Reactor (MVAR)
500	600	
345	1,157	(1,600)
230	1,227	(45)
161	1,675	(310)
138	7,680	
120	640	
118	32	
115	5,167	(125)
72	99	
69	6,767	(61)
46	2,713	
41.6	22	(5)
36	525	
34.5	723	(157)
27.6	565	
26.4	29	
26.2	313	
24.9	7	(125)
23	142	
15	20	
14.4	77	
13.8	319	(402)
13.2	98	(27)
12.5	20	
12.47	17	(30)
11.5	91	
8.32	23	
4.4	5	
4.2	26	
0.69	17	
0.66	11	
0.6	386	
0.48	51	
Total	**31,243**	**(2,887)**

5.2 Demand

Without adding demand from Midwest ISO's new membership in 2009 and 2010, the average growth rate in gross demand forecasts over the ten-year assessment time frame is 0.9%, slightly down from the last year's forecast of 1.0%. This drop is not as significant as the 5% decrease reported in 2009 relative to 2008. These decreases in gross demand forecasts are driven by the economic downturn.

New Midwest ISO members reflect a positive 3.9% average growth rate over this year's assessment timeframe and after including them to the forecast described above, a 1.1% growth rate is forecasted over this year's 2010 assessment time frame.

Midwest ISO does not prepare a long-term load forecast. Instead, load projections are reported by Network Customers as required under the Resource Adequacy section (Module E) of the Tariff. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads. To account for uncertainties in load forecasts, Midwest ISO applies a probability distribution to consider a larger range of forecasted demand levels. Ten (10) year peak demand and load modifying resource forecasts are detailed in the following sections.

5.2.1 Unrestricted Non-Coincident Peak

The demands as reported by Network Customers are weather normalized utilizing 50/50 forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50% chance the actual load will be higher and a 50% chance the actual load will be lower than the forecast.

A non-coincident peak load forecast is created on a regional basis by summing the forecasts for the individual Load Serving Entities (LSE) in the larger regional area of interest. Table 5.2-1 compares the 2010 unrestricted non-coincident demand forecasts ("Midwest ISO") to that of 2009 ("2009 Forecast"). This forecast is unrestricted, as it is not adjusted for each area's output under system peak conditions through applying the diversity factor discussed in the next paragraph.

Table 5.2-1: Unrestricted Non-Coincident Peak (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
West	38,701	39,170	39,733	40,211	40,602	40,992	41,351	41,758	42,152	42,482
East	37,241	37,727	38,414	38,502	38,544	38,284	38,491	38,641	38,860	39,070
Central	37,106	39,830	41,218	41,377	41,577	41,854	42,116	42,430	42,796	43,170
2010 Forecast	113,048	116,727	119,364	120,089	120,723	121,129	121,959	122,829	123,808	124,723
2009 Forecast	108,599	111,332	111,897	112,301	113,072	113,976	114,962	115,970	116,951	

Using four years of this historic data, a load diversity factor was calculated by observing the individual peaks of each balancing authority and comparing them against the system peak for the load zone. When aggregated, there is a 0.955 diversity factor which was applied to the peak to obtain the total internal demand. The same diversity factor was applied to all ten years. As shown in Table 5.2-2, the Total Internal Demand forecast ranges from 107,961 MW in 2010 to 119,110 MW in 2019.

Table 5.2-2: Total Internal Coincident Demand (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2010 Forecast	107,961	111,475	113,993	114,685	115,290	115,678	116,471	117,301	118,236	119,110
2009 Forecast	103,864	106,478	107,019	107,405	108,142	109,006	109,950	110,914	111,852	

5.2.2 Demand Resources

All demand side management totals and net internal demands use only reported loads and do not assume additional demand side management growth beyond that which is currently registered. Midwest ISO currently separates demand resources into two (2) separate categories: Direct Controlled Load Management (DCLM) and Interruptible Load.

The following demand resources were gathered prior to the 2010 summer peak period and thus do not reflect any changes in designations which occurred after that period.

5.2.2.1 Direct Controlled Load Management

DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for 'peak shaving'. In the Midwest ISO market, air conditioner interruption programs account for the vast majority of DCLM during the summer months. Refer to Table 5.2-3, which details the reported 2010 DCLM forecasts by Planning Region and compares it to the total 2009 data request forecast.

Table 5.2-3: Direct Controlled Load Management (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
West	84	84	84	84	84	84	84	84	84	84
East	242	242	242	242	242	242	242	242	242	242
Central	142	142	142	142	142	142	142	142	142	142
2010 Forecast	467	467	467	467	467	467	467	467	467	467
2009 Forecast	610	610	610	610	610	610	610	610	610	

5.2.2.2 Interruptible Load

Interruptible Load is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. Table 5.2-4 details the reported 2010 Interruptible forecasts by Planning Region and compares it to the total 2009 data request forecast.

Table 5.2-4: Interruptible Load (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
West	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213
East	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257
Central	405	405	405	405	405	405	405	405	405	405
2010 Forecast	2,874	2,874	2,874	2,874	2,874	2,874	2,874	2,874	2,874	2,874
2009 Forecast	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	

5.2.3 Behind-the-Meter Generation

In the Midwest ISO footprint, there is approximately 4 GW of generation capacity that Market Participants designate as a capacity resource which does not participate directly in the Energy and Ancillary Services Market. When producing power these resources act as a load modifier at the load zone—CPNode—where they are connected. This capacity is referred to as Behind-the-Meter Generation (BTMG). Although BTMG acts like a reduction in load at the market meter in real time, for resource adequacy purposes these resources are treated as a Capacity Resource. Table 5.2-5 details the amount of BTMG registered with Midwest ISO.

Table 5.2-5: Behind-the-Meter Generation (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
West	911	911	911	911	911	911	911	911	911	911
East	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921
Central	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
2010 Forecast	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
2009 Forecast	4,216	4,216	4,216	4,216	4,216	4,216	4,216	4,216	4,216	

5.2.4 Net Internal Demand (Coincident)

Net Internal Demand is the Total Internal Demand less Demand Resources as seen in the Figure 5.2-1 formula. During peak conditions, BTMG will act as a load offset as seen by Midwest ISO meters. To account for this effect, a Probable Peak Load number is also calculated which treats BTMG as a load offset as seen in Figure 5.2-2. When calculating Net Internal Demand and Probable Peak Load, it is assumed that all Demand Resources are reducing demand at the reported levels during the system peak. If there is adequate capacity during the system peak, it is not expected that all demand side management programs will be executed.

Net Internal Demand = Total Internal Demand–DCLM–IL

Figure 5.2-1: Net Internal Demand Formula

Probable Peak Load = Total Internal Demand–DCLM–IL–BTMG

Figure 5.2-2: Probable Peak Load

Projected Net Internal Demand for the Midwest ISO market ranges from 104,620 MW in 2010 to 115,769 MW in 2019. An increase in Total Internal Demand caused the Net Internal Demand forecast in the 2010 demand projection to increase by approximately 3.1% compared to 2009. Table 5.2-6 details 2010 and 2009 data request coincident net internal demand forecasts and their associated growth rates. The average growth rate for Net Internal Demand in 2010 is 1.1% compared to a 1.0% average growth rate reflected in the 2009 forecast.

Table 5.2-6: Net Internal Coincident Demand (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2010 Forecast	104,620	108,134	110,652	111,344	111,949	112,337	113,130	113,960	114,895	115,769
Growth Rate		3.4%	2.3%	0.6%	0.5%	0.3%	0.7%	0.7%	0.8%	0.8%
2009 Forecast	101,493	104,107	104,648	105,034	105,771	106,635	107,579	108,543	109,481	
Growth Rate		2.6%	0.5%	0.4%	0.7%	0.8%	0.9%	0.9%	0.9%	

The 3.4% increase in 2011 reflects the Big Rivers Electric Corporation new member integration and the 2.3% increase in 2012 is an overall increase on multiple balancing authorities. To provide a more accurate representation of the metered load during peak conditions, Probable Peak Load values for the next ten years are provided below in Table 5.2-7.

Table 5.2-7: Probable Peak Coincident Load (MW)

Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2010 Forecast	100,578	104,092	106,610	107,302	107,907	108,295	109,088	109,918	110,853	111,727

The Midwest ISO market's adjusted all-time peak demand of 109,157 MW occurred on July 31, 2006. Figure 5.2-3 shows the actual peak load levels from 2005 through 2009 and the forecasted coincident Probable Peak Load from 2009 to 2019. In order to give a more accurate representation of the metered load during peak conditions, the Probable Peak Load values for the next ten years are provided in the graph treating BTMG as a load offset. The 90/10 and 10/90 bands are industry standards for high and low load conditions, respectively. These high and low levels create a bandwidth of possible load conditions that accounts for volatility in load forecasts.

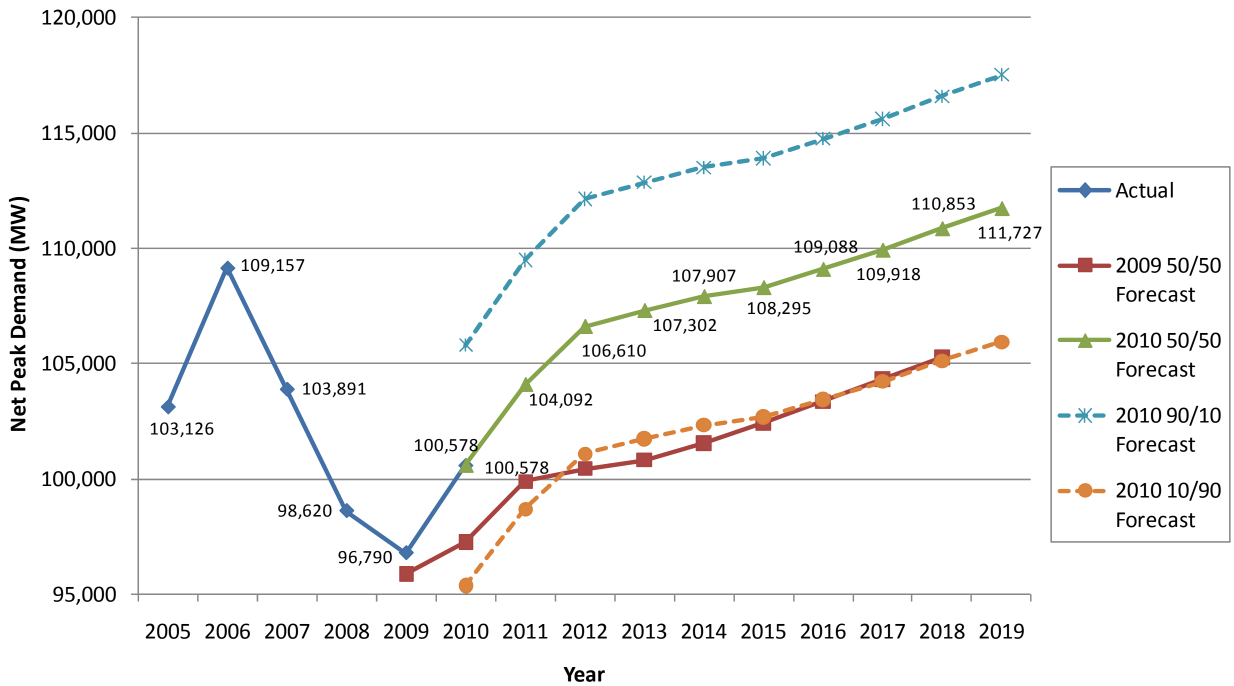


Figure 5.2-3: Historical and Forecasted Peak Demands

5.2.5 Load Forecast Uncertainty Calculations

Load Forecast Uncertainty (LFU) is derived from variance analysis to determine the likelihood forecasts will deviate from actual load. In order to establish a Load Forecast Uncertainty (LFU) value for the summer period, four (4) years of real-time load data was compared to forecasts for those same periods. Load forecasts for the months of June, July, and August were adjusted for the reported demand side management programs to arrive at coincident net internal demand forecast values. Those monthly forecasts were compared to the actual monthly peak loads of the same period and the differences compiled into a sample space from which to derive a standard deviation. A load forecast uncertainty of approximately 4% was calculated using this methodology, which accounts for roughly 4,050 MW of load variability applied to peak projections. This uncertainty can then be used to form the normal distribution seen in Figure 5.2-4, below.

In order to obtain a value which would most closely match an actual metered load value, this analysis treats BTMG generation as a load modifier. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. The 2009 actual market peak was 96,790 MW, the area to the left of this value represents a 20% chance that this year's peak will be less than 2009's and the area to the right represents an 80% chance this year's peak will exceed that of 2009.

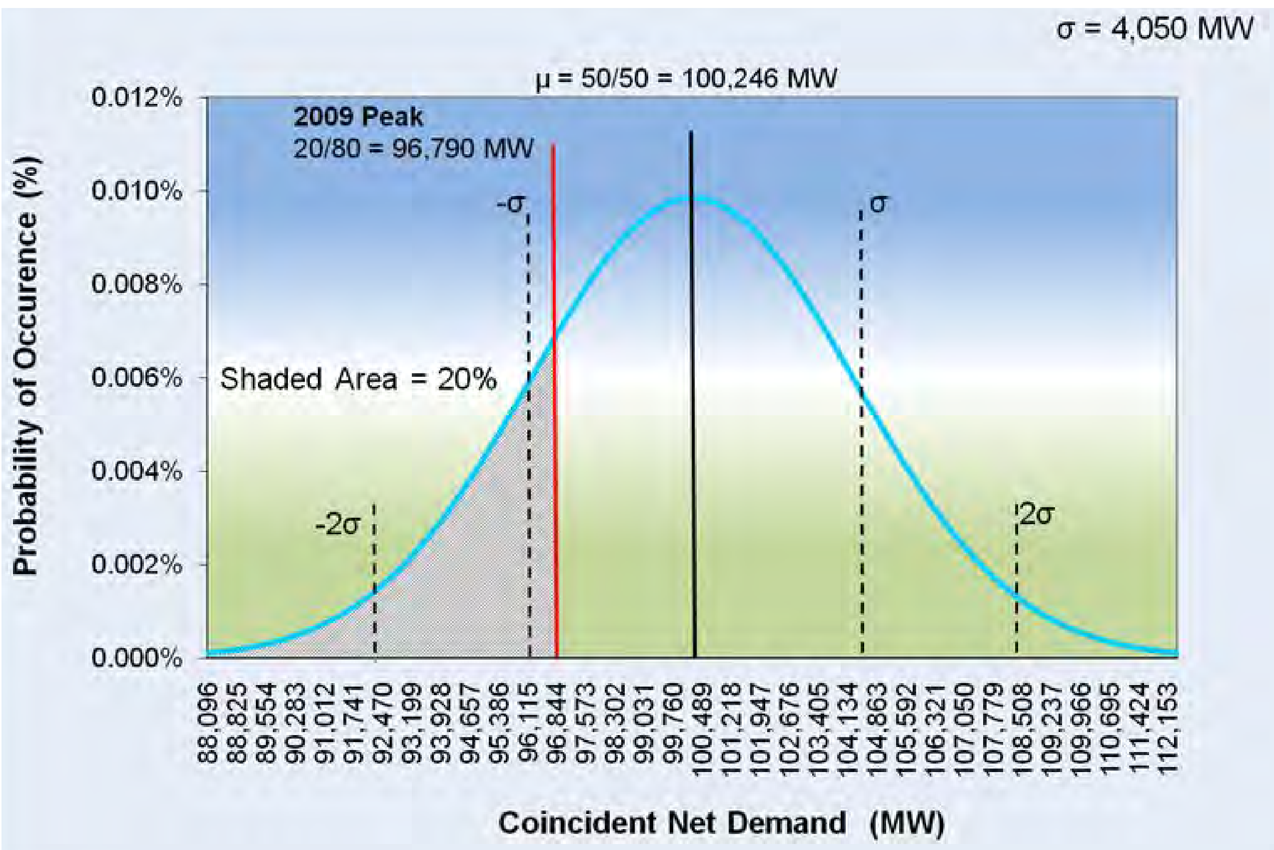


Figure 5.2-4: Net Coincident Demand Probability Distribution

5.3 Capacity

Driven by additions in Midwest ISO membership and the expected capacity additions from the Generator Interconnection Queue, 134,771 MW of capacity resources are projected for 2019, as compared to 131,284 MW in 2010.

5.3.1 Midwest ISO Baseline Generation

A reliable first-year baseline capacity was established in order to create an accurate capacity projection. The following sections detail committed internal resources and committed import capability expected during the 2010 peak.

5.3.1.1 Midwest ISO Generation

The Midwest ISO footprint expects 141,993 MW of nameplate capacity for 2010, but not all of this capacity is committed to serve load. Coal-fire facilities represent over 50% of capacity resources within the Midwest ISO Market. Gas-fueled units account for another 22% of the fleet. A breakdown by fuel type of 2010 nameplate capacity (MW) is depicted in Figure 5.3-1, below.

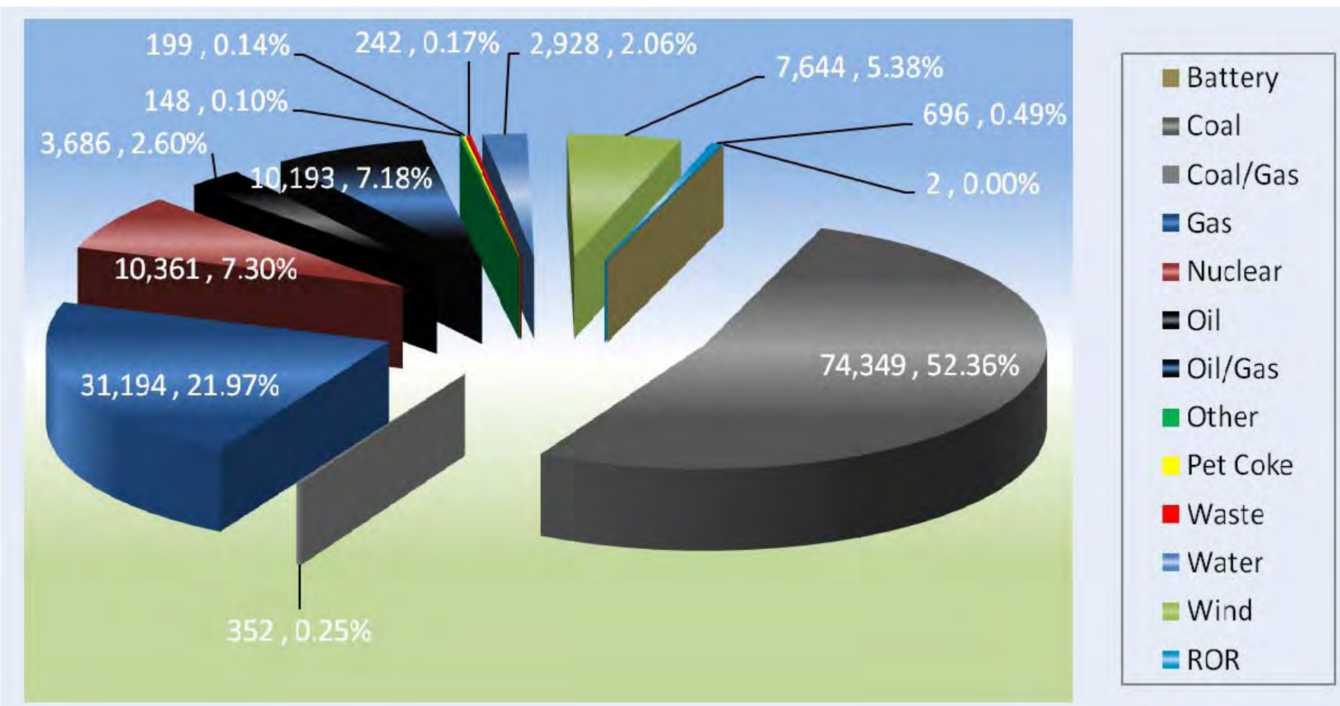


Figure 5.3-1: 2010 Nameplate Capacities (MW, %)

Under Module E requirements and through the Module E Capacity Tracking Tool (MECT), Load Serving Entities (LSEs) designate planning resource capacity to Midwest ISO. LSEs can designate resources as internal, behind the meter generation (BTMG), demand response resources (DRR), or External Resources for each month of the planning year to meet Planning Reserve Margin requirements (PRM). The capacity amount of internally designated units is typically different from internal available generation.

Refer to Figure 5.2-2, which identifies this difference. It is important to note resources meeting PRM have an obligation to be available to meet real-time customer demand within Midwest ISO. These resources are also referred to as Committed or Designated Resources.

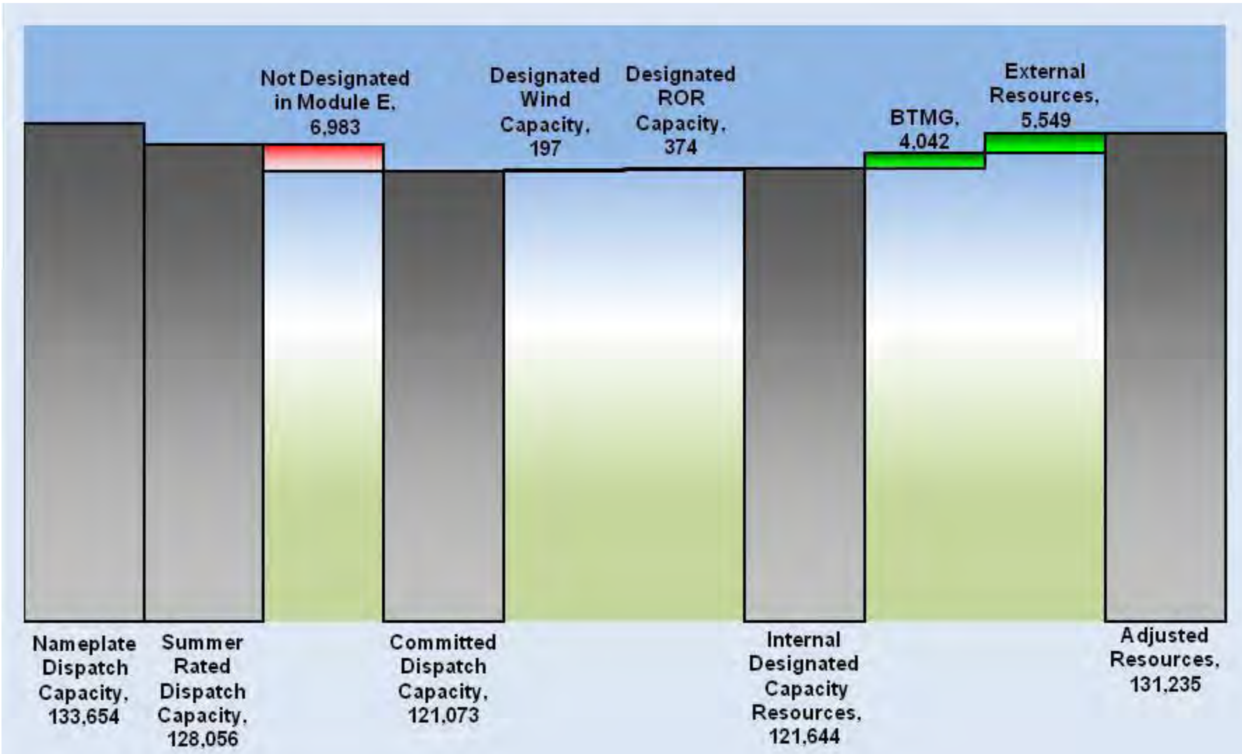


Figure 5.3-2: 2010 Adjusted Resources, MW

The following provides a description of each category in Figure 3.1.2, from left to right:

- **Nameplate Dispatch Capacity**: The manufacturers' reported output of all internal Midwest ISOunits minus the reported capacity of all internal Midwest ISO Wind and Run of River hydro (ROR) units.
- **Summer Rated Dispatch Capacity:** The tested capability of Midwest ISO units less Wind and ROR units. LSEs enter the summer-rated values of their units into the Generator Availability Data System (GADS). If data does not exist in GADS, unit nameplate values are used.
- **Not Designated in Module E**: The difference between Summer Rated Dispatch Capacity and Committed Dispatch Capacity.
- **Committed Dispatch Capacity:** LSEs designated as non-intermittent resources internal to Midwest ISO in order to meet PRM requirements.
  - Note that the term 'Intermittent Resources' includes Wind and ROR.
- **Designated Wind Capacity:** LSE wind resources internal to Midwest ISO designated to meet PRM requirements.[42]
- **Designated ROR Capacity:** LSE Run-of-River resources internal to Midwest ISO designated to meet PRM requirements.[43]

[42] Designated Wind Resources apply an 8% capacity credit applied to Nameplate values.

[43] To arrive at a designated capacity value, designated ROR Resources average their most recent three years of hourly net output (in MW) or—where three years of data does not exist—the last 30 days of hourly net output (in MW) for the hours of 1500–1700 EST from June, July, and August.

- **Internal Designated Capacity Resources:** Committed Dispatch Capacity plus Designated Intermittent Capacity.
- **BTMG:** Designated generation resources used to serve wholesale or retail load located behind a CPNode that are not included in the Transmission Provider's set-point instructions and, in some cases, can also be deliverable to load located within the Transmission Provider Region using Network Integration, Point-To-Point Transmission Service or transmission service pursuant to a Grandfathered Agreement. These resources have an obligation to be made available during emergencies.
- **DRR:** Committed offers to supply energy to the Energy Markets based on the reductions of withdrawals of specified Demand Response Resources, which is treated as capacity in this assessment.
- **External Resources:** designated generation resources located outside of the Metered boundaries of the Midwest ISO Balancing Authority Area.
- **Adjusted Resources:** Internal Designated Capacity Resources plus BTMG, DRR, and External Resources.
  - This is the forecasted generation capacity available to meet Midwest ISO's PRMR during peak conditions in 2010. Midwest ISO is summer peaking.

Refer to Figure 5.3-3, which provides a breakdown by fuel type of 2010 Adjusted Resources.

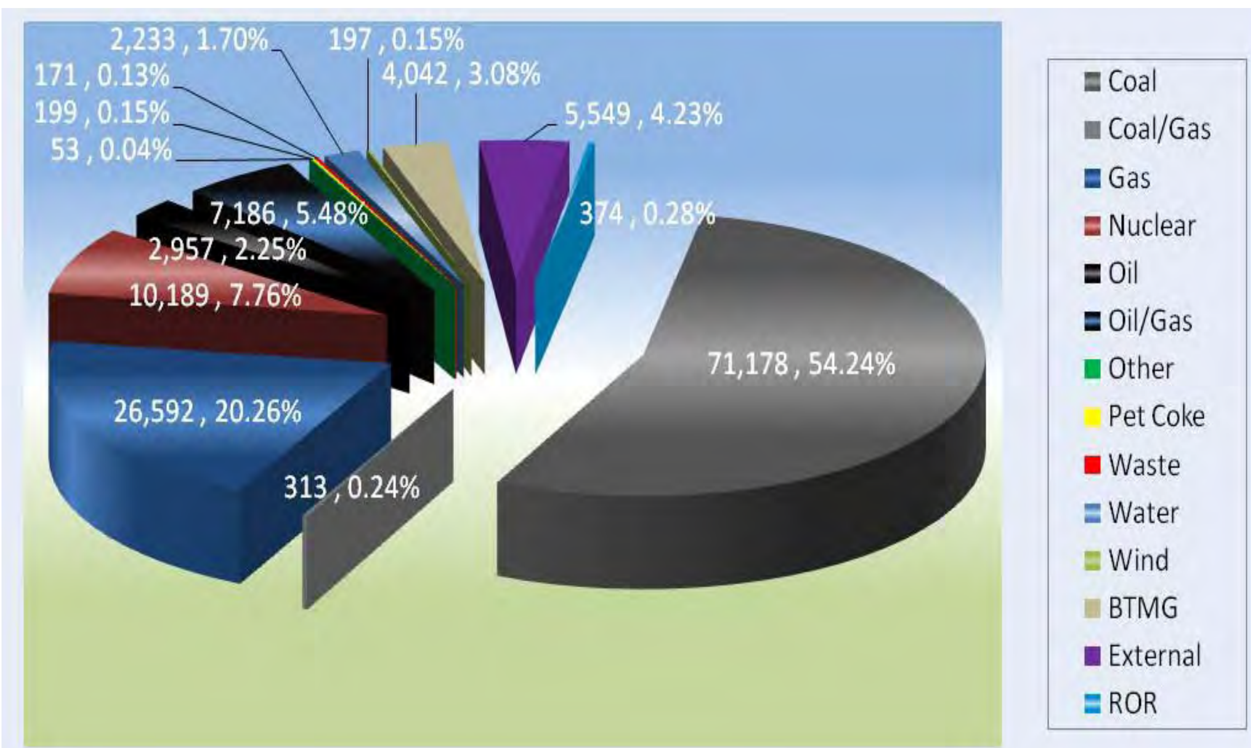


Figure 5.3-3: 2010 Adjusted Resources (MW, %)

5.3.1.1.1 Wind Availability

Due to the variable nature of wind, there is no way to guarantee the wind capacity available on peak. For Planning Year 2010–2011, the maximum wind capacity credit was determined by employing a technique that calculates the Equivalent Load Carrying Capacity (ELCC) for wind generation. For the 2010 summer, ELCC is 8%. For information on wind capacity credit and ELCC analysis, refer to the 2010 LOLE Study, Section 4.2.2[44].

The Designated Wind Capacity referred to in the previous section represents MW of wind capacity that has met all Module E requirements to be a Capacity Resource and which has also been designated by an LSE towards meeting their Resource Adequacy Requirements. A wind capacity credit is applied to each designated resources' capacity as part of these requirements.

5.3.1.1.2 Designated External Resources

During the 2010 summer, Midwest ISO forecasted 5,549 MW of capacity originating outside the Midwest ISO footprint. This capacity is committed to serve load within Midwest ISO and cannot be recalled by the source Transmission Provider. Midwest ISO typically imports over 8 GW of energy during the system peak; however, 5,549 MW is being used as a conservative estimate.

5.3.2 Out-year Generation

Once a reliable first-year baseline capacity was established, a study of Midwest ISO future generation was performed encompassing the ten-year, 2010–2019 assessment timeframe. The following sections detail the selection process used to determine future capacity levels.

5.3.2.1 Generator Interconnection Queue

The Generator Interconnection Queue (GIQ) is the Midwest ISO database containing all proposed generation with an expected in-service date and an overall project status description for each proposed unit. An extensive review of the Midwest ISO GIQ was conducted to determine that portion of out-year generation comprised of GIQ generation.

5.3.2.1.1 Active Queued Capacity

For the purposes of this document, "Active Queued Capacity" refers to those units with the following GIQ attributes:

- Projects with an Active or Done overall project status and not already included in the Midwest ISO Commercial Model
- Projects not in a Parked, Parked (one [1] year rule), or Withdrawn study status. Parked refers to a temporary withdrawal from GIQ project studies.
- Projects with a control area designation
- Projects with an expected online date prior to May 31, 2019 and after May 31, 2010

Unit information contained in the Midwest ISO GIQ was updated with Market Participant supplied information wherever possible. Unless updated, in-service dates were directly referenced from the Midwest ISO GIQ. Data used for this study was derived from the GIQ on March 26, 2010.

[44] Please refer to the 2010 LOLE Report for more information.

Currently, there are 364 Midwest ISO projects in the GIQ totaling 92 GW; however, only 204 projects totaling 41 GW meet Active Queued Capacity criteria for use in this assessment. Of the 204 projects, 179 are proposed wind plants with nameplate capacity totaling 34 GW. Refer to Table 5.3-1, which provides a timeline of cumulative Active Queued Capacity additions, by fuel type, made to Midwest ISO.

Table 5.3-1: Total Cumulative Active Queued Capacity (MW)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Biomass				100	100	100	100	100	100	100
Biomass & Natural Gas			120	120	120	120	120	120	120	120
Coal	102	1,229	1,546	1,546	2,146	3,021	3,021	3,021	3,021	3,021
Co-Gen		135	135	135	135	135	135	135	135	135
Combined Cycle	420	420	420	420	420	420	420	420	420	420
Gas	250	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105
Hydro			112	112	112	112	112	112	112	112
Landfill Gas	3	3	3	3	3	3	3	3	3	3
Natural Gas	50	50	50	50	50	50	50	50	50	50
Nuclear	38	152	152	152	152	152	152	1,715	1,715	1,715
Wind	13,355	22,874	31,350	32,952	33,851	33,851	34,301	34,301	34,301	34,301
Wood		28	28	28	28	28	28	28	28	28
Total	14,218	25,996	35,021	36,723	38,222	39,097	39,547	41,110	41,110	41,110

5.3.2.1.2 Completed IA

Out of 204 Active Queued Capacity projects, 17 have a "Generation Interconnection Agreement (GIA) Complete" and/or "GIA in Progress" Study Status. 14 of the 17 hold a "Status after IA" designation of "In Service" or "Under Construction". Those 14 projects are designated as *Completed IA*. Table 3.2-2 displays Completed IA capacity by year and Generation Deliverability. Refer to Table A.1-1 in Appendix A.1 for greater detail regarding In-Service Dates, Planning Region, and Fuel Type for Completed IA Capacity.

Table 5.3-2: Cumulative Completed IA Nameplate Capacity (MW)

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Dispatchable	500	561	603	603	603	603	603	603	603	603
Intermittent (Wind)	700	999	1099	1099	1099	1099	1099	1099	1099	1099
Total	1200	1560	1702	1702	1702	1702	1702	1702	1702	1702

5.3.2.1.3 Other Queued

Remaining Active Queued Capacity projects are referred to in this report as Other Queued. Table 3.2-3 displays Other Queued capacity by year and Generation Deliverability. Refer to Table A.1-2 in Appendix A.1, for more detail regarding In-Service Dates, Planning Region, and Fuel Type for Other Queued Capacity.

Table 5.3-3: Cumulative Other Queued Nameplate Capacity (MW)

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Dispatchable	363	2561	3068	3168	3768	4643	4643	6206	6206	6206
Intermittent (Wind)	12655	21875	30251	31853	32752	32752	33202	33202	33202	33202
Total	13018	24436	33319	35021	36520	37395	37845	39408	39408	39408

5.3.2.1.4 Confidence Factors

Confidence factors are used to describe the probability a project with a specific queue status will be built. Through historical study of the GIQ, Table 5.3-4 shows the Confidence Factors for Completed IA and Other Queued capacity projects by fuel type. The averages in Table 5.3-4 are applied to projects with other fuel type designations.

Table 5.3-4: GIQ Confidence Factors

Fuel Type	Completed IA	Other Queued
Biomass	80.16%	19.03%
Biomass & Natural Gas	80.16%	19.03%
Coal	54.95%	13.67%
Combined Cycle	80.16%	19.03%
Gas	93.47%	31.44%
Hydro	100.00%	0.17%
Landfill Gas	80.16%	19.03%
Natural Gas	80.16%	19.03%
Nuclear	100.00%	4.63%
Wind	74.73%	6.88%
Wood	80.16%	19.03%
AVERAGE	**82%**	**16%**

Midwest ISO expects confidence factors of GIQ generation will improve over time as Multi-Value Projects (MVPs) are identified and constructed.

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5.3.2.1.5 Cumulative Queued Capacity

Table 3.2-5 displays Cumulative Expected Queued capacity by year, which is arrived at by applying the Confidence Factors above and the 8% wind capacity credit, discussed in section 3.1.1.1, to Tables 5.3-2 and 5.3-3. Note that values for 2010 and 2011 are combined into 2011 since GIQ capacity built in 2010 will not be available to meet 2010 peak conditions. Refer to Tables A.1-3 and A.1-4 in Appendix A.1 for a more detailed look at Completed IA and Other Queued Capacity with Confidence Factors and Capacity Credits applied.

Table 5.3-5: Cumulative Expected Queued Capacity (MW)

Queued Capacity Type	2011	2012	2013	2014	2015	2016	2017	2018	2019
Completed IA	501	542	548	548	548	548	548	548	548
Other Queued	669	776	804	891	1010	1013	1085	1085	1085
Total	**1170**	**1317**	**1351**	**1438**	**1558**	**1560**	**1633**	**1633**	**1633**
Dispatchable	1008	1091	1110	1192	1312	1312	1384	1384	1384
Intermittent	162	226	241	246	246	248	248	248	248

5.3.2.2 New Member Integration

In December 2009, Big Rivers Electric Corporation declared its intent to join Midwest ISO on September 2010, bringing 1,756 MW of coal generation to the Midwest ISO footprint, which is included in the forecast for 2011 and beyond.

5.3.2.3 Exiting Members

First Energy intends to consolidate all assets from Midwest ISO into PJM on June 1, 2011. A total of 13,502 MW of capacity may be removed from Midwest ISO due to First Energy's exit. In addition, Duke Energy Ohio and Duke Energy Kentucky plan to exit the Midwest ISO in 2012, which totals 5,886 MW of capacity.

5.3.2.4 Retirements and Suspensions

Three (3) facilities totaling 205 MW will retire in 2011. The retirements include 160 MW of Coal and 45 MW of Gas. Nine (9) facilities totaling 1,715 MW are on three (3) year suspension from 2011–2013, returning in 2014.[45]

[45] Updates to the Attachment Y process suggest that suspensions will net 419 MW less than forecasted due to facility withdrawals and additional facilities. However, 1,715 MW is used for this assessment.

5.3.3 Projected Capacity

In order to remain consistent with the 2010 Summer Assessment methodology for calculating Adjusted Resource capacity and project resource capacity defined by North American Electric Reliability Corporation (NERC) resource categories, the following section is divided into two subsections. One section represents the Midwest ISO method and the other section represents NERC methodology. Reserve margins are calculated using the various resource capacity values.

Although First Energy and Duke intend to exit Midwest ISO in 2011 and 2012, respectively, this section assumes neither of these two entities exit in the 2010–2019 study timeframe in order to maintain consistency with the NERC Long Term Reliability Assessment (LTRA) report. However, in Reliability Assessment (section 4 of this document), resources are adjusted to show the impact of exiting membership on the Midwest ISO footprint.

5.3.3.1 Midwest ISO Method

New Member Integration, Retirements and Suspensions, and GIQ Capacity are taken into account to project both out-year Nameplate Capacity and Adjusted Resources. For Nameplate Capacity, only Confidence Factors were applied to the GIQ, while Confidence Factors and Capacity Credits were applied for Adjusted Resources. The Nameplate Capacity is expected to raise 6,043 MW from 2010 values to 148,036 MW by 2019. Expected GIQ wind capacity comprises approximately half of this increase with 3,106 MW. A breakdown by fuel type of 2019 nameplate capacity (MW) is depicted in Figure 5.3-4, below.

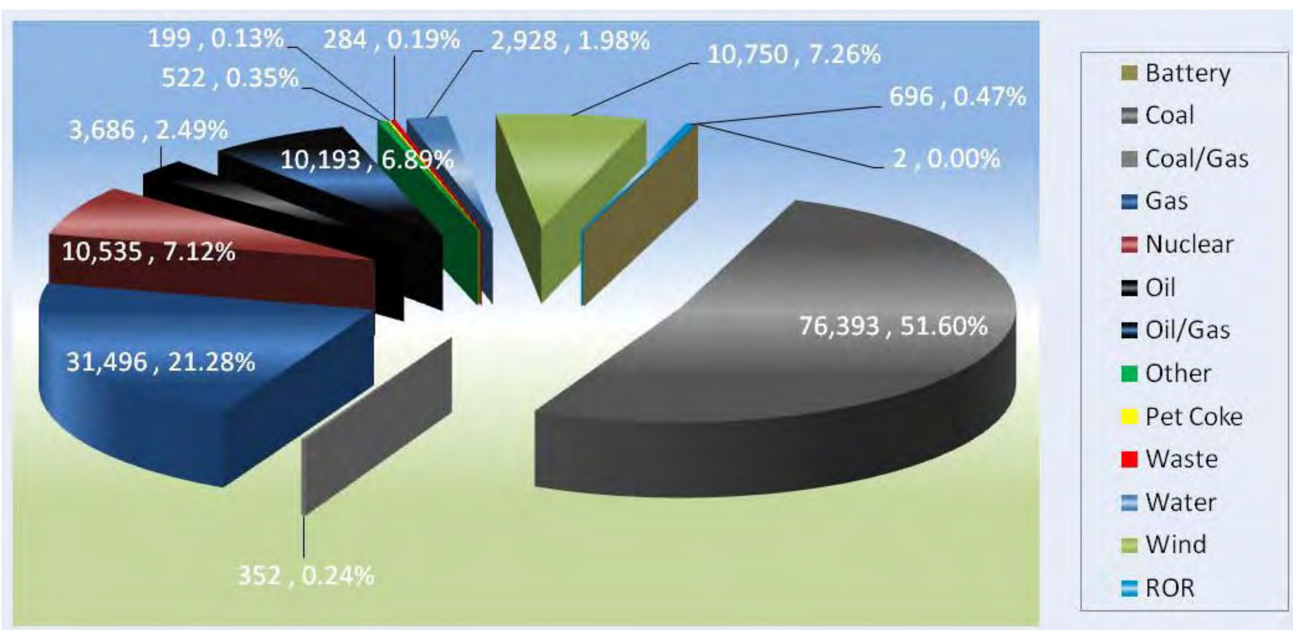

Figure 5.3-4: 2019 Nameplate Capacities (MW, %)

In order to project 2019 adjusted resources a method stemming from the waterfall chart in Figure 5.3-5 was used for each out-year. Refer to Figure 3.3-2 below; which shows the adjustments made to the 2010 baseline Designated Capacity to arrive at 2019 Adjusted Resources. Adjusted Resources is expected to raise 3,184 MW from 2010 values by 2019 to 134,419 MW.

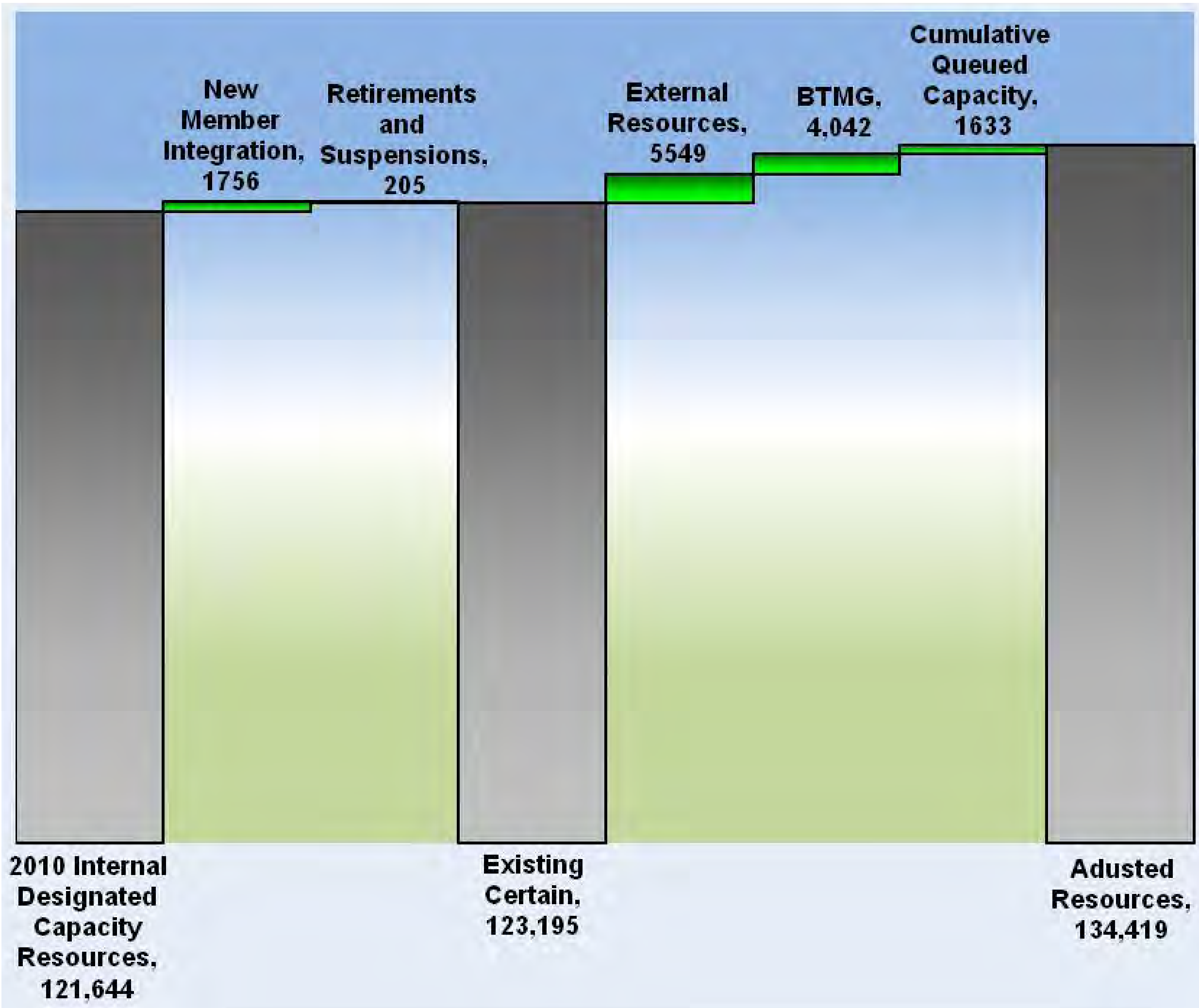

Figure 5.3-4: 2019 Adjusted Resources (MW)

Refer to Tables A.1-5 and A.1-6 in Appendix A.1, which provide all out-year projections using Midwest ISO methodology. A fuel breakdown of 2019 Adjusted Resources is given in Figure 5.3-6, below.

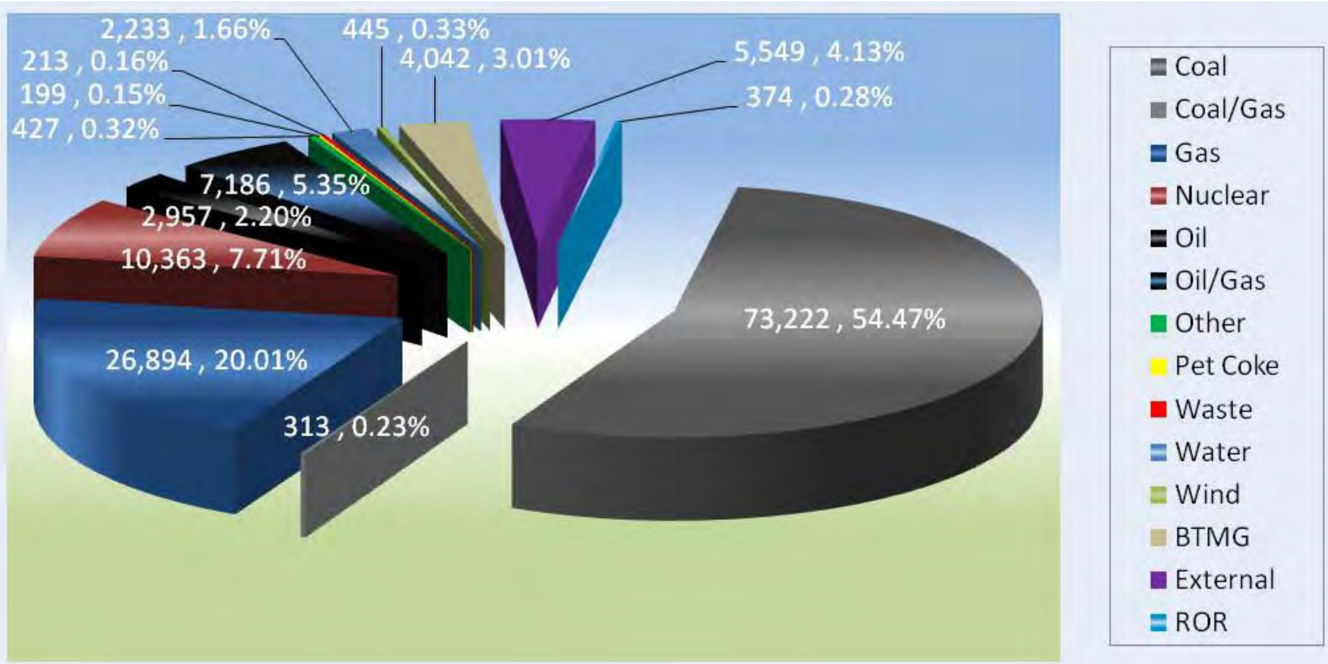

Figure 5.3-6: 2019 Adjusted Resources (MW)

5.3.3.2 NERC Method

The NERC method utilizes the same data as the Midwest ISO methodology but categorizes resources differently. The sections below define terms relevant to NERC methodology.

5.3.3.2.1 NERC Terminology

In this section, Midwest ISO terminology defines the NERC resource categories; however, in Appendix B.1, definitions are taken directly from NERC's 2009 Long-Term Reliability Assessment section entitled "Terms Used in this Report." The four NERC resource categories are given and defined below.

- **Potential Resources** consist of the following:
  - **Existing Certain:** 2010 Internal Designated Capacity Resources (121,644 MW), plus New Member Integration Capacity, minus any Exiting Members' 2010 Designated Capacity (assumed zero), minus any Retired or Suspended units' 2010 Designated Capacity.
  - **Existing Other:** 2010 Nameplate Capacity minus Exiting Members' 2010 Nameplate Capacity, minus any Retired or Suspended units' 2010 Nameplate Capacity minus Existing Certain.
  - **Future Planned:** No forecast exists for Midwest ISO. Refer to NERC definition in Appendix B.1.
  - **Future Other:** Completed IA Nameplate Capacity.
  - **Conceptual Resources:** Other Queued Nameplate Capacity.
  - **Net Firm Transactions:** Summation of 2010 BTMG, DRR, and External Resources held constant throughout the study period.
- **Prospective Resources:** Adjusted Potential Resources less Adjusted Conceptual Resources.

- **Deliverable Resources** consist of the following:
  - Existing Certain
  - Future Planned (zero)
  - Net Firm and Expected Transactions
- **Existing Certain and Net Firm Transactions:** Combination of Existing Certain and Net Firm Transactions.

Refer to Table 5.3-6 below, which shows the average of each of the four (4) categories described above over the study timeframe.

Table 5.3-6: Ten (10) Year NERC Resource Averages

	Potential Resources	Prospective Resources	Deliverable Resources	Existing-Certain & Net Firm Transactions
Capacity (MW)	184679	144651	132116	132116

A useful table for each out-years' NERC resources calculations is provided in Table A.1-7 in Appendix A.1.

5.3.3.3 Summary

Five (5) different projected capacities provide a varied look at the future Midwest ISO resource capability. As stated previously, expected Adjusted Resources capacity for 2019 is 134,419 MW, compared to 131,235 MW in 2010. These projections will be used to calculate the reserve margin. Refer to Figure 5.3-7 below, which provides a visual comparison of all capacity projections over the study period. Values are in GWs.

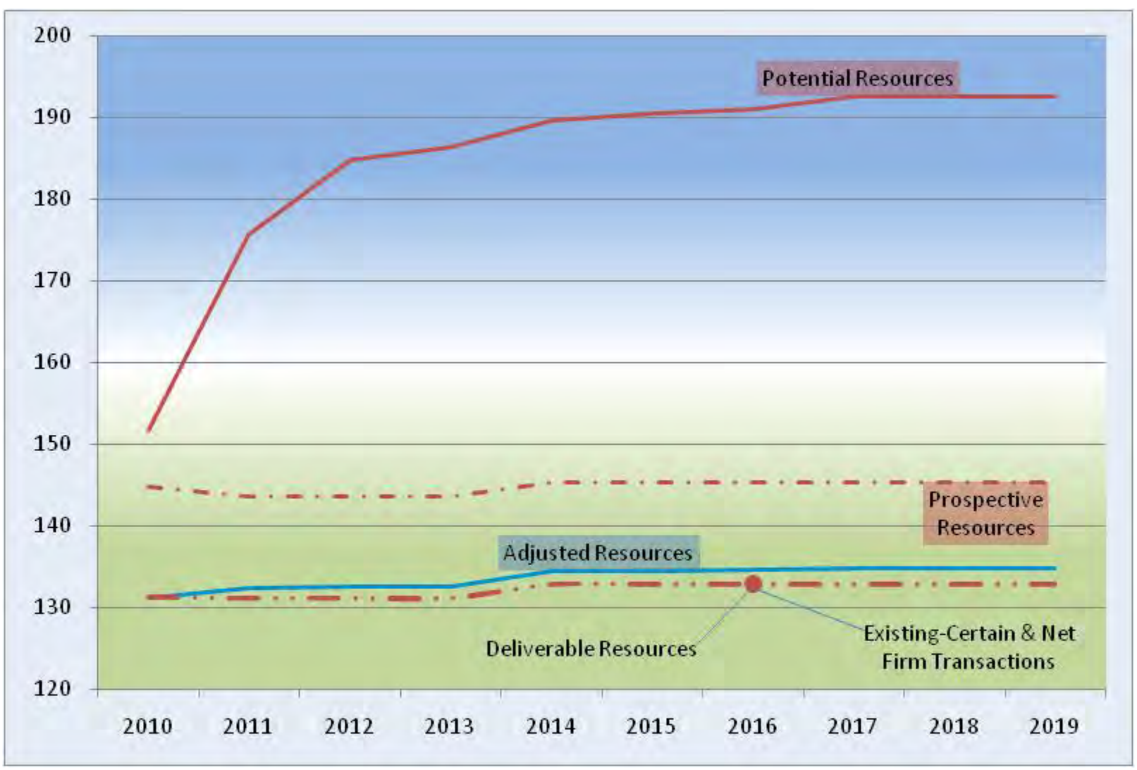

Figure 5.3-7: Resource Capacities Overview (GW)

5.4 Reserve Margin Requirements

The Midwest ISO Planning Reserve Margin (PRMSYSIGEN) for the 2010/11 Planning Year (PY) is 15.4%, unchanged from the 2009/10 Planning Year. Although overall system PRM was unchanged from 2009/10, there were some marginal differences in PRM components. Generator-forced outage rates were up, driven by the replacement of class average outage rates with actual performance data for those units that did not historically collect Generator Availability Data System (GADS) data. However, there was less internal congestion and increased import capability from the external system, which slightly reduced the PRM and offset the increase in forced outage rates.

Benefits associated with system-wide diversity must be considered since compliance with Module E Resource Adequacy Requirements is determined on an individual CPNode by each Load Serving Entity's (LSE) non-coincident monthly peak demand. Midwest ISO has determined that a diversity factor of 3.00% will be used for the 2010/11 Planning Year. This is an increase from the 2.35% diversity factor used last year, based on 2006 LBA diversity. Midwest ISO believes the 0.65% increase in diversity factor is appropriate in order to appropriately capture the diversity of all LSEs within the LBA without significantly increasing the loss of load risk to the Midwest ISO system. After consideration for load diversity, PRMSYSIGEN is 11.94%.

The final step was determination of the planning reserve margin on an unforced capacity basis. The system wide average XEFORd for generation within the Midwest ISO Market was 6.83% which was computed from the historical data for generators that represented 99.4% of the modeled generation. A system average XEFORd was developed by applying a 6.83% XEFORd value to all 141,991 MW of Generation within the Model and a 0% XEFORd to the 4,053 MW of Demand Resources. This methodology resulted in a System Average XEFORd of 6.644% for use in an Unforced Capacity Reserve Margin. This outage rate was then applied to the capacity in the previous reserve margin ratios. This lower capacity value was then divided by the previously adjusted load value to arrive at a new planning reserve margin of 4.50% which must be served with unforced capacity. Unforced capacity for an individual unit is derived by applying a unit's XEFORd to its maximum capacity rating to arrive at a reliably provided MW value.

A complete report on Midwest ISO Loss of Load Expectation (LOLE) study can be found at the following link:

https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/2010%20LOLE%20Study%20Report.pdf.

5.4.1 Module E: Resource Adequacy Overview

Currently, the Midwest ISO reserve margin is 25.4%. By 2019, the reserve margin is projected to fall to 16.1%. Due to new member integration and new generation from the GIQ, reserve levels are projected to remain above Midwest ISO-established minimums throughout the next ten years.

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves that would result in the Midwest ISO system experiencing one loss of load event every ten (10) years. Analysis resulted with one (1) uniform Planning Reserve Margin per year applicable to the Midwest ISO Market footprint. The PRM for each out-year is given in Table 5.4-1 and 5.4-2 below, shown as Reserve Requirement.

The reserve margin used in this assessment was calculated from the Net Internal Demand, in Table 2.4-1 and the Adjusted Resources in Table A.1-6. To assure a high probability in capacity expansions, confidence factors were applied to Future Other capacity and Conceptual Resources, respectively, within the Midwest ISO Generator Interconnection Queue (GIQ). The projected reserve margins for the Midwest ISO range from 26,615 MW (25.4%) in 2010 to 18,650 MW (16.1%) in 2019.

Refer to Table 5.4-1, which displays these projected reserve margins throughout the assessment time-frame. Projected reserve margins exceed the minimum reserve requirement benchmarks through the entire ten (10) year period.

Table 5.4-1: Reserve Margin Forecasts with First Energy and Duke

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin(MW)	26,615	24,107	21,737	21,078	22,275	22,007	21,217	20,458	19,523	18,650
Reserve Margin (%)	25.4%	22.3%	19.6%	18.9%	19.9%	19.6%	18.8%	18.0%	17.0%	16.1%
Reserve Requirement (%)	15.4%	15.7%	16.0%	16.2%	16.5%	16.2%	15.9%	15.5%	15.2%	14.9%

The reserve margin forecast depicted in Table 5.4-2 below reflects First Energy's plan to terminate its membership with the Midwest ISO in June 2011 along with Duke Energy Ohio and Duke Energy Kentucky (hereinafter referred to as "Duke"), which plans to exit from Midwest ISO in 2012. Projected reserve margins without the inclusion of First Energy and Duke are higher year-to-year and forecasts exceed the minimum reserve requirement benchmark of 15.4% throughout the entire ten (10) year period.

Table 5.4-2: Reserve Margin Forecasts without First Energy and Duke

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin(MW)	26,615	23,878	20,441	19,891	20,631	20,494	19,840	19,223	18,431	17,697
Reserve Margin (%)	25.4%	25.2%	21.9%	21.2%	21.9%	21.7%	20.9%	20.1%	19.1%	18.2%
Reserve Requirement (%)	15.4%	15.7%	16.0%	16.2%	16.5%	16.2%	15.9%	15.5%	15.2%	14.9%

5.5 Long-term Risk Assessment

Loss of Load Expectation (LOLE) analyses were performed for years five (5) and ten (10) in the ten-year assessment timeframe. For the analyses, First Energy and Duke were included within the Midwest ISO footprint. This is due to the fact that when the two entities were removed from analyses, Midwest ISO experienced higher reserve margins; therefore, the two parties were left in to evaluate the highest risk. LOLE levels are not projected to violate the industry standard of one (1) day in ten (10) years within the assessment timeframe. Even if uncertainties such as loss of external support, lack of wind generation, an increase in system forced outage rates, or increased load levels are realized during the assessment timeframe, actual risk levels did not reach the benchmark of (1) day in ten (10) years.

Using the various levels of capacity and demand established in this report, a Loss of Load Expectation (LOLE) study was performed over the summer months for year five and ten over the assessment period. This study quantifies the effects on LOLE by altering the load forecast, external commitments, wind capacity credit, and forced outage rates. The purpose of this analysis is not to determine reserve requirements necessary to meet projected load levels; rather, the purpose of this analysis is to point out the effects of changes in system conditions on LOLE so that future risk can be managed.

5.5.1 Base and High/Low Demand Cases

The purpose of this risk analysis is to provide consideration for the effects of a wide range of possible scenarios and observe the effects of various factors on LOLE. However, to ascertain a starting point for comparison, a base case was established. The cases in this study utilize planning reserve margins after ensuring that only capacity currently available is included within the model. These cases were built for years 2014 and 2019 and utilize the same zonal establishment methodology outlined in the 2010 LOLE Report.[46]

The base case provides our most accurate projection of risk levels in planning years five and ten. However, since the base case demand has a 50% probability that actual load will exceed the forecast and a 50% chance that actual load will be lower than the forecast; a wider range of demands was analyzed to cover a wider range of probabilities.

The Load Forecast Uncertainty (LFU) analysis described in section 2.5 results in the formation of a normal distribution of 2010 load levels as seen in Figure 5.5-1, below. When analyzing variables along a normal distribution, it is industry-standard practice to use 10/90 and 90/10 levels as outlying cases representing extreme values of load. These load values represent a 90% chance the peak will exceed this level in the case of the 10/90 forecast and a 90% chance that the peak will be lesser than the level represented by the 90/10 forecast. These values are represented for 2010 in Figure 5.5-1 as the Low and High Load with the Base Load representing the reported coincident net internal demand around which the normal distribution is constructed.

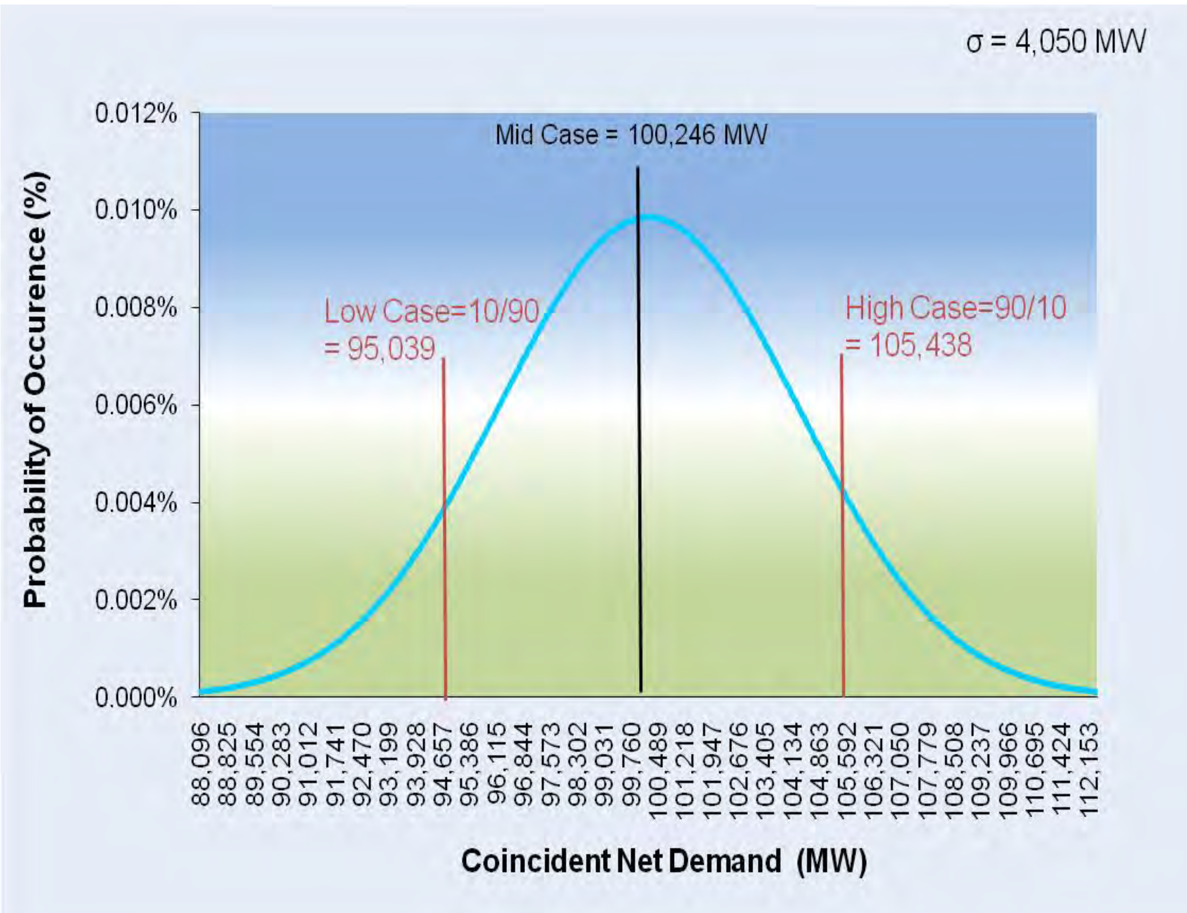

Figure 5.5-1: Case Summary of Net Demand

[46] 2010 LOLE Report

Two Nameplate Reserve Margin case scenarios were analyzed throughout this risk assessment. First cases were constructed without any future expansion. Then, in order to capture future capacity additions, all queued units were considered with their appropriate confidence factors.

Figures 5.5-2 and 5.5-3 (on the following page) provide a projected reserve margin timeline for the base case and high and low demand cases utilizing a nameplate capacity level both with and without unit expansion. A minimum reserve requirement is highlighted on the graph in the form of a red line. This requirement starts at 15.4% for the current planning year and decreases to 14.9% by the end of the ten (10) year period to reflect an increase in congestion that could be experienced without the addition of transmission projects.

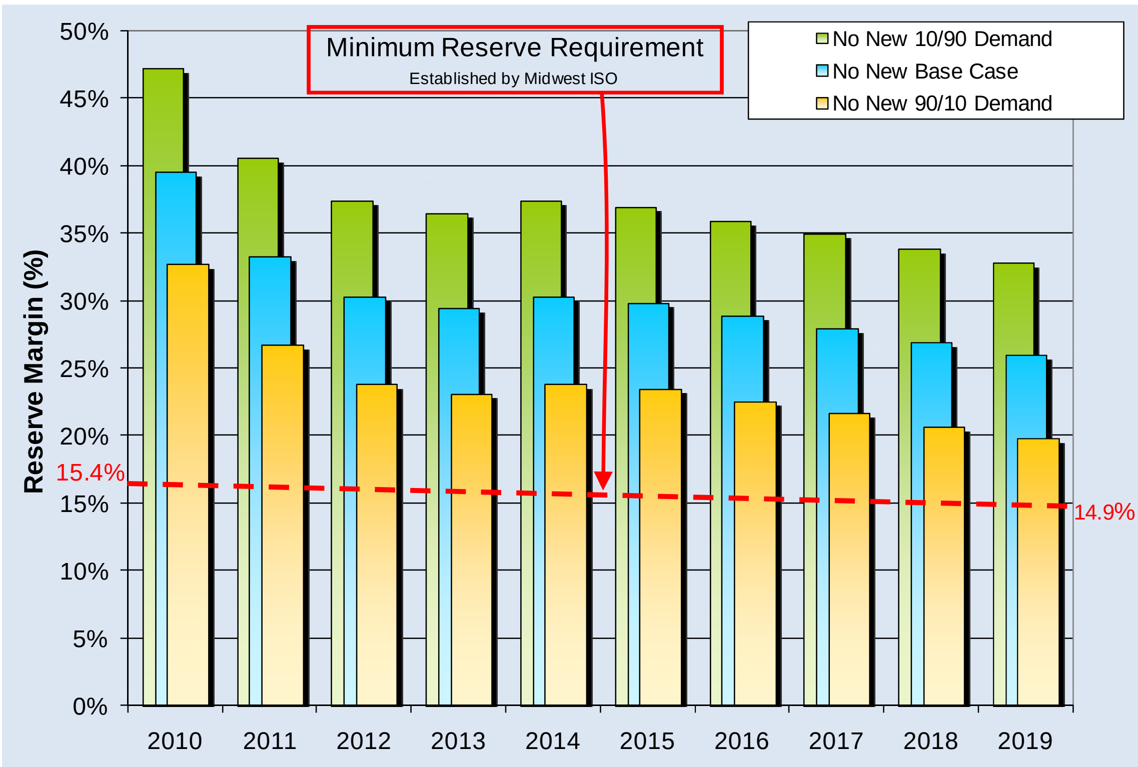

Figure 5.5-2: 2010–2019 Nameplate Reserve Margin Forecast without Capacity Additions

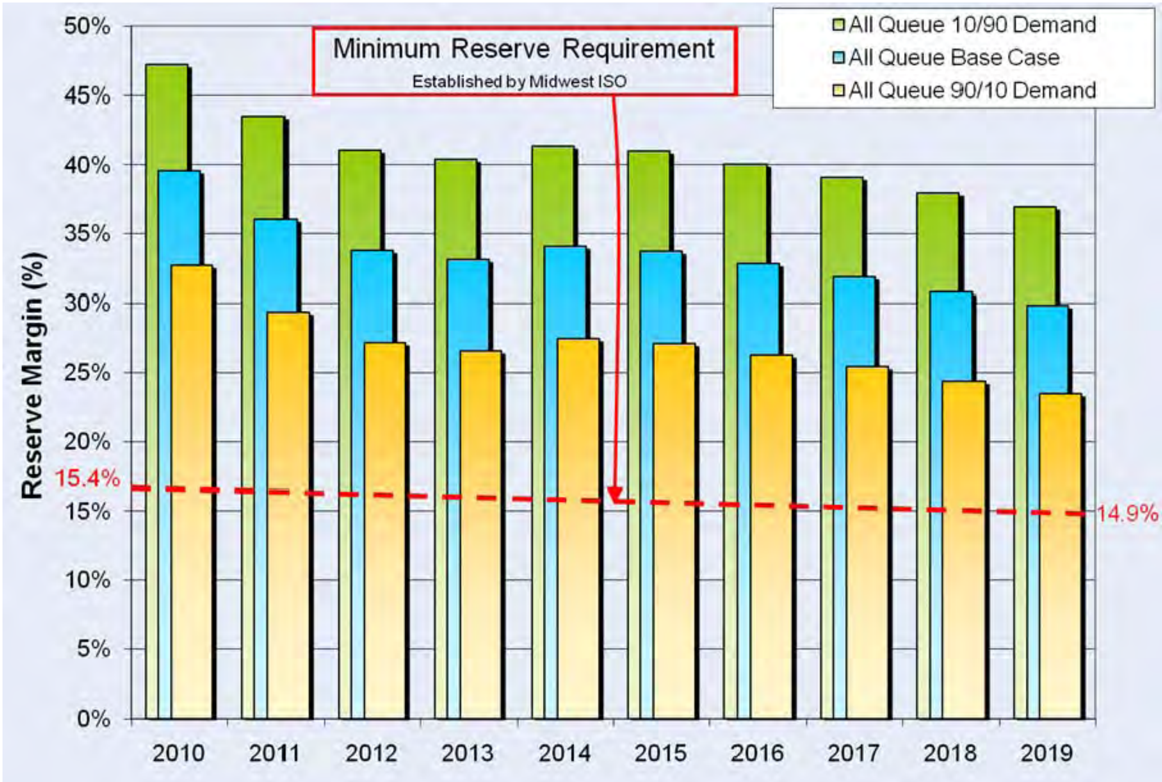

Figure 5.5-3: 2010–2019 Nameplate Reserve Margin Forecast with Capacity Additions

Tables 5.5-1 and 5.5-2 show the values for nameplate reserve margins through the next ten (10) year period without and with capacity expansion.

Table 5.5-1: 2010–2019 Nameplate Reserve Margin Forecast without Capacity Additions

Cases	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Base Load(50/50)										
Reserve Margin(MW)	41,415	35,981	33,463	32,771	33,881	33,493	32,700	31,870	30,935	30,061
Reserve Margin (%)	39.6%	33.3%	30.2%	29.4%	30.3%	29.8%	28.9%	28.0%	26.9%	26.0%
High Load(90/10)										
Reserve Margin(MW)	35,998	30,383	27,734	27,006	28,085	27,676	26,843	25,969	24,986	24,067
Reserve Margin (%)	32.7%	26.7%	23.8%	23.1%	23.9%	23.4%	22.6%	21.7%	20.7%	19.8%
Low Load(10/90)										
Reserve Margin(MW)	46,832	41,580	39,192	38,535	39,677	39,309	38,558	37,770	36,883	36,055
Reserve Margin (%)	47.2%	40.6%	37.4%	36.5%	37.4%	36.9%	35.9%	35.0%	33.9%	32.8%

Table 5.5-2: 2010–2019 Nameplate Reserve Margin Forecast with Capacity Additions

Cases	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Base Load(50/50)										
Reserve Margin (MW)	41,415	39,018	37,383	36,894	38,148	37,880	37,118	36,360	35,425	34,551
Reserve Margin (%)	39.6%	36.1%	33.8%	33.1%	34.1%	33.7%	32.8%	31.9%	30.8%	29.8%
High Load(90/10)										
Reserve Margin (MW)	35,998	33,419	31,654	31,129	32,352	32,063	31,261	30,460	29,476	28,557
Reserve Margin (%)	32.7%	29.4%	27.2%	26.6%	27.5%	27.1%	26.3%	25.4%	24.4%	23.5%
Low Load (10/90) Case										
Reserve Margin (MW)	46,832	44,616	43,112	42,659	43,944	43,696	42,975	42,260	41,374	40,545
Reserve Margin (%)	47.2%	43.5%	41.1%	40.4%	41.4%	41.0%	40.1%	39.1%	38.0%	36.9%

An LOLE of one (1) day in ten (10) years or 0.1 day per year is an industry standard benchmark for the analysis of a system. As LOLE values increase to levels above that of 0.1 day in one (1) year, it can be said the system is less reliable than generally accepted. Figure 5.5-4 displays the projected LOLE levels for the base case and high and low demand cases utilizing the projected capacity when no generation expansion is utilized. Also, Load Forecast Uncertainty was not applied to either the low or high demand cases. It was strictly a shift from the 50/50 demand value. The reserve margins are plotted on the same chart to show as reserve levels erode, risk increases at an exponential rate.

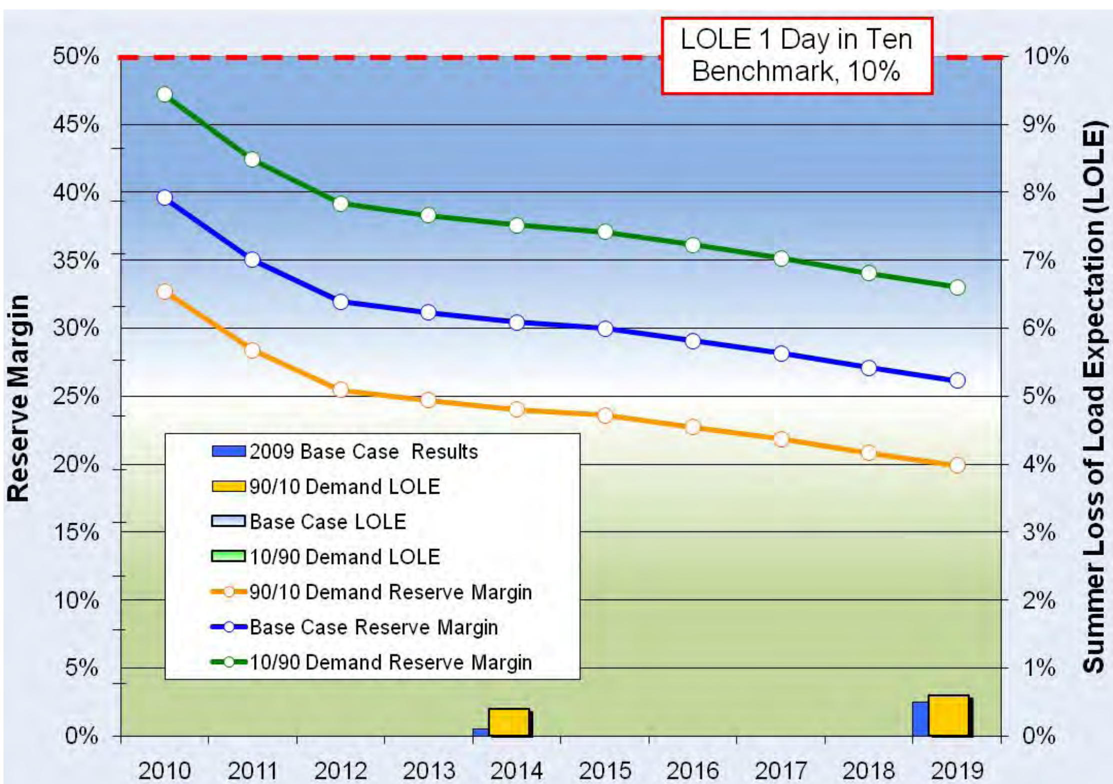

Figure 5.5-4: 2009–2018 Loss of Load Expectation Forecast

As can be seen in Figure 5.5-4, loss of load expectation never exceeds the industry standard of one (1) day in ten (10) years throughout the assessment time frame.

5.5.2 Future Uncertainties–Sensitivity Analysis

Section 5.1 established a base case and accounted for load forecast uncertainties by utilizing a 90/10 and 10/90 load forecast; these cases all employ current projected conditions. However, there are a number of uncertainties that have the potential to affect LOLE. The presence of these uncertainties makes it more probable that actual conditions will be worse than forecasted in the base case. Factors contributing to this probability include:

- The aging generation fleet carries an increased risk of higher forced outage rates.
- Much of the new capacity is wind, whose production may not be at its highest level during peak conditions.
- External reserve margins are falling and therefore future imports may be limited.

To quantify effects each uncertainty has on the base case, each of the three load levels was run while simulating no wind generation during peak, no external support, or increased Forced Outage Rates across the footprint for both 2014 and 2019. In each case, only a single variable was changed to observe the effects that particular variable had on LOLE. A full description for each uncertainty as well as the case set-up is provided in Section 5.2.1.

As determined in the base case analysis, LOLE never exceeded the one (1) day in ten (10) years benchmark. Similarly, when conducting sensitivity analysis, no cases resulted in a LOLE result exceeding the one day in ten year benchmark for either 2014 or 2019.

In the 2014 analysis, it was determined high load conditions resulted in the highest LOLE with the increased FOR case. No wind and lack of external support cases followed but none of the cases reached the one day in ten benchmark. Refer to Table 5.5-3 below for the 2014 analysis results.

Table 5.5-3: 2014 Sensitivity Results

Load Type	Base	Inc. FOR	No External	No Wind
High Load	0.004	0.017	0.008	0.011
Base Load	0.000	0.000	0.000	0.000
Low Load	0.000	0.000	0.000	0.000

2019 results came closer to the benchmark than the 2014 analysis. Similar to the 2014 results, the high load cases came closest to the one (1) day in ten (10) years benchmark. The lack of external support case became much more significant to LOLE in 2019 than in the 2014 results. Refer to Table 5.5-4 below for 2019 analysis results.

Table 5.5-4: 2019 Sensitivity Results

Load Type	Base	Inc. FOR	No External	No Wind
High Load	0.006	0.035	0.024	0.008
Base Load	0.000	0.000	0.000	0.000
Low Load	0.000	0.000	0.000	0.000

Using the base case as a benchmark, it was possible to derive the impact each variable has on LOLE. A range of LOLE was derived for each uncertainty by adjusting the variable under scrutiny. Adjusting variables, it was determined a change in forced outage rate has the largest potential to negatively affect out-year LOLE values.

Assuming no new units were put into service, the risk assessment for 2014 would appear as depicted in Figure 5.5-5 and the 2019 sensitivities would be outlined by Figure 5.5-6. It should be noted these sensitivity results rely on updated load forecasts that take into account economic fluctuations and additions to the Midwest ISO membership. Since it is difficult to ascertain future impacts on load, these results are subject to variation in future years.

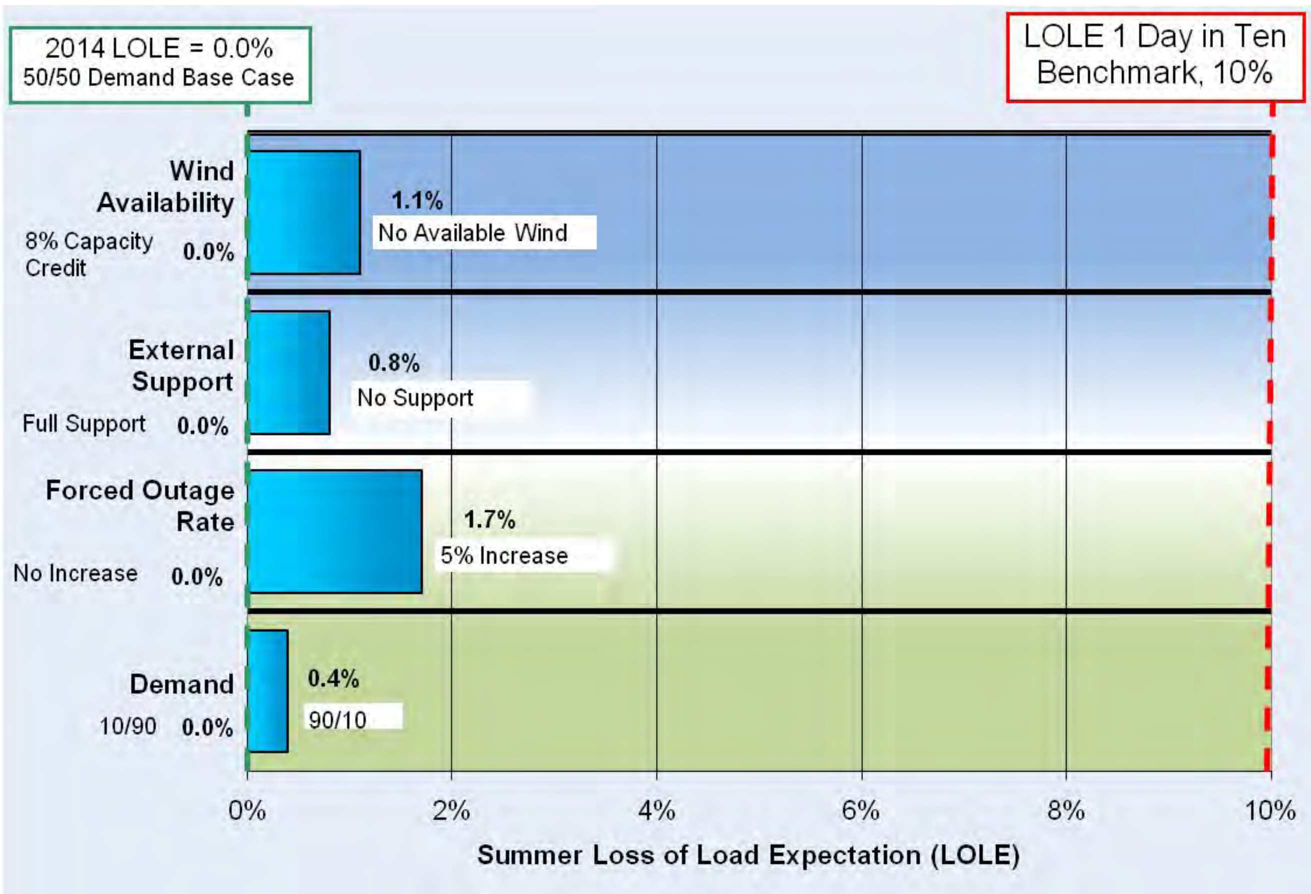

Figure 5.5-5: Year 2014 LOLE Sensitivity to Variable Adjustment

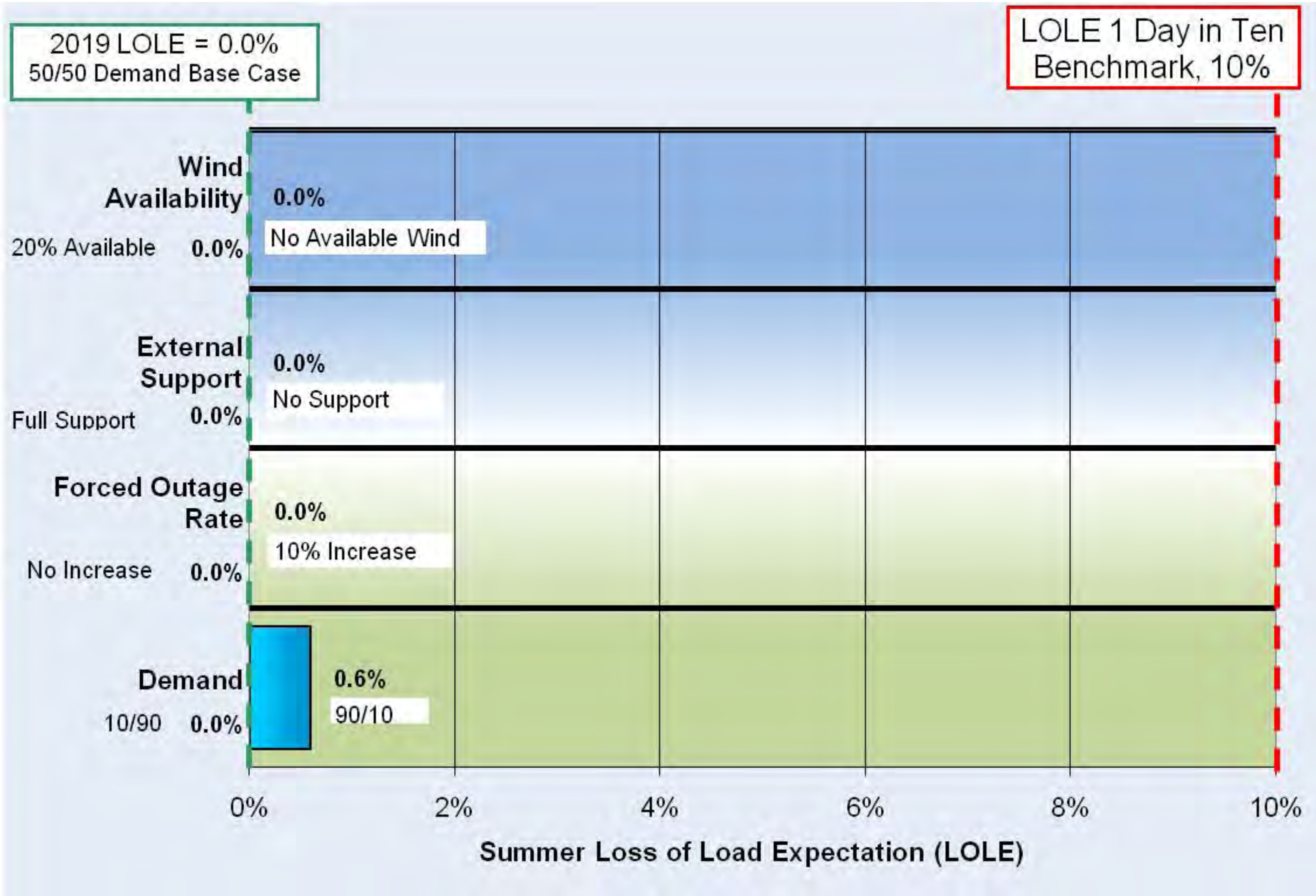

Figure 5.5-6: Year 2019 LOLE Sensitivity to Variable Adjustment

5.5.2.1 Sensitivity Descriptions

5.5.2.1.1 Forced Outage Rate

Forced outage rates will probably rise as the generation fleet ages. Much of this effect is negated by continued maintenance and unit upgrades but there is still a possibility up to a 10% increase in forced outage rates in the future years. The average age of units within the generation fleet can be seen in Figure 5.5-7.

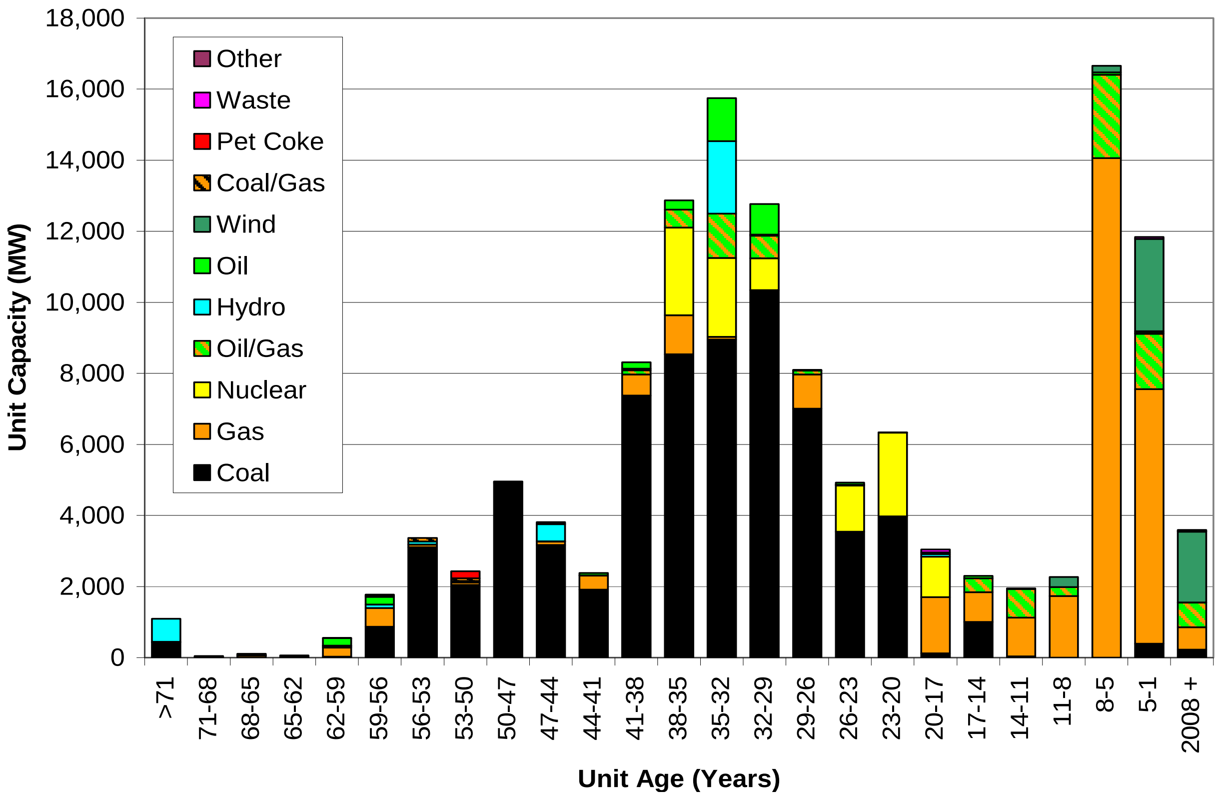

Figure 5.5-7: Age of Generation Fleet by Fuel Type

By examining previous studies on outage rates during peak conditions as seen in Figure 5.5-8, it was observed a 5% increase in forced outage rates (multiplying all outage rates by 1.05) would be a conservative sensitivity for the 2013 case and a 10% increase in the 2018 case would still be within bounds normally experienced during a system peak. Therefore, these same multipliers were applied to the 2014 case (5%) and the 2019 case (10%).

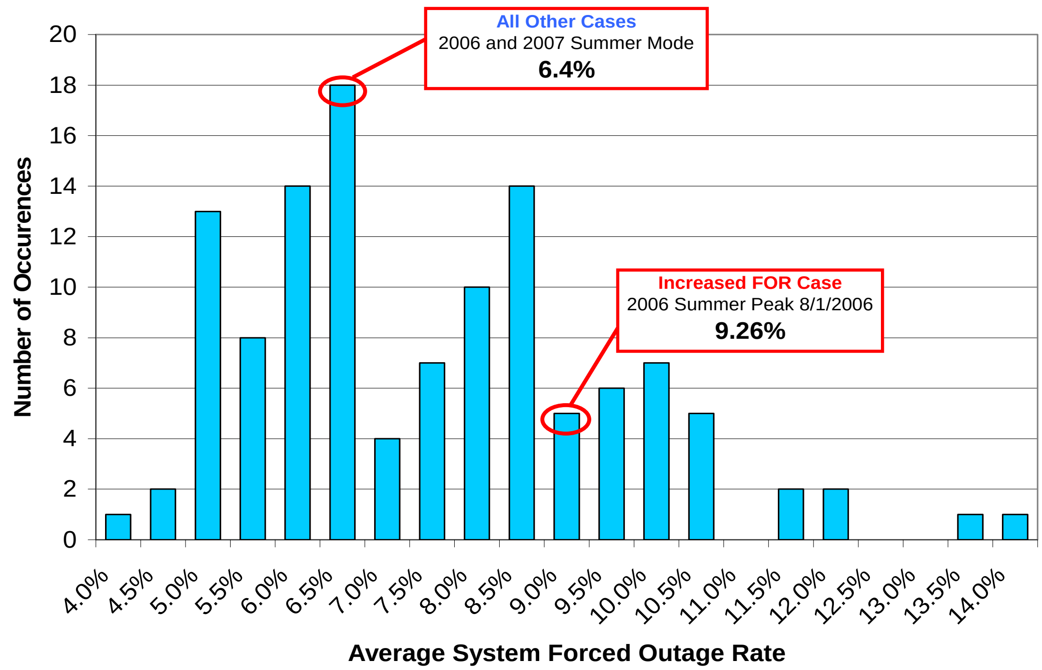

Figure 5.5-8: Case Summary of Average System Forced Outage Rates

5.5.2.1.2 Wind Availability

The intermittent nature of wind capacity creates difficulty in projecting the amount available on peak, as detailed in Section 3.1.1.2. As wind begins to comprise a greater portion of footprint capacity, this variability may become a significant issue. Due to the limited amount and irregular distribution of performance data available, a peak capacity credit cannot be explicitly predicted. Throughout this assessment and in other runs, wind units were assigned an 8% peak capacity credit consistent with previous studies. Note wind was given a 0% capacity credit in the Wind Availability case in order to establish a risk bandwidth and to examine the effects of wind production being at its lowest level during peak conditions.

5.5.2.1.3 External Support

Currently there is 5,549 MW of capacity located outside of the Midwest ISO that has an obligation to exclusively serve Midwest ISO load during peak conditions. During the previous 2006 and 2007 peaks the amount of imports has been closer to 8.5 GW. However, if reserve margins continue to deteriorate, external resources will likely be committed to their source location and the amount of imports the Midwest ISO experiences on peak can be expected to fall. Note import capability was modified to 0 MW in order to simulate the most extreme circumstance where no external commitments are available.

5.5.2.1.4 Demand Forecast Uncertainty

As outlined in Section 5.1, three (3) different load levels were analyzed throughout this assessment. While these levels give a good idea of the possibilities for peak loads during a given year when supplied a mean load forecast they do not account for variations in load growth forecasting.

5.5.3 Risk Management

Risk analysis was performed on cases representing a diverse combination of variables. While a risk level was determined for each case, the probability of occurrence of each case is not stated. It is likely the base case will most appropriately model the system as it occurs throughout the ten (10) year period, but the increasing probability of various uncertainties occurring makes planning exclusively for base case conditions overly optimistic. In the event system conditions exceed the levels modeled within this analysis, these results would no longer speak to the risk experienced by the system.

Each case provided a LOLE value that estimates the percent probability there will be insufficient resources for that case. Although various factors played a part in the risk analysis, an increased forced outage rate proved to play the most integral part in increasing the risk experienced by the system. As reserve levels declined, associated risk levels rose exponentially.

6 Near- and Long-term Reliability Analyses

6.1 New Planning Projects

This section lists projects moving to Appendix A as part of MTEP10. These projects provide mitigations for reliability issues or improved market efficiency.

Note Appendix A is a rolling list that includes all previously approved projects plus those approved in MTEP10. The new projects listed in this section of the report can be identified in Appendix A by the B>A or C>B>A designations. A project with no such designation was approved in a prior MTEP. A project with the B>A designation was either in Appendix B in a prior MTEP cycle or in Appendix C in the beginning of MTEP10 cycle and—as needs were identified—changed designation from C>B and is now recommended for Appendix A. The projects listed and described in Table 6.1-1 are recommended by the Midwest ISO staff for approval by the Board of Directors in this MTEP10. Table 6.1-1 is sorted by:

- Planning Region
- Geographic Location by TO Member System
- State
- Allocation Type per Attachment FF
  - Baseline Reliability Project (BRP)
  - Generator Interconnection Project (GIP)
  - Transmission Service Delivery Project (TDSP)
  - Multi-Value Projects (MVPs)
  - Other
- Share Status
- Estimated Cost
- Expected In Service Date
- Facility under Midwest ISO functional control or with agency agreement

Appendix D.1 contains complete project justifications for those interested in obtaining additional project information. Project region is indicated in the first column of Table 6.1-1, which begins on the following page.

Of the 230 projects being recommended by the Midwest ISO staff for approval by the Board of Directors in MTEP10, 37 are categorized as Baseline Reliability Projects. Baseline Reliability Projects (BRP) are defined as Network Upgrades identified in the base case as required ensuring that the Transmission System is in compliance with applicable National Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by the Regional Reliability Organizations and applicable to the Transmission Provider. These projects are needed to maintain reliability while accommodating the ongoing needs of the existing market participants and transmission customers.

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
Central	AmerenIL	1528	Rising Substation – Increase Xfmr Rating	Increase rating of existing 345/138 kV 450 MVA transformer	IL	Other	Not Shared	$5,000,000	6/1/2012	C>B>A
Central	AmerenIL	1535	Wood River-Stallings	Replace terminal equipment at Stallings, reconductor 6 miles of 138 kV Line 1456 and upgrade Stallings bus conductor to a minimum capability of 1200 A.	IL	BaseRel	Not Shared	$2,036,000	6/1/2012	B>A
Central	AmerenIL	2064	South Bloomington–Old Danvers 138 kV line–Reconductor	S Bloomington-Old Danvers 138 kV Line 1364 Reconductor 3.33 miles from S. Bloomington to West Washington (S Bloomington to Diamond Star Tap).	IL	BaseRel	Not Shared	$2,113,000	6/1/2012	C>B>A
Central	AmerenIL	2288	Washington Street Substation 'In-Out'	Re-Route S. Bloomington to Danvers Line 1364 through the West Washington St. Substation with an "in-and-out" arrangement. Replace existing tap to 138 kV Line 1326 with 'in and out' arrangement.	IL	Other	Not Shared	$4,155,000	6/1/2012	C>B>A
Central	AmerenIL	2956	Edwards-Tazewell 138 kV Line 1363	Edwards-Tazewell 138 kV Line 1363 Replace 1200 A wavetrap at Edwards terminal with a 2000 A unit.	IL	BaseRel	Not Shared	$118,000	6/1/2010	C>B>A
Central	AmerenIL	2957	Edwards-Tazewell 138 kV Line 1373	Edwards-Tazewell 138 kV Line 1373 Reconductor 1.57 miles of 795 kcmil ACSR conductor and 7.5 miles of 927 kcmil ACAR conductor with conductor capable of carrying 1600 A under summer emergency conditions. Replace a 1200 A wavetrap and CT's at the Edward.	IL	BaseRel	Not Shared	$121,000	12/31/2012	C>B>A
Central	AmerenIL	2958	Cahokia-Ashley-2 138 kV Bus Conductor	Cahokia 345/138 kV Substation Replace bus conductor and retap CTs to a minimum SE capability of 1600 A in the Cahokia-Ashley-2 138 kV line.	IL	BaseRel	Not Shared	$485,000	6/1/2010	C>B>A

MidwestISO Energizing the Heartland

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
Central	AmerenIL	2962	Schram City 138 kV Connection for New Customer	Schram City 138-34.5 kV Substation Install new 138 kV terminal equipment.	IL	Other	Not Shared	$1,300,000	12/1/2010	C>B>A
Central	AmerenIL	2965	Meredosia Capacitor Bank	Meredosia, East 138 kV Substation nstall two 40 Mvar, 138 kV capacitor banks, including the required circuit breakers, disconnect switches, and phase reactors on the Meredosia Substation Bus.	IL	BaseRel	Not Shared	$2,710,000	6/1/2011	C>B>A
Central	AmerenIL	2966	Hutsonville Capacitor Bank	Hutsonville Plant Install 2-stage, 70 Mvar (2 x 35 Mvar) 138 kV capacitor bank. Need 2-138 kV PCB's.	IL	BaseRel	Not Shared	$2,707,000	12/31/2010	C>B>A
Central	AmerenIL	2968	Midway-N. Staunton Reconductoring	Midway-N. Staunton 138 kV Line 1446 Reconductor 9.91 miles of 1272 kcmil ACSR conductor in the Midway-Litchfield Tap line section with conductor capable of carrying 2000 A under summer emergency conditions. Reconnect or replace 2-1600 A CT's at the Mid.	IL	Other	Not Shared	$4,905,000	6/1/2011	C>B>A
Central	AmerenIL	2986	North Alton Substation Supply	North Alton 138-34.5 kV Substation Supply Supply new 138-34.5 kV Substation from an in-out by tapping the existing Wood River to Stallings 138 kV line (“in and out”). Build approximately 4 miles of double-circuit 138 kV line to the new North Alton Substation connection to the Wood River-Stallings-1456 138 kV line. Approximately 4 miles of double-circuit 138 kV line needed.	IL	Other	Not Shared	$12,891,000	12/1/2015	C>B>A
Central	AmerenIL	2992	Bondville-S.W. Campus	Bondville-S.W. Campus 138 kV Construct 8 miles of new 138 kV line. Construct 138 kV Ring Bus at Bondville (2 new PCB's) and a 138 kV Ring Bus at Champaign S.W. Campus (4 new PCB's).	IL	Other	Not Shared	$10,000,000	6/1/2014	C>B>A
Central	AmerenMO	2066	Troy Area Bulk Substation–161 kV Supply Lines	Troy Area 161-34.5 kV Bulk Substation–161 kV Supply Lines	MO	Other	Not shared	$15,770,000	6/1/2010	C>B>A

MidwestISO Energizing the Heartland

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
Central	AmerenMO	2961	N. Farmington-Cape-1	N. Farmington-Cape-1 161 kV Increase ground clearance on 5.27 mile Cape-Wedekind Tap line section.	MO	BaseRel	Not Shared	$420,000	7/1/2010	C>B>A
Central	AmerenMO	2969	Cape Area Capacitor Bank	Cape Area Install 2-stage, 120 Mvar (2 x 60 Mvar), 161 kV capacitor bank and 2-161 kV PCB's at Wedekind Substation	MO	BaseRel	Not Shared	$3,109,000	6/1/2011	C>B>A
Central	AmerenMO	2972	Sandy Creek-Joachim Reconductoring	Sandy Creek-Joachim-1 138 kV Line Reconductor 6.2 miles of 795 kcmil ACSR with conductor having 1600 A summer emergency capability between Sandy Creek and Bailey Substations.	MO	BaseRel	Not Shared	$3,305,700	6/1/2012	C>B>A
Central	AmerenMO	2976	Central Substation Relocation	Central 138-34.5 kV Substation Move Central 138-34 kV Substation approximately one-half mile and reterminate existing 138 kV supply lines (Cahokia-Central-1&2 and Central-Watson-1).	MO	Other	Not Shared	$4,632,900	12/1/2012	C>B>A
Central	AmerenMO	3107	Arnold Substatsion : Install 4-138 kV Breakers	Install 4-138 kV Breakers at Arnold Substation. Install 138 kV breaker on the Arnold-Meramec-3 line position. Establish 138 kV Bus #3, install 138 kV Bus 2-3 tie breaker, and rearrange the existing Tyson-Meramec-4 line connection to an in-out arrangement.	MO	BaseRel	Not Shared	$2,283,200	6/17/2011	C>B>A
Central	DEM	1520	Durbin 230/69	Construct a new Durbin 230/69kv 150mva substation with 2 69kv line terminals.	IN	Other	Not Shared	$7,000,000	6/1/2017	C>B>A
Central	DEM	1903	Fishers N. to Fishers 69kV reconductor	Reconductor 1.05 miles 69kV line from Fishers No to Fishers with 954ACSR@100C conductor.	IN	Other	Not Shared	$455,229	6/1/2014	C>B>A
Central	DEM	2050	Dresser 345/138kV Bank 3 addition	Add a 3rd 345/138kV transformer at Dresser Sub.	IN	BaseRel	Shared	$12,700,000	6/1/2011	B>A
Central	DEM	2123	Bloomington to Martinsville 69kV Rebuild	Bloomington to Martinsville 69kV–6903 ckt. Rebuild 9.2 miles of 336ACSR with 954ACSR@100C.	IN	Other	Not Shared	$2,020,000	6/1/2012	C>B>A

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Central	DEM	2134	Bloomington 230 to Needmore Jct 69kV reconductor	Bloomington 230kV Sub to Needmore Jct (Pole #825-3379) Reconductor 6949 line with 954ACSR 100C conductor and replace (2) Needmore Jct. 69kV–600 amp switches with 1200 amp switches.	IN	Other	Not Shared	$2,712,500	6/30/2013	C>B>A
Central	DEM	2136	Greenwood HE Honey Creek Jct to Frances Creek Jct 69kV uprate	Greenwood HE Honey Creek Jct to Frances Creek Jct Uprate 69kV–69102 line 1.12 mile for 100C.	IN	Other	Not Shared	$63,533	6/30/2012	C>B>A
Central	DEM	2137	Greenwood Averitt Rd Jct to HE Honey Creek Jct 69 kV Uprate	Greenwood Averitt Rd Jct to HE Honey Creek Jct 69 kV–69102 Uprate 1.05 mile line section of 477acsr for 100C conductor temperature operation.	IN	Other	Not Shared	$53,461	6/30/2012	C>B>A
Central	DEM	2143	Frances Creek 345/69kV Bank 2	Add Frances Creek 345/69kV Bank 2–200MVA with LTC.	IN	Other	Not Shared	$6,887,000	6/1/2014	C>B>A
Central	DEM	2333	Butler REC Huston Sub 138kv	New Butler REC Huston Sub 138kV–F3281 loop through sub w/ 954acsr	OH	Other	Not Shared	$433,238	10/1/2010	C>B>A
Central	DEM	2858	Geist to Fortville 69kv–69130 ckt. Reconductor	Reconductor 69kV 3.62 mile line from Geist sub to Fortville sub with 954ACSR conductor.	IN	Other	Not Shared	$1,820,000	6/1/2017	C>B>A
Central	DEM	2859	Peru Muni J to Wabash J 69kV–6986 ckt. Reconductor	Peru Muni J to Wabash J 6986 Reconductor approx., 10.3 miles of 4/0 ACSR with 477 ACSR.	IN	Other	Not Shared	$3,810,000	6/1/2012	C>B>A
Central	DEM	2860	Brazil East to Reelsville J 69kV–6938 ckt. Reconductor	Reconductor 6938 line from Brazil East to Reelsville Jct. with 477ACSR 100C conductor. Replace Reelsville Jct switches with 1200 amp switches.	IN	Other	Not Shared	$2,550,000	6/1/2012	C>B>A
Central	DEM	2861	Greencastle Madison J to Greencastle East J 69kV–6996 ckt. Reconductor	Reconductor 6996 line from Greencastle Madison Jct to Greencastle East Jct. with 954ACSR 100C conductor. Replace or upgrade 600 amp Greencastle East Jct switches to 1200amp.	IN	Other	Not Shared	$1,482,000	6/1/2012	C>B>A

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Central	DEM	2863	Carmel SE to new Jct in 69145 ckt–new 69kV line	Build new 69kV-954ACSR circuit from Carmel SE to new Jct in the 69145 line, completing a loop from Carmel 146th St to Geist.	IN	Other	Not Shared	$4,274,200	6/2/2012	C>B>A
Central	DEM	2865	Frankfort Burlington to Middlefork 69kV–69133 ckt Uprate	Frankfort Brlngtn St to Midfrk–69133 ckt Uprate 11.5 miles of 4/0ACSR to 100C and reconductor 1.0 mile of 2/0CUB7 to 954ACSR@100C.	IN	Other	Not Shared	$582,035	6/1/2012	C>B>A
Central	DEM	2866	Fairfield to City of Hamilton 138kV–F5781 Re-Route	Build new section of 138 kV Feeder 5781 to allow existing section to be sold to city of Hamilton.	OH	Other	Not Shared	$1,148,000	12/31/2010	C>B>A
Central	DEM	2867	EKPC Webster Rd.–138kV tap	Tap 138kV–ckt. F6282 between Hands & Buffington for new EKPC Webster Rd 138/69kV sub. Includes 3–138kV CB and associated Duke owned facilities. New Tie from DEM to EKPC.	KY	Other	Not Shared	$4,083,000	5/1/2011	C>B>A
Central	DEM	2869	Zimmer 345kV Gas Insulated Sub. Repl.	Replace 345kV gas insulated sub with an air insulated sub.	OH	Other	Not Shared	$4,032,000	6/1/2012	C>B>A
Central	DEM	2870	WVPA Monitor 69kV feed	Install 2-1200A switches and bus through new WVPA Monitor dist sub in the 6909 line with 1 mile double ckt 69kV source lines (477ACSR@100C).	IN	Other	Not Shared	$650,000	11/1/2010	C>B>A
Central	DEM	2871	EKPC Hebron–138kV ring bus	Add new EKPC Hebron 138/69kV transformer (outside DEM area 208). Includes 3 position–138kV CB ring bus and associated Duke owned facilities (inside DEM area 208). 138kv Tie from DEM to EKPC is being revised slightly. 100% to be paid for by EKPC.	KY	Other	Not Shared	$3,345,000	6/1/2011	C>B>A
Central	DEM	2872	Manhattan Dist Sub 138kV tap switches	Install 1200A–138kv line switching on both sides of proposed tap line to new joint use DEM/WVPA Manhattan distribution sub.	IN	Other	Not Shared	$525,723	12/31/2011	C>B>A

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Central	DEM	2874	Noblesville to Geist 230kV–23007 line relocate	Relocate section of 23007 between Noblseville and Giest to new RoW around expanding mine operation–approx. 0.6 mile of added line length	IN	Other	Not Shared	$800,000	12/1/2011	C>B>A
Central	DEM	2875	Edwardsville 138kV switches and tap line	Construct new Edwardsville 138/12kV distribution substation–single 22.4 MVA transformer	IN	Other	Not Shared	$323,000	12/31/2011	C>B>A
Central	DEM	2876	Redbank 345kV Gas Insulated Bus. Repl.	Replace 345kV gas insulated bus with an air insulated bus	OH	Other	Not Shared	$3,467,832	6/1/2013	C>B>A
Central	DEM	2877	West End 138kV relocation for B.S. Bridge	Apply modifications to West End Substation facilities, 138 kV transmission lines and distribution lines to accommodate Brent Spence Bridge project.	OH	Other	Not Shared	$13,780,000	12/31/2015	C>B>A
Central	DEM	2878	Miami Fort 345kV Gas Insulated Bus. Repl.	Replace 345kV gas insulated bus with an air insulated bus.	OH	Other	Not Shared	$1,440,000	6/1/2014	C>B>A
Central	DEM	2879	Brazil West 69kV tap switches and tap line	Construct Brazil West 10.5MVA 69/12kV sub in the 6902 Line to be located on 900N east of 425W.	IN	Other	Not Shared	$150,000	12/31/2012	C>B>A
Central	DEM	2880	Willey CB 843 replacement	Replace bus tie breaker #843 and associated disconnect sw's–new limit will be 2000A.	OH	Other	Not Shared	$176,354	12/31/2010	C>B>A
Central	DEM	2882	Lateral replace CB 840	Replace bus tie breaker #840 and associated disconnect sw's–new limits will be CB–3000A and D/S's–2000A.	OH	Other	Not Shared	$445,302	12/31/2012	C>B>A
Central	HE	3075	Dolan Transformer Upgrade	Upgrade Dolan Substation 69/12.47kV Transformer.	IN	Other	Not Shared	$550,000	6/1/2010	C>B>A
Central	HE	3076	Kossuth Substation Rebuild	Rebuild of Kossuth Substation from aging wood to steel.	IN	Other	Not Shared	$750,000	6/1/2010	C>B>A
Central	HE	3077	Martinsville Park Ave + Tapline	Martinsville Park Avenue Substation and Tapline	IN	Other	Not Shared	$1,030,000	6/1/2010	C>B>A

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Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
Central	HE	3078	Napoleon to Sunman Thermal Upgrade	Thermal Upgrade of Napoleon to Sunman Transmission Line Segment	IN	Other	Not Shared	$330,000	6/1/2010	C>B>A
Central	HE	3079	Pioneer to Intat Junction Thermal Upgrade	Thermal Upgrade of Pioneer to Intat Junction Transmission Line Segment	IN	Other	Not Shared	$200,700	6/1/2010	C>B>A
Central	HE	3080	Rocklane Tie to Duke 69kV	Build 69kV Transmission from HE Rocklane to Duke 69kV Transmission.	IN	Other	Not Shared	$3,000,000	6/1/2011	C>B>A
Central	HE	3081	Wilbur Transformer Upgrade	Upgrade Wilbur Substation 69/12.47kV Transformer.	IN	Other	Not Shared	$450,000	6/1/2010	C>B>A
Central	IPL	2896	Petersburg–Thompson 345 kV line rating upgrade	Increase line rating from 956 MVA to 1195 MVA.	IN	BaseRel	Not Shared	$1,500,000	6/1/2010	C>B>A
Central	IPL	2900	Northwest–Southwest 138 kV line rating upgrade	Increase line rating from 242 to 382 MVA.	IN	BaseRel	Not Shared	$1,500,000	6/1/2011	C>B>A
East	FE	2802	Burger wave trap replacement on the Brookside 138kV exit	On the Brookside line exit @ Burger, replace the 400A wave trap with 1600A wave trap.	OH	BaseRel	Not Shared	$19,961	6/1/2010	C>B>A

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Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
East	FE	2803	Campbell-McDowell #2–new 69kV line	Rebuild Y-10 out of McDowell from McDowell to 3-way tap point (approx. 3.7 mi) with 336.4 ACSR at 138kV height for possible future double ckt 138/69kV line. Add 69kV breaker and protection for McDowell 12.47kV Distribution Load to free up the existing Y-10 line exit (if possible move old relaying to new TR position and install new relays on Y-10 exit). Add 69kV line exit at Campbell 69kV Substation with breaker, relays, meters. Add 69kV breaker at Campbell 69kV Substation for the Campbell-McDowell #1 (Y-249 line) 69kV exit. (this was formerly part of the 21.6MVAr cap bank addition project at Campbell which has been deferred indefinately). Build new 69kV line from Campbell Sub to 3-way tap (approx. 6.5 mi) and tie into rebuilt Y-10 out of McDowell to create Campbell-McDowell #2 69kV line.	PA	Other	Not Shared	$1,800,264	6/1/2012	C>B>A
East	FE	2804	Clark Substation 138kV Breaker addition	Add a new 138kV breaker to the Clark substation. Relocate the Clark–Urbana 138kV line exit to the new position in the ring bus.	OH	BaseRel	Not Shared	$313,000	6/1/2011	C>B>A
East	FE	2806	New Castle-State Line Y-200 69kV Line Terminal Upgrade	Upgrade relays and replace substation terminal conductor at New Castle on the Y-200 Line. Replace OC CR 600 Amps Overcurrent Relay with new SEL relay and 336.4 ACSR substation conductor riser with 477 ACSR for increased line loadability.	PA	Other	Not Shared	$85,000	6/1/2012	C>B>A
East	FE	2807	NewCastle-StateLine Y-200–design temp correction.	Rebuild sections of New Castle–State Line SW ST (Y-200) between Darlington and State Line Switching Station that are presently rated for 120 deg F design temp, and increase to 212 deg F design temp.	PA	Other	Not Shared	$157,000	6/1/2010	C>B>A
East	FE	2808	State Line 69kV Switching Station–replace existing protection	Replace existing protection equipment with 2 sets of SEL-321 and SEL-311B relays.	PA	Other	Not Shared	$82,000	6/1/2010	C>B>A

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East	FE	3186	Sammis-Wylie Ridge Second 345 kV Line	Add parallel conductors to the exising Sammis-Wylie Ridge 345-kV line, using available tower space, and corresponding terminal upgrqades lo increase line rating to the conductor thermal rating.	OH	Other	Not Shared	$750,000	6/1/2011	C>B>A
East	ITC	2918	Breaker Replacement Program 2012	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$6,000,000	12/31/2012	C>B>A
East	ITC	2919	NERC Relay Loadability Compliance 2012	Upgrade relays throughout system.	MI	Other	Not Shared	$2,400,000	12/31/2012	C>B>A
East	ITC	2920	Potential Device Replacement 2012	Replace aging potential devices.	MI	Other	Not Shared	$300,000	12/31/2012	C>B>A
East	ITC	2921	Relay Betterment Program 2012	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2012	C>B>A
East	ITC	2922	Wood Pole Replacement 2012	Replace deteriorating wood pole.	MI	Other	Not Shared	$1,200,000	12/31/2012	C>B>A
East	ITC	2923	Capacitor Replacement 2012	Replace capacitor banks.	MI	Other	Not Shared	$600,000	12/31/2012	C>B>A
East	ITC	2924	Blanket for Customer Interconnection 2010	Throughout system	MI	Other	Not Shared	$2,000,000	12/31/2010	C>B>A
East	ITC	2925	Blanket for Customer Interconnection 2011	Throughout system	MI	Other	Not Shared	$2,000,000	12/31/2011	C>B>A
East	ITC	2926	Blanket for Customer Interconnection 2012	Throughout system	MI	Other	Not Shared	$2,000,000	12/31/2012	C>B>A

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East	ITC	2927	Blanket for Customer Interconnection 2013	Throughout system	MI	Other	Not Shared	$2,000,000	12/31/2013	C>B>A
East	ITC	2928	Blanket for Customer Interconnection 2014	Throughout system	MI	Other	Not Shared	$2,000,000	12/31/2014	C>B>A
East	ITC	2929	Ariel Substation (formerly Holland)	Distribution Interconnection to add two new 120/13.2kV transformers at Holland. Connects to the Wheeler to Troy 120kV circuit.	MI	Other	Not Shared	$2,800,000	12/30/2012	C>B>A
East	ITC	2930	Upper Rouge	Distribution Interconnection to add a new 120/4.8kV transformer at Upper Rouge.	MI	Other	Not Shared	$1,900,000	12/30/2015	C>B>A

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East	ITC	3168	Candidate MVP Portfolio 1– Michigan Thumb Wind Zone	Connect proposed transmission line into a new station to the south and west of the Thumb area that will tap three (3) existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two (2) new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two (2) existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three (3) ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.	MI	MVP	Shared	$510,000,000	12/31/2015	C>B>A

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East	METC	2502	McGulpin Shunt Reactor	Install shunt reactor McGulpin.	MI	BaseRel	Not Shared	$3,000,000	12/31/2011	B>A
East	METC	2903	Battery Replacement 2012	Replace batteries and chargers.	MI	Other	Not Shared	$300,000	12/31/2012	C>B>A
East	METC	2904	Breaker Replacement Program 2012	Replace defective, damaged, or over -dutied breakers throughout system.	MI	Other	Not Shared	$6,000,000	12/31/2012	C>B>A
East	METC	2905	NERC Relay Loadability Compliance 2012	Upgrade relay throughout system.	MI	Other	Not Shared	$2,400,000	12/31/2012	C>B>A
East	METC	2906	Potential Device Replacement 2012	Replace aging potential devices.	MI	Other	Not Shared	$300,000	12/31/2012	C>B>A
East	METC	2907	'Power Plant Control Relocation 2012	Relocate substation controls currently located in power plants control rooms.	MI	Other	Not Shared	$1,200,000	12/31/2012	C>B>A
East	METC	2908	Relay Betterment Program 2012	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2012	C>B>A
East	METC	2909	Sag clearance 2012	Identify and remediate inherent sag limitations on heavily loaded METC transmission lines throughout the system.	MI	Other	Not Shared	$3,600,000	12/31/2012	C>B>A
East	METC	2910	Wood Pole Replacement 2012	Replace deteriorating wood pole.	MI	Other	Not Shared	$3,600,000	12/31/2012	C>B>A
East	METC	2911	Blanket for Customer Interconnections 2010	Throughout system	MI	Other	Not Shared	$2,500,000	12/31/2010	C>B>A
East	METC	2912	Blanket for Customer Interconnections 2011	Throughout system	MI	Other	Not Shared	$2,500,000	12/31/2011	C>B>A

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East	METC	2913	Blanket for Customer Interconnections 2012	Throughout system	MI	Other	Not Shared	$2,500,000	12/31/2012	C>B>A
East	METC	2914	Blanket for Customer Interconnections 2013	Throughout system	MI	Other	Not Shared	$2,500,000	12/31/2012	C>B>A
East	METC	2915	Blanket for Customer Interconnections 2014	Throughout system	MI	Other	Not Shared	$2,500,000	12/31/2014	C>B>A
East	METC	2916	Livingston–Vanderbilt 138 kV Rebuild	Rebuild 9.7 miles of 138 kV 266 ACSR to 954 ACSR FDC 230 kV construction.	MI	BaseRel	Shared	$10,646,000	6/1/2013	C>B>A
East	METC	2917	David Jct–Hubbardson Jct–Bingham Sag Remediation	Improve sag clearance by replacing 16 wood poles with 138 kV FDC steel poles.	MI	BaseRel	Not Shared	$1,400,000	6/1/2011	C>B>A
East	MPPA	3072	Gray–HL Thermal Upgrade	Line Maintenance–4/0 ACSR Line Re-rate to 46MVA.	MI	Other	Not Shared	$20,000	6/1/2010	C>B>A
East	MPPA	3074	TC East – Parsons TLine	New 4.1 mi 69kV transmission line from new TC East Sub to existing Parsons Sub	MI	Other	Not Shared	$1,600,000	7/1/2011	C>B>A
East	MPPA/METC	3073	TC East Substation	New 138/69kV Substation Interconnection	MI	Other	Not Shared	$7,700,000	6/30/2012	C>B>A
East	NIPS	1991	Upgrade 138/69 kV Transformer Capacity at E. Winamac substation	Replace the existing (2) 138/69 KV 45 MVA transformers at East Winamc Substation with (2) 138/69 KV 112 MVA transformers.	IN	BaseRel	Not Shared	$3,952,092	12/1/2010	B>A
East	NIPS	2315	Bailly Dune Acres Modernization	Upgrade microwave communication equipment and install new fiber optic communication equipment, between Bailly Substation and the Dune Acres Substation yard.	IN	Other	Not Shared	$310,943	12/11/2009	B>A

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East	NIPS	2322	Green Acres Sub.- 345-138kV Transformer	Install a 560 MVA 345/138 kV transformer, (1) 345 kV and (1) 138 kV circuit breaker and associated equipment at Green Acres Substation.	IN	BaseRel	Shared	$7,417,000	12/1/2011	B>A
East	NIPS	3155	Relay upgrade on circuit 13857, Goodland to Reynolds	Increase the CT ratio on circuit 13857 line relays at Reynolds and upgrade the protection at both the Goodland and Reynolds terminals.	IN	Other	Not Shared	$177,232	5/28/2010	C>B>A
East	WPSC	3060	Morley Capacitor Bank	Install a Capacitor Bank tap at the Morley substation	MI	Other	Not Shared	$260,000	12/31/2011	C>B>A
East	WPSC	3061	Tremaine	New Distribution Interconnection from the Burnips to Portland circuit	MI	Other	Not Shared	$200,000	6/1/2011	C>B>A
East	WPSC	3062	Blendon Transformer Upgrade	Replace Blendon Transformer with a larger transformer.	MI	Other	Not Shared	$3,750,000	12/31/2013	C>B>A
East	WPSC	3063	Redwood to Baseline Rebuild	Rebuild the Redwood to Baseline line section with a larger conductor.	MI	Other	Not Shared	$2,000,000	12/31/2012	C>B>A
East	WPSC	3064	Blendon to Fairview Rebuild	Rebuild the Blendon to Fairview line section with a larger conductor.	MI	Other	Not Shared	$3,600,000	12/31/2010	C>B>A
East	WPSC	3065	Grawn Transmission Upgrade	Upgrade to replace outdated equipment. Bus, breakers, relays, and other equipment as necessary.	MI	Other	Not Shared	$280,000	12/31/2010	C>B>A
East	WPSC	3066	Altona Capacitor Bank	Install a Capacitor Bank at the Altona substation.	MI	Other	Not Shared	$260,000	12/31/2010	C>B>A
East	WPSC	3067	Rodgers Capacitor Bank	Install a Capacitor Bank at the Rodgers substation.	MI	Other	Not Shared	$260,000	12/31/2011	C>B>A
East	WPSC	3068	South Boardman Capacitor Bank	Install a Capacitor Bank at the South Boardman substation.	MI	Other	Not Shared	$260,000	12/31/2010	C>B>A
East	WPSC	3069	Weidman Capacitor Bank	Install a Capacitor Bank at the Weidman substation.	MI	Other	Not Shared	$260,000	12/31/2011	C>B>A
East	WPSC	3070	Posen Capacitor Bank	Install a Capacitor Bank at the Posen substation.	MI	Other	Not Shared	$260,000	12/31/2010	C>B>A

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Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	ATC LLC	884	Spring Green 32 (2-16.33) MVAR capacitor bank	2-16.33 MVAR 69 kV capacitor banks at Spring Green	WI	Other	Not Shared	$1,200,000	6/1/2011	B>A
West	ATC LLC	1282	Install 1-4.08 MVAR 69 kV cap bank at the Osceola substation in Houghton County, MI.	Install 1-4.08 MVAR 69 kV cap bank at the Osceola substation in Houghton County, MI.	MI	Other	Not Shared	$800,000	12/4/2009	B>A
West	ATC LLC	1554	Indian Lake 138kV Capacitor Bank	Install 2x8.16 MVAR Capicator bank at Indian Lake substation.	MI	Other	Not Shared	$584,007	12/17/2010	B>A
West	ATC LLC	1626	Summit Capacitor Banks	Install two 24.5 MVAR 138-kV capacitor banks at Summit substation.	WI	BaseRel	Not Shared	$2,100,000	5/21/2010	B>A
West	ATC LLC	1627	Uprate Bain-Albers 138-kV line	Increase clearance of the Bain-Albers 138-kV line.	WI	BaseRel	Not Shared	$122,666	6/1/2010	C>B>A
West	ATC LLC	1686	Brandon-Fairwater 69 kV line	Construct Brandon-Fairwater 69 kV line.	WI	Other	Not Shared	$2,800,000	12/16/2009	B>A
West	ATC LLC	1690	Rebuild Verona-Oregon 69 kV line	Rebuild the Verona-Sun Valley 69 kV line Y119.	WI	Other	Not Shared	$6,100,000	6/1/2010	B>A
West	ATC LLC	1691	Uprate McCue-Milton Lawns 69 kV line	Uprate terminal limitations at McCue for the McCue-Milton Lawns 69 kV line.	WI	Other	Not Shared	$800,000	11/25/2010	B>A
West	ATC LLC	1704	Uprate Sheepskin-Dana 69 kv line	Uprate Sheepskin-Dana 69 kv line to 95 MVA.	WI	Other	Not Shared	$726,000	4/12/2010	B>A
West	ATC LLC	1731	Blount-Ruskin 69 kV line replacement	Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line.	WI	Other	Not Shared	$6,500,000	3/31/2011	C>B>A

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Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	ATC LLC	1940	M38 capacitor bank	Expand the M38 138 kV substation to add a 2nd 138 kV bus and accommodate a new 8.16 MVAR 138 kV capacitor bank. Move the Atlantic and Cedar lines to new terminations on the new 138 kV bus.	MI	BaseRel	Not Shared	$3,300,000	10/17/2009	C>B>A
West	ATC LLC	2019	Uprate Chandler Delta 69 kV #1	Increase line clearance to 167 deg F SN/SE	MI	Other	Not Shared	$120,642	6/9/2010	C>B>A
West	ATC LLC	2020	Uprate Chandler Delta 69 kV #2	Increase line clearance to 187 deg F SN/SE	MI	Other	Not Shared	$71,000	10/31/2012	C>B>A
West	ATC LLC	2028	Uprate Y-61 & add Fulton Caps	Uprate Y-61 McCue-Lamar 69 kV line to achieve 300 deg F SE line ratings and install 2-12.45 Mvar 69 kV cap banks at Fulton	WI	Other	Not Shared	$2,855,042	11/10/2010	C>B>A
West	ATC LLC	2032	2nd Shorewood-Humboldt 138 kV UG cable	Add a second parallel underground line from Humboldt terminal to Shorewood.	WI	Other	Not Shared	$5,928,473	11/17/2010	C>B>A
West	ATC LLC	2033	Uprate Bain-Kenosha 138-kV	Upgrade substation equipment at Bain & Kenosha.	WI	Other	Not Shared	$6,960,473	11/1/2010	C>B>A
West	ATC LLC	2035	Uprate X23 Colley Rd Terminal	Uprate X23 Colley Rd Terminal (Colley Rd-Marine).	WI	Other	Not Shared	$2,592,000	6/1/2010	B>A
West	ATC LLC	2163	Replace Ellinwood Tr #2	Replace Ellinwood 138-69 kv Tr #2.	WI	Other	Not Shared	$2,012,243	10/22/2010	C>B>A
West	ATC LLC	2165	Uprate Femrite-Royster 69 kV	Up-rate Femrite-Royster 69 kV.	WI	Other	Not Shared	$441,446	5/12/2010	C>B>A
West	ATC LLC	2451	Brodhead-S Monroe 69kV Rebuild	Rebuild Brodhead- S Monroe 69kV line with T2 477 kcmil ACSR	WI	Other	Not Shared	$11,800,000	3/1/2012	C>B>A
West	ATC LLC	2793	G883/4 Uprate Point Beach-Sheboygan EC 345-kV	G883/4 Increase ground clearance of the Point Beach-Sheboygan EC 345-kV to 167 deg F.	WI	GIP	Shared	$2,900,000	3/1/2010	C>B>A

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	ATC LLC	2815	Uprate Lake Park-City Limits-Kaukauna Combined Locks Tap 138-kV	Increase line clearance to achieve a 200 deg F operating temperature.	WI	BaseRel	Not Shared	$18,740	3/4/2010	C>B>A
West	ATC LLC	2816	Uprate Forsyth-Munising 138kV	Increase line clearance to achieve a 200 deg F operating temperature.	MI	BaseRel	Not Shared	$133,334	10/31/2010	C>B>A
West	ATC LLC	2817	Uprate Winona-M38 138kV	Increase line clearance to achieve a 125 deg F operating temperature.	MI	BaseRel	Not Shared	$380,619	3/1/2010	C>B>A
West	ATC LLC	2818	Uprate Kaukauna Central Tap-Meadows Tap-Melissa 138kV	Increase line clearance to achieve a 200 deg F operating temperature.	WI	BaseRel	Not Shared	$852,153	6/30/2010	C>B>A
West	ATC LLC	2819	Replace Bluemound 230/138kV transformerT3	Replace Bluemound 230/138kV transformer T3 with a 400 MVA unit.	WI	Other	Not Shared	$8,000,000	11/30/2011	C>B>A
West	ATC LLC	2821	Replace NFL transformers T31 & T32 with a single 100MVA unit	Replace NFL transformers T31 & T32 with a single 100MVA unit.	WI	BaseRel	Not Shared	$3,260,000	12/31/2010	C>B>A
West	ATC LLC	2835	Rebuild Chaffee Creek-Plainfield 69 kV line	Rebuild 9.3 miles of line y-90 from Chaffee Creek-Hancock and the double circuited portion of line y-49 with T2-4/0.	WI	Other	Not Shared	$4,956,792	6/10/2010	C>B>A
West	ATC LLC	2836	Rebuild Whitcomb-Wittenberg 69 kV line	Rebuild the existing 4.8 miles of line y-86 with T2-4/0.	WI	Other	Not Shared	$3,680,620	3/15/2011	C>B>A
West	ATC LLC	2837	Uprate Cypress-Arcadian 345 kV line	G833/4-J022/3 Uprate Cypress-Arcadian 345 kV line to 584 MVA SE = 125 deg F clearance.	WI	GIP	Shared	$200,000	12/2/2009	C>B>A
West	ATC LLC	2839	Point Beach #2 uprate	G833-J022 Point Beach #2 Uprate increase Pmax from 514 MW to 617.06 MW & replace GSU.	WI	Other	Not Shared		5/31/2011	C>B>A

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	ATC LLC	2840	Blanchardville-Forward 69 kV Rebuild	Rebuild the Blanchardville-Forward 69 kV line with T2 4/0 ACSR Penguin and increase ground clearance for the line to 200 deg F SN and 300 deg F SE.	WI	Other	Not Shared	$5,200,000	3/22/2010	C>B>A
West	ATC LLC	2841	Replace existing Council Creek transformer	Replace the existing Council Creek transformer with a larger bank.	WI	Other	Not Shared	$3,289,895	11/24/2010	C>B>A
West	ATC LLC	2843	Uprate the Autrain 69-kV line	Increase ground clearance for the Autrain 69 kV line to 293 Amps for all seasons.	MI	Other	Not Shared	$260,000	3/31/2011	C>B>A
West	ATC LLC	3088	Install Distribution Caps at Dickinson	Install 2x 9.6 Mar Distribution Caps on the low voltage side of the Dickinson 138/24.9 kV Tr at Dickinson for transmission voltage support.	WI	Other	Not Shared	$362,000	6/1/2010	C>B>A
West	ATC LLC	3090	Wick Rd T-D Interconnection	Install 0.4 mi of new double circuit line to interconnect a new breakered Wick Rd SS.	WI	Other	Not Shared	$4,753,450	3/11/2010	C>B>A
West	ATC LLC	3093	Uprate V-74 Cranberry-Three Lakes-Venus 115kV line	Increase ground clearance for the V-74 Cranberry-Three Lakes-Venus 115kV line.	WI	Other	Not Shared	$133,930	3/24/2010	C>B>A
West	ATC LLC	3094	Construct a new Milton Tap-Milton 69kV line	Construct a new Milton Tap-Milton 69kV line.	WI	Other	Not Shared	$2,970,035	12/15/2010	C>B>A
West	ATC LLC	3109	Increase ground clearance for the East Krok-Kewaunee 138kV line to 200 deg f clearance	Increase East Krok-Kewaunee 138kV line ground clearance.	WI	BaseRel	Not Shared	$1,254,433	12/31/2010	C>B>A
West	ATC LLC	3110	Install 1-32.66 Mvar cap bank at Femrite 138kV	Install 1-32.66 Mvar cap bank at Femrite 138kV.	WI	BaseRel	Not Shared	$1,208,185	6/1/2011	C>B>A

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	ATC LLC	3111	Install 1-32.66 Mvar cap bank at Kegonsa 138kV	Install 1-32.66 Mvar cap bank at Kegonsa 138kV.	WI	BaseRel	Not Shared	$1,977,800	6/1/2011	C>B>A
West	ATC LLC	3114	Uprate CRBU11 line Cranberry-St Germain 115kV	Increase ground clearance for the CRBU11 line Cranberry-St Germain 115kV by moving a dirt mound.	WI	Other	Not Shared	$1,000	5/1/2010	C>B>A
West	ATC LLC	3115	Uprate Fitchburg-Syene-Nine Springs 69kV line	Increase ground clearance for Fitchburg-Syene-Nine Springs 69kV line.	WI	Other	Not Shared	$155,125	3/31/2010	C>B>A
West	ATC LLC	3116	Rebuild/uprate Y-207 Sigel-Auburndale-Rozellville 69kV line	Rebuild/uprate Y-207 Sigel-Auburndale-Rozellville 69kV line.	WI	Other	Not Shared	$2,081,005	2/25/2010	C>B>A
West	ATC LLC	3120	Install 25MVAR of reactors at the Straits SS	Install a 10 MVAR reactor on the Tertiary of Straits 138/69kV Tr #1 & a 15 MVAR reactor on the Tertiary of Straits 138/69kV Tr #2.	MI	BaseRel	Not Shared	$2,071,100	8/1/2010	C>B>A
West	ATC LLC	3122	Reconductor a portion of Dam Heights-Okee Tap 69kV	Reconductor 1.94 mi of 3-0 and 336 ACSR line conductor with T-2 4-0 ACSR keeping the T-2 3-0 ACSR for the DHT-Okee Tap section of line Y-8, replace 26 1919 vintage lattice towers and 4 wood poles.	WI	Other	Not Shared	$2,177,421	6/19/2012	C>B>A
West	ATC LLC	3123	Uprate Perch Lake-M38 138kV	Increase ground clearance for the 605 ACSR Perch Lake-M38 138kV line to 130 deg F clearance.	MI	Other	Not Shared	$224,500	7/1/2010	C>B>A
West	ATC LLC	3162	Y-105 Hillman-Eden Uprate	Y-105 Hillman-Eden 69kV line Uprate.	WI	Other	Not Shared	$621,630	9/30/2010	C>B>A
West	ATC LLC	3163	Hillman substation upgrade	Hillman substation upgrades Replace 69kV OCBs. Remove Y-105 relay limits. Replace 138kV 500 Cu 37 Bus. Replace Jumpers. Replace X-15 800A Trap at Hillman. Replace two (2) 138kV switches.	WI	Other	Not Shared	$1,734,791	12/1/2010	C>B>A

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Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	GRE	1018	Little Falls–Pierz conversion to 115 kV	CWP Little Falls-MP Little Falls 115 kV line	MN	Other	Not Shared	$1,705,000	11/30/2012	C>B>A
West	GRE	1542	G532, 38539-01	Net: tap Odin Tap–Odin 69kV line structure 88 install switches and metering equipment.	MN	GIP	Shared	$174,498	11/1/2007	C>B>A
West	GRE	2564	Sartell (SEA) 3.0 mile, 115 kV line	Sartell (SEA) 3.0 mile, 115 kV line	MN	Other	Not Shared	$1,318,016	10/29/2010	B>A
West	GRE	2565	Frazer Bay Development	Frazer Bay Development	MN	Other	Not Shared	$17,167,700	11/5/2012	C>B>A
West	GRE	2566	Potato Lake (IM) 7 mile, 115 kV line	Potato Lake (IM) 7 mile, 115 kV line	MN	Other	Not Shared	$3,226,245	7/11/2011	B>A
West	GRE	2567	Northport (BENCO) 1 mile, dbl ckt 115 kV line	Northport (BENCO) 1 mile, dbl ckt 115 kV line	MN	Other	Not Shared	$1,200,000	5/29/2012	C>B>A
West	GRE	2570	Ravenna (DEA) 161 kV Substation	Ravenna (DEA) 161 kV Substation	MN	Other	Not Shared	$1,053,552	6/1/2012	C>B>A
West	GRE	2573	H-Frame 230 kV Storm Structures	H-Frame 230 kV Storm Structures	MN	Other	Not Shared	$526,397	5/24/2010	C>B>A
West	GRE	2574	St. Lawrence Substation and Tap–MVEC	St. Lawrence Substation and Tap–MVEC	MN	Other	Not Shared	$370,231	5/1/2014	C>B>A
West	GRE	2576	Pokegama (LCP) 8.0 mile, 115 kV line	Pokegama (LCP) 8.0 mile, 115 kV line	MN	Other	Not Shared	$3,837,556	12/1/2011	C>B>A
West	GRE	2577	Elmcrest (CE) 69 kV Substation	Elmcrest (CE) 69 kV Substation	MN	Other	Not Shared	$140,000	5/3/2011	B>A
West	GRE	2579	Foster Lake (WH) 69 kV Substation	Foster Lake (WH) 69 kV Substation	MN	Other	Not Shared	$140,000	4/29/2011	C>B>A

Table 6.1-1: MTEP10 New Appendix A Projects

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West	GRE	2581	Niniger (DEA) 115 kV Substation	Niniger (DEA) 115 kV Substation	MN	Other	Not Shared	$219,051	5/2/2011	C>B>A
West	GRE	2585	Woodland (WH) 1 mile, 115 kV line	Woodland (WH) 1 mile, 115 kV line	MN	Other	Not Shared	$621,187	6/1/2011	C>B>A
West	GRE	2589	Barnes Grove (DEA) 2.0 mile, 69 kV line	Barnes Grove (DEA) 2.0 mile, 69 kV line	MN	Other	Not Shared	$950,000	5/1/2012	C>B>A
West	GRE	2605	Bunker Lake #2 (CE at GRE) 69 kV Substation	Bunker Lake #2 (CE at GRE) 69 kV Substation	MN	Other	Not Shared	$107,972	3/1/2011	C>B>A
West	GRE	2620	Sandstone-Sandstone MP Temperature Upgrade	Sandstone-Sandstone MP Temperature Upgrade	MN	Other	Not Shared	$74,400	12/1/2010	B>A
West	GRE	2621	Effie 230/69 kV source	Effie 230/69 kV transformer, Effie-Big Fork 69 kV line, Wirt Tap 3-way switch, Jessie Lake 3-way switch, Big Fork 3-way switch	MN	Other	Not Shared	$10,527,910	6/1/2013	C>B>A
West	GRE	2624	Hudson 115 kV conversion	115 kV conversion	MN	Other	Not Shared	$380,000	11/1/2011	B>A
West	GRE	2630	Resag Big Fork-Wirt Tap-Jessie Lake Retemp	Resag Big Fork-Wirt Tap-Jessie Lake Retemp.	MN	Other	Not Shared	$1,290,000	5/1/2012	C>B>A
West	GRE	2631	Resag Deer River-Jessie Lake Retemp	Resag Deer River-Jessie Lake Retemp.	MN	Other	Not Shared	$1,340,000	12/1/2012	C>B>A
West	GRE	2636	Spicer 230/69 kV Source	Spicer 230/69 kV Source	MN	Other	Not Shared	$14,316,500	6/1/2015	C>B>A
West	GRE	2648	Milaca Breaker	Milaca Breaker	MN	Other	Not Shared	$169,561	12/15/2009	C>B>A
West	GRE	2667	Rush City-Adrian Robinson Rush City Dist Retemp	Rush City-Adrian Robinson Rush City Dist Retemp	MN	Other	Not Shared	$284,800	6/1/2012	C>B>A

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West	GRE	2670	North Perham 115/41.6 Source	North Perham 115/41.6 Source	MN	Other	Not Shared	$4,560,000	6/3/2013	C>B>A
West	GRE	2671	Soderville-Ham Lake-Johnsville (6.18 mi.) Retemp	Soderville-Ham Lake-Johnsville (6.18 mi.) Retemp	MN	Other	Not Shared	$257,000	6/1/2010	B>A
West	GRE	2672	Rush City–Bear Creek–Effie Transformer Swap	Rush City–Bear Creek–Effie Transformer Swap	MN	Other	Not Shared	$3,600,000	12/1/2011	C>B>A
West	GRE	2731	Lake Lillian (KEPCA) 3.0 mile, 69 kV line	Lake Lillian (KEPCA) 3.0 mile, 69 kV line	MN	Other	Not Shared	$1,140,000	6/1/2012	C>B>A
West	GRE	2833	Lake Caroline	Lake Caroline (WH) 69 kV Distribution Substation	MN	Other	Not Shared	$570,000	7/22/2012	C>B>A
West	GRE	2834	Rice Lake	Rice Lake (MKR) 69 kV Distribution Substation	MN	Other	Not Shared	$1,722,500	11/1/2012	C>B>A
West	GRE	3104	G514 Heartland Wind	Required equipment: 1485.4 MV A rating at Wilmarth sub, it is necessary to replace two existing 345kV 2000A gas circuit breakers (8S23 & 8S25) with 3000A gas circuit breakers. Replace two existing 345kV 2000A gas circuit breakers (8S23 & 8S25) with 3000A gas circuit brealcers.	MN	GIP	Shared	$796,000	10/1/2009	B>A
West	GRE	3105	G252	3-way group operated disconnect	MN	GIP	Shared	$150,000	11/30/2009	B>A
West	GRE	3106	Tamarac MISO Interconnection (G619)	Tamarac-Cormorant Junction	MN	GIP	Shared	$2,630,000	10/12/2011	B>A
West	ITCM	3046	SW Cedar Rapids 69kV System Upgrade (Phase 1) Near ADM	Re-route 69kV lines near the load to connect to the 161/69kV transformer at the Beverly substation. Install two breaker terminals and a main breaker to connect the re-routed lines. This adds significant capacity to the 69kV system with minimal line construction and no new transformer purchases.	IA	Other	Not Shared	$1,800,000	12/31/2012	C>B>A

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West	ITCM	3047	IA Falls Industrial TRF	Upgrade the IA Falls Ind 115/69kV TRF with a dual high side (161-115kV)/69kV TRF.	IA	Other	Not Shared	$1,980,000	12/31/2010	C>B>A
West	ITCM	3048	Jefferson Co-Perlee 69kV Rebuild	Rebuild the Jefferson Co-Perlee 69kV line section.	IA	Other	Not Shared	$2,700,000	12/31/2011	C>B>A
West	ITCM	3049	Huxley Industrial Park Terminal Addition	Add a 161kV line terminal to tie to the rerouted Boone Jct-Huxley Park Ind 161kV line.	IA	Other	Not Shared	$750,000	12/31/2012	C>B>A
West	ITCM	3050	Alden-Buckeye dist. Sub tap	Constuct a new 3 mile 69kV tap to the new Alden-Buckeye dist. Sub from the CBPC Alden sub site.	IA	Other	Not Shared	$1,080,000	12/31/2011	C>B>A
West	ITCM	3052	Washington 69kV Upgrades	Replace 69kV bus, 2 breakers, relays, and improve breaker configuration, add bus tie breaker, and install a new control building..	IA	Other	Not Shared	$2,400,000	12/31/2011	C>B>A
West	ITCM	3053	Keokuk Hydro-Carbide 69kV Dbl Ckt	Build a new 69kV circuit from Keokuk Hydro-Carbide.	IA	Other	Not Shared	$3,240,000	12/31/2012	C>B>A
West	ITCM	3054	Swisher Breaker Station	Construct a new 3 terminal breaker station.	IA	Other	Not Shared	$1,800,000	12/31/2011	C>B>A
West	ITCM	3055	Cedar Rapids 34kV Conversion Plan	ITCM, working with IP & L, has formed a plan to better serve Cedar Rapids load with new larger, 2-transformer substations that will allow retirement of the 4kV system along with several other small distribution substations. Most of these new substations will be served from a new 69 kV and 161 kV Cedar Rapids transmission system that will use the existing 34.5 kV system right-of-way. This will allow retirement of several existing 34.5kV lines while shifting distribution load to a higher voltage to allow better normal and contingency performance.	IA	Other	Not Shared	$29,020,000	12/31/2014	C>B>A
West	ITCM	3056	Grundy Center-Reinbeck-Hicks tap 69kV line.	Construct a 16 mile 69kV line between Grundy Center and the Hicks tap 69kV line. Constructing this line will allow consolidation of the Dike and Morrison substations into a single new distribution substation and will allow retirement of more than 30 miles of 50 year old 34.5kV line.	IA	Other	Not Shared	$5,760,000	12/31/2012	C>B>A

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West	ITCM	3057	West Branch 34kV Load Shift Projects	Construct 69kV taps for the Moscow & New Liberty dist. Subs	IA	Other	Not Shared	$2,470,000	12/31/2012	C>B>A
West	ITCM	3058	Vinton-Hazleton 34kV Conversion Plan	The plan includes rebuilding a line between Dundee and Vinton substations and converting this line to 69 kV operation. In order to operate this line at 69 kV a 161/69 kV transformer will need to be installed at Vinton. Also, an approximatley 6 mile line will be built to connect the Hazleton source to the Dundee–Vinton line. This plan also includes rebuilding a line between Coggon and Hiawatha substations and converting this line to 69 kV operation. A 161/69 kV transformer will need to be installed at Coggon.	IA	Other	Not Shared	$21,988,000	12/31/2012	C>B>A
West	ITCM	3059	West Branch & West Liberty Switch Stations	Construct two new 3 terminal 69kV breaker stations at West Branch and at West Liberty.	IA	Other	Not Shared	$3,120,000	12/31/2012	C>B>A
West	MEC	2936	Colona Rd 161 kV Line and 161-13 kV Sub	Build new Colona Rd 161-13 kV distribution substation with two 161 kV line breakers. Build new double circuit 161 kV line off the existing Sub 39–Sub 43–Sub 18 line.	IL	Other	Not Shared	$3,500,000	6/1/2012	C>B>A
West	MEC	2940	Raun 345 kV Breaker Replacement	Replace an existing SFA 345 kV breaker with a new unit.	IA	Other	Not Shared	$500,000	6/1/2012	C>B>A
west	MP	2547	Essar	Essar project adds a 95 MW new mine and taconite plant load in fall 2011 with 50 MW DRI facility fall of 2012 total demand to 145 MW. Future load additions could increase total demand to 300 MW	MN	Other	Not Shared	$64,650,000	1/30/2015	B>A
West	MP	2761	Polymet	Add new 138/14 kV substation off MP 138 KV Line #1	MN	Other	Not Shared	$2,005,000	12/30/2011	C>B>A
West	MP	2762	Airpark	New 115/34.5 and 115/14 kV Substation	MN	Other	Not Shared	$4,105,000	6/30/2012	B>A
West	MP	3091	28L reroute	MP's 115 kV Line #28 (28L) must be moved as it crosses the area that Essar will be mining.	MN	Other	Not Shared	$2,900,000	12/30/2011	C>B>A

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West	MPW	2934	Replace South 161/69 kV Transformer	Replace the existing 161/69 kV, 75 MVA transformer at South Sub with at least a 134 MVA transformer by 2011 (633301-633501). Also the 161 kV bus at South Sub will become a ring bus, splitting the three terminal 161 kV line into two sections between 633209 MPW Unit 9–633301 MPW South Sub and 633301 MPW South Sub–636670 MEC Sub 18.	IA	Other	Not Shared	$5,400,000	6/1/2014	C>B>A
West	NWE	3092	Webb Lake 69KV line	Rebuild 34.5KV line to Webb Lake at 69KV with horizontal post construction and #4/0 ACSR.	WI	Other	Not shared	$425,000	6/1/2011	C>B>A
West	OTP	2823	Gwinner Capacitor Bank	Install Capacitor Bank on 115 kV at Gwinner, ND. Two 8 MVAR.	ND	BaseRel	Not Shared	$883,000	12/31/2010	C>B>A
West	OTP	2825	Grant County Wind Farm G-474	20 MW wind farm at Elbow Lake, MN No network upgrades required (cost is for interconnection facilities only).	MN	Other	Not Shared	$0	11/30/2009	B>A
West	OTP	2855	Grafton 41.6 kV Line Upgrade	Rebuild Existing 3-Miles of 41.6 kV Line.	ND	Other	Not Shared	$78,000	10/1/2010	C>B>A
West	OTP	3156	Cass Lake - Nary-Helga - Bemidji 115	Consists of a new 230/ 115 kV Cass Lake transformer and upgraded 115 kV from Cass Lake to Bemidji.	MN	BaseRel	Shared	$11,699,000	12/31/2013	C>B>A
West	OTP/MPC	2742	Bemidji-Wilton 115 kV Line Upgrade	Replace terminal equipment on this existing line to increase capacity for MISO Project A411 (F075).	MN	TDSP	Direct Assigned	$240,000	10/31/2010	C>B>A
West	OTP/MPC	2826	Enbridge Load Expansion Support	Install Capacitor Bank on 115 kV at Clearbrook, MN. One 34 MVAR. Install Capacitor Bank on 115 kV at Karlstad. One 14 MVAR. Install Capacitor Bank on 115 kV at Thief River Falls. One 15 MVAR.	ND	BaseRel	Not Shared	$2,850,000	12/31/2015	C>B>A
West	SMP	2166	City of St Peter, MN load serving upgrades	Add approximately 7.0 line miles of new 69kV transmission line and a new load serving substation (Estimated in service 2010).	MN	Other	Not Shared	$6,000,000	6/1/2011	C>B>A

Table 6.1-1: MTEP10 New Appendix A Projects

Region	Geographic Location by TO Member System	Project ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD (Max)	App ABC
West	SMP	2167	City of Redwood Falls, MN load serving upgrades	Add approximately 6.4 miles of new 115kV transmission line and a new load serving substation (Estimated in service 2010).	MN	Other	Not Shared	$4,000,000	12/1/2011	C>B>A
West	SMP	2171	Mora Land Fill Gas Generator	Addition of 3 MW landfill gas generation and construction of approx 7.0 miles of 12.47kV distribution line.	MN	TDSP	Direct Assigned	$3,700,000	12/1/2010	B>A
West	SMP	2813	Byron-Westside	161 kV line from Byron to Westside	MN	Other	Not Shared	$3,500,000	1/1/2011	B>A
West	XEL	2767	Fenton 115/69 kV Interconnection	Install a new 115/69 kV transformer at Fenton substation. Break the existing 69 kV line between Chandler Tap and Lake Wilson to create an in and out to the Fenton substation.	MN	Other	Not Shared	$3,710,000	1/1/2012	C>B>A
West	XEL	3097	Monroe County 2nd Transformer	Install second 161/69 kV 70 MVA transformer at Monroe County substation.	WI	Other	Not Shared	$3,680,000	6/1/2012	C>B>A
West	XEL	3098	Lake City to Wabasha Line Upgrade	Rebuild 1FCW portion of Lake City to Wabasha 69 kV line to 477A.	MN	Other	Not Shared	$3,300,000	6/1/2011	C>B>A
West	XEL	3100	Westgate 115/69 kV TR upgrade	Upgrade Westgate 115/69 kV transformer #2 to 70 MVA.	MN	Other	Not Shared	$2,070,000	6/1/2012	C>B>A
West	XEL	3101	Chanarambie Line Move	Move the line from Lake Yankton to Chanarambie to a new breaker position 5X100 at Chanarambie. This will eliminate the low voltage problem for breaker failure of 5X94 and allow for a future expansion of an additional 4th collector transformer at the old Lake Yankton position.	MN	BaseRel	Not Shared	$363,000	6/1/2010	C>B>A
West	XEL	3102	Louise 115 kV Interconnection	Tap the existing 115 kV line between Cheery Creek and Lincoln County in Sioux Falls, SD. This is a distribution interconnection request for a new 115 kV source to the City of Sioux Falls. The ultimate build out is for 3-50 MVA distribution transformers.	SD	Other	Not Shared	$6,200,000	12/1/2012	C>B>A

6.2 Reliability Analysis Results

The results of MTEP10 Reliability Analyses are included in Appendix D.3–D.6 and posted at the Midwest ISO File Transfer Protocol (FTP) site at ftp://mtep.midwestiso.org/mtep10/. The Midwest ISO Planning Region is separated into West, Central, and East planning regions. Refer to Table 6-2 on the following pages, which shows generation, load, losses and interchange modeled in each of the five planning models used in MTEP10 Reliability Analysis.

Table 6.2-1: Balancing Area Summary for MTEP10 Models (MW)

Planning Region	BA Name	2015 Summer Peak				2015 Shoulder Peak				2015 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
West	ALTW	3,812	4,492	115	-795	4,213	3,415	291	508	3,328	2,739	247	342
	ALTE	3,573	3,084	105	382	2,312	2,253	115	-58	895	1,699	76	-882
	WEC	8,008	7,446	147	408	5,112	5,418	142	-457	4,404	4,067	108	221
	WPS	2,547	2,903	62	-419	2,719	2,222	79	418	2,238	1,767	65	405
	MGE	384	861	13	-491	47	613	13	-580	61	448	5	-393
	UPPC	52	223	19	-190	46	162	19	-134	36	121	11	-95
	XEL	8,823	10,560	238	-1,979	6,887	7,399	355	-786	5,179	5,335	254	-221
	MP	2,585	1,660	84	841	1,876	1,535	75	267	1,737	1,535	62	140
	SMMPA	184	670	1	-487	39	462	1	-424	48	328	1	-281
	GRE	2,991	3,608	98	-719	2,320	2,526	90	-299	853	1,804	79	-1,032
	OTP	1,484	1,512	83	-112	1,730	1,090	97	543	1,162	991	87	83
	MDU	207	552	16	-361	145	391	14	-261	131	277	10	-156
	MEC	6,282	5,865	119	298	8,071	4,255	242	3,576	5,972	2,562	183	3,227
	MPW	225	167	1	57	226	122	1	103	60	93	0	-33
Central	HE	1717	807	42	868	1,078	807	28	243	1,244	807	24	414
	DEM	10,984	13,300	447	-2773	8,469	9,348	314	-1,205	5,153	6,731	193	-1,782
	Vectren	1,458	1,974	32	-549	1,251	1,630	21	-400	330	1,399	37	-1,106
	IP&L	3481	3,409	75	-6	2,616	2,373	59	181	737	1,685	29	-981

Table 6.2-1: Balancing Area Summary for MTEP10 Models (MW)

Planning Region	BA Name	2015 Summer Peak				2015 Shoulder Peak				2015 Light Load			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
Central continued	CWLD	90	175	1	-85	27	175	1	-148	86	107	0	-22
	AmerenMO	10,276	9025	206	1046	7,535	7,420	126	-11	5,098	3,789	90	1,219
	AmerenIL	11,527	10,528	273	728	10,121	8,697	252	1,174	4,297	4,578	202	-482
	CWLP	561	490	4	68	401	343	2	56	163	148	1	14
	SIPC	290	358	6	-74	219	357	10	-148	176	117	7	52
East	First Energy	13,401	14,413	355	-1367	7,430	10,69 5	241	-3,505	3,120	5,860	122	-2,862
	NIPSCO	2,722	3,662	50	-990	993	2,566	41	-1,614	681	1,834	35	-1,188
	METC	13,006	10,065	333	2,608	7,919	8,330	303	-713	2,064	3,787	186	-1,908
	ITC	11,393	11,042	234	117	9,402	9,387	213	-198	5,132	3,861	135	1,136

6.3 Steady State Analysis Results

MTEP10 Appendix E1.1.4 lists contingencies tested in Steady State Analysis. Contingencies were simulated in MTEP10 2015 Summer Peak and Shoulder Peak Load models. Results tables listing all steady state analysis-identified constraints and associated mitigations are tabulated in MTEP10 Appendix D.3.

6.4 Voltage Stability Analysis Results

MTEP10 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 that are close to the base load levels modeled in the MTEP10 2015 Summer Peak and Shoulder Peak models. A summary report with associated p-v plots is documented in MTEP10 Appendix D.4.

6.5 Dynamic Stability Analysis Results

MTEP10 Appendix E1.1.4 lists types of disturbances tested in Dynamic Stability Analysis. Disturbances were simulated in MTEP10 2015 Light Load and Shoulder Peak Load models. The system was stable for all faults simulated. Results tables listing all simulated disturbances along with damping ratios are tabulated in MTEP10 Appendix D.5.

6.6 Load Deliverability Analysis Results

A load deliverability analysis was conducted to determine the ability of an area to sufficiently supply its load with generation from inside the area or with externally generated imports. This process was performed as part of the Loss of Load Expectations (LOLE) study. The goal of the LOLE study is to determine the level of reserves that would result in the system experiencing one loss of load event every ten (10) years on average. This equates to a yearly LOLE value of 0.1 days per year, or a one in ten chance for a loss of load event every year. Appendix E1.1.5 of this report includes a discussion on the Midwest ISO Loss of Load Expectation (LOLE) Study, including the process used for determining study zones and the methodology used to set the Planning Reserve Margin on an annual basis.

The 2010-2011 LOLE Study set the required Planning Reserve Requirement (PRM) for the 2010/2011 Planning Year, which covers the period starting in June 2010 and extending through May 2011. The study concluded that a minimum system-wide planning reserve of 15.4% is required to maintain a Loss of Load Expectation of one (1) day in ten (10) years. By adjusting for time diversity among the Load Serving Entities (LSE) individual peaks, non-concurrent with the Midwest ISO system wide Peak Load, a reduced planning reserve of 11.94% was applied to the individual 2010 Summer Peak forecasts of each LSE.

- Along with the determination of the system-wide PRM, the LOLE study also included a review at the zonal level to identify any issues with the delivery of generation to load. This included the following:
  - A load deliverability analysis was conducted to determine the ability of all areas of the system to achieve a LOLE of at least one (1) day in ten (10) years from 2010–2019.
  - The analysis confirmed that all zones have sufficient planned import capability to reliably back up the probable netting of load-generation internal to each zone.
  - It was determined the transfer capability out of some zone limits the delivery of internal generation resources to external zones.

Although this analysis found all zones would be able to meet the one (1) day in ten (10) year benchmark, aggregate generation was not fully deliverable in the 2010 planning year due to congestion. The study was able to quantify the impact of system constraints and found that the congestion contribution to the 15.4% PRM will be 0.4% for 2010. For an examination of the impact of congestion on the PRM through 2018, refer to section 8.3 of this document.

6.7 Generator Deliverability Analysis Results

Table 6.7-1 below shows the list of mitigations proven effective for outstanding generator deliverability constraints from MTEP09.

Table 6.7-1: MTEP09 (2014 SUPK) Technical Review Mitigation Summary

MTEP09 Deliverability Constraint	Total Generation Restricted	Percentage of MWs Impacted	Rating (MVA)	Percent Overload	MTEP Project ID	Target Appendix MTEP10
South Grove 345/138 kV transformer	108	2%	478	108.1	2151	A in MTEP09
Livingston--Vanderbilt 138 kV line	128	3%	180	102.5	2916	A in MTEP10
Riggsville--Rondo 138 kV line	194	4%	144	105.3	2916	A in MTEP10
Palmyra 345/161 kV transformer	458	10%	370	140.1	2997	B in MTEP10
Prairie State--Stallings 345 kV line	223	5%	1195	100.1	2294	B
Turkey Hill 345/138 kV transformer	223	5%	672	101.4	3013	C
Coulterville 230/138 kV transformer	Not in original TRG scope		140	110.9	2063	A in MTEP09
Stallings 345/138 kV transformer	Not in original TRG scope		560	104.1	2065	B

Refer to Table 6.7-2 on the following page, which lists MTEP10 constraints limiting deliverability of about 973 MW of Network Resources. This 973 MW is in comparison to 3,282 MW of limited capacity identified in MTEP09, showing that Midwest ISO addressed 2,106 MW of constrained aggregate deliverable generation. A Technical Review Group was established to work closely with stakeholders on addressing the MTEP09 and MTEP10 generator deliverability constraints. As a result of this effort, the improved generator deliverability in MTEP10 was achieved through newly identified planned and proposed upgrades and, in part, through the reduction of simulation errors. For detailed results, refer to Appendix D.6, which contains a list of impacted Network Resources.

Table 6.7-2 column headings are defined as follows:

- **Overload Branch:** An overload caused by aggregate deliverable generation. Deliverability was tested only up to the granted NR (Network Resource) levels of the existing and future NR units modeled in MTE10 2015 case.
- **Map ID:** Use Map ID to find an approximate location of the overloaded element on Figure 6.7-1.
- **Contingency:** The outage which results in the overload. May be system intact, no outage. Detailed contingency definitions are included in the Appendix.
- **Rating:** The rating of the overloaded element used in the analysis. Normal if system Intact, Emergency for post contingent constrained branches.
- **Delta Increase:** The difference in loading after ramping up generation compared to before ramping up generation in the “gen pocket”.

Table 6.7-2: MTEP10 (2015 SUPK) Baseline Generator Deliverability Constraints Summary

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	Delta Increase
Lake Marion 115/69/13.8 kV transformer	XEL	1	West Faribault--Airtech 115 kV line	71.7	5.5%
Boone Jct.--Ft. Dodge 161 kV line	ALTW	2	B-MT-961	147	4.2%
South Grand View--Salem 161 kV line	ALTW	3	Center Grove--Julian 161 kV line	306	0.1%
East Calamus--Grand Mound 161 kV line	ALTW	3	Salem--Rock Creek 345 kV line	176	0.1%
Powerton--Powerton Jct. 138 kV line	CE	4	Pontiac--Brokaw 345 kV line	162.7	12.0%
Hutsonville-Marathon 138 kV line	AMIL	5	Newton--Robinson 138 kV line	191	0.8%

Refer to Figure 6.7-1. Where applicable in the MTEP11 planning cycle, Midwest ISO will create a Technical Review Group (TRG) comprised of Midwest ISO stakeholders to identify planning solutions that address documented generator deliverability issues.

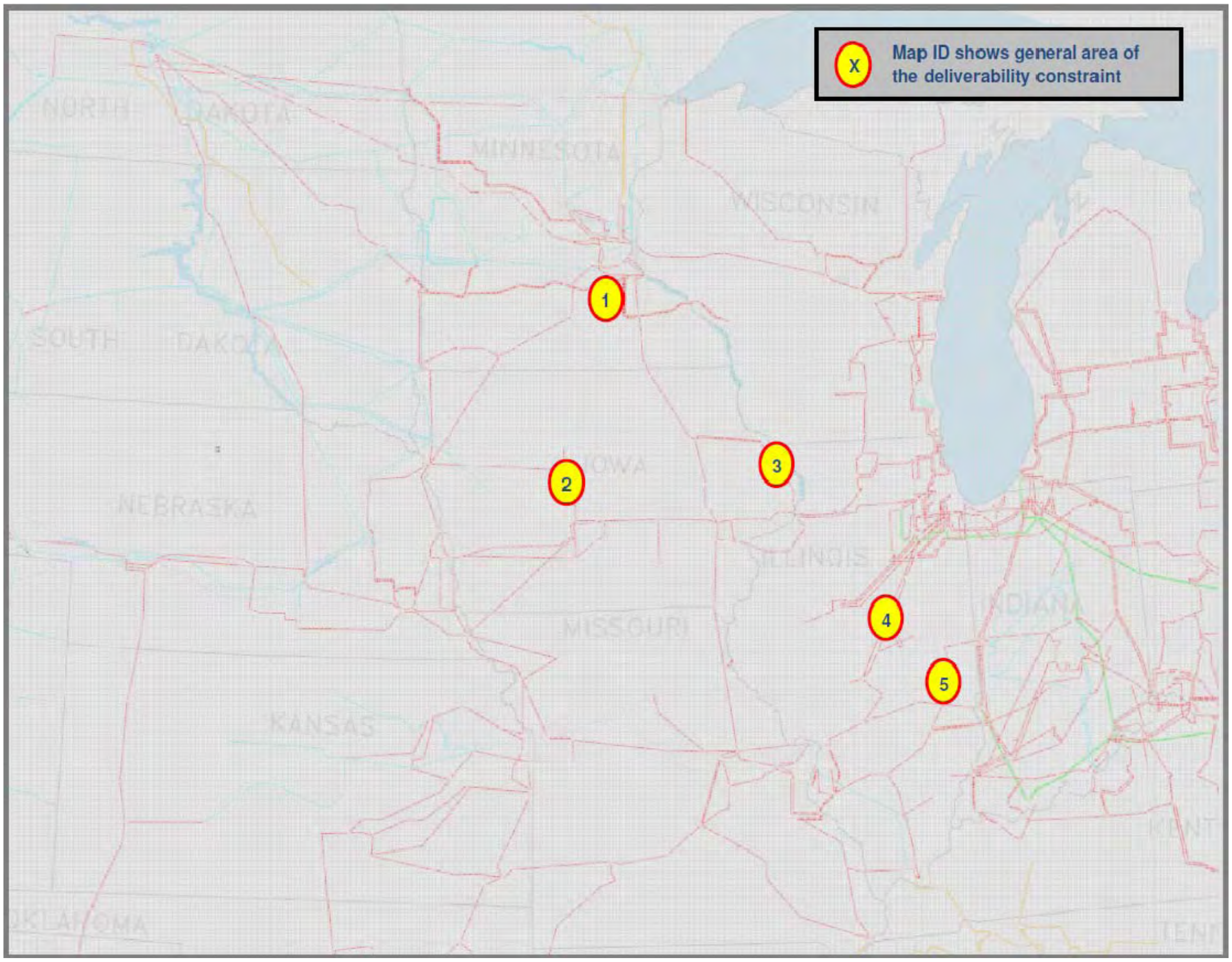


Figure 6.7-1: General location of MTEP10 2015 SUPK Baseline Generator Deliverability Constraints

6.8 Infeasible Long Term Transmission Rights (LTTR) Analysis Results

Refer to Table 6.8-1, which shows the uplift costs associated with the infeasible LTTRs in the 2010 Annual Allocation.

Table 6.8-1: Uplift Costs Associated with Infeasible LTTR in the 2010 Annual Allocation

Year	Total Stage1A (GW)	Total LTTR Payment ($M)	Total Infeasible Uplift ($M)	Uplift Ratio
2010 Allocation	411.5	174.6	9.9	5.60%

Refer to Table 6.8-2, 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. In the table below, constraints with "RT^" as part of their name were created by FTR group to mimic actions taken by Real Time Operation. Constraints without "RT^" in their name are NERC defined flowgates.

Table 6.8-2: Infeasible Uplift to Binding Constraints from the Annual Auction

Constraint	Fall 2010	Spring 2011	Summer 2010	Winter 2010	Grand Total
Pana 345/138 xfmr (flo) Coffeen–Coffeen North 345 + Coffeen UN2 SPS	$557,945	$271,712	$116,759	$0	$946,415
IP Rising 345/138 XFMR 1 (flo) Clinton–Brokaw 345 (IP4535)	$369,781	$217,963	$93,378	$62,952	$744,074
Hanna-Juniper 345 (flo) Mansfield-Chamberlin 345	$182,644	$88,955	$133,575	$311,257	$716,431
Crete-St Johns Tap 345 kV l/o Dumont-Wilton Center 765 kV line	$677,064	$0	$0	$0	$677,064
Northeast Ohio Interface	$182,435	$82,874	$123,476	$246,952	$635,737
Dresden-Elwood 1222 345 kV l/o Dresden-Electric 1223 345 kV	$105,672	$262,637	$86,601	$138,171	$593,080
RT^INLAND_513830 A LN	$156,731	$21,952	$255,117	$8,592	$442,393
Wylie Ridge #7 345/500 xfmr l/o Wylie Ridge #5 & #6 xfmrs (CB WK6 Closed)	$0	$4,390	$364,545	$72,890	$441,825
RT^GOOSECRKIP-4575 1 LN	$169,673	$130,575	$0	$85,288	$385,536
Beaver Valley-Clinton 345kV l/o Crescent-Collier 345kV + Crescent 2 xfmr	$219,761	$9,649	$76,972	$0	$306,382
SAMMIS WYLIERDG FLO TIDD-WYLIE	$0	$0	$0	$305,596	$305,596
RT^CEDAR_RGCEDAROHMSTE1381 LN	$281,349	$489	$0	$0	$281,838
Pleasant Prairie-Zion 345 flo Cherry Valley-Silver Lake 345 R	$185,847	$10,614	$187,712	$49,782	$433,955
RT^SPRTA_TP IP1476 FLO W FRKFT	$104,650	$67,947	$0	$29,997	$202,595
BUR_OAK_SHCFER FLO WLTN DMNT	$0	$196,785	$0	$0	$196,785
COFFEEN 11 20.9 kV to COFFEEN 23 345 kV	$116,657	$13,211	$50,532	$0	$180,399
Sammis-Wylie Ridge 345 flo Tidd-Wylie Ridge 345	$0	$2,396	$0	$162,689	$165,085
Pleasant Prairie–Zion 345kV	$0	$164,042	$0	$0	$164,042

Table 6.8-2: Infeasible Uplift to Binding Constraints from the Annual Auction

Constraint	Fall 2010	Spring 2011	Summer 2010	Winter 2010	Grand Total
RT^STATLINE_WOLFLK FLO BRNHM_S	$151,413	$0	$0	$8,138	$159,552
RT^PLYMOUT2_13819_A FLO BR OAK	$0	$69,660	$0	$75,897	$145,558
SCHAF_BUR OAK FLO WLTN DMT AEP	$0	$138,711	$0	$0	$138,711
Twin Branch-Argenta 345 kV l/o Cook-Palisades AND Cook-Benton Harbor 345 kV lines	$92,920	$2,660	$24,500	$4,814	$124,894
Whitestown-Guion 345 (flo) Whitestown-Hortonville 345	$6,089	$21,604	$1,821	$63,636	$93,149
RT^BURR_OAK XFMR FLO BURROAK-L	$28,490	$48,421	$13,195	$0	$90,106
Burnham-Sheffield 345 flo Dumont-Wilton Center 765	$120,134	$0	($33,367)	$0	$86,767
SCHAHFER 34 345 kV to SCHAHFER 134 138 kV	($51)	$15,599	$59,120	$1,779	$76,447
Grand Total	**$3,970,218**	**$2,278,278**	**$1,815,746**	**$1,909,753**	**$9,973,995**

7 MTEP10 Long Range Projects

7.1 Execution of Value-based Approach

To accomplish long range economic transmission development, a planning horizon of at least fifteen (15) years is necessary to encompass the reality that large transmission projects nominally require ten (10) years to complete. To perform a credible economic assessment over this time frame, several analytical challenges have to be addressed. Specifically, long-range sophisticated resource forecasting, Power Flow and security-constrained economic dispatch models are required to extend to least fifteen (15) years. Since no single model can perform all of the required functions needed for integrated transmission development, a value-based planning process has been developed by taking the best models available and integrating these models as illustrated in Figure 7.1-1. Using this integrated process enables evaluation of long-term transmission requirements.

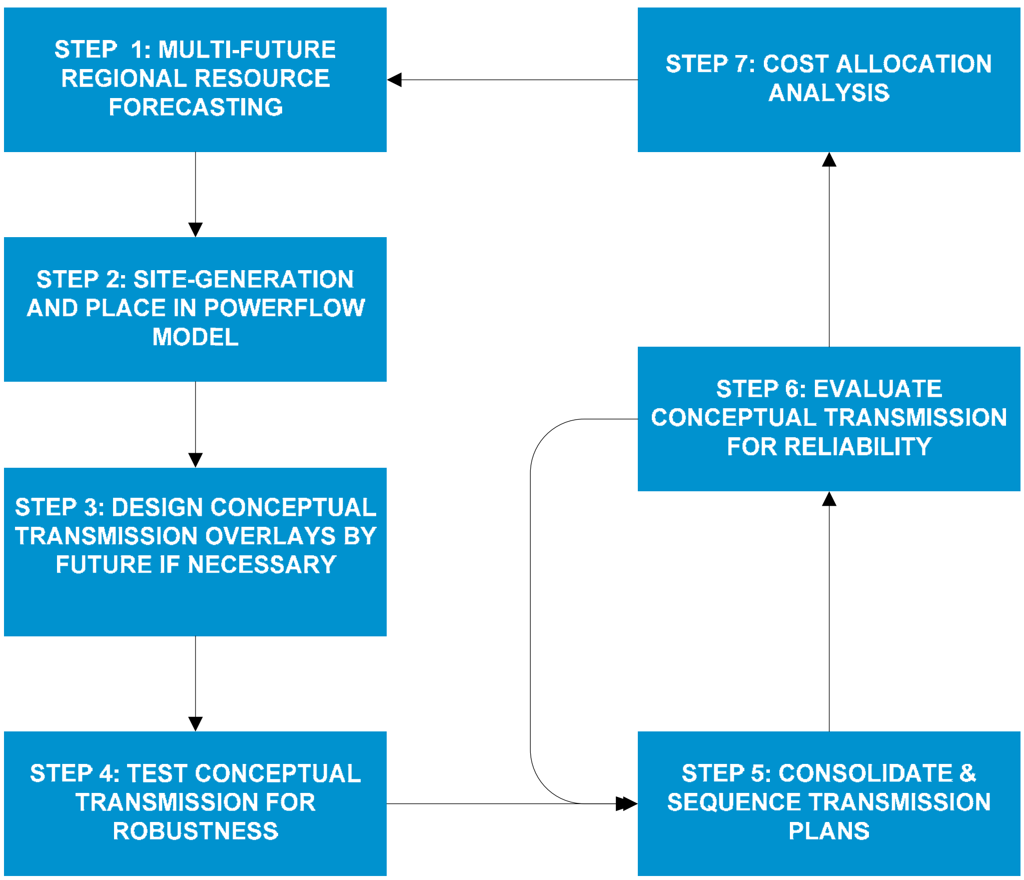


Figure 7.1-1: MTEP10 Process–Economic Transmission Planning

Since energy policies and the resource mix associated with those policies are uncertain or unavailable in the 15-20 year time frame, regional resource forecasting is required to determine total resource needs to supplement Generation Interconnection Queue (GIQ) capacity. The regional resource forecast model determines, on a consistent least-cost basis, the type and timing of new generation and energy efficiency resources that must be incorporated into the planning models in order to maintain adequate regional reserves.

Development of 15-year MTEP10 transmission models requires adjustments to the model building process. The ten-year North American Electrical Reliability Corporation (NERC) planning model developed by the Multi-area Modeling Working Group (MMWG) serves as the starting point. Transmission Owners (TOs) supply known system upgrades, along with load growth forecasts, while generation additions are incorporated from the GIQ, from wind siting, and from the regional resource forecasting process.

Development of long-term Power Flow models allows the development of corresponding PROMOD® security constrained unit commitment and economic dispatch models. PROMOD® requires an underlying Power Flow model for each year being studied. The economic evaluation process is structured to analyze future impacts and incorporate sensitivity and risk assessment in the process.

As an ongoing effort, Midwest ISO continues to evolve its value-based planning approach in order to further the integration of current planning functions. As discussed in section 4.4, the Midwest ISO value-based planning process is shifting away from the design of conceptual transmission plans to the development of a robust business case in order to assess the value of long-term, regional transmission plans. The fourth step in the process, robustness testing, has become a primary focus of the MTEP10 planning cycle. Additional discussions on this process can be found in section 4.4.

7.2 Generation Futures Development

This section summarizes Steps 1 and 2 of the integrated transmission planning process, where Regional Resource Forecasting (RRF) is performed using scenario-based analysis to identify and site generation for several potential future scenarios. With the increasingly interconnected nature of existing organizations and federal interests, RRF greatly enhances the overall planning process for electricity infrastructure. Specifically, optimizing new investment costs by finding the greatest number of synergies in a region will be one of the best ways that regulators and utilities can minimize overall rate impacts on consumers. This is particularly important as it appears Midwest ISO members are at the beginning of a major new generation and transmission investment cycle driven by aging infrastructure and shifting energy policies. The futures analysis provides information on the potential 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.

It is important to note future scenario definitions and assumptions for the models for Steps 1 and 2 were developed with stakeholder involvement. The Midwest ISO Planning Advisory Committee (PAC) served as the platform to provide openness and transparency to comply with FERC Order 890 planning protocols. Scenarios have been developed and subsequently refreshed to reflect shifts in energy policies across the last few years, in coordination with the PAC, through efforts in MTEP09, the Joint Coordinated System Plan (JCSP) and the Eastern Wind Integration and Transmission Study (EWITS).

In 2009, the Organization of Midwest ISO States (OMS) Cost Allocation and Regional Planning (CARP) group developed a number of additional energy policy scenarios focusing on the impacts of renewable portfolio standards and carbon reduction legislation. The Midwest ISO Planning Advisory Committee (PAC) identified several new scenarios to provide further differentiation in potential outcomes in 2010. In recognition of the uncertainties regarding the type and direction of future policies, the overall objective was to develop a wide range of future scenarios to bookend the different outcomes. These future scenarios were used for robustness (best-fit) testing of proposed transmission plans associated with major studies such as the Regional Generation Outlet Study (RGOS) and transmission project evaluations performed in the course of various market efficiency studies.

The assumptions for the models and the results presented in this document reflect the prices and policies for the time period leading up to publication. Midwest ISO recognizes changes have occurred in many of these assumptions and so will continue to update these assumptions in future MTEP iterations and other economic analysis efforts.

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

7.2.1 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 the variables within a given model. The outcome of each modeled future scenario is a generation expansion plan referred to as a generation portfolio. Generation portfolios are capacity expansion results from a 'least cost' optimization of future generation requirements based on specified resource adequacy criteria. A generation portfolio identifies the optimal 'least cost' generation required to meet reliability criteria based on the assumptions for each future scenario. MTEP10 has examined multiple future scenarios, to include the following:

- **OMS Cost Allocation and Regional Planning (CARP) future scenarios:**
  - S1: Business As Usual with high Demand and Energy Growth Rates
  - S2: Federal RPS
  - S3: Carbon Future–Carbon Cap and Trade
  - S4: Federal RPS, Carbon Cap and trade, Smart Grid and Electric Cars
- **Jointed Coordinated System Plan (JCSP)/MTEP09 future scenarios:**
  - S5: Reference
  - S6: Gas Only
- **Eastern Wind Integration and Transmission Study (EWITS) future scenarios:**
  - S7: Scenario 2 20% Federal Wind
- **Planning Advisory Committee (PAC) future scenarios:**
  - S8: Business as Usual with Mid-low Demand and Energy Growth Rates
  - S9: Business as Usual with High Demand and Mid-High Energy Growth Rates
  - S10: Carbon Future–Carbon Cap and Trade with Nuclear

The following bulleted items describe the various future scenarios in greater detail:

- **The Business As Usual with High Demand and Energy Growth Rates future scenario (S1)** is considered a status quo scenario, with a quick recovery from the economic downturn in demand and energy projections. This future 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. This scenario assumes existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential renewable resources that can apply. RPS requirements will be met using the percentage breakdown defined for each state by CARP negotiators.
- **The Federal RPS future scenario (S2)** requires that 20% of the energy consumption in the Eastern Interconnect come from wind by 2025. Wind generation will begin to be forced into the models starting in 2012, accounting for the two year lead time assumed with the generator assumptions. Capacity factors for existing wind generators, taken from the NREL dataset for wind units, vary regionally from 27.6%-44.4%. Solar is modeled with a 10% annual capacity factor. Hydro and Biomass are modeled with 50% annual capacity factors. State mandates are consistent with the Business As Usual scenarios and any additional renewable energy is met with wind to satisfy the 20% renewable energy requirement. All wind is sited onshore.

- **The Carbon Cap and Trade future scenario (S3)** models a declining cap on future CO_2 emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO_2 emissions from a 2005 baseline by the year 2050. That target is achieved through a linear reduction from 2010 to 2050 with mid point goals of 3% reduction in 2012, 17% reduction in 2020 and 42% reduction in 2030. This future scenario employs coal retirements, with the oldest and highest heat-rate coal units retired first.
- **The fourth CARP future scenario (S4)** includes every potential policy outcome from the other three CARP scenarios. It includes a federal RPS, a carbon cap and trade, smart grid, and electric vehicles. The RPS and carbon cap and trade are modeled in the same way as in the CARP RPS Future and CARP Carbon Cap and Trade future scenarios. Smart grid is modeled within the demand growth rate. It is assumed an increased penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled within the energy growth rate. Electric vehicles are assumed to increase off-peak energy usage and—as such—increase overall energy growth rate. The Carbon Cap and Trade, RPS, Smart Grid and Electric Vehicles future scenario has also been referred to as the "Kitchen Sink" future scenario.
- **The JCSP/MTEP09 Reference future scenario (S5)** was the status quo future scenario as of early 2008 when this scenario was developed. This possible future models the power system as it existed at that time with reference values and trends based on recent historical data as of 2008 and assuming existing standards for resource adequacy, renewable mandates, and environmental legislation would remain unchanged. Although Renewable Portfolio Standard (RPS) requirements vary by state and have many potential resources that can apply, it was assumed all incremental needs to meet RPS requirements would come from wind resources.
- **The Gas Only future scenario (S6)** removes non-gas-fired baseload capacity as an option to capacity expansion. It assumes siting of capacity will be load-center focused, with no conceptual transmission expansion based on economic criteria; that is, since new generators built in a Gas Only future scenario will be gas-fired, the economic benefits of coal and nuclear power were not considered.
- **The EWITS scenario 2 20% wind future scenario (S7)** requires that 20% of energy consumption in the Eastern Interconnect to come from wind by 2025. Wind generation will begin to be forced in the models starting in 2012, accounting for the two-year lead time assumed as part of the generator assumptions. Capacity factors for all wind generators are taken from the NREL dataset and vary regionally from 35%-45. Wind is sited both onshore and offshore.
- **The PAC Business As Usual with Mid-low Demand and Energy Growth Rates future scenario (S8)** is considered a status quo future scenario and continues the impact of the economic downturn on growth in demand, energy and inflation rates. This future scenario models the power system as it exists today with reference values and trends, with the exception of demand, energy and inflation growth rates, which are based on recent historical data and assumes that existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply. RPS requirements will be met using the percentage breakdown defined for each state by CARP negotiators.
- **The PAC Business As Usual with High Demand and Mid-high Energy Growth Rates future scenario (S9)** is a sensitivity case on demand and energy growth rates. This future scenario models the power system as it exists today with reference values and trends, based on recent historical data and assumes that existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply. RPS requirements will be met using the percent breakdown defined for each state by CARP negotiators.

- **The PAC Carbon Cap and Trade with Nuclear future scenario (S10)** models a declining cap on future CO2 emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO2 emissions from a 2005 baseline by the year 2050. That target is achieved through a linear reduction from 2010 to 2050 with mid point goals of 3% reduction in 2012, 17% reduction in 2020 and 42% reduction in 2030. This future employs coal retirements, with the oldest and highest heat-rate coal units retired first—Integrated Gasification Combined Cycle (IGGC) with sequestration and Combined Cycle (CC) with sequestration technologies do not mature fast enough to become an option within the study period.

Refer to Table 7.2-1, which illustrates the key variable input assumptions for each future scenario. Each future has a unique set of input assumptions driven by a wide range of potential policy decisions.

Table 7.2.1: Future Scenario Input Assumptions

Future Scenarios	MISO Wind Penetration (GW)	MISO Demand Growth Rate	MISO Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
CARP BAU with High DE (S1)	23	1.6%	2.19%	$6.22	None
CARP RPS (S2)	51	0.75%	1.00%	$6.22	None
CARP Cap (S3)	23	0.3%	0.3%	$8.71	$50/ton (42% by 2030)
CARP RPSSGPHEV (S4)	51	0.75%	2.19%	$8.71	$50/ton (42% by 2030)
MTEP09/JCSP Reference (S5)	23	1.28%	1.5%	$8.98	None
MTEP09/JCSP Gas Only (S6)	23	1.28%	1.5%	$8.98	None
EWITS 20% Wind (S7)	51	1.28%	1.5%	$8.98	None
PAC BAU MLDE (S8)	23	0.75%	1.0%	$6.22	None
PAC BAU HD/ME (S9)	23	1.6%	1.5%	$6.22	None
PAC CAP w/ NUK (S10)	23	0.3%	0.3%	$8.71	$50/ton (42% by 2030)

7.2.2 Generation Portfolio Development

Regional assessments were performed using Electric Generation Expansion Analysis System (EGEAS) on the Midwest ISO East, Central and West regions, as indicated in Figure 7.2-1. Using assumed projected demand and energy for each company and common assumptions for resource forecasting, models were developed to identify least cost generation portfolios needed to meet resource adequacy requirements of the system for each future scenario.

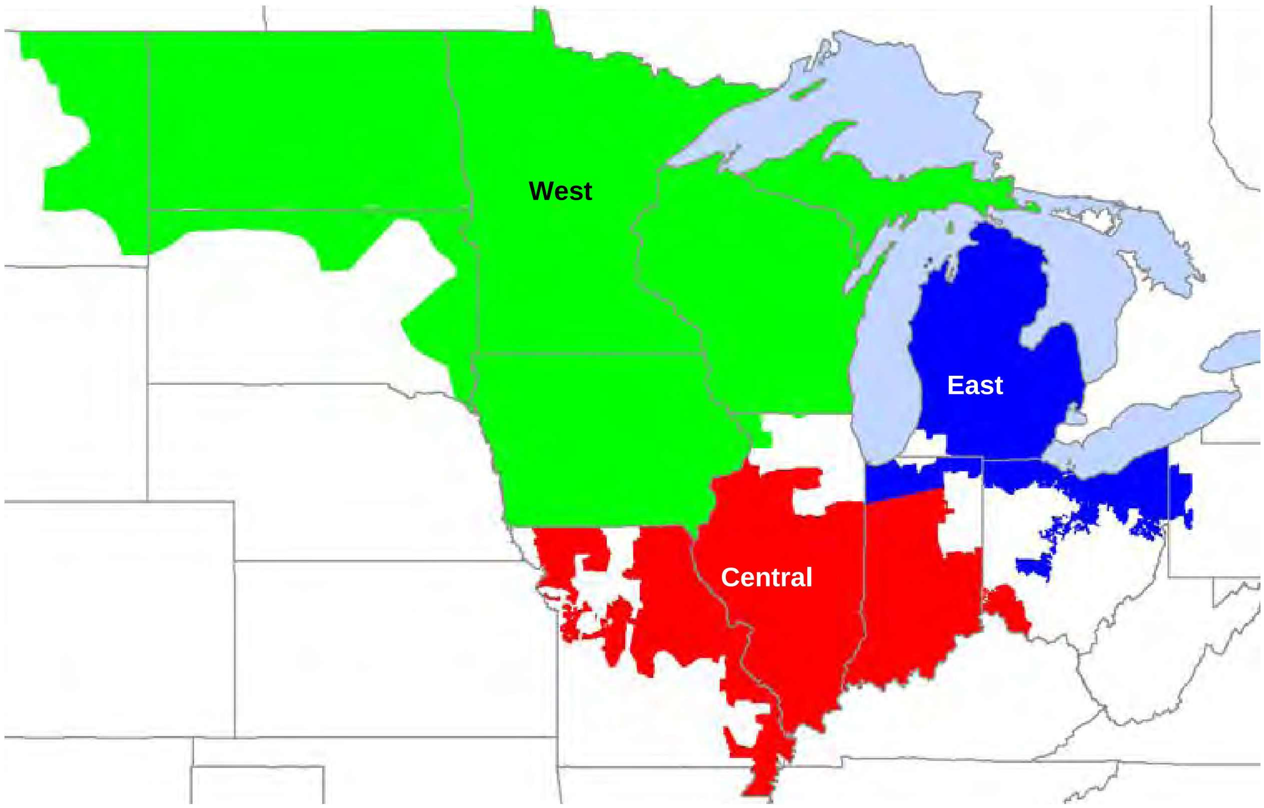


Figure 7.2-1: Midwest ISO Regions

Figure 7.2-2 on the following page represents capacity expansions for each defined future scenario through the 2025 PROMOD® study year. The capacity added is required to maintain stated reliability targets for each region. Stated targets for Midwest ISO are defined by means of the Module E Resource Adequacy Assessment referenced in section 5 of this document.

MTEP10 postulates ten (10) different future scenarios, more than double the number of possible futures examined during previous MTEP cycles. Using ten (10) different futures aids development of a robust set of transmission projects under a wide range of generation portfolios. A diverse set of generation scenarios emerges when examining MTEP10 future scenarios. While making comparisons across futures with different growth rates for demand and energy can be difficult, some basic observations can be made when studying future scenarios as a group or when comparing one scenario to another.

The MTEP09/JCSP and EWITS futures are dominated by coal as the preferred baseload option. When looking at future scenarios developed after MTEP09/JCSP (such as CARP and PAC), needs due to future baseload growth are met with new gas capacity rather than 'traditional' baseload units such as coal or nuclear. This comes as a direct result of natural gas fuel prices. MTEP09/JCSP had natural gas prices modeled in the $9/MMBTU range with a 4% escalation while more current futures model prices in the $6/MMBTU range with lower escalations.

The CARP Carbon Cap and Trade future scenario results showed Integrated Gasification Combined Cycle (IGCC) with sequestration and Combined Cycle (CC) with sequestration as the preferred carbon neutral resources. Capital costs for these plants were priced below nuclear capital costs. However, there are no commercial IGCC or CC plants with sequestration currently built within the Eastern Interconnect. The cost for IGCC plants with sequestration is uncertain, which is also largely true for nuclear plants. A future scenario reflecting these uncertainties was developed by PAC. Accordingly, PAC assumed in one future scenario that sequestration technology would not be mature within the study period. The comparison between these two futures demonstrates that nuclear plants and plants with sequestration are interchangeable in the MTEP10 capacity expansion analysis. There are 8400 MW of IGCC/s and CC/s within the CARP future scenario and 8400 MW of nuclear in the PAC future scenario.

Coal units are retired in order to achieve the 42% carbon reduction cap. In order to meet the carbon reduction cap for the appropriate future scenarios, 27% (22,000 MW) of the oldest and highest heat-rate coal units generation were retired in the analyses. Comparing Carbon Cap and Trade with the PAC Business As Usual (BAU) scenario to the Mid-low Demand and Energy scenario shows roughly 10,000 MW more generation is needed in CARP Carbon Cap and Trade than with PAC BAU.

In both CARP and PAC future scenarios, the increase in state-mandated renewable energy capacity overshadows thermal capacity. This is because most states have renewable energy standards, an abundance of existing capacity, and the presence of lower demand and energy starting points and growth rates during the study period.

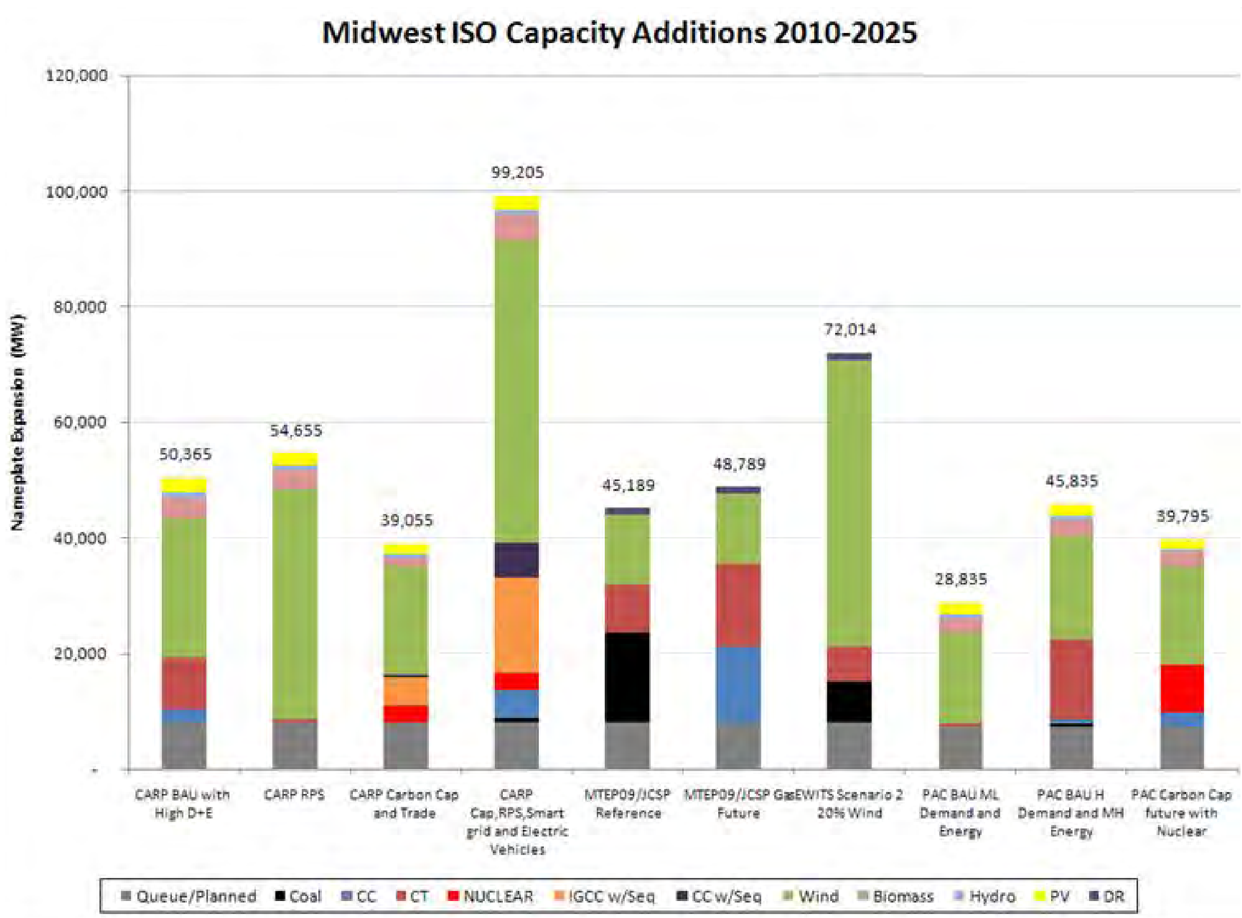


Figure 7.2-2: Midwest ISO Modeled System Aggregate Nameplate-installed MW for 2025 PROMOD® Model

Figure 7.2-3 demonstrates the cumulative present value of costs for the study period through 2025. There are two components of the costs provided: production cost and capital costs. Production costs include fuel, variable Operations & Maintenance (O&M), fixed O&M, and emission costs (where applicable). Capital costs represent the annual revenue requirements associated with addition of new capacity.

Great care must be taken when comparing future costs. Costs are sensitive to many input variables. Not understanding how each future scenario is modeled can result in erroneous conclusions. For example, when comparing the CARP Cap and Trade, RPS, smart grid and electric vehicle future scenario (Scenario S4) and the MTEP09 Reference future scenario (S5), the conclusion could be made the overall generation mix is similar since the production costs are the same for both scenarios. However, this conclusion is incorrect. The scenarios have widely different generation mixes, but the production cost is the same due to the reduced cost of natural gas in the CARP future. This is one example why input assumptions must be carefully considered in all future scenarios.

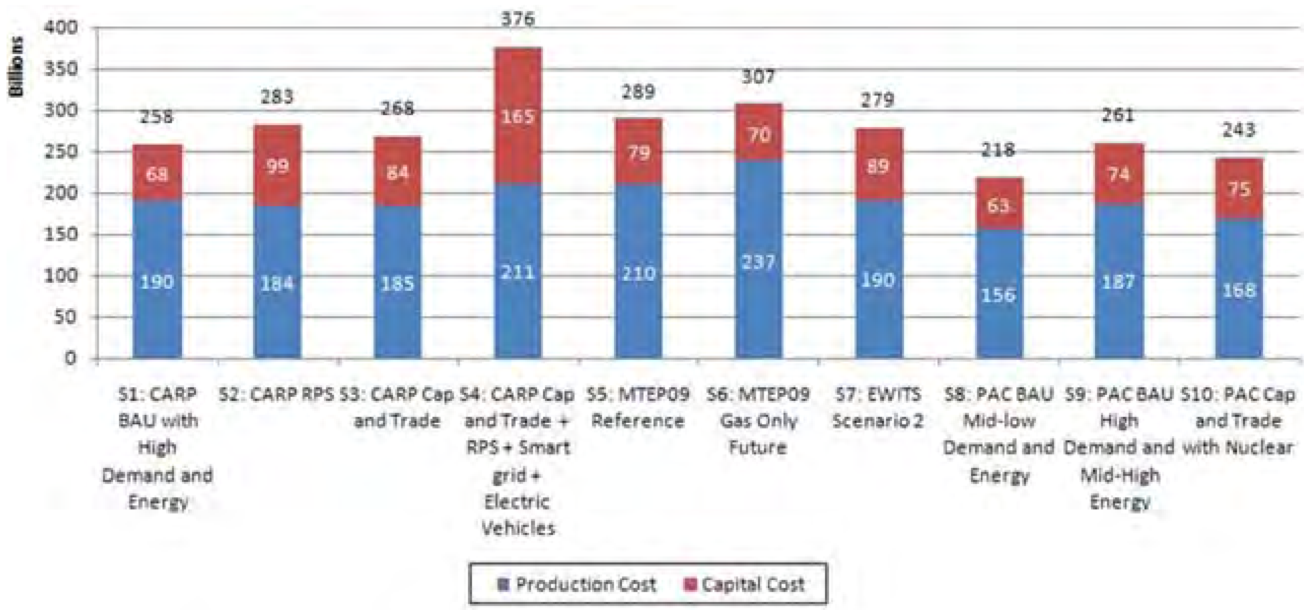


Figure 7.2-3: Midwest ISO Present Value of Cumulative Costs in 2010 USD

Each of the future scenarios has a different impact on carbon dioxide output. Refer to Figure 7.2-4, which demonstrates this varying impact for each of the defined future scenarios. Figure 7.2-4 compares 2005 carbon production provided by the dispatch of a 2005 EGEAS model and year-end 2029 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 annual basis; however, the increased penetration of renewable resources will result in a system reduction in carbon dioxide due to greater dependence on non-carbon producing resources.

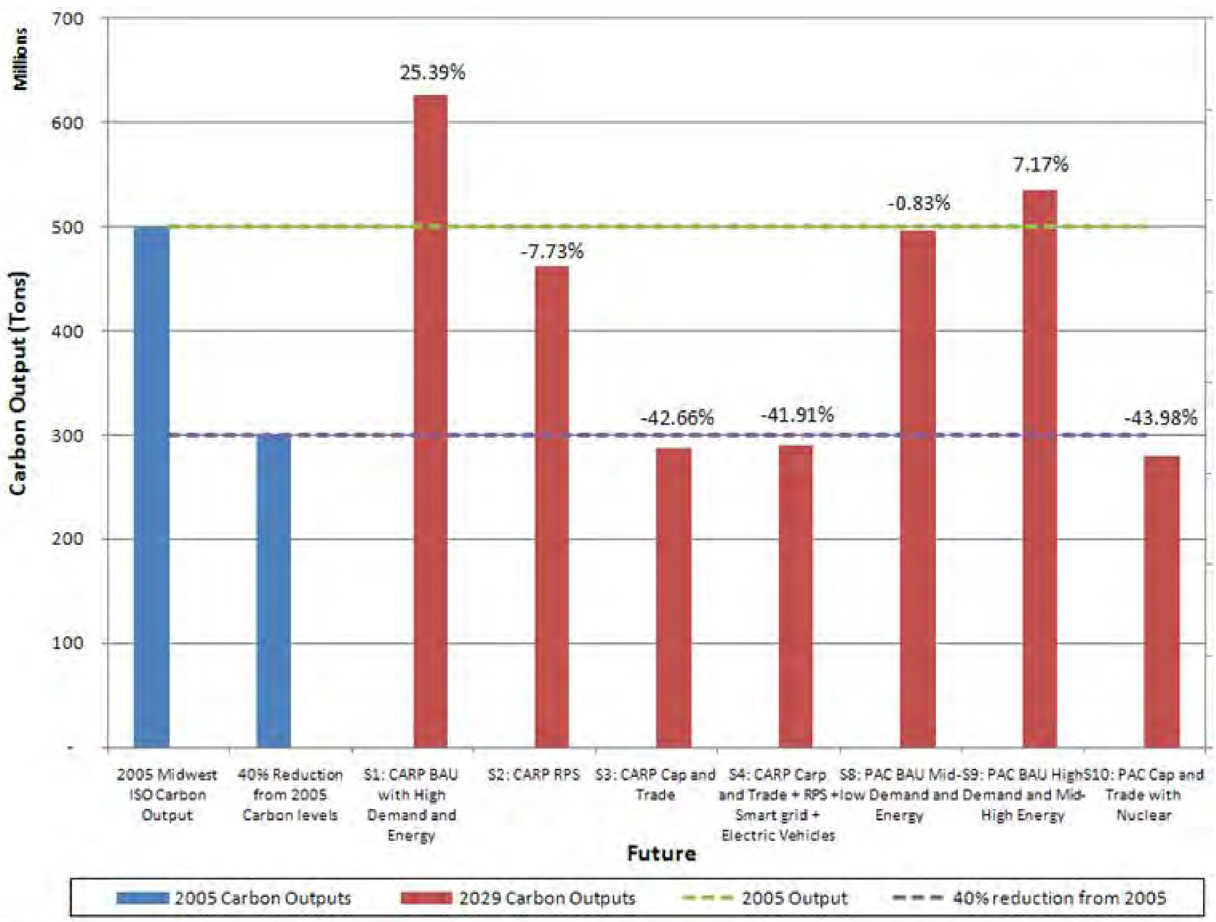


Figure 7.2-4: Midwest ISO Carbon Production

7.2.3 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 7.2-8, which depicts capacity siting associated with the Business As Usual with High Demand and Energy Growth Rates scenario (S1). The siting methodology used for this and the other future scenarios is explained more fully in Appendix F of this document.

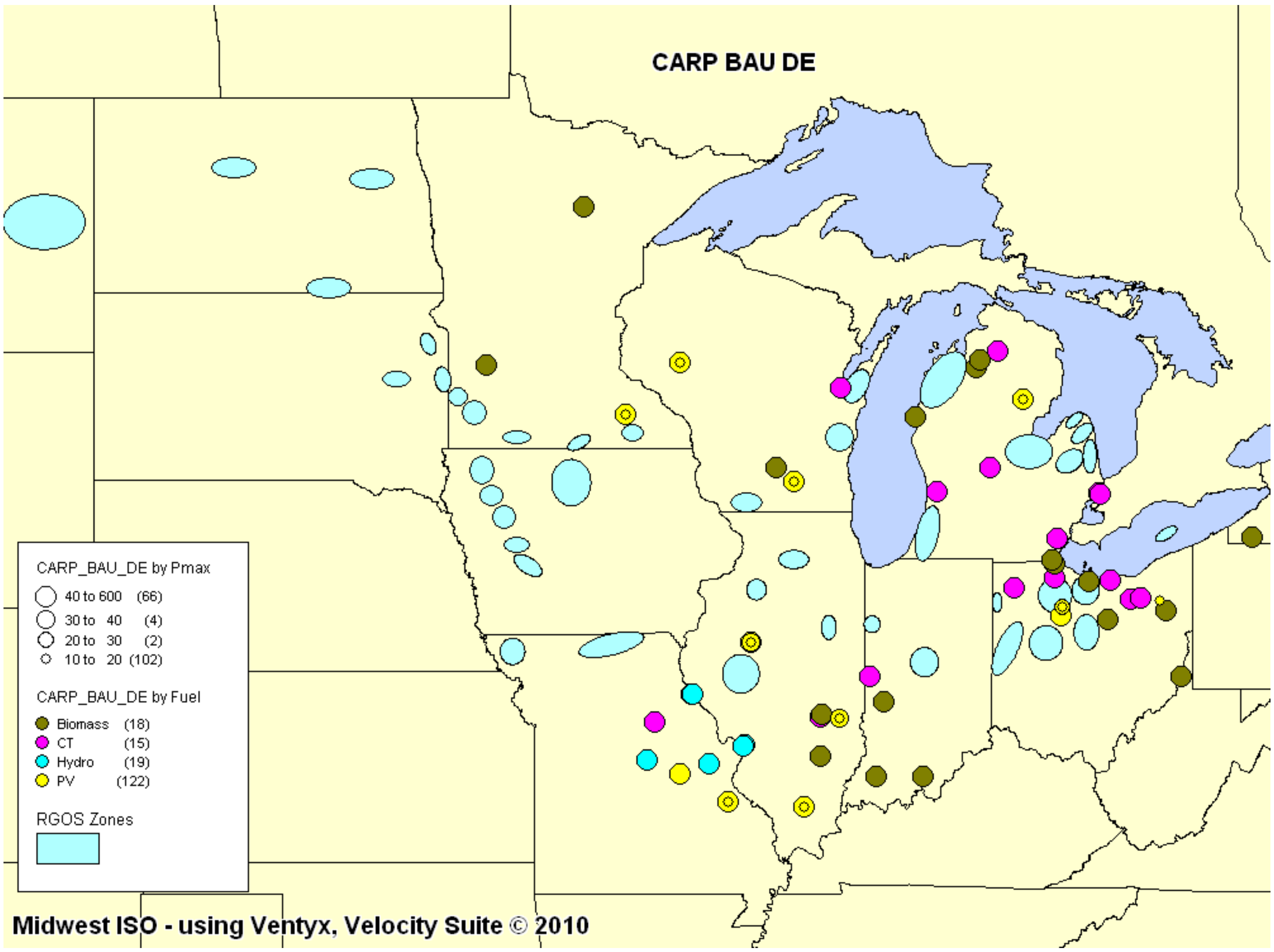


Figure 7.2-8: Midwest ISO CARP BAU with High Demand and Energy S1–Capacity Sites

7.3 Robustness Testing

A major challenge in developing a robust business case is to appropriately determine the benefits of transmission plans over a range of plausible futures. Thus, the primary focus of the continued MTEP10 value-based planning process has been centered on identifying and quantifying the total value of transmission plans or portfolios through a robustness testing process. To perform robustness testing, each long-term transmission plan is assessed against a set of value measures across a broad set of different future scenarios. Ultimately, the goal is to identify the best-fit long-term strategy that would maximize the value of transmission system under multiple future scenarios and result in the least future regrets regardless of policy decisions. With the continued evolution on the integrated transmission planning approach, the identified long-term strategy is intended to provide guidance for short-term transmission development which ensures system reliability in the most efficient way.

As the regional planning approach has evolved, so has the need for consideration of additional value measures in the transmission value evaluation. Developing a list of appropriate value measures is critical to enable a more holistic value assessment of transmission plans or portfolios and create a robust case analysis.

7.3.1 Future Scenario Selection and Weights

Federal and state energy policy discussions continue to be one of the primary factors driving the need for long-term transmission planning. To best manage the uncertainty introduced by potential future policy decisions, a wide range of future scenarios are necessary to capture the bookends of plausible outcomes. With a high level of stakeholder collaboration taking place under the Planning Advisory Committee, the MTEP10 value-based planning process started by updating a set of available future scenarios developed across the last few years and developing a number of additional new futures to provide further variation in potential energy policy outcomes as described in section 7.2.

A total of ten futures were developed as the initial result of future scenario planning. The various input assumptions and uncertain variables defined for each policy driven future dictate a unique set of generation expansion plans on a least cost basis to meet regional resource adequacy requirements. As illustrated in Table 7.3.1, each future scenario falls into one of the four (4) broad categories; i.e., carbon emissions, renewable energy penetration, demand and energy growth rates and gas resource build-out.

Table 7.3.1: Key Drivers of Future Definitions

Carbon Emission	Renewable Energy Penetration	Demand and Energy Growth	Gas Resources
CARP CAP S3	CARP RPS S2	CARP BAU S1	MTEP09 GAS S6
PAC CAP w NUK S10	CARP CAPRPSSGEV S4	PAC BAU HDMHE S9	CARP BAU S1
CARP CAPRPSSGEV S4	EWITS S7	PAC BAU MLDE S8	
		MTEP09 REF S5	

Given the large volume of output from production cost model simulations, the challenge is not only to manipulate large quantities of data and extract the necessary information, but also to analyze and understand the data for transmission value assessment. To alleviate this, Midwest ISO collaborated with its stakeholders and selected five futures for further analyses. This reduction from ten (10) to five (5) future scenarios was based upon the identification of similarities between future scenarios and through the elimination of those future scenarios with great similarities. One of the goals was to maintain bookend futures in order to capture the range of future policy impacts. One future was selected from each of the four primary categories, highlighted in grey as shown in Table 7.3.1. The CARP “kitchen sink” S4 scenario was selected as the fifth future because of its unique ability to address multiple potential policy decisions. Figure 7.3.1 depicts the five (5) future scenarios selected to carry forward robustness testing of transmission plans.

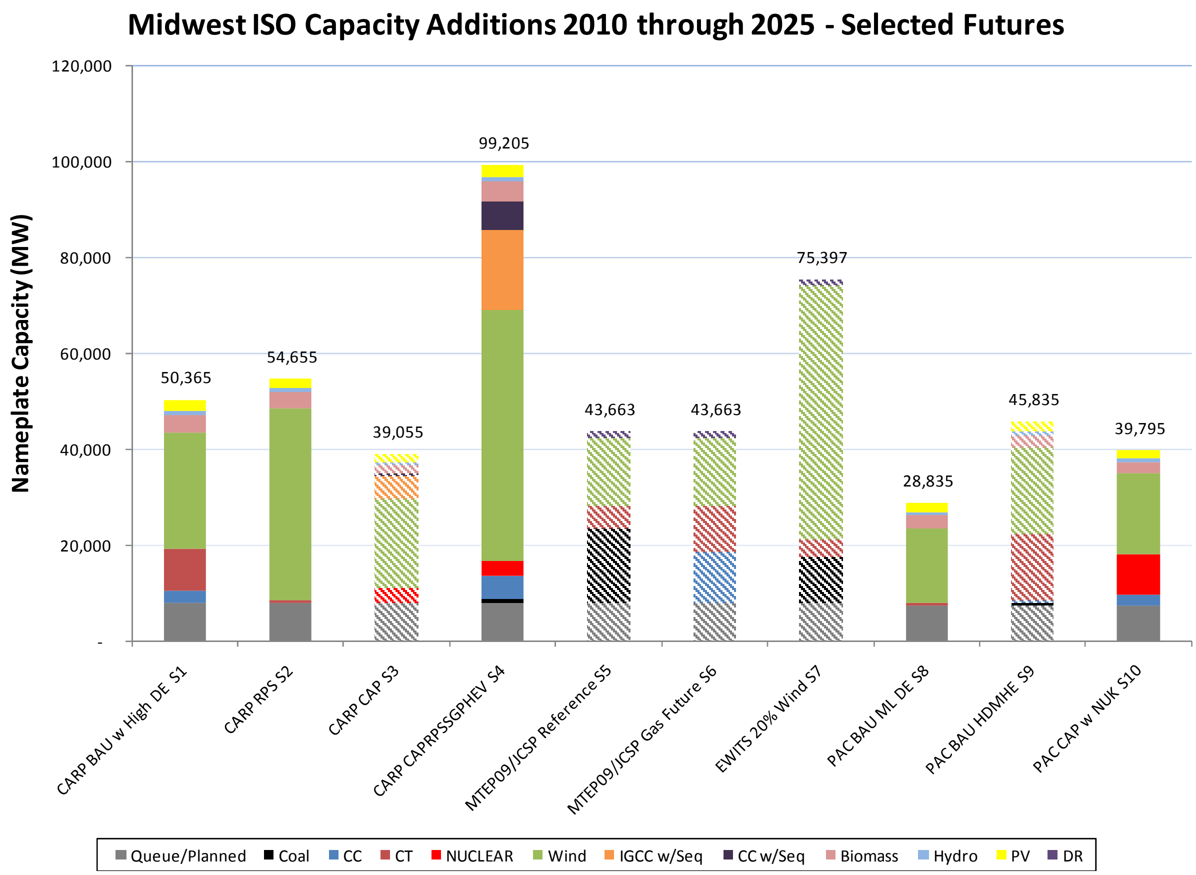


Figure 7.3-1: Selected Futures and Associated Installed Nameplate Capacity Expansion for Midwest ISO

Initial 2025 production cost model simulations were performed on each of the identified ten (10) futures to provide insight for selection of the futures. Figure 7.3.2 represents the 2025 annual energy production level by fuel type for each given future. The futures are ordered by each of the four identified categories mentioned above. As can be seen, S3 and S10 are the two futures to address aggressive carbon reduction policy with the primary difference in their preferred carbon neutral resources, carbon capture and sequestration versus nuclear. S2 and S7 are the RPS futures with different demand and energy growth rates. S8, S9, S5 and S1 provide a range of various demand and energy growth rates with S1 and S8 representing the two bookends. Recognizing the high percentage of gas resource energy usage in S1 and S6, these two futures are considered in the same category in terms of gas resources. By selecting the potential bookend futures from each identified key category, the wide range of outcomes is retained to ensure the viability of the transmission business case analysis.

Refer to Figure 7.3-2.

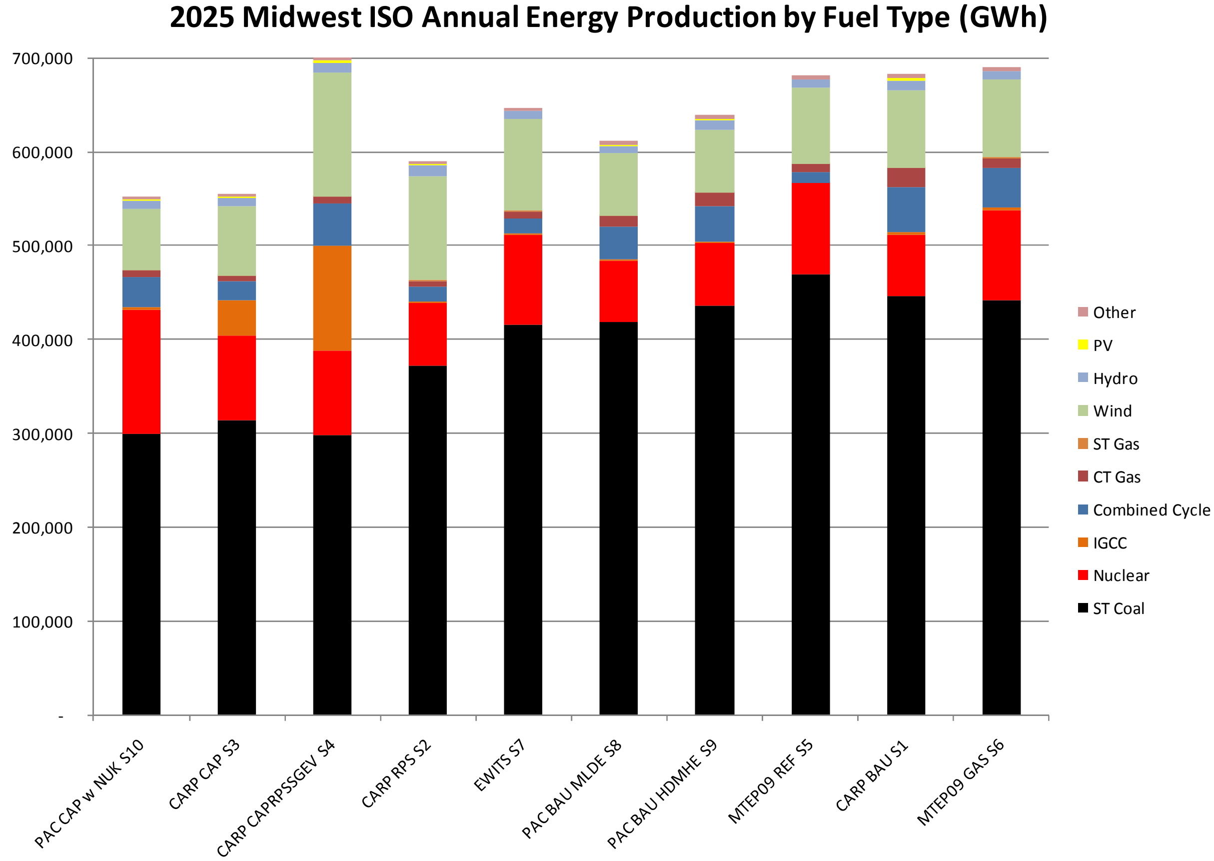


Figure 7.3-2: 2025 Midwest ISO Annual Energy Production by Fuel Type

The flexibility provided by the multi-dimensional scenario planning analysis allows a more complete robustness analysis around the long-term transmission plans. The weighting of the futures and how a transmission project/portfolio performs based on the assigned weights must be taken into account in order to more accurately select the appropriate projects or portfolios. To achieve this end, Planning Advisory Committee (PAC) sectors were requested to provide weights for the five (5) selected futures based on the relative possibility of each. The straight sector average weights assigned to each future are tabulated in Table 7.3.2.

Table 7.3.2: Future Scenario PAC Sector Average Weights

Future Scenarios	Weights
S8: PAC Business as Usual Mid-Low D+E	34%
S2: CARP Federal RPS Future	26%
S10: PAC Carbon Future–Carbon Cap with Nuclear	15%
S1: CARP Business as Usual with high growth rate for D+E	14%
S4: CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars	11%

7.3.2 Robustness Testing Process

In the MTEP10 value-based planning process, an attempt was made to implement a decision tree based methodology for robustness analysis around transmission projects/portfolios. As illustrated in Figure 7.3.3, robustness testing involves a comprehensive value assessment for transmission solutions. To perform robustness testing, each transmission solution is tested across multiple future scenarios which it might not be designed for. The value of the transmission for each given future is then evaluated and quantified against a complete set of value measures. By applying the assigned future weights to the values derived from each future, the overall weighted average value is determined for each transmission solution. The ultimate goal of robustness testing is to identify the transmission projects/portfolios that can provide the best value under most, if not all, future outcomes to minimize the risk associated with the uncertainty level around policy discussions.

A key component of transmission value assessment is the development of a complete set of appropriate value measures that can capture the total benefits of transmission plans in the best possible manner for making value comparisons. Further detailed discussions on value measure development will continue in section 7.3.3.

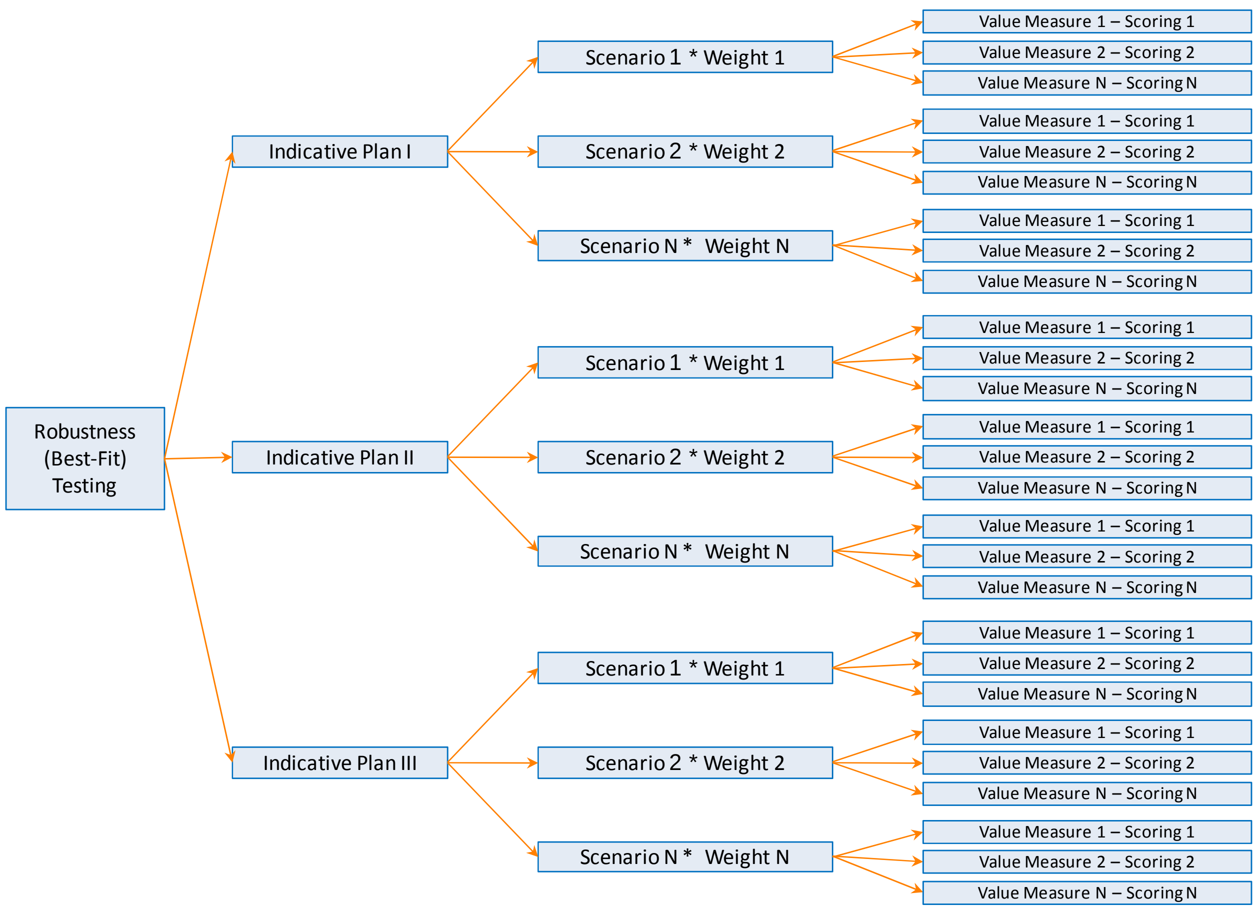


Figure 7.3-3: Indicative Robustness Testing Decision Tree Diagram

7.3.3 Value Measure Development and Considerations

As a starting point, MTEP10 robustness testing study effort focused on identifying a list of financially quantifiable benefit metrics from production cost models in order to address potential transmission value issues. The Midwest ISO utilizes PROMOD IV®, a commercial production cost model, to evaluate potential economic benefits of transmission projects or portfolios. Production cost model simulations are performed with and without each developed transmission project or portfolio. Taking the difference between these two cases provides the economic benefits associated with each project or portfolio. The financially quantifiable measures for transmission value assessment may include—but are not necessarily limited to—the following:

- **Adjusted Production Cost Savings** where total annual generation production costs include fuel, variable operating and maintenance (O&M) and start up costs, and are adjusted for off-system purchases and sales: The off-system purchases and sales are quantified using load weighted LMP and generator-weighted LMP, respectively. Adjusted Production Cost savings can be achieved through reduction of transmission congestion costs and more efficient generation resource utilization.
- **Load Cost Savings** where load cost represents the annual load payments, measured by projections in hourly load weighted LMP: Load cost savings and Adjusted Production Cost savings are essentially two alternative benefit measures to address a single type of economic value and are not additive measures. Load cost savings were not used to calculate the total value of the RGOS plans in MTEP10.
- **Capacity Loss Savings** where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour: The intent is to capture the value of reducing the amount of capacity reserves that are required to maintain system reliability. The avoided capacity investment due to loss reduction is quantified using a generic overnight construction cost of $960,000 per MW.
- **Capacity Savings Due to Planning Reserve Margin Reduction:** The intent of measure is to capture the value associated with transmission plans by potentially lowering the overall Planning Reserve Margin requirement through congestion relief. Recognizing that a relatively small reduction in reserve requirement would allow a significant amount of benefits to accrue, this measure is under consideration for inclusion in future evaluation of transmission plans/portfolios.
- **Carbon Emission Reduction Cost Savings:** To address carbon reduction legislation in some future scenarios, a certain cost on carbon is combined with uneconomic coal plant retirements to achieve a high level of carbon reductions. The cost of carbon is modeled in a way to only impact the unit dispatch as a penalty and exclude the costs associated with carbon emissions from production costs. The benefits of carbon emission reduction are additive to the Adjusted Production Cost savings described above. The corresponding carbon cost modeled in each scenario is used to quantify the dollar value of carbon emission reductions.
- **Generation Revenue Due to Wind Curtailment Reduction:** With new transmission corridors to access remote wind resources, the curtailment level of wind energy is reduced substantially, particularly for the futures with aggressive RPS requirements. The revenue is quantified using annual generator-weighted LMP for the RGOS footprint as an estimate. The intent of this measure is to provide a standalone value associated with wind curtailment reduction and is not included in the overall value calculation, as this value is embedded in Adjusted Production Cost savings described above.

MTEP10 robustness testing focused on financially quantifiable metrics. Other benefit measures, including qualitative benefits and risk factors, also need to be taken into account to allow a more complete value to be captured for transmission plans or portfolios. As some value measures are not readily quantifiable in dollars, the challenge is to determine how to incorporate these measures in the business case analysis for transmission since it is important to recognize non-financial measures in the analysis. Because of this, some level of subjectivity is needed to identify the best-fit projects/portfolios. The balance between quantitative and subjective analyses must be addressed in such a way to provide a robust business case.

Midwest ISO will continue to collaborate with stakeholder on further development of value measures and their relative weights over the next few planning cycles.

7.3.4 RGOS Transmission Plan Value Assessment

In response to the increasing level of focus on renewable energy policy, the Regional Generation Outlet Study (RGOS) was iterated in MTEP10 to develop three long-term transmission plans that could be used to meet state renewable energy standards and goals in the Midwest ISO footprint. In 2010, the three preliminary RGOS transmission plans were evaluated based on the identified list of financially quantifiable measures[47]. The value measure methodology needs further refinement, including both financially quantifiable measures and non-financial measures, before the benefits of the RGOS transmission plans can be fully evaluated and a preferred long-term strategy can be selected. Additional discussion on the RGOS transmission development can be found in section 9.1.

From the list of financially quantifiable measures described in section 7.3.3, only mutually exclusive and additive measures were used to calculate total value of RGOS transmission plans during the MTEP10 planning cycle to avoid overstating the value of the plans. The straight sum of Adjusted Production Cost savings, capacity loss savings and carbon emission reduction cost savings were used to determine the value of each plan for a given future scenario. Although the capacity savings due to PRM reduction is additive, it was not evaluated due to time constraints. The overall aggregated financially quantifiable value for each RGOS plan is then determined by applying PAC assigned future weights to the value derived for each future. The total financially quantifiable value results for the three (3) RGOS plans are indicative and are subject to change depending on the assumptions made to quantify the identified value measures and additional value measure inclusion. In general, the additive financially quantifiable benefits are considered for transmission value assessment. However, for potential market efficiency projects, the RECB II economic benefit metric—a blend of 70% adjusted project cost benefit and 30% load cost savings—is used for transmission value evaluation. Specifically in MTEP10, the financially quantifiable value of each RGOS transmission plan was determined as follows:

Value of transmission plan (per future) = Sum of values of financially quantifiable measures

= Adjusted Production Cost savings + Capacity loss savings + Carbon emission reductions[48]

Value of transmission plan (overall) = Sum of value of the plan per future * future weights

=34%*Scenario 8 +26%*Scenario 2 +15%*Scenario 10+14%*Scenario 1+11%*Scenario 4

For each of the three RGOS transmission plans, the value of each individual financially quantifiable measure for each future scenario, the total value per future and the overall weighted value are shown in the decision tree diagram in Figure 7.3-4 through 7.3-6.

[47] The RGOS transmission plans are still in development. The plan version used for robustness testing is dated May 25, 2010.

[48] Capacity savings due to PRM reduction is additive and is under development for inclusion in total value evaluation.

Looking at the results, a wide range of potential benefits are achieved across the five (5) selected futures. Based on the robustness analysis described above, the three (3) RGOS plans are expected to bring an annual weighted financially quantifiable benefit ranging from $1,064 million to $1,830 million in year 2025 for the RGOS study footprint. Note the values derived are indicative and only for robust business case development purposes.

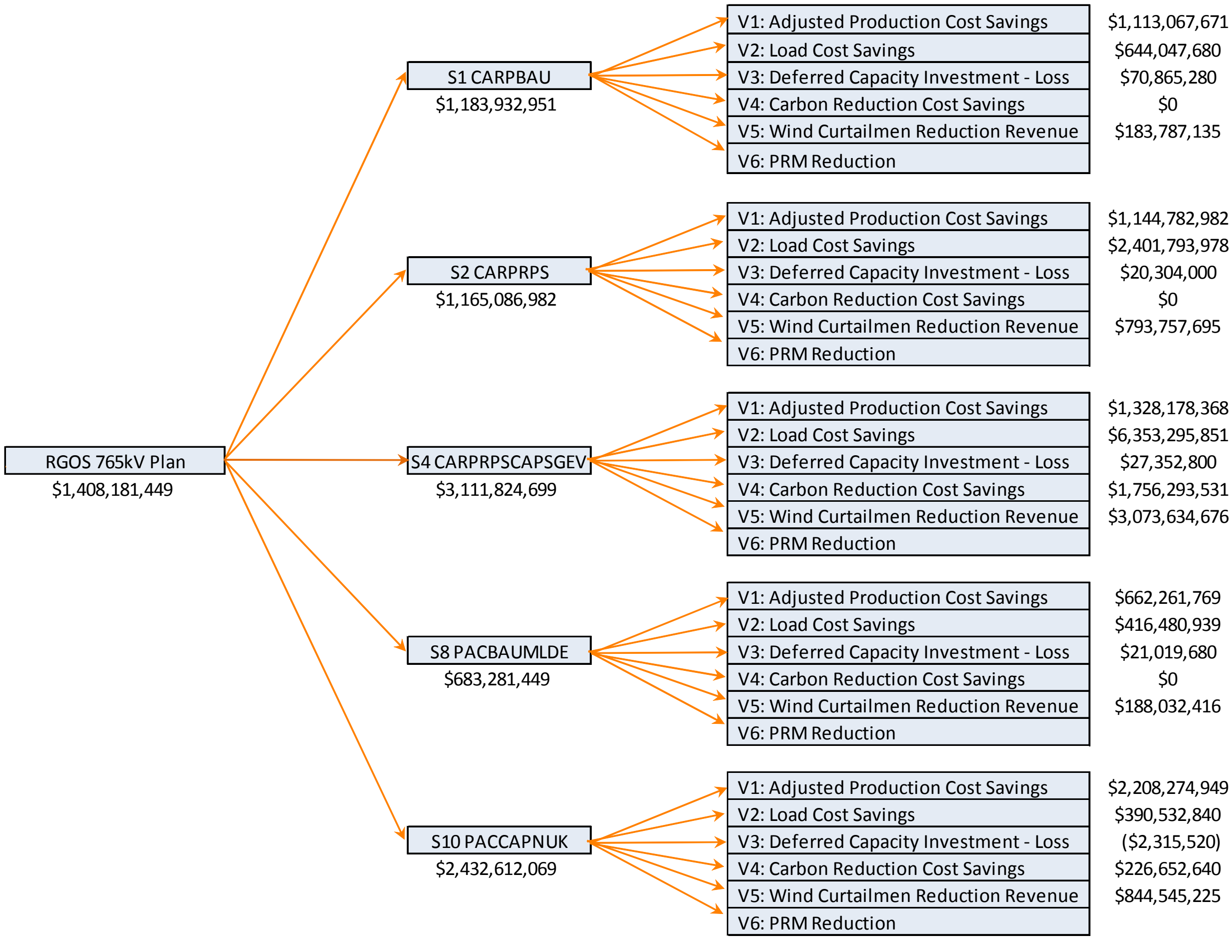


Figure 7.3-4: Indicative RGOS 765kV Plan Robustness Testing Results[49]

[49] RGOS transmission plans are still in development and the plan version used for robustness testing is dated May 25, 2010. All results illustrated in the diagram are **2025 annual benefits** and are calculated for the RGOS study footprint.

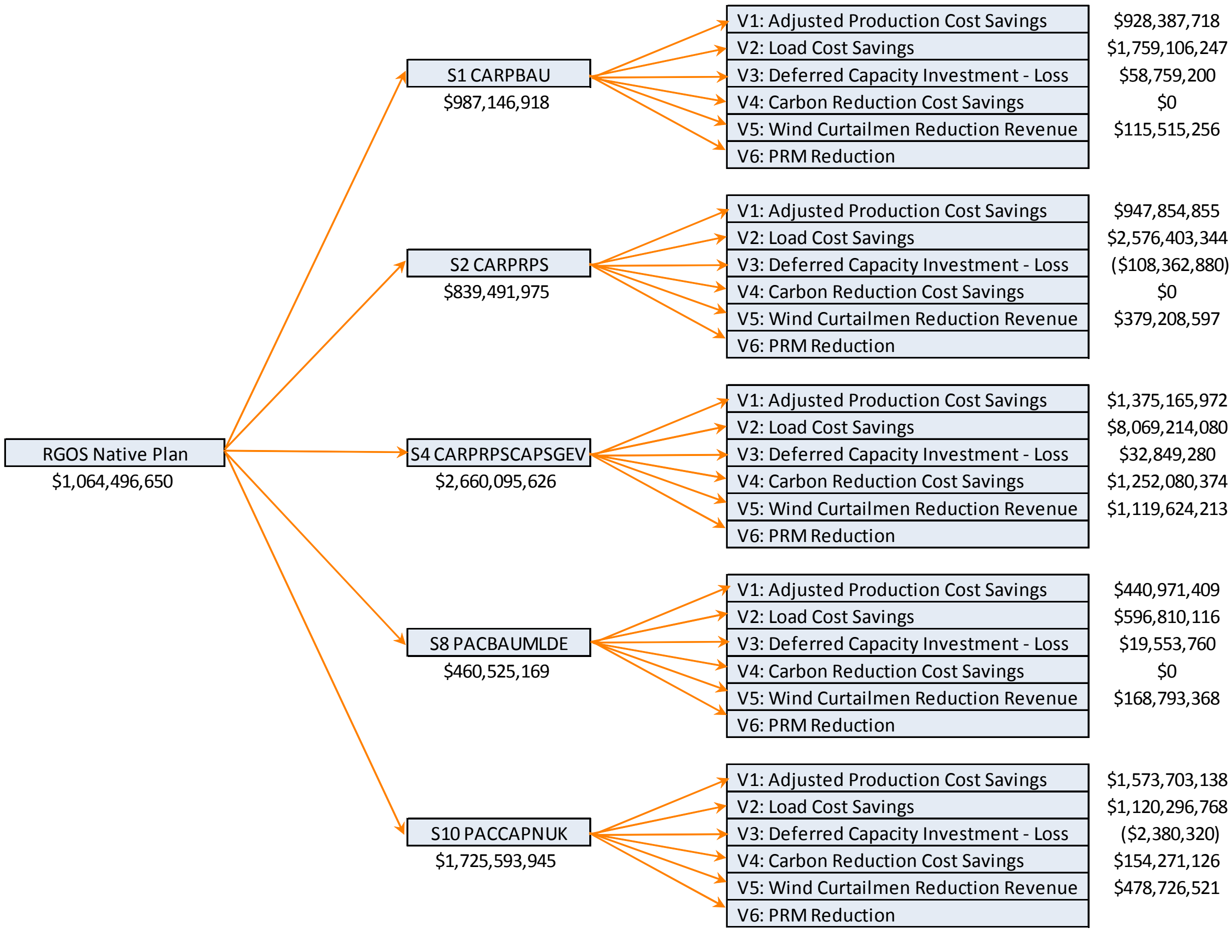


Figure 7.3-5: Indicative RGOS Native Voltage Plan Robustness Testing Results[50]

[50] RGOS transmission plans are still in development and the plan version used for robustness testing is dated May 25, 2010. All results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

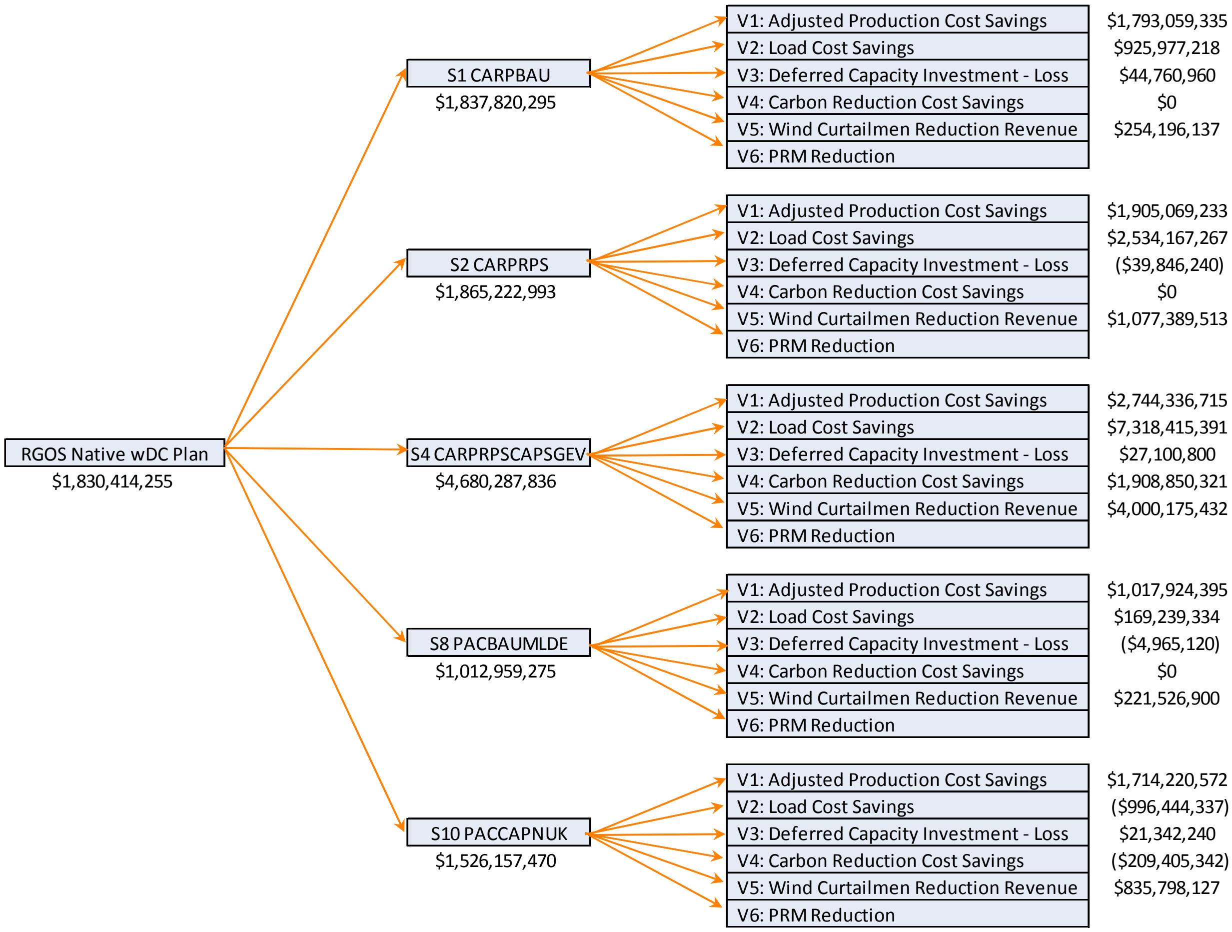


Figure 7.3-6: Indicative RGOS Native Voltage with DC Plan Robustness Testing Results[51]

[51] RGOS transmission plans are still in development and the plan version used for robustness testing is dated May 25, 2010. All results illustrated in the diagram are **2025 annual benefits** and are calculated for RGOS study footprint.

Table 7.3.3 summarizes the annual costs, financially quantifiable values and benefit to cost ratios associated with each of the three RGOS transmission plans. It shows that the native with DC option provides the highest benefit to cost ratio based on an annual analysis in year 2025. However, before determining an overall definitive long-term transmission strategy, an expanded business case analysis needs to be performed with a more complete list of value measures. Each RGOS plan has its own risks and other pertinent factors that may significantly impact the way to identify the preferred strategy. Table 7.3.4 shows results of some additional measure Candidates that can be incorporated into the process.

Table 7.3.3: RGOS Transmission Plan Cost and Benefit Comparison (2025 USD in Millions)

Transmission Plan Options	2025 Annual Transmission Cost [52]	2025 Annual Total Financially Quantifiable Value [53]	2025 B/C ratio [54]
RGOS 765kV	4,684	1,408	0.30
RGOS Native	3,816	1,064	0.28
RGOS Native With DC	4,868	1,830	0.38

Table 7.3.4: RGOS Transmission Plan Comparison–Other Quantifiable Measures

Transmission Plan Options	Acres of Right of Way	Hourly Transmission Utilization (%) [55]	Future Measure development
RGOS 765kV	131,896	17%	TBD
RGOS Native	122,451	16%	TBD
RGOS Native With DC	137,576	21%	TBD

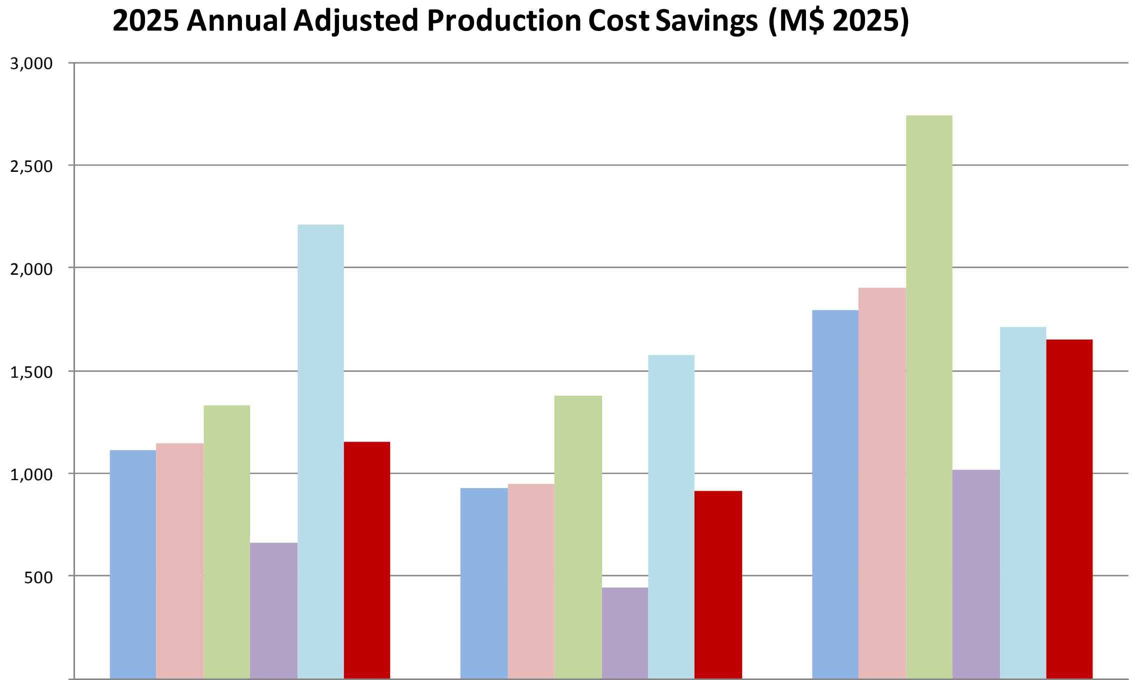
[52] Annual cost in 2025$ is calculated using 18.3%, which is the Midwest ISO annual average charge rate based on 2010 attachment O and 3% escalation rate. The RGOS plans are assumed to be in service at 2019. It is important to note that the cost estimates are used for the benefit to cost ratio calculation only.

[53] The total financially quantifiable value numbers are indicative and are subject to change depending on the assumptions on how to quantify the identified value measures and additional value measure development.

[54] The benefit to cost ratios are indicative and calculated using 2025 annual values only, NOT present values. The results are only intended to provide the comparison between transmission plans relative to each other.

[55] The percentage of hourly new transmission utilization is calculated for the CARPBAU future only, using the straight average of the hourly flows on the new RGOS transmission lines divided by the ratings.

Figure 7.3.-7 shows 2025 annual Adjusted Production Cost savings per future for the three (3) RGOS plans, as well as the weighted values associated with each plan using the PAC future weights. The RGOS plans yield an annual weighted Adjusted Production Cost savings ranging from $914 million to $1,651 million for RGOS study footprint. The Appendix E3 details the additional value measure results.



	RGOS 765kV	RGOS Native	RGOS Native with DC
CARP BAU	1,113	928	1,793
CARP RPS	1,145	948	1,905
CARP CAPRPSSGEV	1,328	1,375	2,744
PAC BAU MLDE	662	441	1,018
PAC CAP NUK	2,208	1,574	1,714
Weighted	1,156	914	1,651

Figure 7.3-7: 2025 Adjusted Production Cost Savings Comparison for RGOS Plans

7.3.5 Going Forward

To expand business case analysis, Midwest ISO will continue to refine the list of value measures and develop a methodology to better utilize non-financially quantifiable value measures through extensive stakeholder involvement. Looking forward to MTEP11, the primary focus of the value-based planning process and robustness testing will be on the refinement of identified 2011 Candidate Multi-Value Project (MVP) portfolio and the delineation of a long-term strategy ensuring an integrated transmission expansion planning process. In addition, future scenario definitions and underlying uncertainties regarding variable assumptions will be refreshed to better align with potential energy policy shifts. The inclusion of sensitivity and risk analyses on future scenarios will furnish additional dimensions to the analysis, making the value assessment of transmission projects and portfolios more robust.

8 Market Efficiency Analysis

To identify opportunities for improving energy market performance, in-depth analyses have been conducted upon those 44 individual flowgates (FGs) that have experienced congestion more than 1% of the time since market start. Significant transmission system upgrades are planned for many of these flowgates—primarily to address long-term baseline reliability concerns but which should also serve to reduce congestion. Refer to Table 8.2-1, which summarizes Top 44 status.

Table 8-1: Status of Related Activity Regarding 44 Most Congested Flowgates

# of Flowgates	Status Description
15	Solution(s) identified through annual planning cycles
6	Evaluated in Top Congested Flowgate Study(s)
3	Evaluated in Cross Border Congested Flowgate Study
1	Evaluated in both Top Congested Flowgate and Cross Border Congested Flowgate Studies
13	Coordinated flowgate: No solution(s) identified
6	Midwest ISO flowgate: No solution(s) identified

When engaging in expansion planning, careful consideration is necessary to identify transmission investments required to address chronic congestion as opposed to impulsively reacting to acute but short-lived congestion. It is also important to note congestion on a particular flowgate may have only taken place part of the time in the relatively short five-year span of the market; thus, discretion should be taken before regarding historical congestion information as the sole consideration driving long-term expansion.

Because transmission system constraints generally represent limitations to commercial use of the system, Midwest ISO has undertaken several studies in recent years seeking to identify possible economic transmission solutions to both historic and projected congestion. In 2010, Midwest ISO undertook the continuation of the Top Congested Flowgate Study, designed to identify transmission projects where market efficiency impacts exceed project costs, and enlisted its neighbors and stakeholders to participate in the Cross Border Congested Flowgate Study. Continuing to address congestion is a critical component to the maintenance of a low reserve margin. For example, it is estimated by 2015 that congestion will require an incremental contribution to the reserve margin of 1.6%.

8.1 Congestion Analysis Evolution

The process used by Midwest ISO to review system congestion has changed since it was introduced in MTEP03. Prior to market start, for example, Transmission Loading Relief (TLR) was the primary congestion study tool used in operations, with little correlation between TLR activity and actual Available Flowgate Capability (AFC). MTEP06 was the first iteration of the MTEP report where TLR and binding of constraints in the market were combined into a single congestion metric. MTEP07 was the first iteration of the MTEP report where congestion was compared to planned reliability projects for possible mitigation of future congestion upon historically impacted flowgates (refer to Table 8.2-2). Table 8.1-1, below, depicts the evolution of congestion metrics used in the MTEP since 2003.

Table 8.1-1: Evolution of Congestion Tracking and Metrics in MTEP Reports

A	B	C	D	E	F	G	H	I	J	K	L
MTEP Report	TLR	Track Reliability Based Completed or Pending Projects	Rank by Total Post MKTFG-Hr	AFC	Historical Shadow Price	Real Time Bound Hours As Un-bundled	Combined TLR & Real Time as Congestion Hours	Tracked Incremental Year to Year Changes	Track IMM NCA's	Investigate Cost Effective Projects	Track Annual Ranking Ranges And Median
MTEP03	x	x	x	x							
MTEP05	x	x		x							
MTEP06	x	x	x	x	x	x					
MTEP07	x	x	x		x		x	x			
MTEP08	x	x	x		x		x	x	x		
MTEP09	x	x	x		x		x	x	x	x	X
MTEP10	x	x	x		x		x	x		x	X

The Independent Market Monitor (IMM) has declared three (3) areas as Narrowly Constrained Areas (NCAs)[56]. In prior MTEP cycles, all necessary transmission solutions were brought forward to address these NCAs. As a result, MTEP10 has discontinued tracking IMM NCAs and has applied the metrics that emerged in MTEP09, as reflected in Table 8.1-1, above MTEP10 will focus on columns H, D, and L plus the geographic location of the flowgate.

[56] According to FERC, a Narrowly Constrained Area (NCA) is an electrical area defined by one or more transmission constraints that are expected to be binding for at least 500 hours during a given twelve month period, within which one or more suppliers is pivotal. A supplier is pivotal when the output of some of its generation resources must be changed to resolve the transmission constraint during some or all hours when the constraint is binding. In other words, it is pivotal when a binding transmission constraint cannot be relieved without changing the base loadings for other suppliers' generation resources.

8.1.1 Flowgate Congestion Overview

MTEP10 congestion analysis accomplishes the following:

- Captures five (5) years of Midwest ISO market operations.
- Continues (from MTEP09) to identify the volatility of flowgate activity by computing the median ranking of each flowgate across all five (5) market years. To determine which flowgates are chronically congested, the flowgate congested for the most hours in a given Market Year is assigned #1 rank, with other, less congested flowgates following in ascending order; i.e., #2, #3, #4... Examining the different rankings a flowgate has realized over a period of years and calculating the median of those rankings tends to filter out single years that may have had extremely high or low hours of congestion due to uncommon or not likely repeated circumstances.
- Identifies future congestion from among the following sources:
  - 2010 Loss of Load Expectation report for the ten-year, look-ahead period of 2010 through 2019 (Refer to section 8.3 of this document.)
  - Top Congested Flowgate Study (section 8.4.)
  - Cross Border Congested Flowgate Study (section 8.5.)

Refer to Table 8.1-2 on the following page, which illustrates both increased utilization of congested flowgates and the number of flowgates congested annually.

Congestion is an ongoing, dynamic series of occurrences when measured from year to year—or even from month to month. The imputation of historical hours is just one of several inputs used to determine whether or not system expansion is warranted to reduce congestion. Column G reflects the current snapshot of evolving new flowgates versus the repeated use of earlier congested flowgates. Some flowgates used in the past are not utilized going forward because these flowgates have become inactive for a period of time or have been replaced altogether. This transient aspect of flowgate activity can be attributed to changing transmission and generation infrastructure and unique maintenance or weather-driven effects within a given time period. Until this year (2010), the number of post-market flowgates utilized each year (Column B) has been slowly decreasing while the overall average annual hours each flowgate experienced congestion remains in the range of 25–35 hours per flowgate, as shown in Column E.

Refer to Column D, which shows an increasing congestion trend in the Midwest ISO footprint since 2001. After peaking during the 1st Market Year in 2005, congestion then showed a reduction in the 2nd Market Year and has grown slowly through the 5th Market Year. The 5th Market Year realized 25,167 Flowgate Hours (FG-Hours), continuing at a somewhat reduced level from the maximum of 27,842 FG-Hours experienced during the 1st Market Year. Congestion analyzed here reflects the combined quantification of re-dispatch from Real-Time operations and NERC TLR activity. Column D also shows, in the pre-Midwest ISO Market time frame, fairly constant annual (April to April) congestion: between 10,000 and 11,000 FG-Hours per year from April 2002 to April 2005. The increased level in the annual Flowgate-Hour (FG-Hour) metric after April 1, 2005 demonstrates the advantages offered by Locational Marginal Pricing (LMP), which better utilizes and effectively exploits use of the available transmission system up to reliability limits.

While the overview summary in Table 8.1-2 utilizes averages to reveal general trends, more detailed discussion follows in this section and in Appendix G2. Specifically, refer to the Appendix_G2_Congestion_Summary spreadsheet, which contains itemized hours pertaining to each of the 3,200 flowgates for pre-market and each post-market year.

Table 8.1-2 Evolutionary Nature of Number of Flowgates Utilized and Annual FG-Hours Since January 1, 2001

A	B	C	D	E	F	G
	Number of Flowgates Utilized					At End of 5 MKT Years
Time Period	During Time Period	Cumulative Utilized Since January 2001	Congestion FG-Hours In Period	Average Hours/FG In Period		Number of FG Sustained Uniquely In each ofSix Time Periods
April 2009–April 2010	875	3,200	25,167	29		596
April 2008–April 2009	653	2,604	23,137	35		309
April 2007–April 2008	798	2,213	20,748	26		417
April 2006–April 2007	829	1,672	20,392	25		445
April 2005–April 2006	841	1,105	27,842	33		522
April 2004–April 2005	200	358	11,050	55		226
April 2003–April 2004	174	316	11,094	64		^
April 2002–April 2003	89	116	10,172	114		^
January 2001-April 2002	64	64	6,432	101		^
		Note: The 6th Time Period is Composite of all four Pre-Market Periods				
		Subtotal: Occurred in 1 of 6 Time Periods				2,515
		Occurred in 2 Time Periods				418
		Occurred in 3 Time Periods				146
		Occurred in 4 Time Periods				66
		Occurred in 5 Time Periods				29
		Occurred in 6 Time Periods				26
		Total: Cumulative Utilized Since January 2001				3,200

8.2 Congestion History

Historical congestion review encompasses real-time (RT) operations in the five-year period since April 2005, during which congestion has been managed through a combination of Transmission Loading Relief (TLR) and by binding elements in the Midwest ISO market. Midwest ISO uses centrally controlled, security constrained, economic dispatch (SCHED) as a part of the Locational Marginal Prices (LMP)-based market. This means of dispatch is now the primary process for controlling security constraints on an operational basis. The central dispatch process is directed at economically dispatching the system while honoring constraints and avoiding security violations.

8.2.1 Congestion History as a Metric of System Performance

To have an element or flowgate “bound” means a defined flow limit has been set for the element within the Midwest ISO market SCHED program. The market will then be re-dispatched at a resulting higher cost level in order to maintain the flow within the defined set limit. TLR (through curtailment of scheduled transactions) and market re-dispatch (by means of binding elements) are available for implementation when warranted by system conditions. Both processes are targeted to prevent system security violations if a contingency occurs. However, commercial limitations to use of the transmission system give rise to congestion costs that may or may not exceed the costs of relieving the constraints through expansion of the transmission system. Much of the congestion realized throughout the system simply reflects proper management of the system within reliability limits and is not reflective of other eminent problems or expansion needs. More succinctly, any subsequently realized transmission congestion has two aspects:

- When transmission limits are reached and adequate generation resources are available to shift supply, reliability risk is very low. This is the situation most of the time.
- Alternatively, when a transmission limit is reached and generation resources are fully utilized, the situation presents concern because there could be limited choices for an alternative dispatch.

Deficient dispatch can result if there is insufficient generation available; conversely, adequate generation may exist system-wide but be limited by transmission congestion. Such generation would not then effectively meet overall Planning Reserve levels. Findings from the 2010-2011 Loss of Load Expectation (LOLE) study report for future planning reserve requirements point to areas of the system where transmission limitations prevent the full sharing of generation from those areas to the balance of the system during peak load times. (Refer to section 8.3.) The LOLE study calculated 443 MW of trapped generation during peak conditions. The following subsections provide information about the constraints most frequently involved in limiting transactions via TLR, binding in the Midwest ISO market dispatch, or a combination of the two. Both TLR and Midwest ISO market redispatch measures are used to maintain system reliability.

Summarizing congestion history provides a consistent metric of system performance. Because the physically installed generation and transmission system changes over time, this summary does not include tracking interactive impacts among flowgates, the introduction of new flowgates, or other dynamics. While no particular attempt has been made in this document to dissect specific historical data or to group commonly impacted flowgates, this summary (particularly individual flowgate charts depicted in Appendix_G2_Congestion_History_072110.pdf) provides a basis for in-depth data mining and detailed investigations. This type of information, along with further local knowledge incorporated into more detailed discussions, is commonly utilized to meet specific project needs or when addressing stakeholder questions about the transmission system.

8.2.2 Historical Congestion as Analytical Tool

Historically predominant congestion locations may or may not be associated with need for transmission facility expansion because historical congestion realized by Transmission Loading Relief (TLR) or binding in the Midwest ISO market has predominantly functioned as a security operating mechanism where expansion solutions were not necessary.

- Since MTEP07, emphasis has been placed on the post-market timeframe, which has now matured to sixty (60) months of Midwest ISO market operations (April 1, 2005 through March 31, 2010). Aggregated or averaged summaries can be misleading because these summaries do not reflect modifications to the network over time or the impact of rare patterns due to weather or other unusual generation availability patterns. Unusual events can cause a flowgate to be congested for a relatively high number of hours for a few months' duration, but the flowgate not present a long-term problem.
- Prior to MTEP06, congestion tracking was accomplished by analyzing TLR records only. Since the start of the Midwest ISO market on April 1, 2005, congested transmission elements may have contributed to the congestion component of the Real-Time (RT) LMP. Note the term "bound" is used to refer to an element or flowgate requiring an out-of-order dispatch of generation resulting in a Marginal Congestion Component (MCC) within calculated LMP price.

Note this review of historical congestion data will identify a flowgate as a Midwest ISO flowgate if a given facility is within the footprint of the Midwest ISO Reliability Authority (RA). This identification includes, for example, flowgates owned by Midwest ISO Transmission Owners (TOs), as well as those flowgates of non-member systems in the Mid-Continent Area Power Pool (MAPP) group of transmission companies contracting their Reliability Coordinator (RC) functions to Midwest ISO. For greater insight and detail, refer to Appendix_G2_Congestion_History_72110.pdf, which delineates and describes monthly congestion patterns of the 25 most active flowgates. On occasion, Midwest ISO and its members have provided more intensive analysis and explanations for specific flowgates of interest, and will continue to contribute to various targeted study efforts and other forums beyond MTEP scope and audience.

8.2.3 Top 1% Congested Flowgates Summary

Refer to Table 8.2-1 on the following page. Table 8.2-1 lists 44 flowgates that, on average, were congested more than 1% of the time in the post-Midwest ISO market period (over 438 hours in the five-year period). The fourth column of Table 8.2-1 shows total post-market hours of congestion and itemizes the hours for each year. Given observed historical congestion, the last column in Table 8.2-1 addresses how already planned projects may mitigate historically observed congestion situations.

There are many flowgates not part of the Midwest ISO system listed in Table 8.2-1, yet these flowgates are included here to underscore opportunities to improve energy market performance by coordinating with neighboring systems. Midwest ISO expects to work with neighboring systems to determine which flowgates may be cost-effectively mitigated and provide value to the Midwest ISO market. Note, too, the abbreviation *flo* following many of the flowgates listed under the Flowgate Name/Description heading in Table 8.2-1, which denotes *for loss of*. The limiting or monitored element is listed first, with the contingent element following the *flo* designation. For cross-referencing purposes, also refer to Table 8-1 on the first page of this section.

Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
1/100	Kammer 765/500 kV XFMR (flo) Belmont–Harrison 500 kV	VA	4803 = 1733+338+938+1457+337	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate
2/2353	Black Oak–Bedington 500 kV (flo) Pruntytown–Mt. Storm 500 kV	MD	3137 = 914+1157+909+152+5	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate
3/3006	Eau Claire–Arpin 345 kV	WI	2969 = 1529+245+794+362+39	**Solution(s) identified through annual planning cycles:** P1: Arrowhead-Gardner Park 345 kV line (ISD January 2008), and P574–Monroe Co–Council Creek 161 (ISD June 2013)
4/3270	State Line–Wolf Lake 138 kV (flo) Burnham–Sheffield 345 kV	IN-IL	2153 = 151+481+847+425+249	**Solution(s) identified through annual planning cycles:** P2798: Proposed project to Reconductor State Line–Wolf Lake–Sheffield 138 kV line, Estimated ISD pending at mid 2010.
5/9160	ONT-NYIS	NY	2083 = 0+0+21+923+1139	**Coordinated flowgate: No solution(s) identified.** Not Midwest ISO flowgate
6/6007	Gerald Gentleman–Red Willow 345 kV	NE	2012 = 271+186+312+623+620	**Evaluated in Cross Border Congested Flowgate Study:** Several mitigation methods identified, including one two build a new 345 kV line from GGS to Red Willow to Axtell
7/2980	Dune Acres -Michigan City 138 kV ckts 1&2 (flo) Wilton Center–Dumont 765 kV	IN-IL	1935 = 241+107+59+742+786	**Evaluated in Top Congested Flowgate Study(s):** P2797: Proposed project to upgrade breakers at Michigan City 138 kV breaker, Estimated ISD pending at late 2009. Market Operational Issue during high West to East Transfers.
8/2352	Pruntytown–Mt. Storm 500 kV (flo) Black Oak–Bedington 500 kV	VA	1796 = 468+395+142+670+121	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate
9/2245	Blue Lick–Bullitt Co. 161 kV (flo) Baker–Broadford 765 kV	KY	1749 = 1699+44+6+0+0	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate

Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
10/3012	Paddock 345/138 kV XFMR (flo) Paddock–Rockdale 345 kV	WI	1589 = 405+420+477+261+26	**Solution(s) identified through annual planning cycles:** 2nd Wempletown-Padock 345 kV line (in service in 2005) and P1256 (Paddock Rockdale 345 kV circuit #2 ISD 4/1/2010)
11/6009	Cooper South Interface	NE	1570 = 696+234+76+172+392	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate.
12/6126	S1226-Tekamah 161kV flo S3451-Raun 345kV	IA-NE	1434 = 36+0+714+640+44	**Evaluated in both Top Congested Flowgate and Cross Border Congested Flowgate Studies:** **Several mitigation methods identified, including a rebuild of the S1226-Tekamah 161 kV line and upgrade of the Tekamah substation equipment**
13/522	EFrankfort_Crete345_flo_Dumont_WiltonCenter765	IL	1432 = 0+0+0+319+1113	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate.
14/3145	Pana 345/138 kV XFMR (flo) Coffeen–Coffeen North 345 kV	IL	1397 = 24+164+230+947+32	**Evaluated in Top Congested Flowgate Study** **Several mitigation methods identified, including a new 345 kV line from Coffeen to Coffeen North.**
15/2872	Frankfort East-Tyrone 138 (flo) Ghent-West Lexington 345	KY	1283 = 1151+132+0+0+0	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate.
16/3167	St. Francois–Lutesville 345 kV	MO	1226 = 39+18+217+936+16	**Midwest ISO flowgate: No solution(s) identified:**

Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
17/6004	Minnesota Wisconsin Stability Interface (MWSI)	MN-WI	1162 = 806+212+144+0+0	**Solution(s) identified through annual planning cycles:** P1: Arrowhead-Gardner Park 345 kV line, ISD January 2008, P1024: SE Twin Cities-Rochester, MN-LaCrosse, WI 345 kV project (ISD 2015), and P574–Monroe Co–Council Creek 161 (ISD June 2013) The MWSI interface was retired and replaced with the MWEX interface (FG6193) in October 2008.
18/3429	Oak Grove-Galesburg 161 flo Nelson-Electric Jct 345	IL	1088 = 0+0+239+63+786	**Midwest ISO flowgate: No solution(s) identified:**
19/3567	ATC LLC Flow South Interface	WI-MI	1027 = 646+172+25+117+67	**Solution(s) identified through annual planning cycles:** Stiles-Plains 138 kV dbl ckt rebuild project (in-service 2006). P177 (Gardner Park-Highway 22 345 kV line projects) and P345 (Morgan-Werner West 345 kV line) P352 (Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV)
20/none	Culley–Grandview 138 kV (flo) Henderson 161/138 kV XFMR	IN	1017 = 539+284+189+0+5	**Solution(s) identified through annual planning cycles:** P1259: New transmission line Dubois to Newtonville, ISD June 2006
21/6145	Lake Road-Nashua 161 flo Iatan-Stranger Creek 345kV	MO	1004 = 51+0+0+15+938	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate.
22/122	Wylie_Ridge_7_tx_l_o_Wylie_5_tx_SPS_in_service	OH	979 = 573+375+31+0+0	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate; however, congestion trend is downward.
23/2463	Kokomo HP 230/138 kV XFMR (flo) Jefferson–Greentown 765 kV	IN	882 = 132+750+0+0+0	**Midwest ISO flowgate: No solution(s) identified:** No reliability project identified; however, congestion trend is downward.
24/9159	Ontario–ITC Interface	MI	868 = 79+251+475+60+3	**Midwest ISO flowgate: No solution(s) identified**

Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
25/2086	Newtonville 161/138 kV Transformer #1	IN	861 = 28+8+502+103+220	**Midwest ISO flowgate: No solution(s) identified:** Driven by ice storm-related damage in early 2007
26/3706	Arnold–Hazleton 345 kV	IA-NE	812 = 112+480+156+46+18	**Solution(s) identified through annual planning cycles:** P1340: Build a new Hazleton-Lore-Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer ISD: December 2011.
27/2975	Crete-St Johns Tap 345 kV l/o Dumont-Wilton Center 765 kV line	IN-IL	806 = 6+2+0+31+767	**Evaluated in Cross Border Congested Flowgate Study:** Several mitigation options identified, including a short-term option to re-sag or reconductor Crete to St. John and upgrade a NISPCO CT
28/none	Culley–Grandview 138 kV (flo) Henderson–A.B. Brown 138 kV	IN	700 = 586+84+30+0+0	**Solution(s) identified through annual planning cycles:** P1259: New transmission line Dubois to Newtonville,
29/111	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	OH-VA	686 = 58+92+172+364+0	**Evaluated in Top Congested Flowgate Study(s):** Several mitigation options identified, including one to add a second circuit to the 345 kV line from Erie W to Ashtabula to Perry
30/6164	Plymouth-Sioux City 161kV flo Raun-Sioux City 345kV	IA	611 = 0+139+470+2+0	**Solution(s) identified through annual planning cycles:** Future Midwest ISO flowgate. It was upgraded in early 2008, and was congested only 2 hrs during the 4th Market Year and not congested in 5th Market Year.
31/none	AMCBV158_RIV_RIV_NOFM_1_A	MO	600 = 22+109+68+401+0	**Midwest ISO flowgate: No solution(s) identified:**
32/2934	Sammis_Wylie_Ridge_345_flo_Tidd_Wylie_Ridge_345	OH	597 = 2+0+133+398+64	**Evaluated in Top Congested Flowgate Study(s):** Several mitigation options identified, including one to add a second circuit to the 345 kV line from Erie W to Ashtabula to Perry

Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
33/3250	15502_Nels_EJ_for_15616_Cher_Silv	IL	579 = 17+1+55+160+346	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate.
34/3102	Bland–Franks 345 kV	MO	553 = 347+206+0+0+0	**Solution(s) identified through annual planning cycles:** No congestion since Callaway-Franks line ISD 2006; See chart in Appendix F2
35/6006	Gerald Gentleman Station	NE	531 = 0+531+0+0+0	**Evaluated in Cross Border Congested Flowgate Study:**
36/3724	Arnold–Vinton 161 kV (flo) Arnold–Hazelton 345 kV	IA	530 = 105+216+135+72+2	**Solution(s) identified through annual planning cycles:** P1340: Build a new Hazleton-Lore-Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer ISD: December 2011and P1739: Reconductor the 161 kV from Arnold-Vinton-Dysart-Washburn, sum rate 446 MVA.
37/6085	Genoa–Coulee 161 kV (flo) Genoa-LaCrosse-Marshland 161 kV	WI	506 = 158+344+4+0+0	**Solution(s) identified through annual planning cycles:** P584: Genoa-Coulee 161 kV rebuild. In Service
38/3812	Indian_LakXF_T2_flo_Indian_LakeXF_T1	MI	502 = 0+0+0+233+269	**Evaluated in Top Congested Flowgate Study(s):** Proposed mitigation identified includes a new 138 kV line from Indian Lake to Hiawatha and P2846 (Straits controller).
39/3186	West Mt. Vernon–E W Frankfort 345 kV	IL	489 = 188+12+119+156+14	**Solution(s) identified through annual planning cycles:** P739: The Franklin County plant interconnection includes a 345 kV switchyard and "in and out" connection to the Mt. Vernon-E W Frankfort 345 kV line. Detailed design changes that may mitigate impact on flowgate, are TBD.
40/140	Elrama_Mitchell_138kV_flo_Ft_Martin_Ronco_500kV	PA	473 = 72+12+382+7+0	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate

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Table 8.2-1: Flowgates Congested More Than 1% (with Correlation to Expansion Projects)

Post -MKT Rank/ NERC ID	FLOWGATE Name/Description	State	Post-MKT Congested Hours and itemized for 1st, 2nd, 3rd, 4th, & 5th Year	Status
41/2131	Wylie Ridge-Sammis 345 kV line	VA	472 = 40+41+15+369+7	**Evaluated in Top Congested Flowgate Study(s):** Several mitigation options identified, including one to add a second circuit to the 345 kV line from Erie W to Ashtabula to Perry
42/102	Kammer #200 765/500-kV xfmr l/o Belmont 765/500-kV xfmr	VA	459 = 0+0+0+15+444	**Coordinated flowgate: No solution(s) identified:** Not Midwest ISO flowgate
43/3532	Ellington_Hintz_138_flo_NAppleton_WernerWest_345	WI	443 = 0+86+286+71+0	**Solution(s) identified through annual planning cycles:** Uprates of Ellington–Hintz 138 kV line (completed August 2007 and May 2008) and commercial operation of Weston 4 (June 2008) have helped reduce congestion on this FG. Also, the now-completed P177: Gardner Park-Highway 22 345 kV line and P345: Morgan-Werner West 345 kV line will assist.
44/291	Pierce B 345/138 kV transformer l/o Pierce-Foster 345 kV	OH	436 = 4+31+393+8+0	**Solution(s) identified through annual planning cycles:** P625: Add a third transformer rated 400 MVA.

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8.2.4 TLR and Bound Activity

The nine (9) Transmission Loading Relief (TLR) levels are listed in Table 8.2-2, below.

Table 8.2-2: TLR Level Description

TLR Level	Description/Course of Action
Level 0:	Normal operation (accounting for those transactions defaulted to zero MW due to improper Tag information)
Level 1:	Notify Reliability Coordinators of potential operating security limit violations.
Level 2:	Hold interchange transactions at current levels to prevent operating security limit violations.
Level 3a:	Curtail transactions using Non-firm Point-to-Point transmission service to allow transactions using higher priority Point-to-Point transmission service and to mitigate anticipated operating security limit violations.
Level 3b:	Curtail transactions using Non-firm Point-to-Point transmission service to mitigate actual or anticipated operating security limit violations.
Level 4:	Reconfigure transmission system to allow transactions using Firm Point-to-Point transmission service to continue.
Level 5a:	Curtail transactions (pro rata) using Firm Point-to-Point Transmission Service to allow new transactions using Firm Point-to-Point Transmission Service to begin (pro rata) and to mitigate anticipated operating security limit violations.
Level 5b:	Curtail transactions using Firm Point-to-Point transmission service to mitigate actual or anticipated operating security limit violations.
Level 6:	Perform emergency action.

Figures and other summaries referencing the term ‘TLR’ in this document are inclusive of TLR levels ranging from Level 3a to Level 6. This TLR range and the binding of elements by the RT Midwest ISO Market represent actual observed flows on the system whereas lower levels of TLR and Day Ahead (DA) Midwest ISO market operations are reflective of actions in anticipation of high flows. Most flow reductions obtained through TLR are achieved in the range of Levels 3a–4; flow relief seldom requires Level 5 schedule reductions or higher.

Refer to Figure 8.2-1, which depicts the sum of monthly flowgate (FG) congestion hours and the relative method of managing congestion since January 2001 through March 2010. Note the exclusive use of Transmission Loading Relief (TLR) for congestion management in the pre-Midwest ISO market period while the post-Midwest ISO market period utilizes both TLR and bound constraints in the LMP central dispatch. The legend terms in Figure 8.2-1 denote the following:

- **Bound Only** refers to flowgate congested hours managed through re-dispatch by adjusting LMP prices without TLR assistance.
- **TLR Only** refers to the flowgate congested hours exclusively managed by the NERC TLR process.
- **Bound and TLR** refers to flowgate congested hours in which TLR and Bound re-dispatch were employed concurrently.

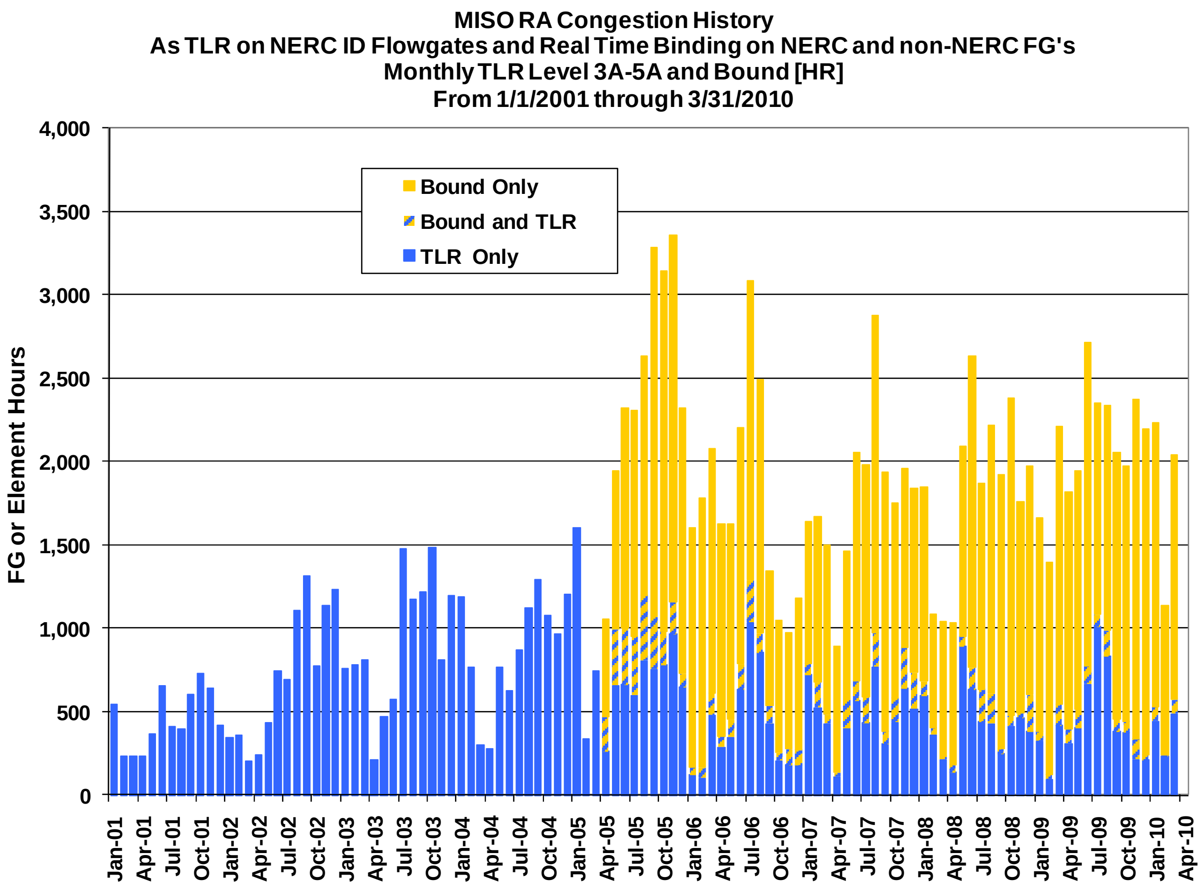


Figure 8.2-1: Overview History of Midwest ISO Congestion and Method

For the post-market period, Figure 8.2-2 shows itemization by TLR Level for hours affected exclusively or in part by TLR. The "Bound Only" portions in Figure 8.2-2 are identical to the post-market "Bound Only" portions plotted in Figure 8.2-1.

As shown in Figures 8.2-1 and 8.2-2, the first six months of the Midwest ISO market (April 1, 2005 through September 30, 2005) had higher levels of congestion activity than the latter time periods. Market analysis has shown the predominant factor was a lag in business activity between the Midwest ISO market footprint and bordering non-Midwest ISO market participant areas. In effect, the two adjoining groups, Midwest ISO and non-Midwest ISO, tended to conduct business as segregated systems. After the first six months, congestion activity was reduced as familiarity increased with new systems and business practices permitting transactions into and out of the Midwest ISO market.

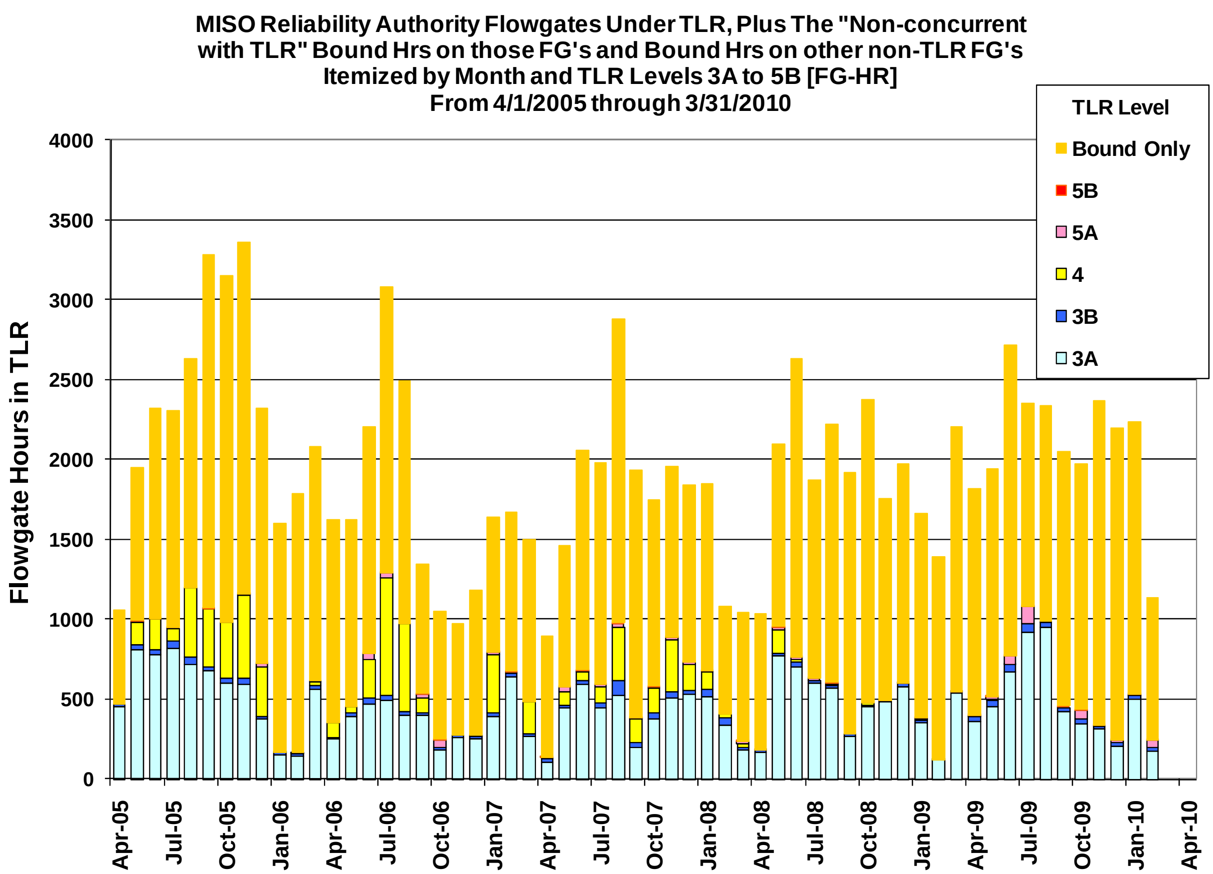


Figure 8.2-2: Overview History with TLR Affected Hours Itemized by TLR Level

Figure 8.2-3 itemizes the top 44 flowgates (FGs) by total hours exclusively bound and hours at each TLR Level (3a–5b). Approximately half of the congestion experienced by the top 44 flowgates is due to flowgates **not** under the direct influence of the Midwest ISO Planning Authority (PA). Refer to Table 8.2-2 on the previous page, which identifies the specifically ranked flowgate on the X-axis of Figure 8.2-3, below.

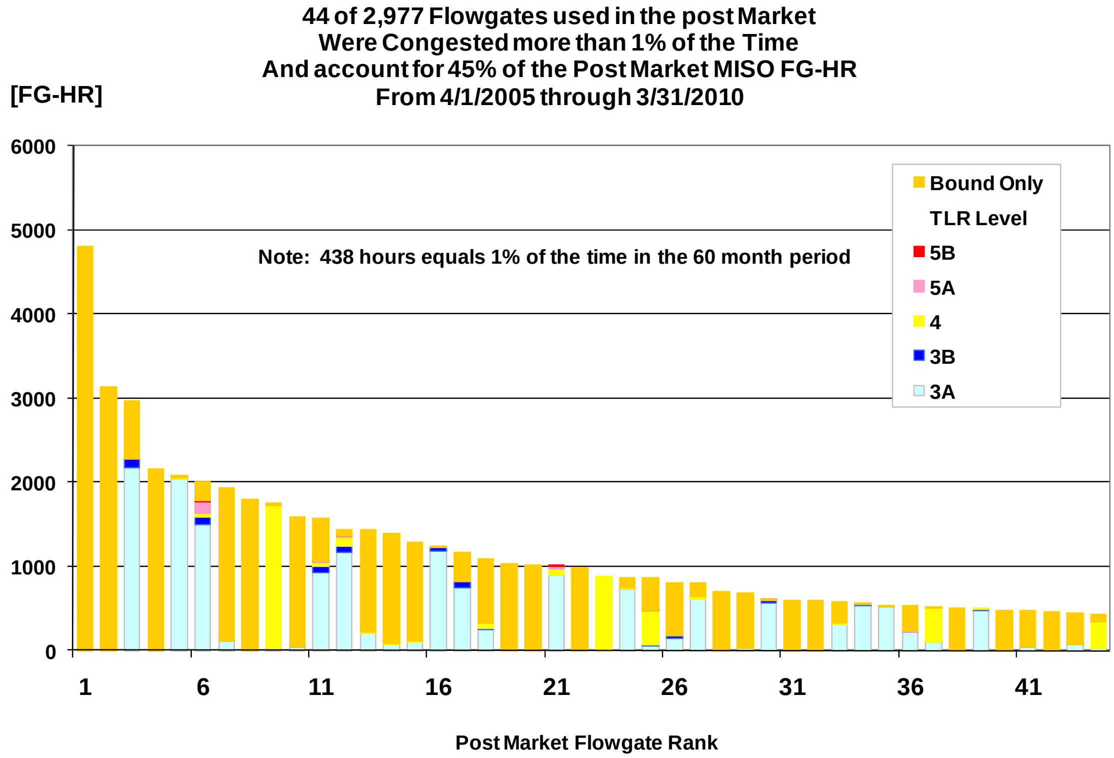


Figure 8.2-3: Top 44 Most Congested Post Market FGs

Figure 8.2-4 on the following page offers an accompanying bar chart to illustrate the volatility of flowgate activity. The bar portion depicts the corresponding median rank of each flowgate over the past five years. Note that flowgates with persistently high ranks high have respective median values oriented more to the left of the chart. The total length of the bars in a given row offers context, and indicates the level of flowgate volatility about its median. The median of annual rankings method tends to discount the impact of individual flowgates with an extremely low or high rank in one year. The label on the vertical axis in Figure 8.2-4 identifies FG NERC ID number, FG Name or Description, and ranking on the basis of total post Midwest ISO FG-Hr.

Information in Figure 8.2-4 is gleaned by row. For example, the third row of bars depicted in Figure 8.2-4 denotes FG # 3006 EAU CLAIRE-ARPIN 345 kV, in Wisconsin. The third row signifies that this flowgate has the third highest congestion hours in the total 5 year post market period. In addition:

- Supporting historical congestion data shows 1st, 2nd, 3rd, 4th, and 5th individual year rankings were respectively 3, 17, 4, 14, and 116, where:
  - Highest Annual Ranking = 3, Median = 14, Lowest Annual Ranking = 116

Itemized monthly congestion histories for each of the 25 top flowgates are shown in Appendix G2. Appendix G2—Appendix_G2_Congestion_History_072110.pdf—is a compendium of additional individual flowgate histories containing Figures 8.2-6 through 8.2-9 and other charts, including the lookup table Appendix_G2_Congestion_Summary_072110.xls, a spreadsheet displaying the hours congested on each of 3,200 flowgates since January, 2001.

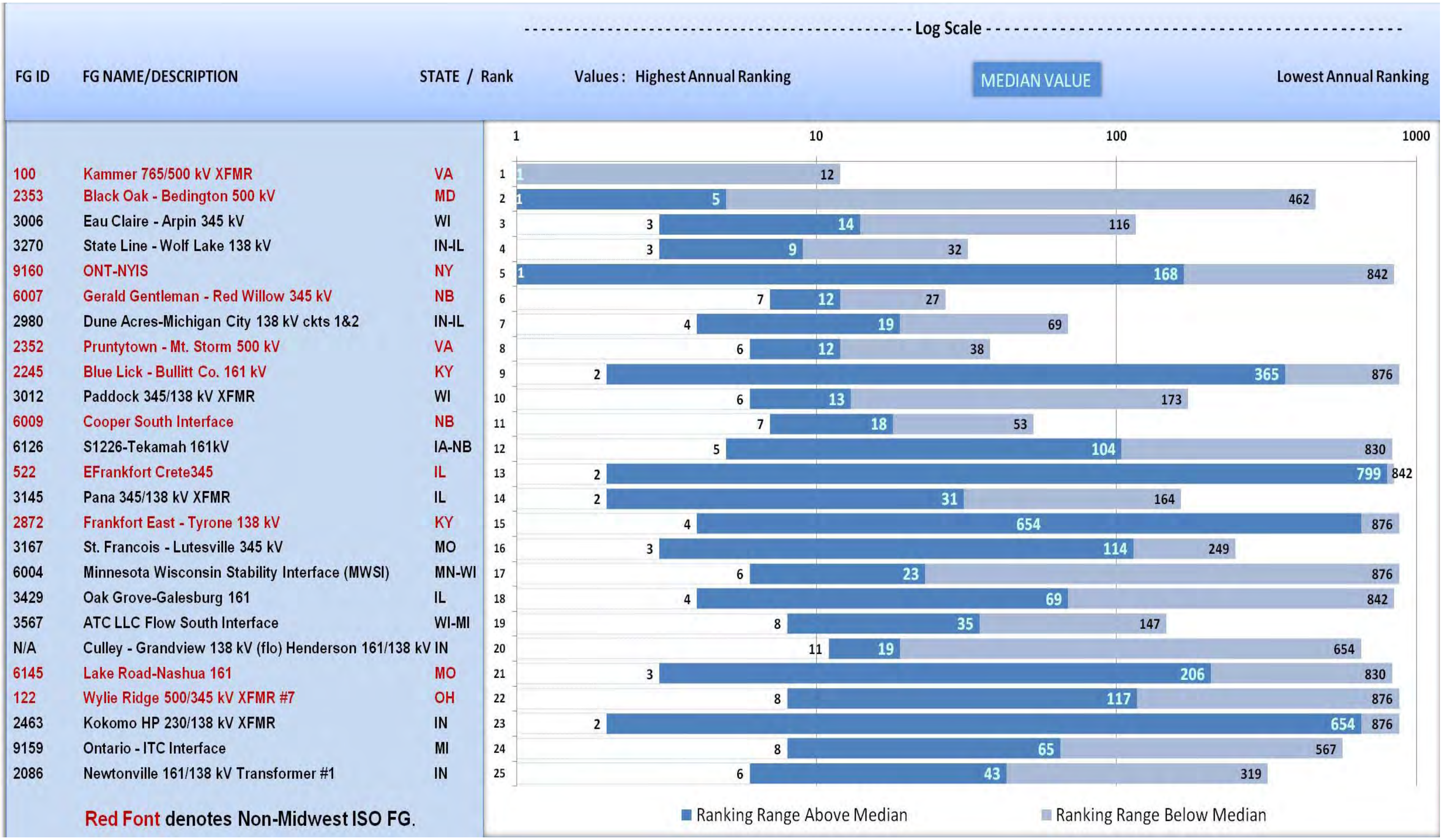
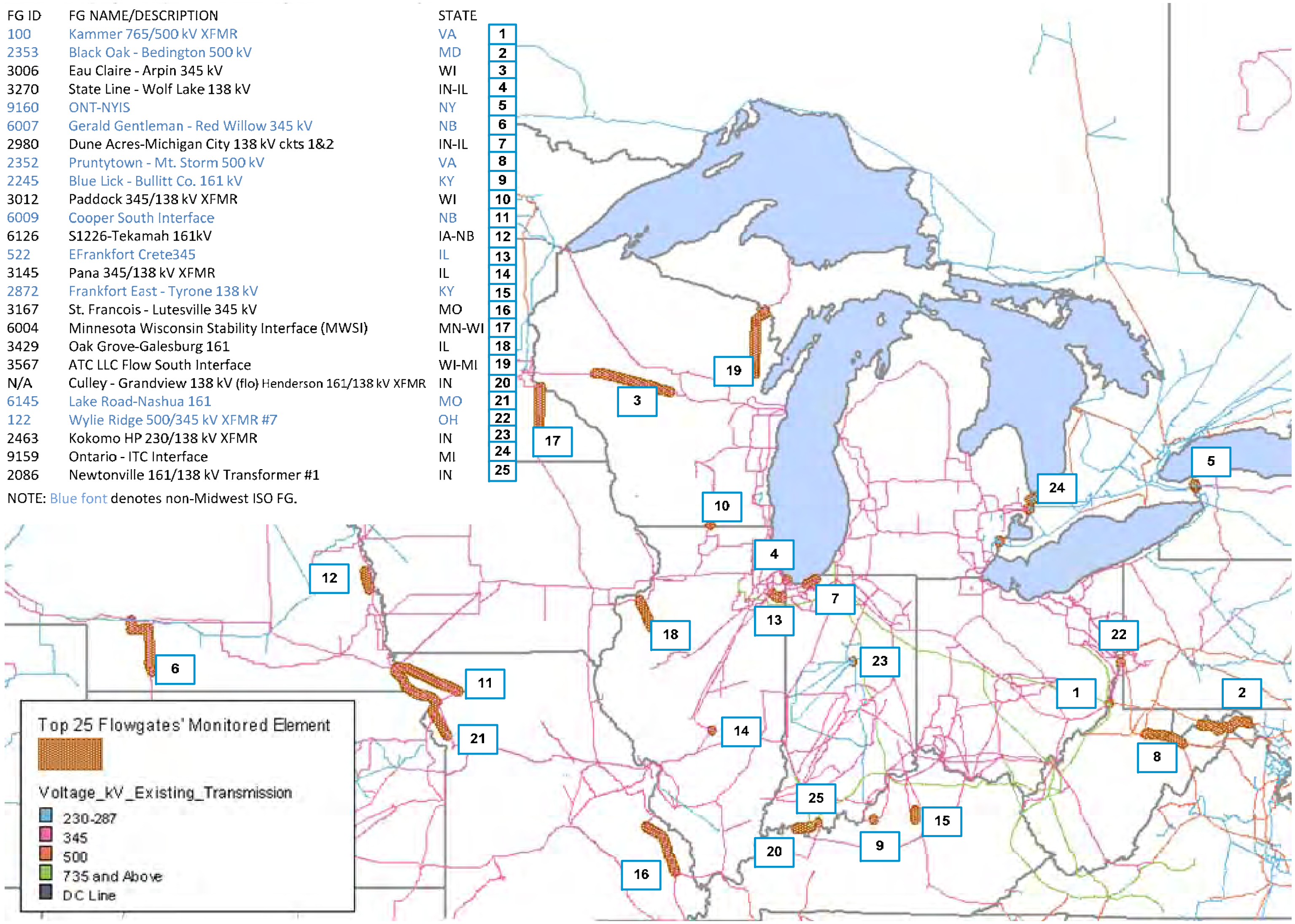


Figure 8.2-4: Top 25 Most Congested Flowgates Based on Median Rank–All Five (5) Market Years

MidwestISO Energizing the Heartland

Refer to Figure 8.2-5, which depicts the general geographic location of the Top 25 most congested post Midwest ISO market flowgates (FGs).



FG ID	FG NAME/DESCRIPTION	STATE	
100	Kammer 765/500 kV XFMR	VA	1
2353	Black Oak - Bedington 500 kV	MD	2
3006	Eau Claire - Arpin 345 kV	WI	3
3270	State Line - Wolf Lake 138 kV	IN-IL	4
9160	ONT-NYIS	NY	5
6007	Gerald Gentleman - Red Willow 345 kV	NB	6
2980	Dune Acres-Michigan City 138 kV ckts 1&2	IN-IL	7
2352	Pruntytown - Mt. Storm 500 kV	VA	8
2245	Blue Lick - Bullitt Co. 161 kV	KY	9
3012	Paddock 345/138 kV XFMR	WI	10
6009	Cooper South Interface	NB	11
6126	S1226-Tekamah 161kV	IA-NB	12
522	EFrankfort Crete345	IL	13
3145	Pana 345/138 kV XFMR	IL	14
2872	Frankfort East - Tyrone 138 kV	KY	15
3167	St. Francois - Lutesville 345 kV	MO	16
6004	Minnesota Wisconsin Stability Interface (MWSI)	MN-WI	17
3429	Oak Grove-Galesburg 161	IL	18
3567	ATC LLC Flow South Interface	WI-MI	19
N/A	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	IN	20
6145	Lake Road-Nashua 161	MO	21
122	Wylie Ridge 500/345 kV XFMR #7	OH	22
2463	Kokomo HP 230/138 kV XFMR	IN	23
9159	Ontario - ITC Interface	MI	24
2086	Newtonville 161/138 kV Transformer #1	IN	25

NOTE: Blue font denotes non-Midwest ISO FG.

Figure 8.2-5: Location of the Top 25 Most Congested Post-market Flowgates

8.3 Potential Resource Deliverability Risks

The 2010 Loss of Load Expectation (LOLE) Study Report is the second annual Midwest ISO report documenting results of the study to determine the reliability-driven Planning Reserve Margin Requirement (PRM). Given the context of historical congestion and the already planned facilities incorporated into future network models (primarily those facilities listed and described in MTEP Appendices A and B), this section offers an overview of future congestion relative to the ability to share generation reserves throughout the Midwest ISO market area.

- The LOLE Study Report determined the Resource Adequacy Requirement (RAR) for the Planning Year (PY) 2010, and provided an indication of planning reserve requirements to 2019. For a given future year, the LOLE Study Report includes the appropriate future facilities from MTEP Appendices A and B that have in-service dates through the given year.
- The LOLE Study is repeated annually, with each iteration of the LOLE Study Report providing results for the next ten (10) years. Thus, the first Planning Year of an annual LOLE Study Report will always include an up-to-date complement of transmission plans as new projects are approved. The full study methodology was implemented for 2010, 2014 and 2019, and interpolation techniques were applied to intervening years in order to provide an estimate for all years. The assessment included transmission system modeling so that any limitations to the sharing of generator reserves would be recognized in the process.
- According to the 2010 LOLE Study Report, the system is reliable in all years studied and meets loss of load expectation standards. The LOLE Study Report also quantified estimates for additional PRM needed because the transmission system does not provide unlimited transfer capability. The major factors driving PRM are outage rates of generation and uncertainty of load. Only 0.4 % of the 15.4% PRM is due to internal congestion.

Table 8.3-1 is derived from the 2010 LOLE Study Report and shows the Planning Reserve Margin (PRM) found necessary to maintain the reliability standard Loss of Load Expectation of less than one (1) day in ten (10) years. Table 8.3-1 also shows the total LOLE itemized by the impact of transmission congestion (designated as Congestion Contribution). Results show the congestion contribution to the $PRM_{SYSIGEN}$ starts at 0.4% and significantly increases for the first half of the 10-year period before decreasing in 2019 to 0.9%, which is half of its peak value in 2014 (1.8%). This change in congestion can be attributed to the change in size of the export limited system (shown by the blue areas in Figures 8.3-2 and 8.3-3). The export zones (blue zones) for 2014 cover both a larger geographical area and contain more capacity and load than the single export zone for 2019. The expectation congestion will improve at a future date is consistent with future transmission expansion plans, where a group of upgrades is scheduled in the West Region of Midwest ISO. As 2019 results indicate, decreasing congestion serves to lower overall PRM.

Table 8.3-1: Expected $PRM_{SYSIGEN}$ for 2010-2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PRM_{SYSGEN} (Results Ignoring Congestion)	**15.0%**	14.9%	14.9%	14.8%	**14.7%**	14.6%	14.4%	14.3%	14.1%	**14.0%**
PRM_{SYSGEN} (Congestion Contribution)	**0.4%**	0.8%	1.1%	1.5%	**1.8%**	1.6%	1.4%	1.3%	1.1%	**0.9%**
PRM_{SYSGEN} (Accounting for Congestion)	**15.4%**	15.7%	16.0%	16.2%	**16.5%**	16.2%	15.9%	15.5%	15.2%	**14.9%**

By comparing 2010 LOLE Study Report results with those obtained in the 2009 LOLE Study Report, it can be seen congestion drove the Congestion Contributor to the PRM from 0.6% in 2009 to 2.3 % by 2018. That corresponded to approximately 675 MW of bottled-up generation, which would not be able to effectively serve the aggregate load during peak times. The 2010 LOLE Study Report shows 443 MW of bottled-up generation, which corresponds to the 0.4% Congestion Contributor to the PRM for congestion in 2010. Refer to Figure 8.3-1, which depicts a comparison of results obtained from both 2009 and 2010 LOLE Study Reports.

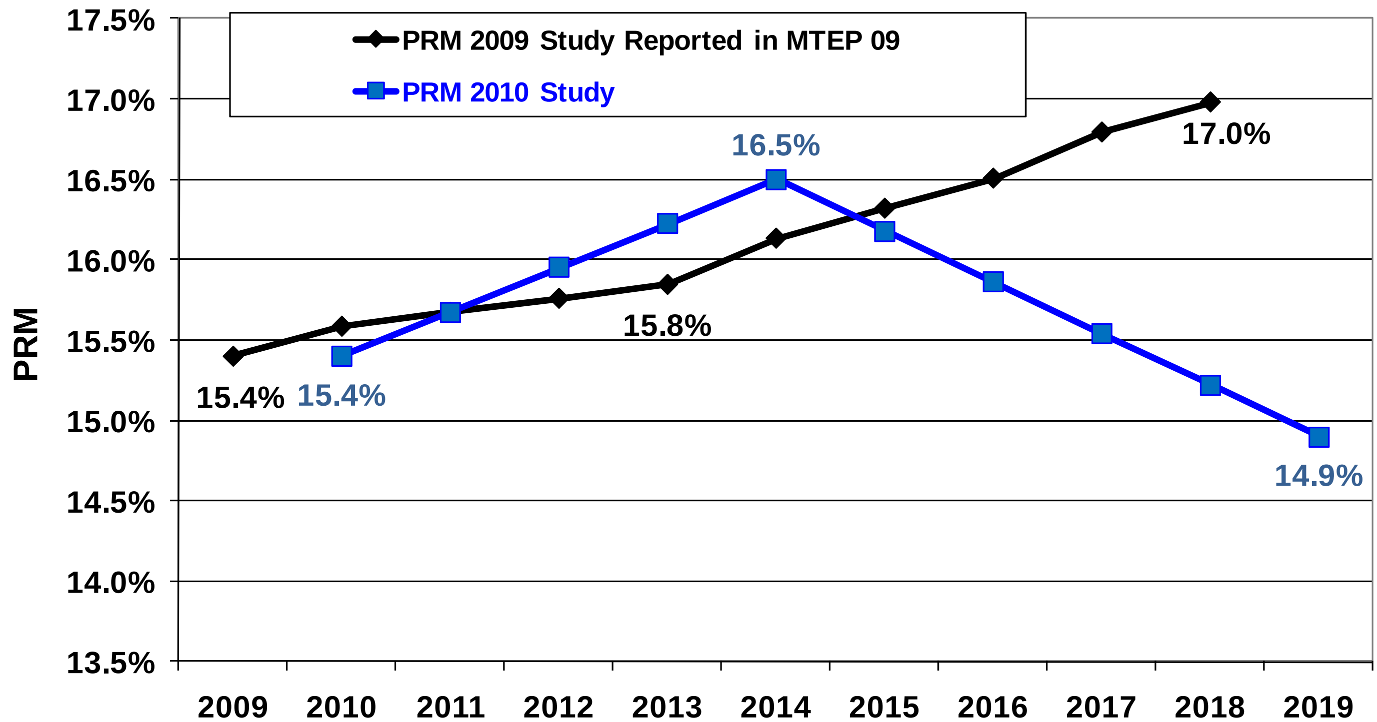


Figure 8.3–1: Multiple-year PRM Comparison: 2009 LOLE Study Results v. 2010 LOLE Study Results

Since the LOLE process incorporates the current outlook for planned transmission facilities, identifying those transmission plans which may reduce the future congestion levels becomes a targeted task for future MTEP studies. Although adequate reserve is a reliability-driven metric, the solution has obvious economic aspects. Since either generation or transmission could be added to the system in order to maintain needed reliability, the desired balance between new generation and transmission additions will be affected by the cost of the additional amount of generation or additional transmission. Further, while Midwest ISO has authority to plan and commit required transmission facilities, it will be highly important to convey information pinpointing the most effective generation locations to generation entities. The generation interconnection process (and its associated study process) is one means of disseminating this information, along with the general MTEP transmission planning cycle.

Refer to Figure 8.3-2.

- Blue areas in Figure 8.3-2 (and Figure 8.3-3 on the following page) indicate areas where the full rating of generation is statistically not deliverable to the aggregate of the Midwest ISO market area on a reliability basis during summer peak load times. The legend phrase "Always 0 or Negative" refers to the Marginal Congestion Component (MCC) of the LMP. Within the specific steps outlined in the LOLE Study Report, negative MCC value means congestion throughout the system *always* impacted the blue areas by re-dispatching generation to a lower level during peak load times. This means the full amount of capacity was not always deliverable to the balance of the system, thus demonstrating that some amount of generation was bottled-up and was not reliable to count toward the PRM requirement. Compared to a theoretical transmission system free of congestion, blue areas represent a shortfall in effectively sharing approximately 443 MW of installed capacity in 2010 (down from 695 MW bottled-up in 2009). For 2010 and 2011, PRM is affected upward by flows being limited out of Minnesota to the south and east (Byron-Pleasant Valley 345, Silver Lake-Rochester 161), and from SE Wisconsin into ComEd (Pleasant Prairie-Zion 345[57]).
- Red areas are locations where the LOLE Study Report addressed specific tests conducted to determine if load might not be reliably served even when there is adequate generation supply throughout the Midwest ISO. In all years, the tests revealed that load in red areas could be reliably served and meets the reliability criteria.
- Yellow areas indicate those utilized in the detailed study process and are included here to communicate the location of areas found not to have bottled up generation or for which internal load needed to be tested to confirm load is served reliably.

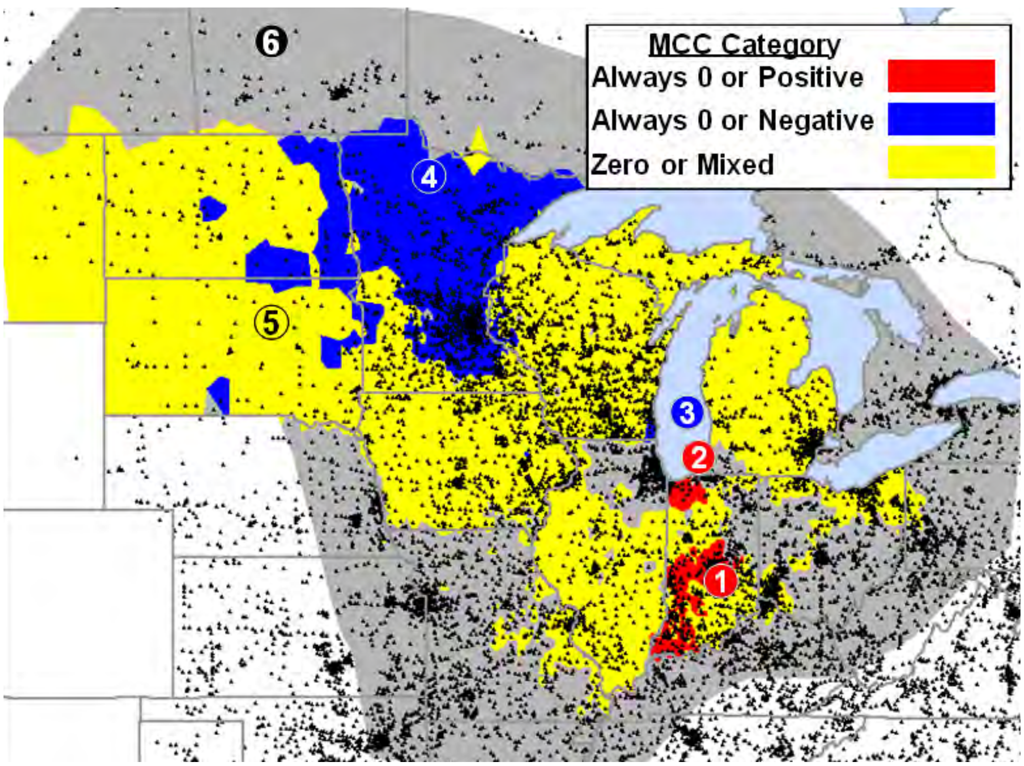


Figure 8.3-2: Congestion-based Zones Modeled in 2010

[57] Pleasant Prairie-Zion 345kV is a tie line between ATC (Midwest ISO) and ComEd (PJM). Existing Pleasant Prairie-Zion 345kV rating is based on a wave trap limitation on the ComEd facilities within PJM. Since the period during which LOLE simulations were conducted, ATC has reviewed and confirmed higher ratings on the ATC portion of the line and is working with ComEd to upgrade the wave trap and related terminal facilities on an expedited schedule. ATC has submitted P3188 to the MTEP database to track the upgrade of the line ratings on the non- Midwest ISO facilities.

Figure 8.3-3 indicates the areas where (in 2014) the full rating of generation is not statistically deliverable to the aggregate of the Midwest ISO market on a reliability basis during summer peak load times.

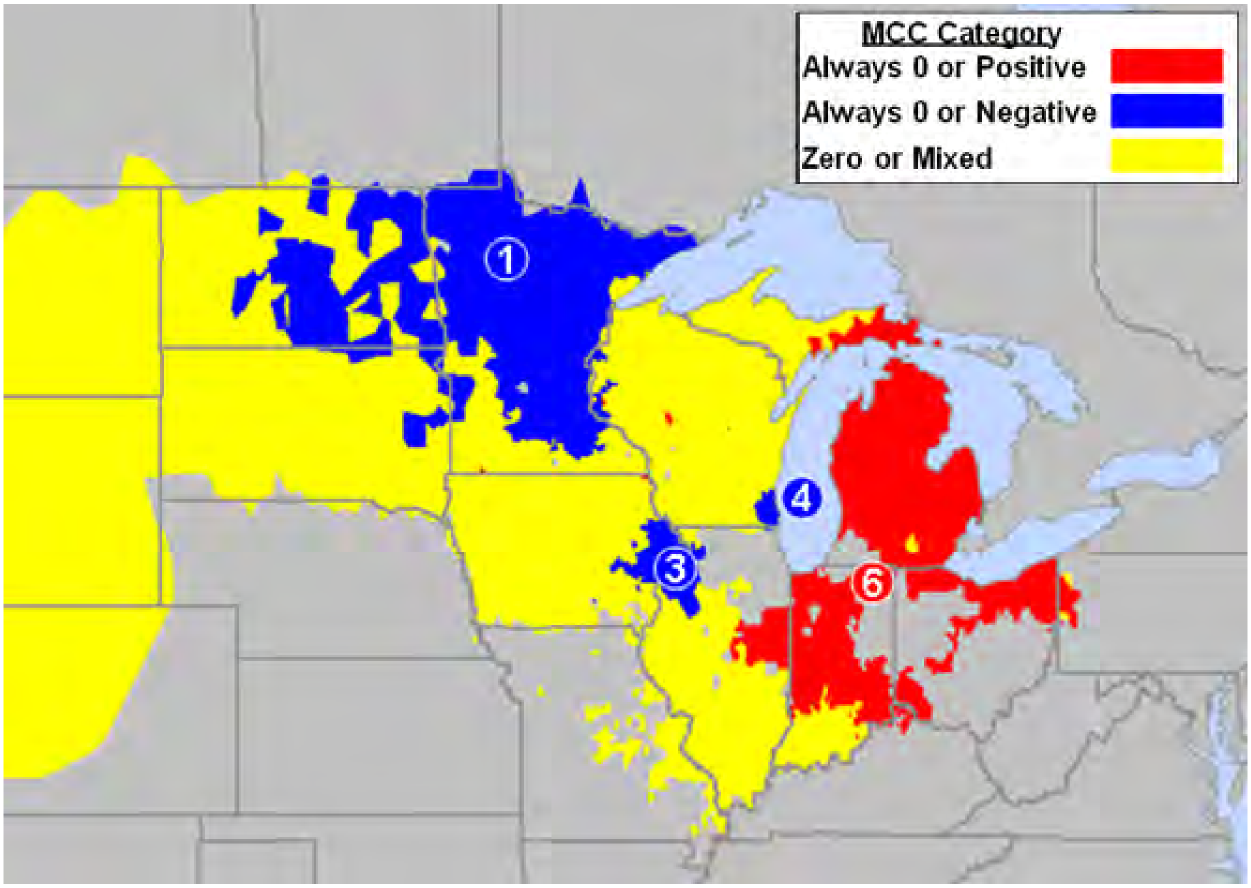


Figure 8.3-3: Congestion-based Zones Modeled in 2014

Figure 8.3-4 indicates the areas where (in 2019) the full rating of generation is not statistically deliverable to the aggregate of the Midwest ISO market on a reliability basis during summer peak load times. The change in reduced blue areas between Figure 8.3-3 and Figure 8.3-4 reflects the effect of the same Midwest ISO West transmission additions that cause the 2010 LOLE Study Report curve in Figure 8.3-1 to fall below the 2009 Study Report curve in the second half of the study period years. 2014 congestion issues remain identical to those issues encountered in 2010 and 2011. Transmission upgrades coming into service between 2010 and 2014 had little effect, or may even have exacerbated congestion.

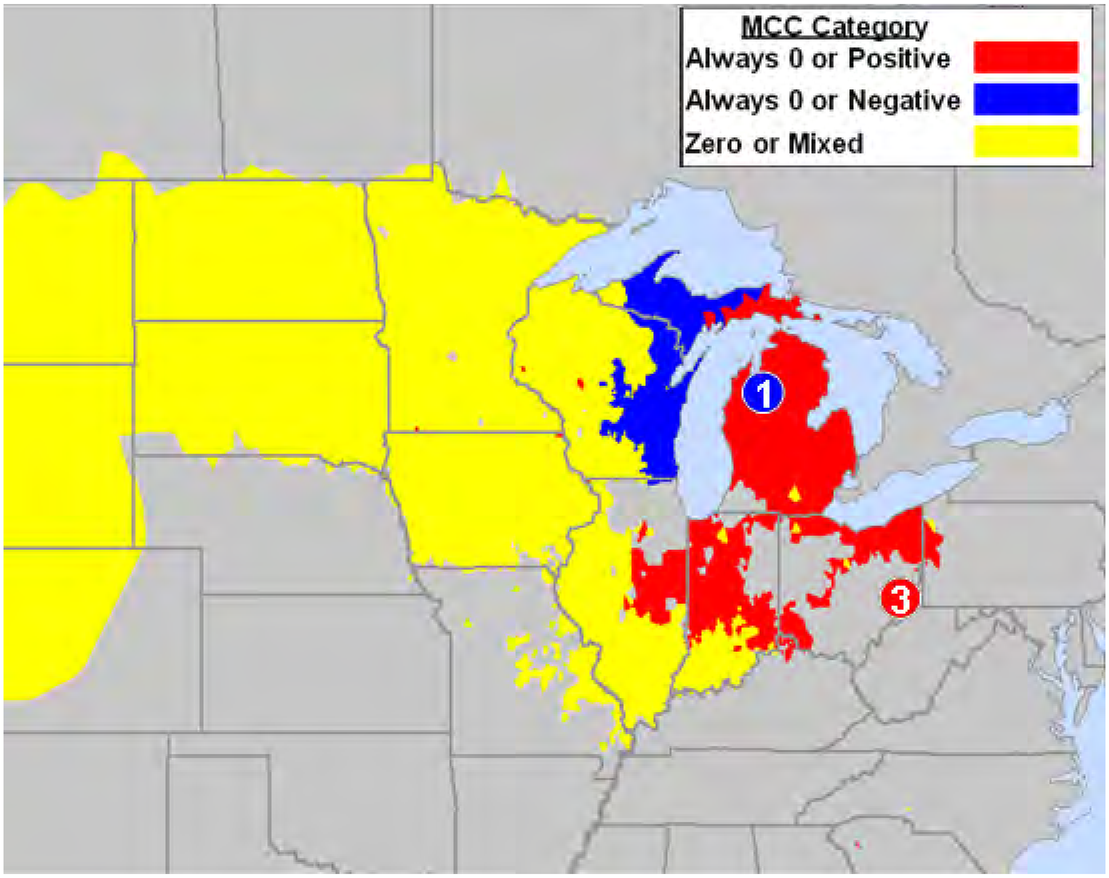


Figure 8.3-4: Congestion-based Zones Modeled in 2019

In each of the three (3) fully calculated years, new generation additions and planned transmission additions were modeled. The large blue area in Midwest ISO West in 2010 is not sustained in 2019 largely because estimated load growth in Midwest ISO West is greater than the amount of generation expected to be added during the nine-year projection period. In addition, notable transmission additions are expected to be made in Midwest ISO West. The remaining blue areas may be caused in part by constraints outside Midwest ISO, making coordination and associated cost sharing over a large area a likely emerging issue. For 2019, CapX 2020 additions, including the Hampton-Rochester-La Crosse 345 kV transmission project and the Brookings County-Twin Cities 345 kV project, relieve the Minnesota trapped generation identified in the 2010 and 2014 models. Congestion in SE Wisconsin expands geographically to all of eastern Wisconsin and the Upper Peninsula of Michigan. Note the timing of these LOLE study results does not account for recent efforts underway to upgrade non-Midwest ISO ratings limitations on the Pleasant Prairie-Zion 345kV line. Those upgrades are expected to be completed in the near-term and would be in effect for the 2014 and 2019 years of this analysis. Constraints along the eastern Wisconsin-Illinois border continue to drive generation redispatch in Eastern Wisconsin. This same effect observed in progressive degrees in 2010, 2014, and 2019 simulations has also been realized in real-time (RT) operations.

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8.4 Midwest ISO Top Congested Flowgate Study

The Midwest ISO Top Congested Flowgate Study (MTCFS) is an annual process in its third year. Originating in MTEP08, the purpose of the MTCFS was to identify highly congested flowgates within the Midwest ISO Market Footprint and determine the best-fit plans to mitigate both historical and future congestion on an economic basis. Mitigation plans that were determined to be economically beneficial beyond the Energy Market Tariff's established threshold were recommended to the MTEP Appendix A or B under RECB II and mitigation plans were also eligible for self-funding. MTEP Appendix A, B, and C are defined in section 2.2. Because MTCFS transmission projects are flowgate specific and primarily or even exclusively beneficial to local members, if a project was designated eligible for cost sharing it was tested under RECB II rather than Multi-Value Project (MVP) criteria. The MTCFS utilized an annual economic production cost model to calculate the potential economic benefits of each transmission project, focusing. solely on Midwest ISO market flowgates and mitigation plans within the market footprint. A complementary Cross Border Coordinated Congested Flowgate Study was initiated in 2010 to study flowgates on the seams, described in greater detail in section 8.4.

The 2010 MTCFS was presented with a unique challenge: to bridge the gap between operational planning/analysis and large-scale economic overlay planning. While historical operations information is has been established, there are multiple alternative directions that can be taken regarding a transmission overlay. Currently, there are multiple simultaneous efforts underway to produce an optimal means of integrating high amounts of wind energy into the Midwest ISO system, including the RGOS (Section 9.1), Green Power Express, Strategic Midwest Area Transmission Study (SMART), and MEGA-GONZO. The construction of any one of these plans has the potential to drastically change congestion patterns, but there is no certainty any one of the proposed overlay schemas will be adopted. Meanwhile, transmission planning efforts such as the MTCFS are necessary to ensure reliability and market efficiency. Further complicating matters within the 2010 MTCFS was uncertainty regarding the new cost allocation methodology. In the 2010 MTCFS, every effort was made to ensure proposed transmission projects did not compete with proposed transmission overlays discussed previously. Care was taken to create proposed solutions that were complementary and beneficial to the Midwest ISO market under a wide variety of potential economic and policy outcomes.

The MTCFS was open to all stakeholders and interested parties. A stakeholder Technical Review Group (TRG) was an integral part of the study and was involved in all decisions and discussions. The TRG originated nearly all flowgate mitigation plans and provided input and model verifications. Top congested flowgates were identified using three (3) separate data sources:

- Midwest ISO Real-Time Operations
- Midwest ISO Day-Ahead Market
- 2015 Production Cost Models

Multiple future scenarios were used within the production cost model congestion identification to quantify how economic, public policy, and transmission overlay decisions would affect future transmission congestion. From all these data sources, the TRG identified eight (8) flowgates for further analysis. Three (3) of the eight (8) top congested flowgates identified were associated with transmission placed into Appendix B through the 2009 MTCFS study effort. Through numerous meetings, multiple transmission mitigation plans were developed for each top congested flowgate. All proposed mitigation plans were evaluated using 2015, 2020, and 2025 Reference Case production cost models. An eleven (11) year total net present value (NPV) benefit was calculated by linear interpolation of three (3) years of data and then tested against the RECB II economic benefits criteria. Transmission plans associated with the three 2009 MTCFS Appendix B projects were further analyzed with the five (5) future scenarios developed through the Planning Advisory Committee (PAC). Using the PAC developed scenario probability weighting, a combined benefit to cost ratio was calculated.

Throughout the 2010 MTCFS, a total of forty-nine different mitigation plans were proposed and studied. The MTCFS used an iterative process to refine many of the projects. Over 600 production cost simulations were performed, totaling over 33,000 hours of computation time. (Please note only final results are included in this report unless results are specifically designated as non-final.) Through the 2010 MTCFS work, one project was identified as RECB II-eligible: upgrading the Wheatland–Breed 345kV line to 1,386 MVA and closing the Wheatland tie breaker to mitigate the congestion on the Wheatland–Breed 345kV flowgate. This mitigation plan met all MTEP Appendix A economic requirements. At the direction of the TRG, this project will remain in MTEP Appendix B at this time. This flowgate will continue to be studied in future MTCFS to determine if this mitigation plan or one of the alternatives is the best-fit plan while considering the MTEP11 Candidate MVP analysis and the future cost allocation tariff. Midwest ISO will perform reliability analysis on closing the Wheatland tie-breaker as part of MTEP11. The 2010 MTCFS also yielded numerous projects that meet RECB II B/C thresholds but were under cost or voltage requirements. Generally, potential benefits delineated in the 2010 MTCFS were demonstrably lower than those reported through the 2009 MTCFS, the result of a decreased load forecast and (partial) mitigation plans in place for many of the most severe system constraints. While no projects moved forward through the MTEP Appendices, the results provide valuable insight to market participants. Each of the plans studied in the 2010 MTCFS will have an opportunity to be studied in future MTCFS, and many will be evaluated in the MTEP11 Candidate MVP portfolio analysis.

8.4.1 Background–2009 MTCFS

The 2009 MTCFS was the first in-depth study to attempt to bridge the gap between market/operational analysis and economic planning. Production cost models in previous MTEP reports were primarily used for larger scale transmission overlay analysis. The purpose of the 2009 MTCFS was to identify highly congested flowgates within the Midwest ISO market footprint and then to test flowgate-specific transmission mitigation plans under RECB II criteria. The top congested flowgates were identified using two (2) sources: historical Midwest ISO Real-Time operations data and a 2014 MTEP09 reference case production cost model. After considering the congestion data from these two (2) sources, the TRG identified fourteen (14) flowgates for further analysis. Multiple TRG recommended mitigation plans for each flowgate were evaluated using a 2014 case. Transmission projects that showed the potential to exceed the RECB II criteria were further analyzed via 2019 and 2024 production cost models. Through the 2009 MTCFS work, three projects qualified for MTEP Appendix B: Rising–Sidney 345kV, Lakefield Junction–Rutland 345kV, and Bloomington–Hanna 345kV. No reliability analysis was performed on these three (3) projects.

The 2009 MTCFS was the first study to recommend economically based, flowgate-specific transmission projects to MTEP Appendix B. However, during the course of the 2009 MTCFS there were several recommended analyses Midwest ISO was not able to perform due to time and computational constraints. The TRG identified several areas of improvement for future Top Congested Flowgate Studies:

- Mitigate the effect of Midwest ISO forecast (RRF) generation units on potential economic benefits or congestion rankings.
- Projects not meeting RECB II criteria should continue to be analyzed for all years for both regulatory permitting and self-funding purposes.
- Additional sources of information should be used to identify and rank the top congested flowgates.

Because of the 2009 TRG recommendations and concurrent Midwest ISO study work, the 2010 MTCFS features some notable scope changes in comparison to the 2009 study. First, the purpose of the study has changed from finding RECB II-eligible transmission mitigation plans to finding the best-fit transmission mitigation plan, which may be either RECB II-eligible or market participant self-funded. Identifying the 2010 top congested flowgates required not only the utilization of an updated version of the 2009 MTCFS sources, but also Day-Ahead market data and multiple production cost futures. In the 2010 MTCFS, all mitigation plans were analyzed using 2015, 2020, and 2025 production cost models.

Throughout MTEP10, an emphasis was placed on utilizing multiple future scenarios in production cost models. These futures not only allowed Midwest ISO to calculate a range of possible economic benefits or a “risk bandwidth” over a variety of economic and public policy outcomes, but also—when combined—decreased the effects of inaccuracies in the forecasted generation included in the study. A total of five (5) future scenarios were utilized in identifying top congested flowgates and determining the potential economic benefits of possible mitigation plans.

8.4.2 MTCFS Model Development

Midwest ISO used PROMOD IV® as the primary tool to evaluate the economic benefits of the potential transmission upgrade options in the MTCFS.

To account for different possible future economic conditions or public policy decisions, such as a federal renewable portfolio standard (RPS) or carbon emission regulations, Midwest ISO used multiple scenarios. In MTEP10, five (5) future scenarios developed through state regulatory and stakeholder groups were analyzed, which provided Midwest ISO with a multi-dimensional forecast. While it is unlikely any one of these futures will exactly match economic conditions ten to twenty years from now, there is a high degree of confidence that future conditions will be within the bounds created by the set of these scenarios. Utilizing multiple futures allows Midwest ISO to find projects that are not only beneficial under one possible future scenario but are robust enough to be beneficial across multiple outcomes. Section 7.2 Generation Futures Development and Appendix E1 contain details on each future scenario.

To ensure out-year regional reserve requirements were met, Regional Resource Forecast (RRF) units were added to the production cost models. These forecasted units were added using a least-cost capacity expansion methodology through an open stakeholder process. The location of RRF units can impact flowgate congestion and thus have an effect on the potential benefits of transmission upgrades. To alleviate these biases, multiple scenarios were utilized, each with a different generation forecast.

MTEP10 developed 2015 and 2020 Power Flow models, and these models are used as the base basis for the MTCFS effort. Because there are no significant transmission topology changes between 2020 and 2025, 2025 production cost models utilize the same transmission topology as 2020.

The PROMOD study footprint included the majority of the Eastern Interconnection excluding ISO-New England, Eastern Canada, and Florida. A total of nine (9) pools were defined in the PROMOD study footprint: Midwest ISO, PJM, SPP, MRO, SERC, TVA, MHEB, NYISO, and IESO. Fixed transactions were modeled to represent the purchases and sales between the study footprint and external regions. MidAmerican Energy Company, Muscatine Power & Water, Dairyland Power Cooperative, and all of Duke Energy Corporation were included in the Midwest ISO pool. First Energy was represented as a member of PJM. East Kentucky Power Cooperative was represented as a member of TVA.

PROMOD utilized an “event file” to provide pre-contingent and post-contingent ratings for monitored transmission lines. The latest *Midwest ISO Book of Flowgates* and *NERC Book of Flowgates* were used to create the event file consisting of the transmission constraints in the hourly security constrained model. Rating and configuration updates from the 2009 MTCFS TRG and concurrent studies were included in the event file.

8.4.3 Benefit/Cost Assumptions and Calculations

A common set of assumptions and formulas were utilized to calculate economic benefits throughout the MTCFS. While there are multiple benefits to transmission projects such as wind curtailment reduction, improved system reliability, decrease line losses, and deferred capacity investment, the MTCFS economic benefits focused solely on Adjusted Production Cost savings and load cost savings.

8.4.3.1 Economic Benefits

To calculate the economic benefit savings for transmission mitigation plans, two (2) cases were defined: a base case and a project case. All aspects of the base case and project case were identical with the exception of the congestion mitigation plan contained within the project case. For each case, Adjusted Production Cost and load cost were calculated, where the Adjusted Production Cost is equal to the combined costs required for a generation fleet to produce energy and then adjusted for import costs and export revenue. As transmission congestion is relieved, there is greater access to less expensive generation, thus causing a decrease in Adjusted Production Cost.

Company Annual Adjusted Production Cost =

$$\sum_{i=1}^{8760}\sum_{j=1}^{M} C_{ij} + \sum_{i=1}^{8760} Load\_Weighted\_LMP_i * Purchase_i - \sum_{i=1}^{8760} Generator\_Weighted\_LMP_i * Sale_i$$

Where:

C_{ij} is the production cost of generator j during hour i.

M is the number of total generators in the company.

$Load\_Weighted\_LMP_i$ is load weighted LMP during hour i.

$Generator\_Weighted\_LMP_i$ is generator weighted LMP during hour i.

$Purchase_i$ is company's MW purchase during hour i.

$Sale_i$ is company's MW sale during hour i.

Load cost is the cost that load serving entities pay to have their load served; it is the MW of load multiplied by the load-weighted Locational Marginal Pricing (LMP). Load cost is representative of the cost of the marginal unit. In a congested system LMPs are highest in areas of high resource deficiency. As congestion is relieved, the LMPs equalize across a pool allowing most loads to pay a decreased cost.

Company Annual Load Cost =

$$\sum_{i=1}^{8760}\sum_{j=1}^{N} LMP_{ij} * L_{ij}$$

Where:

L_{ij} is MW load on bus j during hour i.

LMP_{ij} is LMP at bus j during hour i.

N is the number of total load buses in the company.

Adjusted Production Cost savings and load cost savings were obtained by calculating the difference between the base and project case. The benefit value metric utilized in the 2010 MTCFS was the RECB II benefit which is calculated as follows:

*RECB II Benefit = 70% * Adjusted Production Cost Savings + 30% *Load Cost Savings*

8.4.3.2 Benefit to Cost Ratio

In the 2010 MTCFS, nearly all projects and their associated cost estimates were directly supplied by the TRG. The exceptions were Midwest ISO introduced combinations of various project segments or variations of the supplied projects. For projects without a TRG supplied cost, the cost per mile assumptions shown in Table 8.4-1 developed through the 2009 MTCFS were utilized. The total project cost for projects without a supplied cost included a 25% adder to approximate the costs of substations, transformers, and transmission routing. The 25% adder is consistent with other Midwest ISO studies.

Table 8.4-1: MTCFS Transmission Cost per Mile Assumptions
Transmission Cost $M-2010/Mile

kV	MN/Dak	IA	WI	IL (ComEd)	IL (Ameren)	MO
115	0.5		0.6			
115-2	0.9		0.9			
138			0.8			
138-2			1.1			
161	0.65					
230	0.75					
345	1.75	1.75	2.2	1.8	1.75	1
345-2	2.5	2.1	3	2.6	2.5	1.5
500						
765						

In the 2010 MTCFS, all projects were assumed to be in-service in 2015. The benefits and costs applied in the benefit to cost (B/C) ratio calculations were the present value for the first ten (10) years of the project life after the in-service year. Three (3) years of PROMOD production cost simulations, 2015, 2020, and 2025, were performed to calculate benefits spanning across an eleven (11) year timeframe. The benefit savings for years between the three (3) simulated years were derived using linear interpolation. Eleven (11) year net present value (NPV) RECB II benefit savings were calculated using an 8.39% discount rate.

A transmission owner-specific declining balance rate of return (ARR) was used in the 2010 MTCFS to determine annual cost of transmission projects. ARRs range from 29% to 14% in year one depending on the transmission owner. In calculating annual projects costs, a single transmission owner's ARR was utilized–projects were not shared between multiple owners. By utilizing a transmission owner-specific declining balance ARR as opposed to a leveled fixed charge rate similar to the 2009 MTCFS approach, the 2010 MTCFS was able to increase the accuracy of results and comply with the exact calculations specified in the Energy Markets Tariff (RECB II). 2010 project costs were escalated to 2015 dollars using an inflation rate of 1.74% in PAC future scenarios and 2.91% in CARP future scenarios. B/C ratio was calculated by dividing eleven (11) year RECB II NPV benefits by eleven (11) year NPV project costs.

8.4.4 Top Congested Flowgate Identification

Three (3) sources were used to identify flowgates with the most congestion in the Midwest ISO Market: historical Real-Time Market data Day-Ahead Market data, and forward-looking 2015 MTEP10 production cost models. Flowgate congestion was measured and ranked in terms of the number of binding hours and total shadow prices.

The historical Real-Time Market information utilized a subset of the data and rankings from section 8.2. The purpose of the MTCFS was to identify future projects to mitigate both present and future congestion. To appropriately capture only current and future congestion, congestion history from market years four and five, April 2008 through April 2010, was utilized. As detailed in section 8.2, many of the highly congested flowgates from earlier market years have been relieved. Only flowgates within the Midwest ISO Market Footprint were included in the analysis.

The 2010 MTCFS also used historical Day-Ahead information to aid in the identification of areas of congestion. This was the first MTEP study to utilize this data and therefore only a limited dataset—January 2009 to September 2009—was available. In future MTCFS, a larger Day-Ahead dataset that is comparable to the Real-Time Market data will be utilized. Because of the smaller dataset, less weight was placed on the Day-Ahead data by the TRG when determining the top congested flowgates for analysis.

The third source of information was obtained from the 2015 MTEP10 production cost models detailed in section 8.4.2. To evaluate congestion levels under a variety of economic, public policy, and transmission overlay outcomes three (3) future scenarios were simulated:

- PAC BAU with Mid-Low Demand (PAC BAUMLDE)
- PAC Carbon Cap and Nuclear Generation (PAC CAPNUK)
- CARP RPS

Additionally, an analysis was performed on the effects of the RGOS 765kV indicative overlay with the PAC BAUMLDE future scenario. MTEP10 production cost models included data for most of the Eastern Interconnect; however, only flowgates in the Midwest ISO market were included in the flowgate data for the MTCFS. Flowgates on the RTO seams were included in the Cross Border Coordinated Congested Flowgate Study (section 8.5).

Refer to Table 8.4-2 on the following page, which lists and describes the top twenty (20) Midwest ISO market flowgate in terms of both binding hours and shadow prices. Rankings are in ascending order, meaning if a cell has a ranking of one (1) then that flowgate possesses the highest total shadow price or total number of binding hours. A blank cell indicates a ranking greater than twenty. Comments are included in Table 8.4-2 to explain why certain flowgates were not considered for further analysis in the 2010 MTCFS. Detailed rankings including the quantified total number of binding hours and shadow prices are contained within Appendix G3 for each of the six (6) sources.

Table 8.4-2(a): 2010 MTCFS–2015 PROMOD Runs (06/18/2010) Flowgate Congestion Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Breed-Wheatland 345kV FLO Rockport-Jefferson 765kV		19	11	9	4	1	4	2	6	2	5	2	Identified as ***Flowgate D***, MTEP09 Appendix B
Indian Lake 138/69kV 2 Xfmr FLO Indian Lake 138/69kV 1 Xfmr	3	5	2	4	10	12			10	14	1	3	Identified as ***Flowgate E***
Rivermines-N Farmington 138kV FLO St. Francis-Lutesville 345kV	4	6			7	9	9	10	7	13	3	10	Original MTCFS Candidate. Congestion mitigation only benefits external regions.
Overton 345/161/13.8kV Xfmr FLO Montgomery-McCredie-Overton 345kV			16		5	6	5	6	5	5	4	5	Identified as ***Flowgate C***
Fondulac–Hibbard 115kV					6	2	8	1	8	4	12	1	Identified as ***Flowgate F***
Oak Grove-Galesburg 161kV FLO Nelson-Electric Jct. 345kV	5	4	1	2			17	16	15	16			Included in the Cross-Border Study
Leoni–Plymouth 138kV					12	7	10	7	19	10	10	4	TRG chose not to study due to only out year congestion. Will monitor in future studies.
Nason-Ina 138kV FLO EW Frankfurt–Mt. Vernon 345kV					13	18	12	14	9	15	9	17	Identified as ***Flowgate B***
Duff-Dubois 138kV FLO Ratts-Victory 161kV					14	16	7	8	17	20	11	15	Identified as ***Flowgate G***

Table 8.4-2(a): 2010 MTCFS–2015 PROMOD Runs (06/18/2010) Flowgate Congestion Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Fox Lake-Rutland 161kV FLO Lakefield Jct. - Wilmarth 345kV	7				1	4	1	3	1	1			Identified as ***Flowgate* H**, MTEP09 Appendix B
Arch Tap-Steeleville 138 kV FLO W. Mt. Vernon-E. W. Frankfort 345 kV					19	14		18	18	19	8	6	Mitigation Plan Exists–rating updates, removed from MTCFS Candidate list
Atlanta Jct.-Atlanta 138kV FLO Thetford-Jewell 345kV					3	5	2	5	2	3			Mitigated in ITC Double/Single Circuit 345kV Thumb Loop Expansion MVP Study
Rising 345/138 Xfmr FLO Wilton Center-Dumont 765kV					2	3	3	4	4	6			Identified as ***Flowgate A***, MTEP09 Appendix B
Bain–Kenosha 138kV FLO Zion–Pleasant Prairie 345kV					8	11	11	12	12	17			Included in the Cross-Border Study
Alma-Wabaco 161kV FLO King-Eau Claire 345kV					9	8	14	15		18		19	Original MTCFS Candidate, but congestion was minimal after applying TRG supplied updated contingency definition
Marion–Renshaw 161kV FLO EW Frankfurt–Shawnee 345kV					17		16	13			7	8	Next on MTCFS Candidate list. WIll monitor in future studies.
Pana 345/138kV Xfmr FLO Coffeen-Coffeen North 345kV	2	2	3	5									Mitigation Plan Exists–Coffeen-Coffen N, removed from MTCFS Candidate list

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Table 8.4-2(a): 2010 MTCFS–2015 PROMOD Runs (06/18/2010) Flowgate Congestion Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Dune Acres-Michigan City 138kV 1&2 FLO Wilton Center-Dumont 765kV	1	1	13	20									Mitigation Plan Exists–rating updates, removed from MTCFS Candidate list
Hazleton T21 345/161kV FLO Hazleton T22 345/161kV	11	13	6	7									Mitigation Plan Exists–Salem-Hazleton 345 KV in 2011, removed from MTCFS Candidate list
Schahfer-Burr Oak 345kV FLO Wilton Center-Dumont 765kV	14	8	9	11									High Ranking due to impacts of Multiple Planned Outages, removed from MTCFS Candidate list
Burr Oak 345/138kV Xfmr FLO Burr Oak-Leesburg 345kV	12		17								6	9	High Ranking due to impacts of Multiple Planned Outages, removed from MTCFS Candidate list

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Table 8.4-2(b): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Rising 345/138 Xfmr FLO Clinton–Brokaw 345	9	17			11	10							Combined with "Rising 345/138 Xfmr FLO Wilton Center-Dumont 765kV" as ***Flowgate A***, MTEP09 Appendix B
Nelson Dewey 161/138kV Xfmr						13		11	14	11			Out of top 10, removed from MTCFS Candidate list
Livingston–Gaylord 138kV					18	19					13	16	Out of top 10, removed from MTCFS Candidate list
Reynolds-Monticello 138kV FLO Dequine-Westwood 345kV							13		3	9			Out of top 10, removed from MTCFS Candidate list
St. Francois–Lutesville 345kV		3									17	13	Out of top 10, removed from MTCFS Candidate list
Paddock–Townline Road 138kV FLO Paddock-Blackhawk 138KV	13	9		16									Out of top 10, removed from MTCFS Candidate list
Steeleville-Tilden 138kV FLO EW Frankfurt–Mt. Vernon 345kV	17	16	7										Out of top 10, removed from MTCFS Candidate list
Swamp Fox–Marion 115kV FLO Arnold 345/161 Xfmr	6		19	17									Out of top 10, removed from MTCFS Candidate list
Butler-Granville 138kV FLO Granville-Tosa 138kV			12	14							19		Out of top 10, removed from MTCFS Candidate list
Holland–Mason 138kV FLO Duck Creek–Tazewell 345kV					15		15	19					Out of top 10, removed from MTCFS Candidate list

Table 8.4-2(b): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Newton-Robinson 138kV FLONewton-Casey 345 kV					16	17					20		Out of top 10, removed from MTCFS Candidate list
Lanesville Xfmr 345/138kV FLO Kinc-Lath-Pont 138kV & Kinc-Pawnee 345kV	15						20	20					Out of top 10, removed from MTCFS Candidate list
Hazleton–Black Hawk 161kV FLO Hazleton-Washburn 161kV			5	3									Out of top 10, removed from MTCFS Candidate list
Michigan City-Trail Creek 138kV FLO Olive 345/138kV; Laporte-Olive 138kV											2	7	Out of top 10, removed from MTCFS Candidate list
Palmyra 345/161kV Xfmr FLO Montgomery-Spencer 345kV							6	9					Out of top 10, removed from MTCFS Candidate list
Swamp Fox–Marion 115kV FLO Arnold–Hazelton 345kV			4	13									Out of top 10, removed from MTCFS Candidate list
Lakefield–Lakefield Gen 345kV									11	7			Out of top 10, removed from MTCFS Candidate list
Duff–Dubois 138kV FLO Duff–Ramsey 345kV			8	10									Out of top 10, removed from MTCFS Candidate list
Raab Road - Washington St. 138kV FLO Dresden-Pontiac 345kV									13	8			Out of top 10, removed from MTCFS Candidate list

Table 8.4-2(b): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
State Line-Wolf Lake 138kV FLO Burnham-Sheffield 345kV			18	6									Out of top 10, removed from MTCFS Candidate list
Whitcomb-Caroline 115kV FLO Rocky Run-Werner West 345kV	10	15											Out of top 10, removed from MTCFS Candidate list
Two Harbors–Waldon 115kV											14	11	Out of top 10, removed from MTCFS Candidate list
Werner West-Werner 115kV FLO Werner West-North Appleton 345kV		11		15									Out of top 10, removed from MTCFS Candidate list
Rush Island-St. Francois 345kV 1 FLO Rush Island-St. Francois 345kV 2											16	12	Out of top 10, removed from MTCFS Candidate list
Wisdom-Triboji 161kV FLO Raun-Lakefield Jct. 345kV									16	12			Out of top 10, removed from MTCFS Candidate list

Table 8.4-2(c): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Newtonville 161/138kV 3 Xfmr FLO Newtonville 161/138kV 5 Xfmr	19	10											Out of top 10, removed from MTCFS Candidate list
Joppa 345/161kV Xfmr FLO Shawnee 500/345kV Xfmr											15	14	Out of top 10, removed from MTCFS Candidate list
Iola–Roseholt 69kV FLO Rocky Run–Gardner Park 345kV	18	12											Out of top 10, removed from MTCFS Candidate list
Gillespie Tap–LaClede Tap 138kV FLO Coffeen–Roxford 345kV							18	17					Out of top 10, removed from MTCFS Candidate list
Monticello-East Winamac 138kV FLO Dumont-Stillwell 345kV					20		19						Out of top 10, removed from MTCFS Candidate list
Adams–Beaver Creek 345kV FLO Mitchell County–Hazleton345			20	19									Out of top 10, removed from MTCFS Candidate list
Arrowhead-Stone Lake 345 kV						20						20	Out of top 10, removed from MTCFS Candidate list
Manistique TR1				1									Out of top 10, removed from MTCFS Candidate list
Eau Claire-Arpin 345kV		7											Out of top 10, removed from MTCFS Candidate list
Greenfield-Lakeview 138kV FLO Beaver–Davis Besse 345kV	8												Out of top 10, removed from MTCFS Candidate list
MWEX: Arrowhead–Arrowhead PST 230kV; King-Eau Claire 345kV				8									Out of top 10, removed from MTCFS Candidate list

Table 8.4-2(c): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Rocky Run 345/138kV Xfmr FLO Rocky Run-Werner West 345kV			10										Out of top 10, removed from MTCFS Candidate list
Detour 69/12.5kV Xfmr				12									Out of top 10, removed from MTCFS Candidate list
State Line-Roxana 138kV FLO Sheffield 345/138kV Xfmr			14										Out of top 10, removed from MTCFS Candidate list
Paddock 345/138kV Xfmr FLO Wempletown-Rockdale 345kV		14											Out of top 10, removed from MTCFS Candidate list
North Coulterville 230/138kV Xfmr FLO Steelville–Grand Tower 138kV			15										Out of top 10, removed from MTCFS Candidate list
Wabaco-Rochester 161kV FLO Prairie Island-Byron 345kV						15							Out of top 10, removed from MTCFS Candidate list
Bondurant-Boone Jct. 161kV FLO Lehigh-Webster 345kV	16												Out of top 10, removed from MTCFS Candidate list
Cayuga-Nucor 345kV FLO Wheatland-Amo 345kV											18		Out of top 10, removed from MTCFS Candidate list
Breed-Wheatland 345kV FLO Eugene–Cayuga 345kV												18	Out of top 10, removed from MTCFS Candidate list
Point Beach–Sheboygan 345kV				18									Out of top 10, removed from MTCFS Candidate list
Coulterville 230/138kV FLO EW Frankfurt–Mt. Vernon 345kV		18											Out of top 10, removed from MTCFS Candidate list

Table 8.4-2(c): Historical Real-Time, Historical Day-Ahead and 2015 PROMOD Simulation Flowgate Rankings

Flowgate Description	Real-Time		Day-Ahead		PAC_BAUMLDE		PAC_CAPwNUK		CARP_RPS		PAC_BAUMLDE w/ RGOS765		Comments
	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	Shadow Price	Binding Hours	
Rantoul-Paxton-Sidney 138kV FLO Rising-N. Champaign-Mahomet 138kV	20												Out of top 10, removed from MTCFS Candidate list
Poweshiek-Reasnor 161 kV FLO Montezuma-Bondurant 345 kV									20				Out of top 10, removed from MTCFS Candidate list
Schahfer-Burr Oak 345kV		20											Out of top 10, removed from MTCFS Candidate list

The differences between historical and forward-looking rankings shown in Table 8.4-2 were expected, resulting from infrastructure changes, system outages, potential public policy decisions, and demand forecast deviations.

During the 3rd TRG meeting on June 15th, 2010, the Midwest ISO Market Flowgate congestion rankings (Table 8.4-2) were presented to the MTCFS TRG. The TRG was tasked with narrowing the list of congested flowgates to a manageable subset for further analysis. The best candidates for further study were flowgates with a high amount of both historical and future congestion. These flowgates represent current problem areas not expected to be fixed by any current MTEP project, transmission overlay, or shift in public policy. The TRG, in conjunction with Midwest ISO staff, nominated eight (8) top congested flowgates for study. Figure 8.4-1 and Table 8.4-2 display each of the eight (8) flowgates. Only the monitored elements of each flowgate are used to identify each flowgate.

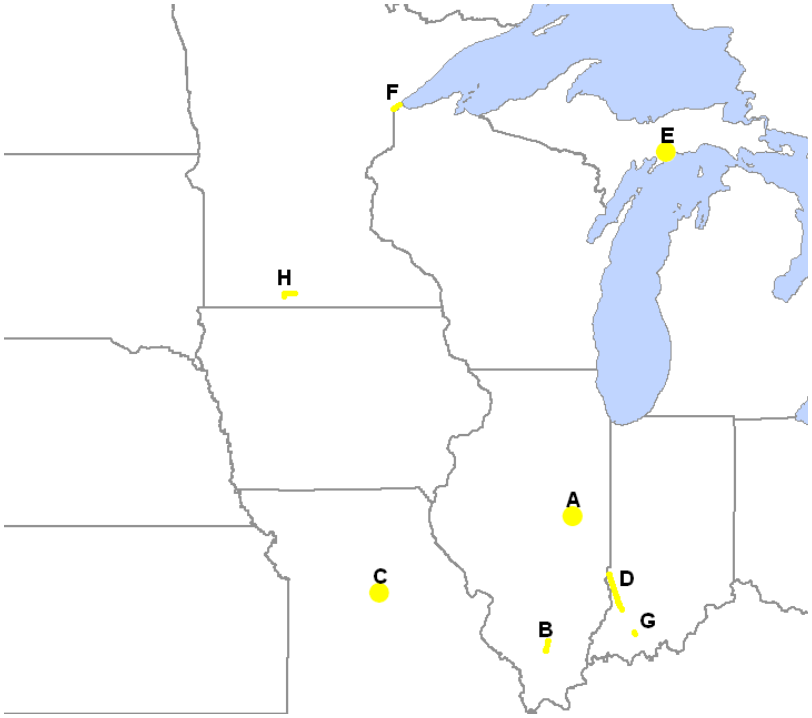

Figure 8.4-1: Top Congested Flowgates

Table 8.4-2: Top Congested Flowgate (Figure 8.4-1 Key)

Flowgate ID	Flowgate Name
A	Rising 345/138 Xfmr
B	Nason–Ina 138kV
C	Overton 345/161/13.8kV
D	Wheatland–Breed 345kV
E	Indian Lake 138/69kV 2 Xfmr
F	Fondulac–Hibbard 115kV
G	Duff–Dubois 138kV
H	Fox Lake–Rutland 161kV

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Three (3) of the eight (8) identified top congested flowgates shown in Table 8.4-3 were associated with the three (3) plans placed into Appendix B through the 2009 MTCFS effort, thus confirming the need for a mitigation plan at these flowgates:

- **A:** Rising 345/138kV Transformer
- **D:** Wheatland–Breed 345kV
- **H:** Fox Lake–Rutland 161kV

Additionally, Flowgate E: Indian Lake 138/69kV Transformer #2 was studied under the 2009 MTCFS; however, under the previous scope a project could not be formulated to meet the B/C ratio thresholds. American Transmission Company included this flowgate in its "ATC Energy Collaborative-Michigan" study in order to identify additional reliability drivers for resolution of this constraint Other 2009 MTCFS top congested flowgates were included in this year's Cross Border Study (section 8.4) or were excluded from the 2010 MTCFS due to the limited economic benefit potential to Midwest ISO or in response to TRG comments.

8.4.5 MTCFS Mitigation Plan Evaluation

On July 8, 2010, a TRG meeting was held to address the essential background information and facilitate the development of transmission mitigation plans for the eight (8) top congested flowgates selected. Nearly all mitigation plans were provided directly by the TRG; Midwest ISO staff TRG mitigation plans with combinations and variations of the TRG-supplied projects and RGOS segments. All projects were assumed to be in-service in 2015; thus, a 2.0 B/C threshold was required for each project to meet RECB II cost allocation criteria.

Each mitigation plan was evaluated using 2015, 2020, and 2025 production cost models under the PAC BAUMLDE future scenario. This future was considered the MTEP10 reference case and was regarded as the most probable scenario by the PAC. Additionally, mitigation plans associated with the three 2009 MTCFS flowgates were evaluated using all five futures for the three years. The MTCFS study goal was to move the best-fit 2009 MTCFS Appendix B flowgate mitigation plans to MTEP Appendix A and the best-fit flowgate mitigation plans that were not part of the 2009 MTCFS to MTEP Appendix B.

To facilitate these two (2) objectives, two analyses were undertaken, focusing on potential MTEP Appendix A-eligible projects and potential MTEP Appendix B-eligible projects. Both analyses used the methodologies described in Section 8.3.3 to determine 11-year NPV economic benefits. The only difference between the two (2) analyses was the use of multiple future scenarios for the potential Appendix A-eligible projects. The following sections detail the potential economic benefits associated with each mitigation plan. Section 8.4.5.1 contains the results from the 2009 MTCFS Appendix B flowgate projects that were studied for Appendix A eligibility. Section 8.3.5.2 contains the results from other projects studied for Appendix B eligibility.

8.4.5.1 2009 MTCFS Appendix B Flowgate Mitigation Plan Results

In the 2009 MTCFS, three (3) flowgates possessed Appendix B-eligible mitigation plans. In the 2010 MTCFS, these three flowgates continued to show high congestion levels even with a decreased load forecast and (partial) mitigations plans in place. In 2010, the goal was to move a best-fit mitigation plan for each one of these flowgates to Appendix A. To evaluate each of the mitigation plans over a variety of economic and public policy outcomes, each project was evaluated using the five (5) futures refreshed or developed through the PAC for 2015, 2020, and 2025. While the advantage of using multiple scenarios is to develop a range (or ‘risk bandwidth’) for purposes of project comparison and brevity, the single PAC-weighted combined total for each project is displayed throughout this section unless otherwise noted. Appendix G3 contains the annual and NPV potential economic benefits for each mitigation plan under each of the five (5) future scenarios. Scenario probability weighting developed through the PAC is displayed in Table 8.4-3.

Table 8.4-3: PAC Future Weighting

Future Scenario	Weight
PAC Business as Usual Mid-Low D+E (PAC BAUMLDE)	34%
CARP Federal RPS Future (CARP RPS)	26%
PAC Carbon Future–Carbon Cap with Nuclear (PAC CAPNUK)	15%
CARP Business as Usual with High Growth Rate for D+E (CARP BAU)	14%
CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars (CARP CAPRPSSGEV)	11%

8.4.5.1.1 Flowgate A: Rising 345/138kV Transformer

During the 4th TRG meeting, three plans were proposed to mitigate the congestion on the Rising Transformer. The PAC weighted eleven (11) year NPV economic benefits are displayed in Table 8.4-5. In both Options 1 and 2 multiple project cost estimates were supplied by the TRG.

Table 8.4-5: MTCFS Flowgate A Mitigation Plans' PAC Weighted Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	Rising–Sidney 345kV	50,000,000–68,000,000	(248,864,721)	223,187,920	81,572,128	0.98–0.72
2	Pana–Mt. Zion–Kansas–Sugar Creek 345kV	195,000,000–250,000,000	(225,224,687)	355,197,095	181,070,561	0.56–0.44
3	Clinton–Brokaw 345kV 2nd Circuit	49,284,375	51,682,492	120,973,315	100,186,068	1.23

Both Options 1 and 2 served to mitigate the congestion on the Rising Transformer for the conditions studied. The second Clinton–Brokaw circuit relieved only the congestion under a Clinton–Brokaw contingency and not under the Wilton Center–Dumont contingency which was the higher congested event in out-year models. With all options the greatest economic benefit potential was shown in the PAC CAPNUK scenario where a future nuclear unit was sited at the Clinton substation. Options 1 and 2 allowed Midwest ISO central region export capability to increase, resulting in higher Adjusted Production Cost savings for these options. The Rising–Sidney 345kV project export capability increase was limited because the Eugene–Bunsonville 345kV line started to bind.

In last year's 2009 MTCFS, the Rising-Sidney mitigation plan had approximately $1,209 million in NPV RECB II savings. The decreased benefits associated with the 2010 MTCFS were attributed to the self-funded Rising Transformer upgrade expected to be in-service in 2014, a decreased load forecast, and future generation siting assumptions. The Rising Transformer upgrade partially mitigated the flowgate congestion and thus decreased potential 11-year NPV RECB II benefits by approximately $200 million in the PAC BAUMLDE future. In the 2009 MTCFS a single reference scenario was utilized. In the 2010 MTCFS, the PAC CAPNUK scenario produced results that were similar to the 2009 analysis for this flowgate due to the inclusion of a second Clinton nuclear unit. The PAC CAPNUK future had approximately $877 million in 11-year NPV RECB II benefits.

After the 5th TRG meeting, four (4) additional plans were proposed to mitigate both the Rising Transformer congestion and the Eugene–Bunsonville 345kV constraint. These plans were tested solely under the PAC BAUMLDE future. The project cost, eleven (11) year NPV load cost savings, Adjusted Production Cost savings, RECB II benefits, and B/C ratio for these four (4) sensitivities, as well as the three (3) plans in Table 8.4-5 are provided in Table 8.4-6.

Table 8.4-6: MTCFS Flowgate A Mitigation Plans' PAC BAUMLDE Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	Rising–Sidney 345kV	50,000,000–68,000,000	(139,109,874)	79,216,355	13,718,487	0.18–0.13
2	Pana–Mt. Zion–Kansas–Sugar Creek 345kV	195,000,000–250,000,000	(29,002,107)	311,077,022	209,053,283	0.68–0.53
3	Clinton–Brokaw 345kV 2nd Circuit	54,850,000	52,373,443	20,127,696	29,801,420	0.35
4	Rising–Sidney–Eugene 345kV	105,000,000	(193,552,983)	311,669,996	160,103,102	0.97
5	Rising–Sidney–Cayuga 345kV	113,750,000	(205,842,085)	326,442,243	166,756,944	0.94
6	Rising–Eugene 345kV	102,812,500	(207,176,096)	315,884,122	158,966,057	0.99
7	Rising–Cayuga 345kV	111,562,500	(198,701,367)	323,028,217	166,509,341	0.95

Each of the four (4) additional plans (Options 4–Option 7) and Option 2 tap into the eastern 345kV north-south lines allowing Midwest ISO Central Region export capability to rise. The increased export capability yields Adjusted Production Cost savings of approximately $300 million.

While each plan showed benefits to the Midwest ISO system, no options met RECB II B/C ratio criteria. The Rising–Sidney 345kV line is currently proposed to be included in 2011 Candidate MVP portfolio analysis and evaluated for MVP eligibility.

8.4.5.1.2 Flowgate D: Wheatland–Breed 345kV

The TRG initially proposed eleven (11) plans to mitigate the congestion on the Wheatland–Breed flowgate. The PAC weighted eleven (11) year NPV economic benefits are displayed in Table 8.4-7.

Table 8.4-7: MTCFS Flowgate D Mitigation Plans' PAC Weighted Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Franklin Twp–Hanna 345kV	84,000,000	112,201,838	103,793,307	106,315,866	0.79
2	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Gwynneville 345kV	132,000,000	130,729,501	106,519,580	113,782,556	0.54
3	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Duke Bedford–Duke Gwynneville 345kV	196,000,000	127,475,893	108,949,052	114,507,104	0.36
4	Sullivan-Meadow Lake-Greentown 765kV	700,000,000	404,721,299	187,559,158	252,707,800	0.26
5	Wheatland–Breed to 1386 MVA; Close Wheatland Tie Breaker; Tap Breed–Wheatland & Connect to Merom 345kV	26,000,000	68,326,912	62,008,169	63,903,792	1.53
6	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker	12,000,000	135,300,434	100,631,596	111,032,247	5.76
7	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Franklin Twp 345kV	72,000,000	135,553,650	100,611,601	111,094,216	0.96
8	Wheatland–Breed 345kV to 1386 MVA	12,000,000	79,678,153	44,366,638	54,960,092	2.85
9	Wheatland–Breed 345kV to 1195 MVA	1,000,000	86,358,171	41,934,713	55,261,751	34.39
10	Close Wheatland Tie Breaker		(216,124,132)	(110,899,999)	(142,467,239)	
11	Option 5; Bloomington–Franklin Twp–Hanna 345kV	98,000,000	37,271,175	67,263,850	58,266,048	0.37

In most Wheatland–Breed proposed mitigation plans, the Wheatland–Breed line was upgraded to 1,386 MVA. This upgrade relieved the congestion for the conditions studied, and obtained nearly all the potential congestion relief benefits for this flowgate. When additional lines were added, such as the Bloomington–Hanna 345kV line, these lines increased both the congestion and LMPs for areas west of the flowgate. The benefits of these additional projects to Midwest ISO as a whole were minimal, with PJM and TVA receiving the bulk of load cost savings.

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To relieve this additional congestion, the Technical Review Group (TRG) proposed a series of portfolios using lines from the 2009 and 2010 MTCFS. These plans were tested under the PAC BAUMLDE future. The project cost, eleven (11) year NPV load cost savings, Adjusted Production Cost savings, RECB II benefits, and B/C ratio for each of the eight (8) additional and eleven (11) original projects are provided in Table 8.4-8.

Table 8.4-8: MTCFS Flowgate D Mitigation Plans' PAC BAUMLDE Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Franklin Twp–Hanna 345kV	84,000,000	95,630,198	53,223,792	65,945,714	0.52
2	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Gwynneville 345kV	132,000,000	104,128,660	52,888,707	68,260,693	0.34
3	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Duke Bedford–Duke Gwynneville 345kV	196,000,000	93,242,958	55,484,700	66,812,177	0.22
4	Sullivan-Meadow Lake-Greentown 765kV	700,000,000	(112,676,735)	20,899,735	(19,173,206)	(0.02)
5	Wheatland–Breed to 1386 MVA; Close Wheatland Tie Breaker; Tap Breed–Wheatland & Connect to Merom 345kV	26,000,000	86,051,985	36,868,140	51,623,294	1.31
6	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker	12,000,000	120,002,295	57,345,745	76,142,710	4.18
7	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Franklin Twp 345kV	72,000,000	120,067,053	57,348,147	76,163,819	0.70
8	Wheatland–Breed 345kV to 1386 MVA	12,000,000	38,602,095	23,556,816	28,070,399	1.54
9	Wheatland–Breed 345kV to 1195 MVA	1,000,000	40,497,279	23,655,050	28,707,719	18.92
10	Close Wheatland Tie Breaker		(229,155,419)	(83,649,768)	(127,301,463)	
11	Option 5; Bloomington–Franklin Twp–Hanna 345kV	98,000,000	26,355,565	37,758,434	34,337,573	0.23
12	Option 1; Rising–Sidney 345kV	152,000,000	(50,555,186)	128,293,366	74,638,801	0.32
13	Merom–Newton 345kV	109,375,000	66,239,141	203,560,689	162,364,224	0.98
14	Option 1; Merom–Newton 345kV	193,375,000	72,361,242	255,503,052	200,560,509	0.68

Table 8.4-8: MTCFS Flowgate D Mitigation Plans' PAC BAUMLDE Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
15	Option 1; Rising–Sidney 345kV; Merom–Newton 345kV	261,375,000	7,898,354	359,199,385	253,809,076	0.64
16	Option 11; Rising–Sidney 345kV	166,000,000	(101,762,753)	109,754,985	46,299,664	0.18
17	Option 11; Merom–Newton 345kV	207,375,000	50,962,459	264,640,989	200,537,430	0.64
18	Option 11; Rising–Sidney 345kV; Merom–Newton 345kV	275,375,000	(23,382,386)	504,264,971	345,970,764	0.83
19	Norris City–Albion 345kV	59,062,500	224,391,217	132,766,603	160,253,987	1.79

The addition of Rising–Sidney 345kV or Merom–Netwon 345kV lines increased the area’s export capability and Adjusted Production Cost savings. With project portfolios, the ultimate goal was to find synergic benefits where porfolio benefits exceed the summation of individual project benefits. Option 18’s portfolio benefits exceeded the summation of individual project benefits by approximately 35%. While multiple portfolios displayed synergic benefits, no portfolios met the 2.0 RECB II B/C threshold.

Upgrading the Wheatland–Breed line to either 1,386 MVA or 1,195 MVA yielded a B/C ratio in excess of the 2.0 RECB II threshold. The benefits of upgrading the Wheatland–Breed line were amplified when the Wheatland tie breaker was closed. In the 2009 MTCFS, the 1,386 MVA upgrade was required to mitigate the congestion on the Wheatland–Breed flowgate; however, the decreased demand levels in the 2010 MTCFS allowed both rating upgrades to achieve nearly the same benefits. The 1,195 MVA option is below the RECB II cost criteria. The Wheatland–Breed 1,386 MVA line rating upgrade coupled with closing the Wheatland tie breaker meets all MTEP Appendix A economic requirements. Reliability analysis will be required prior to moving to this mitigation plan to Appendix A.

At the direction of the TRG, the Wheatland-Bread 1,386 MVA upgrade project will remain in MTEP Appendix B at this time. Midwest ISO Expansion Planning will perform reliability analysis on closing the Wheatland tie breaker as part of the MTEP11 study. As evident in the sensitivities performed, the benefits of associated mitigation plans were dependent on nearby projects or portfolios. The 2011 Candidate MVP Portfolio analysis will evaluate multiple projects that could affect the potential benefits of Wheatland–Breed mitigation plans. Additionally, when this project was routed through the Merom substation (Option 5), it increased export capability and therefore provided significantly more potential benefits to the PJM system. This project could potentially be Cross Border Cost Sharing eligible under future system conditions. This flowgate will continue to be monitored in future MTCFS efforts.

8.4.5.1.3 Flowgate H: Fox Lake–Rutland 161kV

Four transmission plans were initiated through the TRG to mitigate the congestion on the Fox Lake–Rutland 161kV flowgate. The PAC weighted eleven (11) year NPV economic benefits are displayed in Table 8.4-9.

Table 8.4-9: MTCFS Flowgate H Mitigation Plans' PAC Weighted Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	2nd Fox Lake–Rutland–Winnebago 161kV	25,350,000	1,280,689,434	263,005,335	568,310,565	10.23
2	Lakefield Jct–Winnebago–Adams 345kV	600,000,000	2,169,977,079	445,978,674	963,178,195	0.73
3	Lakefield Jct–Winnebago–Webster–Blackhawk–Hazelton 345kV	591,575,000	2,496,563,374	464,143,436	1,073,869,418	0.83
4	Lakefield Jct–Mitchell Co 345kV	600,000,000	1,743,156,374	335,872,591	758,057,726	0.58

The potential benefits associated with these mitigation plans were directly correlated with the amount of wind sited west of this flowgate. The CARP RPS and CARP CAPRPSGEV futures with elevated wind levels provided the greatest potential benefit for all projects. All mitigation plans relieved flowgate congestion under study conditions, but projects with intermediate buses; i.e., Winnebago, Webster, or Blackhawk, had increased benefits because these projects were able to collect additional wind sited near or on these buses. The costs for these projects were only estimates based upon line mileage, and were not granular enough to determine if additional intermediate stations were worth the additional costs.

Under these configurations and assumptions, all of the four (4) options were not RECB II-eligible. Option 1 showed a B/C ratio larger than 2.0 but did not meet RECB II voltage criteria. This option was market participant self-funding-eligible only. The Lakefield Junction–Winnebago project as well as a variation of the Lakefield Junction–Winnebago–Webster–Blackhawk–Hazelton 345kV project are currently proposed to be included in the Candidate MVP Portfolio analysis to be studied for MVP eligibility.

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8.4.5.2 Non-2009 MTCFS Appendix B Flowgate Mitigation Plan Results

In the 2010 MTCFS, five (5) flowgates did not posses Appendix B-eligible mitigation plans resulting from the 2009 MTCFS efforts. Each of the mitigation plans was studied under the PAC BAUMLDE future for 2015, 2020, and 2025 to determine the best-fit mitigation plan for each flowgate and potential Appendix B-eligible mitigation projects. Thus, only eleven (11) year NPV economic benefits are displayed throughout this section; Appendix G3 contains 2015, 2020, and 2025 results for each of the mitigation plans.

8.4.5.2.1 Flowgate B: Nason–Ina 138kV

The TRG proposed three (3) plans to mitigate the congestion on the Nason-Ina flowgate. Eleven (11) year NPV economic benefits are displayed in Table 8.4-10.

Table 8.4-10: MTCFS Mitigation Plan Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C ratio
1	Nason–Ina 138kV to SE 304/356MVA		(9,940,995)	1,703,169	(1,790,080)	
2	Baldwin–Grand Tower–Joppa 345kV	196,000,000	185,832,894	1,166,013	56,566,077	0.18
3	Baldwin–Grand Tower–W Cape–Lutesville 345kV	182,000,000	38,195,132	34,329,724	35,489,347	0.12

All three (3) plans effectively relieved the congestion for the conditions studied and the specific flowgates considered in the event file; however, none of the projects were able to achieve enough potential benefits to warrant a move to MTEP Appendix B. The negative RECB II savings in Option 1 are the product of decreased external region LMPs from increased Midwest ISO central region export capability. Because of the limited Midwest ISO economic benefits associated with Option 1, the TRG did not want to spend the resources to develop a project cost estimate. In MTEP10, a portion of Option 3, West Cape to Lutesville 345 kV, was placed in MTEP Appendix B as a reliability-based project.

8.4.5.2.2Flowgate C: Overton 345/161/13.8 kV

A single mitigation plan was proposed to mitigate the congestion on the Overton Transformer. Eleven (11) year NPV economic benefits are displayed in Table 8.4-11.

Table 8.4-11: MTCFS Mitigation Plan Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C Ratio
1	Overton 345/161/13.8kV	17,000,000	234,522,191	30,303,788	91,569,309	4.04

The mitigation plan relieved the flowgate congestion under the studied conditions and showed RECB II benefits greater than 2.0. The TRG supplied project cost includes the expansion of the 345 kV ring bus and a 161 kV breaker addition. As the voltage of the low-side of the transformer is 161kV, this project did not meet the criteria to be considered as a potential Market Efficiency Project. However, it could be moved to Appendix B as either a self-funded project or part of MVP portfolio (if applicable). At the direction of the TRG, this project will be studied in future MTCFS to verify its value and determine how it should be classified prior to being moved from MTEP Appendix C.

8.4.5.2.3 Flowgate E: Indian Lake 138/69kV 2 Xfmr

Two (2) mitigation plans were provided to relieve the Indian Lake 138/69kV Transformer flowgate. The project cost, eleven (11) year NPV load cost savings, Adjusted Production Cost (APC) savings, RECB II benefits, and B/C ratio are provided in Table 8.4-12.

Table 8.4-12: MTCFS Mitigation Plan Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C Ratio
1	Two Variable Frequency Transformer phase shifting devices; Indian Lake–Hiawatha 138kV	80,000,000	(105,105,461)	(10,977,863)	(39,216,143)	(0.35)
2	Back-to-Back HVDC at Straits substation; Indian Lake–Hiawatha 138kV	84,375,000	115,888,821	(17,713,130)	22,367,455	0.19

Back-to-back Voltage Sourced Converter (VSC) HVDC technology and Variable Frequency Transformers (VFTs) were chosen as the candidate technologies for flow control and mitigation of this congestion. While the 2009 MTCFS assumed the Indian Lake–Hiawatha 138kV line relieved the congestion on the Indian Lake 138/69kV transformers, the resulting increased flow exacerbated other low voltages and system overloads. Currently, to resolve flow concerns in this area, the 69 kV circuits are opened between the central and eastern UP to redirect flows south of Lake Michigan. This temporary operating guide is not a viable permanent solution because it prevents maintenance outages and creates high voltage scenarios under very light loads. Both mitigation plans for the 2010 MTCFS include the Indian Lake to Hiawatha 138kV line as part of the overall flow control solution. However, to mitigate this constraint, flow control technology is required. Under these configurations and assumptions, both options were not RECB II-eligible. The back-to-back HVDC project (Option 2) has reliability benefits beyond the economic benefits shown in Table 8.4-12 due to its independent and fast control ability of active and reactive power flows and its ability to provide dynamic voltage support at the converter stations.

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8.4.5.2.4 Flowgate F: Fondulac–Hibbard 115kV

One (1) mitigation plan was provided to relieve the Fondulac–Hibbard 115kV flowgate. Project cost, eleven (11) year NPV load cost savings, Adjusted Production Cost savings, RECB II benefits, and B/C ratio are provided in Table 8.4-13.

Table 8.4-13: MTCFS Mitigation Plan Eleven (11) Year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C Ratio
1	Tap Arrowhead–Gary 115kV & Connect to Fondulac; Move FonDuLac–Hibbard 115kV to FonDuLac–Hilltop 115kV	4,500,000	(9,189,756)	6,024,068	1,459,921	0.18

The mitigation plan relieved the congestion for the conditions studied, with the specific flowgate considered in the event file, but demonstrated RECB II benefits lower than 2.0. Under these configurations and assumptions, this option is not RECB II-eligible.

8.4.5.3 Flowgate G: Duff-Dubois 138kV

Four (4) mitigation plans were provided to relieve the Duff-Dubois 138kV flowgate. The New Albany station mitigation plan was excluded from the 2010 MTCFS and included in the Cross Border Study, because in addition to mitigating congestion around the Duff-Dubois flowgate this project also helps to relieve congestion on the Indiana-Kentucky seam—a potential cross-border market efficiency project. Section 8.5 contains the study results for this project. The project cost, eleven (11) year NPV load cost savings, Adjusted Production Cost savings, RECB II benefits, and B/C ratio for the four (4) options are provided in Table 8.4-14.

Table 8.4-14: MTCFS Mitigation Plan 11 year Annual NPV

Option ID	Option Description	Project Cost ($-2010)	NPV Load Cost Saving ($-2015)	NPV APC Saving ($-2015)	NPV RECB II ($-2015)	B/C Ratio
1	IPL Pete–BREC Coleman 345kV	114,000,000	(153,908,008)	(27,286,620)	(65,273,036)	(0.39)
2	Convert Duff–Dubois–Newtonville–Coleman to 345 kV	76,000,000	(183,625,344)	(48,845,858)	(89,279,704)	(0.81)
3	Wheatland–Breed 345kV to 1386 MVA; Close Wheatland Tie Breaker; Bloomington–Franklin Twp–Hanna 345kV	84,000,000	94,743,027	54,083,347	66,281,251	0.52
4	Extra line terminal at Dubois for Z84–Close Dubois TAP-Dubois 138 KV Line	1,500,000	3,254,325	7,826,656	6,454,957	2.95

Under the study configurations and assumptions, all four (4) options were not RECB II-eligible. Option 4 had a B/C ratio larger than 2.0 but was under the RECB II voltage threshold. This option was market participant self-funding-eligible only.

8.4.6 Conclusions and Going Forward

Through the course of 2010 MTCFS work, one (1) project was RECB II-eligible: the upgrade of the Wheatland–Breed 345kV line to 1,386 MVA and the closing of the Wheatland tie breaker in order to mitigate the congestion on the Wheatland–Breed 345kV flowgate. This mitigation plan met all MTEP Appendix A economic requirements although an additional reliability-based analysis will be required prior to moving the plan to Appendix A. At the direction of the TRG, this project will remain in MTEP Appendix B at this time. This flowgate will continue to be studied in future iterations of the MTCFS to determine if this mitigation plan or one of the alternatives is the best-fit plan while considering the MTEP11 Candidate MVP Portfolio analysis and the future cost allocation tariff. Midwest ISO Expansion Planning will perform reliability-based analysis on closing the Wheatland tie breaker as part of MTEP11.

The 2010 MTCFS also yielded numerous projects that met some RECB II criteria, such as the B/C thresholds, but not others such as the cost or voltage requirements. Generally, the 2010 MTCFS potential benefits were lower than those reported through the 2009 MTCFS; as the result of a decreased load forecast and (partial) mitigation plans for the most severe system constraints. While no projects moved forward through the MTEP Appendices, the results provide valuable insight to help market participants with their decisions. Each of the plans studied in the 2010 MTCFS will have an opportunity to be studied in future MTCFS and several will be evaluated in the 2011 Candidate MVP Porfolio analysis.

The MTCFS is an annual process in its third year. From 2009 to 2010 the scope, level of detail, and stakeholder participation increased, a trend Midwest ISO hopes will continue. The 2010 MTCFS possessed some significant scope changes that were driven by 2009 MTCFS Technical Review Group (TRG) comments. To continue to evolve and improve future MTCFS efforts, several suggestions were made by the TRG to guide the effort going forward:

- An aggressive schedule was followed in both the 2009 and 2010 MTCFS. The pace of the schedule was determined by the availability of data inputs and the MTEP report schedule. Unfortunately, aggressive scheduling limited the amount of time the TRG needed to review assumptions, verify results, and provide comments. The TRG would like more time with each part of the study. One possible solution lies in starting with an older vintage model and then applying incremental updates throughout the study process.
- Based on comments resulting from the 2009 MTCFS, a separate Cross Border Top Congested Flowgate Study was originated. While every effort was made to have the respective scope of the two study projects complement each other since it was often not clear which study was the appropriate place to study a given project. Going forward, better coordination is needed between the two efforts. An additional suggestion for improvement was to combine the studies and determine whether a project is RECB II- or cross-border-cost sharing-eligible based on single study results.
- In the 2009 MTCFS, an effort was made to not only consider individual projects but also project portfolios. In the 2010 MTCFS, time constraints limited the number of portfolios that could be studied. In future studies, the TRG would like portfolios to be considered.
- A final suggestion was to move every studied mitigation plan to MTEP Appendix C in an effort to more effectively share knowledge and results between Midwest ISO studies.

Midwest ISO relied upon a dedicated TRG throughout the 2010 MTCFS process; this single aspect has been and will continue to be the key for present and future Top Congested Flowgate Study success.

8.5 Cross Border Top Congested Flowgate Study

The Cross Border Top Congested Flowgate Study (CBTCFS) began in MTEP10 as an outgrowth of stakeholder requests that Midwest ISO coordinate more closely with adjacent Regional Transmission Organizations (RTOs) to more aggressively address congestion on the RTO seams. This study was performed under the auspices of Joint Operating Agreements (JOAs), which allow for ad hoc sensitivity studies to be performed based on the review of the Joint RTO Planning Committee (JRPC) of discrete reliability problems or operability issues that arise due to changing system conditions. The agreements allow for the formation of ad hoc study groups on an as-needed basis in order to address localized seams issues, to perform targeted studies of particular areas, needs, or potential expansions, and to ensure the coordinated reliability and efficiency of the systems. The Cross Border Top Congested Flowgate Study was conducted within the purview of the following broadly based objectives:

- Address Cross Border non-reliability planning issues per JOAs and Order 890 provisions.
- Identify potential projects that are eligible for tariff-based Cross Border Market Efficiency Project (CBMEP) treatment.
- Identify potential projects that may be eligible for Midwest ISO Market Efficiency or Multi Value Projects or PJM internal tariff treatment as economic projects.
- Identify other potential solutions and their values that may be participant-funded. For participant-funded, individual projects or portfolios, reliability-based no-harm tests would be performed to move projects to Appendix A.

Performed in conjunction with the Top Congested Flowgate Study, the Cross Border Top Congested Flowgate Study is expected to be an ongoing effort, not a one-time, ad-hoc study. Together, these two studies address market congestion inside and along the seams of the Midwest ISO footprint. Over the course of the study process, projects or portfolios demonstrating value in the reduction of chronic congestion would be recommended to move to MTEP Appendix B or Appendix A (as applicable). During the study process, three (3) Technical Review Groups (TRGs) were formed, focusing on three (3) seams areas:

- Lower Lake Michigan
- Indiana-Kentucky
- Iowa-Nebraska

The first step in the study process was to identify congested flowgates from various sources including—but not limited to—stakeholder input, real-time historical data, and future congestion studies. The next step in the process was to benchmark the cross border analysis tool against past real-time congestion data in order to demonstrate the predictive ability of the analysis in determining the economic value of proposals considered to mitigate congestion.

Portfolios with positive overall Midwest ISO economic benefit were tested under the Midwest ISO RECB II criteria, which includes three (3) years (2015, 2020 and 2025) of simulations. The results of the RECB II test can be found in section 8.5.7. None of the tested portfolios provided enough benefit to be eligible for cost sharing under the RECB II methodology.

The lower Lake Michigan area congestion was of particular interest to stakeholders and an especially difficult problem to address. This interface is heavily congested in real-time and—based on past experience—it was readily apparent that no proposal addressing a single congested flowgate would work, as focusing on a single flowgate simply shifts the problem to an adjacent flowgate, yielding no real benefit. Due to the complex nature of the region, the Lake Michigan area economic study was supplemented with transfer analysis emulating market flow patterns. This transfer analysis was crucial in predicting new congestion patterns by identifying multiple limits at various steps in transfers. This information was utilized to identify more robust plans for testing in the economic study.

While the Cross Border Congestion Flowgate study focused on reducing congestion on some of the most congested flowgates on the Midwest ISO seams, it should be noted four (4) flowgates on the Midwest ISO seams included in this study also resulted in an aggregate annual market uplift of over $2.1 million, as shown in the 2010 LTTR Infeasibility Study. These four (4) flowgates are listed below:

- Pleasant Prairie to Zion 345 kV
- Nelson to Electric Junction 345 kV
- Burr Oak 345/138 kV Transformer
- Crete to St. John 345 kV

A combination of some short- and long-term projects in the East and West Lake Michigan area yields annual Adjusted Production Cost savings of approximately $45 million in ComEd, $25 million in WE Energies, $6 million in MidAmerican and $6 million in NIPSCo, as shown in Portfolio 12c. The bulleted items below offer a high-level summary of study findings for each region:

- **Lake Michigan Interface–East Lake Michigan side:** It is critical to address the Burr Oak Transformer constraint and to complete the NIPSCO Northwest Reconfiguration project in order to realize the potential benefits of other projects in this area. This can be seen though a comparison of Portfolio 8 with 9, which includes all projects in portfolio 8 in addition to the Burr Oak Transformer, and through a comparison of Portfolio 9 and 9a, which includes all projects in portfolio 9 in addition to the Northwest Reconfiguration Project.
  - While portfolio 8 resulted in increased Adjusted Production Cost savings, adding a 2nd transformer at Burr Oak and including the NIPSCO Northwest Reconfiguration increased the Adjusted Production Cost (APC) savings for companies in the Lake Michigan area and increased the transfer capability across the NIPSCO system.
  - Other valuable short-term projects considered in more than one portfolio included resagging the East Frankfort-Crete and Crete to St. John lines and implementing rating changes for the Michigan-Laporte and Burnham-Munster lines. Also, some long term projects which required less new right of way showed promise in their potential to both reduce chronic congestion and to integrate wind energy in Indiana. These projects included the Reynolds to Burr Oak to Hiple line conversion and the installation of a second 345 kV circuit from Babcock to Stillwell to Dumont. These two (2) projects helped to increase the Adjusted Production Cost savings in the Lake Michigan area by about $30 million, as shown though the comparison of Portfolio 10a with 10.
- **Lake Michigan Interface–West Lake Michigan side:** There are two (2) primary congestion paths on the West side of Lake Michigan. These paths are a north-south tie between ATC and ComEd systems and a west-east tie on the ComEd system. It was determined that it would be counterproductive to reconductor these existing circuits without the construction of new higher voltage lines, as the reconductor of the lines decreased the system impedance without providing a significant enough rating increase. It was also determined that if one of these two paths was mitigated by means of a reconductor and the other constraint was mitigated by a new line, the economic benefits of the upgrades would be disproportionally skewed to companies with generation behind the new line

The analyses showed that congestion in the Western Lake Michigan area may be reduced by a new Racine to Zion 345 kV line, along with either a new 345 kV circuit from Byron to Charter Grove to Wayne or a new 345 kV line from Oak Grove to Fargo. These lines also helped to increase the generation revenues for companies within the Lake Michigan area. Portfolio 13, which includes the new Racine–Zion Energy Center 345 kV line and the Oak Grove–Fargo 345 kV line, increased Adjusted Production Cost savings in ComEd, WeEnergies and MidAmerican by over $30 million and increased Load Cost savings in ComEd, Ameren and NIPSCo by over $210 million. Load Cost savings for Ameren and NIPSCo increased by $54 million.

- **Lake Michigan Interface–East and West side combined:** The Cross Border Congestion Flowgate Study analysis showed that portfolios which address congestion on the West and East sides of the lower Lake Michigan area generally demonstrated higher economic benefits than portfolios which focused on only one side of the lake. Also, it was shown that relieving critical path congestion in the NIPSCo area and on the WE/ComEd interface improved the transfer capability for the entire lower Lake Michigan area, creating economic benefits for all the Lake Michigan companies. The best congestion mitigation and highest economic benefit for the lower Lake Michigan area was shown to be the a combination of long-term transmission projects including the Racine-Zion Energy Center 345kV line, the reconductoring of the East Frankfort-Crete-St. John line, and the construction of a second Burr Oak transformer. These benefits were demonstrated in Portfolio 12d.

  Two (2) HVDC options and one (1) HVDC plus AC option were also introduced in this study to address congestion in the lower Lake Michigan region. While the HVDC options resulted in large Adjusted Production Cost (APC) savings and substantial generation revenue increases to WE Energy and to the Lake Michigan-area, the capital costs to build the HVDC line were very high.

  - Portfolio 12d, which includes the Racine-Zion Energy Center 345 kVline, the Byron-Charter Grove-Wayne double circuit 345kV line improvements, and most of the NIPSCo short-term/intermediate fixes, provided the largest APC savings to the entire Lower Lake Michigan region. The APC savings were equal to $82.3 million; $52 million of the savings occurred within the ComEd area.
  - The best APC savings and the highest generation revenue increase for WE Energy were provided by Portfolio 14b, which includes the Oak Creek to Cook HVDC line and the Racine to Zion Energy Center 345kV AC line. WE Energy experienced a projected APC savings of $33.8 million and a generation revenue increase of 22.6%.

- **Iowa-Nebraska Interface:** Seams congestion on the Iowa-Nebraska interface was alleviated through either the new Gerald Gentleman Station (GGS)–Red Willow–Axtell line (Run 2) and the Hoskins–Omaha 345 kV line (Run 7). However, the benefit-to-cost ratios of these projects were very low in both Midwest ISO and SPP footprints.
- **Indiana-Kentucky Interface:** Two (2) options were tested to reduce congestion for the following constraints:
  - Gallagher to Paddys West
  - Duff-Dubois 138kV
  - Clifty Creek–Trimble County

  Individually, both the New Albany Station (the first option) and the Paddy West to Speed 345kV line (the second option) mitigated the Gallagher to Paddys West constraint, reduced congestion on the Duff-Dubois 138kV flowgate, and provided both positive APC savings and positive Load Cost savings for LG&E. However, the benefit-to-cost (B/C) ratios of these two (2) projects were negative within the Midwest ISO footprint.

The 2010 Cross Border Top Congested Flowgate Study results described in this report are a snapshot of the study's progress as of August 16, 2010. Additional work is required to fully complete the Cross Border analysis and to recommend any applicable projects to Appendix A.

8.5.1 Study Scope

The objective of the 2010 Cross Border Top Congested Flowgate Study (CBTCFS) was to identify and implement transmission upgrades to relieve congestion on RTO seams flowgates[58] in a manner consistent with tariff provisions and existing regional and interregional processes and protocols. The candidate PJM, TVA, SPP, and Midwest ISO congested seam flowgates considered in the study were the flowgates that have both consistently demonstrated negative cross-border impacts and are projected to continue to cause negative cross-border impact on any of the participating systems (PJM, SPP, TVA, and Midwest ISO). The list of flowgates was derived from multiple sources, which included the following:

- Binding constraints identified in Real Time (RT) and Day Ahead Markets
- Transmission constraints identified as future congested flowgates in out-year PROMOD based economic planning studies
- Transmission elements identified as constraints restricting Long Term Transmission Rights
- Transmission elements identified as constraints restricting the deliverability of aggregate deliverable Network Resources and generator feasibility
- Binding constraints identified from day to day Market-To-Market operations

A preliminary set of congested flowgates is shown in Figure 8.5-1. Details on these flowgates are located in Appendix G4. The sources of these flowgates were:

- MISO RT market Top 44 congested flowgates based on the total binding hours from April 2005 to April 2009
- MISO RT market Top 25 congested flowgates based on the total binding hours or total shadow prices from April 2007 to April 2009
- Top 50 congested flowgates based on the total binding hours or total shadow prices from MISO 2014 PROMOD case
- Lake Michigan flowgates proposed by We Energies and Exelon Power Team
- PJM review of Market-To-Market flowgates with the highest and persistent market impacts

In Figure 8.5-1 on the following page, PJM, Midwest ISO, SPP, TVA, and cross-RTO flowgate are listed. This preliminary flowgate list includes flowgates that may not currently be involved in market-to-market operations, but these flowgates may become the limiting market-to-market elements if the current market-to-market flowgates are mitigated. The initial output of the study was a mutually agreed upon list of justified seams flowgates, which were evaluated for solutions that may be cost shared as:

1. Market participants self-funded project
2. MISO RECB II projects
3. Cross Border Market Efficiency Project under the applicable agreements; or
4. Other applicable cost sharing mechanism

The full scope of this study was driven by Midwest ISO initiatives to improve coordination on all of its seams. The study was also implemented to respond to requests by multiple market participants to address congested flowgates across their seams, as a part of Order 890 regional coordination protocols. Various entities have been engaged on those seams relevant to their respective regions, to the extent cross-border issues were identified.

[58] A seams flowgate here means a flowgate that exists on the system of one entity and impacts operations on another.

As apparent from Figure 8.5-1 below, the candidate cross-border congested flowgates were mainly located in:

- Lower Lake Michigan
- Iowa-Nebraska
- Indiana-Kentucky

This study was thus divided into three (3) sub-studies with each sub-study targeting one of the cross border areas noted above. A formal scope document was established before the beginning of the study, containing the list of congested flowgates in current markets for each of these study areas. Modifications to this list were implemented based on the 2015 PROMOD simulation results, after which—based on demonstrated need—the final list of top congested flowgates was identified.

A Technical Review Group (TRG) was formed. The TRG advised Midwest ISO on the study methodology, verified the models, helped to design and develop the solutions, and reviewed the study results. Each Planning Coordinator solicited TRG participation from registered stakeholder groups and processes and assumed responsibility for full and open communication and discussion of study details with respective stakeholder forums. Midwest ISO staff regularly reported on study updates at the MTEP Sub-Regional Planning Meetings.

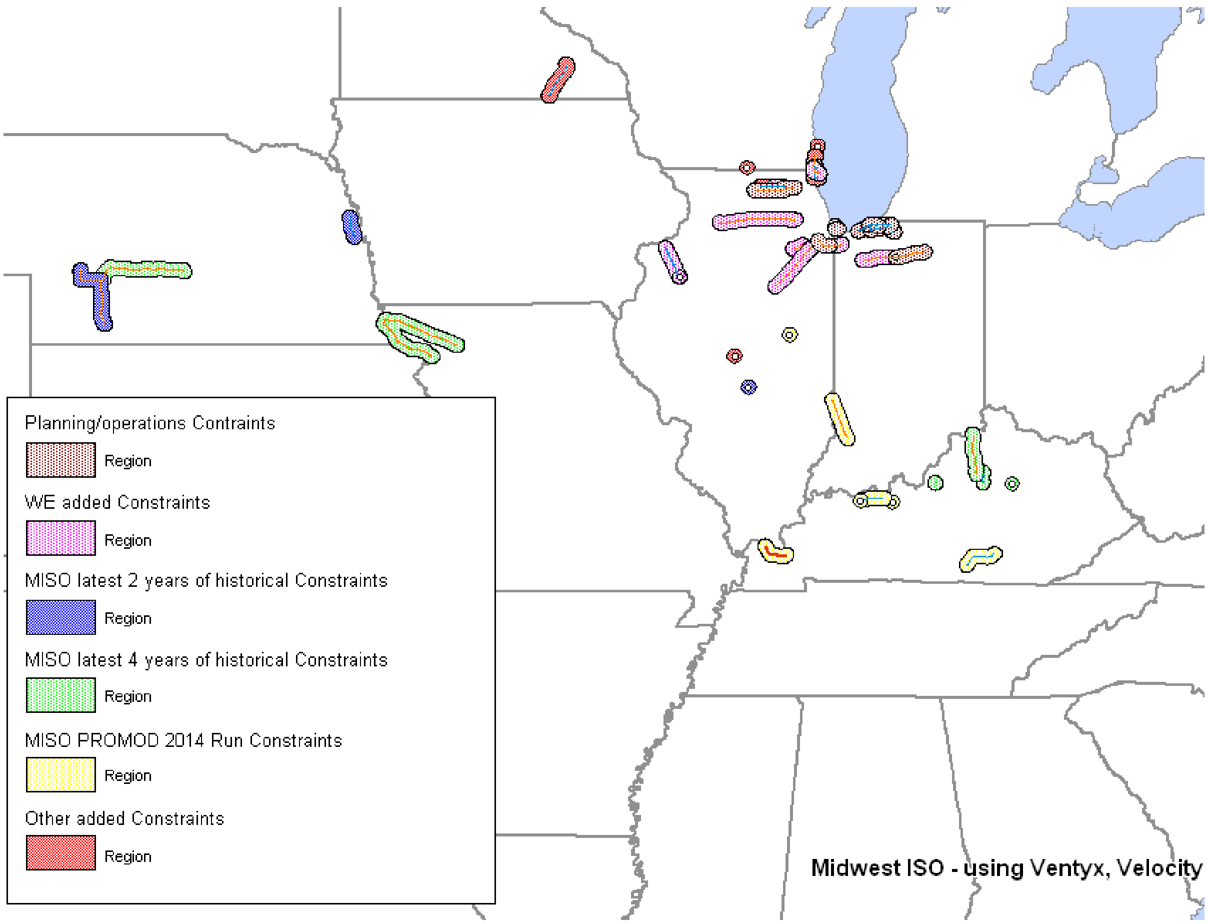

Figure 8.5-1: Top Congested Flowgates from Various Sources

Study results and modeling data were made available to Midwest ISO, PJM, SPP and TVA TRG participants for consideration in their respective planning processes subject to applicable confidentiality and CEII provisions. Potential transmission upgrades were jointly developed by Midwest ISO staff in coordination with the respective seams entities and Transmission Owners (TOs).

The Cross Border Top Congested Flowgate Study (CBTCFS) considered transmission upgrades that did not meet the tariff cost sharing criteria but may be funded by a Market Participant as a direct assigned cost upgrade eligible for incremental Auction Revenue Rights (ARRs) or equivalent rights under the Midwest ISO tariff. The study reported economic project benefit metrics as applicable, including production cost and Load Cost savings, to individual RTOs for each transmission upgrade.

The CBTCFS leveraged regional plans from inter-regional studies such as the Regional Generation Outlet Study (RGOS). The cost allocation for projects from these regional studies was not included in the CBTCFS analyses; the allocation will be determined under separate processes. The benefits of the projects identified in CBTCFS may be used in other applicable studies to accelerate the targeted in-service dates of transmission projects.

8.5.2 CBTCFS Model Development

The 2015 CBTCFS PROMOD case was based on the Midwest ISO MTEP10 2015 planning models developed during the 2010 planning cycle. Midwest ISO coordinated with PJM, SPP and TVA to incorporate each entity's best available topology into the CBTCFS model. Coordination was also required to update the powerbase data with latest available PJM, SPP and TVA data for 2015.

PROMOD IV® is a commercial production cost model that performs hourly chronological security constrained unit commitment and economic dispatch, recognizing both generation and transmission impacts. It can be used to evaluate the economic benefits of transmission expansion projects. Midwest ISO used PROMOD IV® as the primary tool to evaluate the economic benefits of the potential transmission upgrade options in the CBTCFS.

The PROMOD study footprint included the majority of the Eastern Interconnection, excluding ISO-New England, Eastern Canada, and Florida. A total of nine pools were defined in the PROMOD study footprint: Midwest ISO, PJM, SPP, MAPPCOR, SERCNI, TVASUB, MHEB, NYISO, and IESO. Fixed transactions were modeled to represent the purchases/sales between the study footprint and external regions. MidAmerican Energy Co., Muscatine Power & Water, and Dairyland Power Cooperative were included in the Midwest ISO pool and Nebraska companies were represented as members of SPP.

PROMOD utilizes an event file to provide pre-contingent and post-contingent ratings for monitored transmission lines. The latest *Midwest ISO Book of Flowgates* and *NERC Book of Flowgates* were used to create the event file consisting of the transmission constraints in the hourly security constrained model. Rating and configuration updates from the previous studies were included in the event file development and a separate review and update was conducted by the TRG.

8.5.3 Benefit/Cost Assumptions and Calculations

A common set of assumptions and formulas were utilized throughout the CBTCFS to calculate economic benefits.

8.5.3.1 Calculating Economic Benefit

To calculate the economic benefit savings for transmission mitigation plans, two (2) cases were defined: a base case and project case. All aspects of the base case and project case were identical with the exception of the congestion mitigation plan contained within the project case. For each case, Adjusted Production Cost and Load Cost were calculated as follows:

Company Annual Adjusted Production Cost =

$$\sum_{i=1}^{8760}\sum_{j=1}^{M} C_{ij} + \sum_{i=1}^{8760} Load\_Weighted\_LMP_i * Purchase_i - \sum_{i=1}^{8760} Generator\_Weighted\_LMP_i * Sale_i$$

Where:

C_{ij} is the production cost of generator j during hour i.

M is the number of total generators in the company.

$Load\_Weighted\_LMP_i$ is load weighted LMP during hour i.

$Generator\_Weighted\_LMP_i$ is generator weighted LMP during hour i.

$Purchase_i$ is company's MW purchase during hour i.

$Sale_i$ is company's MW sale during hour i.

Company Annual Load Cost =

$$\sum_{i=1}^{8760}\sum_{j=1}^{N} LMP_{ij} * L_{ij}$$

Where:

L_{ij} is MW load on bus j during hour i.

LMP_{ij} is LMP at bus j during hour i.

N is the number of total load buses in the company.

Adjusted Production Cost savings and Load Cost savings were obtained by calculating the difference between the base case and project case. The benefit value metric utilized in the 2010 CBTCFS was the RECB II benefit which is calculated as follows:

*RECB II Benefit = 70% * Adjusted Production Cost Savings + 30% *Load Cost Savings*

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8.5.3.2 Calculating the Benefit to Cost Ratio

In the 2010 CBTCFS, all projects and their associated cost estimates were supplied directly by the TRG. The benefits and costs applied in the benefit to cost (B/C) ratio calculations were the present value of the benefits and costs for the first ten (10) years of the project life after the in-service year. Three (3) years of PROMOD production cost simulations, 2015, 2020, and 2025, were performed to calculate benefits spanning across an eleven (11) year timeframe. The benefit savings for years between the three (3) simulated years were derived using linear interpolation. Eleven (11) year net present value (NPV) RECB II benefit savings from 2015 to 2025 were calculated using an 8.39% discount rate.

In the 2010 CBTCFS, a 15% leveled fixed charge rate (LFCR) was utilized to determine annual costs for preliminary planning stages. 2010 project costs were escalated to 2015 dollars using an inflation rate of 1.74%. The B/C ratio was calculated by dividing the eleven year RECB II NPV benefits by the eleven (11) year NPV project costs.

8.5.4 CBTCFS–Lake Michigan Area

8.5.4.1 Flowgate Identification

Refer to Table 8.5-1, which displays congested flowgates identified in the Lake Michigan area from multiple sources. These flowgates were modeled in PROMOD cases and monitored during the CBTCFS simulation.

Table 8.5-1: Congested Flowgates for Lake Michigan area

Area	Congested Flowgate	Sources
N ILL	Crete-East Frankfort 345 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	Schahfer-Burr Oak 345 (flo) Wilton Center-Dumont 765	From We Energies–NIPSCO Constraints
N ILL	Nelson-Electric Junction 345 (flo) Cherry Valley-Silver Lake 345	From We Energies–Illinois / Wisconsin Constraints
E NIPS	Dune Acres-Michigan City 138 1&2 (flo) Wilton Center-Dumont 765	MISO Top 25 (latest 2 years data)
N ILL	Oak Grove-Galesburg 161 kV (flo) Nelson-Electric Junction 345	From We Energies–Illinois / Wisconsin Constraints
N ILL	Dresden to Ellwood 345 kV (flo) Dresden to Electric Junction 345 kV	From We Energies–Illinois / Wisconsin Constraints
N ILL	Crete-St. John 345 (flo) Wilton Center-Dumont 765	From We Energies–NIPSCO Constraints
E NIPS	Burr Oak 345/138 (flo) Burr Oak-Leesburg 345	Planning/Operations
W NIPS	Leesburg-Northeast 138 (flo) Leesburg-Hiple 345	Edison Mission Energy
SE WISC	Pleasant Prairie-Zion 345 PTDF[59]	From 2014 PROMOD (Top 50)
SE WISC	Pleasant Prairie-Zion 345 (flo) Cherry Valley-Silver Lake 345	From We Energies–Illinois / Wisconsin Constraints
N ILL	12204 Belvidere-Pleasant Valley 138 kV line l/o Cherry Valley-Silver Lake (15616) 345 kV line	Others
SE WISC	Pleasant Prairie to Racine_345 kV (flo) Pleasant_Prairie to Arcadian 345 kV	Others
N ILL	Cherry Valley-Silver Lake 345 (flo) Nelson-Electric Junction 345	Planning/Operations
SE WISC	BAIN_KENOSHA138kVZion_PleasantPrarie	Others

[59] An updated rating was received from ATC for the Pleasant Prairie to Zion line late in the study. When this new rating was applied, the Pleasant Prairie to Zion line was not binding in the base case.

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Table 8.5-1: Congested Flowgates for Lake Michigan area

Area	Congested Flowgate	Sources
SE WISC	Oak Creek 345/230 XFMR (flo) Oak Creek 230/138 kV XFMR #851	Others
W NIPS	Marktown-Inland Steel 5 13830 (flo) Whiting-Marktown 13824	Planning/Operations
E NIPS	Dune Acres-Michigan City 138 1 (flo) Dune Acres-Michigan City 138 2	Planning/Operations
SE WISC	Lakeview-Zion 138 (flo) Pleasant Prairie-Zion 345	Others
SE WISC	Pleasant Prairie–Racine 345KV	Others
SE WISC	Pleasant Prairie-Zion 345 (flo) Arcadian-Zion 345	From 2014 PROMOD (Top 50)
Central	Pontiac-Wilton Center 345 (flo) Pontiac-Dresden 345	From We Energies–Illinois / Wisconsin Constraints
SE WISC	Kenosha-Lakeview 138 for PleasPr-Zion 345	Others
SE WISC	Zion_Waukegan138_flo_Zion_Pleasant_Prairie345	Others
N ILL	Marengo-Pleasant Valley 138 (flo) Cherry Valley-Silver Lake 345	From We Energies–Illinois / Wisconsin Constraints
N ILL	Galesburg circuit 1392 138 kV (flo) Nelson to Electric Junction 345 kV	From We Energies–Illinois / Wisconsin Constraints
Central	Powerton Junction to Edwards 138 kV (flo) Dresden to Pontiac 345 kV	From We Energies–Illinois / Wisconsin Constraints
Central	Lever Road to Champagne 138 kV (flo) Dresden to Pontiac 345 kV	From We Energies–Illinois / Wisconsin Constraints
Central	Danvers Tap/ Raab Road –Washington St. to Bloomington 138 kV (flo) Dresden to Pontiac 345 kV	From We Energies–Illinois / Wisconsin Constraints
Central	Rising 345/138 XFMR 1 (flo) Clinton–Brokaw 345kV	From 2014 PROMOD (Top 50)
Central	PANA XFMR (flo) COFFEEN-COFFEEN NORTH	MISO Top 25 (latest 2 years data)
Central	Pana Xfmer (flo) Kincaid–Pawnee 345 kV (L2106)	Exelon PowerTeam
W NIPS	State Line-Wolf Lake 138 (flo) Burnham-Sheffield 345	From We Energies–NIPSCO Constraints
Central	Breed-Wheatland 345 kV line (flo) Rockport-Jefferson 765 kV	From 2014 PROMOD (Top 50)
Central	Lanesville 345/138 xfmr (flo) Pawnee-Kincaid-Latham T-Pontiac 345	Others
Central	Breed–Wheatland 345 kV (flo) Eugene–Cayuga 345 kV	Exelon PowerTeam
SE WISC	PADDOCK XFMR 1 (flo) PADDOCK-ROCKDALE	Others
SW WISC	Paddock–Townlie 138 kV (flo) Paddock–Blackhawk 138 kV	Exelon PowerTeam
E NIPS	Michigan City-Maple 138 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	New Carlisle-Trail Creek 138 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	Michigan City-Trail Creek 138 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	Michigan City-Trail Creek 138 (flo) Olive 345/138 (contingency includes Laporte-Olive 138)	Planning/Operations
E NIPS	Trail Creek-New Carlisle 138 (flo) Olive 345/138 (contingency includes Laporte-Olive 138)	Planning/Operations
E NIPS	Michigan City-Laporte 138 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	Burr Oak-Leesburg 345 kV (flo) WILTON CENTER-DUMONT 765	Planning/Operations
E NIPS	Marktown-Inland Steel 5 13830 (flo) Wilton Center-Dumont 765	Planning/Operations
E NIPS	Marktown-Inland Steel 5 13830 (flo) Burnham-Sheffield 345	Planning/Operations

Table 8.5-1: Congested Flowgates for Lake Michigan area

Area	Congested Flowgate	Sources
N ILL	Electric Junction–Waterman 138 kV (L11323) (flo) Cherry Valley–Silver Lake 345 kV (L15616)	Exelon PowerTeam
N ILL	Cherry Valley–Glidden 138 kV (L15627) (flo) Cherry Valley–Silver Lake 345 kV (L15616)	Exelon PowerTeam
N ILL	Burnham–Munster 345 kV (L17703) (flo) Wilton Center–Dumont 765 kV (L11215)	Exelon PowerTeam
N ILL	Kincaid–Pana 345 kV (L2105) (flo) Wilton Center–Dumont 765 kV (L11215)	Exelon PowerTeam
N ILL	Kincaid–Pana 345 kV (L2105) (flo) Pontiac–Wilton Center 345 kV (L8012)	Exelon PowerTeam
N ILL	Kincaid–Pana 345 kV (L2105) (flo) Kincaid–Pawnee 345 kV (L2106)	Exelon PowerTeam
N ILL	East Frankfort–Crete 345 kV (L6607) (flo) Burnham–Munster 345 kV (L17703)	Exelon PowerTeam
N ILL	Electric Junction–Waterman 138 kV (L11323) under base case conditions	Exelon PowerTeam
N ILL	Burnham–Munster 345 kV (L17723) (flo) Crete–St. Johns Tap 345 kV (L94507)	Exelon PowerTeam
N ILL	Stillman–Dixon 138 kV Red (L15621) (flo) Nelson–Electric Junction 345 kV (L15502)	Exelon PowerTeam
N ILL	Marengo–Pleasant Valley 138 kV Red (L12204) (flo) Nelson–Electric Junction 345 kV (L15502)	Exelon PowerTeam
N ILL	Clybourne–Diversey 138 kV Blue (L4013) under base case conditions	Exelon PowerTeam
N ILL	Quad Cities–Cordova 345 kV (L0402) (flo) Quad Cities–H471 345 kV (L0404)	Exelon PowerTeam
S MI	Palisades-Argenta 345 kV l/o Twin Branch-Argenta 345 kV	PJM
S MI	111 ELEC138 KV 11105 L/O 345L11126 Electric Jct-Wayne 345 kV Line	PJM
S MI	Cook-Palisades345/BentnHrbr-Palisades345	PJM
E NIPS	Dumont–Stillwell 345 kV (flo) Wilton Center–Dumont 765 kV (L11215)	Exelon PowerTeam
S IND	Sullivan Xfmr #1 (flo) Sullivan Xfmr #2	Exelon PowerTeam
N ILL	Pleasant Valley Xfmr # 81 (flo) Cherry Valley–Silver Lake 345 kV	Exelon PowerTeam

Table 8.5-2 displays the initial list of congested flowgates for Lake Michigan area from 2015 PROMOD case simulation. The list was considered an initial list because of the nature of this interface; i.e., if a given project was not robust enough, individual projects tested to mitigate one flowgate would prove to be counter-productive by actually increasing congestion on other flowgates not included in the list below.

Table 8.5-2: Congested flowgates for Lake Michigan area (2015 PROMOD simulation results)

Monitored element	Contingency Elements	2015 Total Binding Hours	2015 Total Shadow Price (k$/MWH)
MAREN;RT 271975 CE P VAL; R 272257 CE	CHERR; R -SILVE; R 1:	2220	348.8
17MCHCTY 255153 AEP 05LAPORT 243327 NIPS	05DUMONT -WILTO; 1:	1859	446.9
LAKEVIEW 699362 CE ZION ; 272896 WEC	ZION ; R -PLS PR21:	1657	68.7
NELSO; B 270828 CE P20 294490 CE	CHERR; R -SILVE; R 1:	1284	56.9
17MUNSTR 255109 NIPS BURNH;0R 270677 CE	05DUMONT -WILTO; 1: 17WOLFLK -SLINE; R 1:	1186	23.2
KENOSH45 699345 WEC LAKEVIEW 699362 WEC	ZION ; R -PLS PR21:	979	127.2

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Table 8.5-2: Congested flowgates for Lake Michigan area (2015 PROMOD simulation results)

Monitored element	Contingency Elements	2015 Total Binding Hours	2015 Total Shadow Price (k$/MWH)
KEWAN; 4 271838 CE KEWAN; 3 271839 CE	DRESD; R -PONTI; R 1:	943	45.4
17BUROAK 255101 NIPS 17BUROAK 255122 NIPS	17BUROAK -17LESBRG 1:	750	58.0
CORDO; B 270700 CE NELSO; B 270828 CE	QUAD3-11 -H471 ; 1:	432	10.5
LORET; B 270704 CE WILTO; B 270926 CE	DRESD; R -PONTI; R 1:	396	24.6
GALESBR5 636672 AMIL 4E GALES 348915 MIDAM	NELSO; B -P20 1:	348	25.1
7RISING348882 AMIL 4RISING348883 AMIL	05DUMONT -WILTO; 1:	229	5.3
17LESBRG 255146 NIPS 17NRTHES 255163 NIPS	17HIPLE-17LESBRG 1:	185	35.3
KEWAN; 5 271837 CE KEWAN; 4 271838 CE	DRESD; R -PONTI; R 1:	75	6.8
CRETE;BP 274750 NIPS 17STJOHN 255112 CE	05DUMONT -WILTO; 1:	43	1.2
LORET; B 270704 CE PONTI; B 270852 CE	DRESD; R -PONTI; R 1:	33	0.7
05NEWCAR 243349 AEP 17MAPLE255152 NIPS	05DUMONT -17STLWEL 1:	13	5.7
E FRA; R 270729 CE GOODI;1R 270767 CE	No Outage	11	0.1
17MONTCL 255158 NIPS 17EWINMC 255127 NIPS	05DUMONT -17STLWEL 1:	5	1.7
BYRON; R 270679 CE CHERR; R 270695 CE	BYRON; B -CHERR; B 1:	4	0.4
7RISING348882 AMIL 4RISING348883 AMIL	7BROKAW-7CLINTON 1:	4	0.0
4EDWARDS 349637 CE P39OP1 290054 AMIL	DRESD; R -PONTI; R 1:	3	0.1
WEMPL; B 270918 CE WEMPL;4M 275231 CE	CHERR; R -CHERR;2M 1:	2	0.0
05NEWCAR 243349 AEP 17TRALCK 255184 NIPS	05DUMONT -WILTO; 1:	1	0.0

8.5.4.2 Mitigation Plans

Mitigation plans are divided into west Lake Michigan area plans and east Lake Michigan area plans.

Table 8.5-3: Mitigation Projects in West Lake Michigan Area

Project ID	Proposed Mitigation Solutions TRG/Midwest ISO Staff	For Congested Flowgate
1	Long Term: Double Ckt. 345 kV line from Byron to Charter Grove to Wayne	Marengo-Pleasant Valley 138 kV Nelson-Electric Junction 345 kV Nelson Road to Dixon 138 kV Lakeview-Zion 138 kV
2	Intermediate: Reconductor entire 138 kV path from Cherry Valley to Silver Lake	Marengo-Pleasant Valley 138 kV
9	Intermediate: Rebuild Bain to Kenosha to Lakeview to Zion 138 kV circuit.	Kenosha-Lakeview 138 kV Bain to Kenosha138kV Lakeview-Zion 138 kV
10	Long Term: Add new ATC-ComEd Tie. New 345 kV circuit from Racine to Zion Energy Center: 6 miles of new ROW and approximately 12 miles existing ROW.	Kenosha-Lakeview 138 kV Bain to Kenosha138kV Pleasant Prairie-Zion 345 kV Lakeview-Zion 138 kV Pleasant Prairie-Zion 345 kV
12	Short Term: Replace wave traps and jumpers at ComEd's Zion station. Uprate few segments of 345 kV path (3 spans with clearance issues) between Pleasant Prairie to Zion.	Pleasant Prairie-Zion 345 kV Pleasant Prairie-Zion 345 kV
14	HVDC underneath Lake Michigan from Oak Creek to Michigan City and/or Point Beach to Luddington. WE proposes ratings of 1,000 MW (1,200 MVA), +/- 320 kV	Pleasant Prairie-Zion 345 kV
15	Intermediate: Reconductor Nelson Road to Dixon 138 kV line.	Nelson Road to Dixon 138 kV
19	Long Term: A new 345 kV line from Fargo substation to Oak Grove along with a 560 MVA, 345/138 kV transformer at Galesburg.	Galesburg circuit 1392 138 kV
55	Long Term: LS Power's 345kV project to fix Oa Grove constraints.	Galesburg circuit 1392 138 kV

Table 8.5-4: Mitigation Projects in East Lake Michigan Area

Project ID	Proposed Mitigation Solutions TRG/Midwest ISO Staff	For Congested Flowgate
3	Short Term: Replace line traps, re-sag East Frankfort-Crete	Crete-East Frankfort 345 kV
4	Intermediate: Loop in University Park to Olive 345 kV line into St. John 345 kV Station	Crete-East Frankfort 345 kV Crete-St. John 345 kV
6	Short Term: If limited by terminal equipment, replace terminal equipment.	Michigan City-Laporte 138 kV
7 (51)	Intermediate: Northwest Circuit Reconfiguration at Dune Acres and D. H. Mitchell 138kV Substations (MTEP P2792).	Michigan City-Laporte 138 kV
8 (52)	Long Term: Loop in Michigan City to Babcock 345 kV line into Lutchman Road 138 kV station creating a new 345/138 kV station. New 345 kV circuit from Lutchman Road 345 kV station to Olive 345 kV station	Michigan City-Laporte 138 kV
16	Short Term: Burnham–Replace line trap, relay and CT, Munster–Replace CT, add new breakers, replace conductor–NIPSCO side. Next limit is ComEd Conductor.	Burnham-Munster 345 kV
17	Short Term: Re-sag/re-conductor, plus upgrade NIPSCo CT	Crete-St. John 345 kV
18	Long Term: 2nd 345 kV circuit from St. John to Schahfer to Hiple	Crete-St. John 345 kV
50	E. Frankfort-Crete-St. John reconductoring	E. Frankfort-Crete-St. John
53	Bur Oak 2nd transformer	Bur Oak transformer
54	Babcock-Stillwell-Dumont 2nd 345kV line	138 kV outlets out of Michigan City
56	EON–New Albany substation	Duff-Dubois 138kV
57	Reynolds-E.Winamac-Burr Oak-Hiple	West to East NIPSCo flowgates congested flow loss of Wilton Center–Dumont
58	Reynolds-E.Winamac-Burr Oak-Stillwell	West to East NIPSCo flowgates congested flow loss of Wilton Center–Dumont

Based on individual mitigation projects, an array of portfolios—identified by the numeric and alphanumeric designations in the far left column of Table 8.5-5 below—were developed to fix congested flowgates in Lake Michigan area.

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
1)	3+16+17+18+51+52	NIPSCo	East LM	▪ Portfolio 1 = Portfolio 10+ project 18 (2nd 345kV circuit from St. John to Schahfer to Hiple) ▪ APC savings: $20.5 million to ComEd, $4.2 million to NIPSCo and $2.4 million to WE. ▪ $27.2 million total APC savings in LM area: 75% in ComEd, 16% in NIPSCo and 9% in WE. ▪ Generation revenue increase: 2.2% within ComEd, 1.9% within WE. ▪ 1.4% Total Generation Revenue Increase in LM Area. ▪ Compared to portfolio 10, portfolio 1 provides more benefit to ComEd but less to NIPSCo. Overall benefit is increased. ▪ Reliability Study: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 2,178 MW ($63,766 /MW)
1a)	3+16+17+18+51+52-Lutchman road Transformer	NIPSCo	East LM	▪ Portfolio 1a = Portfolio 1–Lutchman road transformer ▪ APC savings: $34.4 million to ComEd, $2.9 million to NIPSCo and $3.3 million to WE ▪ $40.6 million total APC savings in LM area: 85% in ComEd, 7% in NIPSCo, 8% in WE ▪ Generation revenue increase: 3.2% within ComEd, 2.9% within WE and 4.5% within NIPSCo ▪ 3.3% Total Generation Revenue Increase in LM Area. ▪ Compared to Portfolio 1, portfolio 1a provides better APC savings and total generation revenue for LM area. ▪ Reliability Study: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 2153 MW ($59,862 /MW)
1b)	3+16+17+18+51+52-Lutchman road Transformer-Schahfer 345kV tap	NIPSCo	East LM	▪ Reliability Study results: – Increase in Transfer Capability: 1,946 MW – $/MW Increase in Transfer Capability: $63,660 – Reconductoring East Frankfort-Crete-St. John would yield an additional 800 MW of incremental transfer with next limit at Burnham-Sheffield.

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
1d)	3+16+17+18+51+54	NIPSCo	East LM	▪ Portfolio 1d = Portfolio 1–Luchtman Project + Babcock to Stillwell to Dumont 345 kV 2nd Line ▪ APC savings: $33.7 million to ComEd, $4.7 million to NIPSCo and $3.3 million to WE. ▪ $41.7 million total APC savings in LM area: 81% in ComEd, 11% in NIPSCo and 8% in WE. ▪ Generation revenue increase: 3.1% within ComEd, 2.7% within WE, 8.6% within NIPSCo. ▪ 3.6% Total Generation Revenue Increase in LM Area. ▪ As a comparison to Portfolio 1, which contained the new Luchtman Road 345 / 138 kV Substation and 345 kV line to Olive Substation, the addition of the 2nd Babcock-Stillwell-Dumont 345 kV lines in Portfolio 1d provides considerably greater APC savings and generation revenue increase to LM area. ▪ The LM area, ComEd, NIPSCO and WE all benefit in APC savings ▪ The LM area, ComEd, NIPSCO and WE all benefit in generation savings ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 1,871 MW ($70,274 /MW)
2)	9+2+1	WE/ComEd	West LM	▪ APC savings: $9.8 million to ComEd, $4.2 million to MidAm. ▪ $6.3 million total APC savings in LM area ▪ No generation revenue increase within LM area
3)	10+1	WE/ComEd	West LM	▪ APC savings: $13 million to ComEd, $17.7 million to WE, $0.8 million to NIPSCo, $4.4 million to MidAm ▪ $29.8 million total APC savings in LM area: 41% in ComEd, 3% in NIPSCo, 56% in WE ▪ Big generation revenue increase within WE (13.7%) ▪ 0.3% Total Generation Revenue Increase in LM Area ▪ Load cost savings: $178 million to ComEd, $25.2 million to NIPSCo
4)	10+2	WE/ComEd	West LM	▪ APC savings: $10.7 million to ComEd, $20.7 million to WE ▪ Big generation revenue increase within WE (14.0%) ▪ $32.2 million total APC savings in LM area: 33% in ComEd, 64% in WE, 2% in NIPSCo ▪ 1.1% Total Generation Revenue Increase in LM Area ▪ Load cost savings: $114 million to ComEd, $13.8 millions to NIPSCo

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
5)	3+6+16+17	NIPSCo	East LM	▪ APC savings: $26.9 million to ComEd, $3.4 million to WE ▪ Generation revenue increase: 2.5% within ComEd, 2.5% within WE ▪ 2.0% Total Generation Revenue Increase in LM Area ▪ This portfolio provides good benefit to ComEd. ▪ Reliability Study results: – No-Harm Determination: No Issues – Increase in incremental transfer capability: 0 MW (Significant $'s /MW)
6)	3+6+16+17+2+15+9	NIPSCo/ComEd	East+West LM	▪ Portfolio 6 = Portfolio 5 + West LM area short-term fixes ▪ APC savings: $38 million to ComEd, $0.2 million to WE ▪ Generation revenue increase: 3.0% within ComEd, 0.5% within WE ▪ 1.9% Total Generation Revenue Increase in LM Area
6a)	3+6+16+17+2+15+10	NIPSCo/ComEd/WE	East+West LM	▪ APC savings: $38.1 million to ComEd, $26.4 million to WE, ▪ $64.4 million total APC savings for ComEd and WE: 59% in ComEd, 41% in WE ▪ Generation revenue increase: 0.7% within ComEd, 17.5% within WE ▪ 3.3% Total Generation Revenue Increase in LM Area ▪ This portfolio provides greatest benefit to LM area as a whole. ▪ Compared to Portfolio 6, with new Racine-Zion Energy Center line replacing project to reconductor Bain-Kenosha-Lakeview-Zion line, WE received largest APC savings and generation revenue increase
7)	16+51	NIPSCo	East LM	▪ APC savings: $1.3 to NIPSCo ▪ Generation revenue increase: 6.6% within NIPSCo ▪ This portfolio provides benefit to NIPSCo. ▪ Reliability Study analysis: – No-Harm Determination: No Issues – Increase in incremental transfer capability: 77 MW ($97,169 /MW)

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
8)	3+4+17	NIPSCo	East LM	▪ APC savings: \$8.1 million to ComEd, \$2.7 million to NIPSCo, \$1.4 million to WE ▪ \$12.2 million total APC savings in LM area: 67% in ComEd, 22% in NIPSCo, 11% in WE ▪ Generation revenue increase: 0.7% within ComEd, 0.7% within WE ▪ 0.2% total generation revenue increase in LM area ▪ This portfolio provides positive APC savings to the entire LM area ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 0 MW (Significant\$ /MW)
9)	3+4+17+53	NIPSCo	East LM	▪ Portfolio 9 = Portfolio 8 + 2nd Bur Oak transformer ▪ APC savings: \$8.3 million to ComEd, \$3.2 million to NIPSCo, \$1.2 million to WE ▪ \$12.7 million total APC savings in LM area: 65% in ComEd, 25% in NIPSCo, 9% in WE ▪ Generation revenue increase: 0.7% within ComEd, 0.7% within WE ▪ 0.3% total generation revenue increase in LM area ▪ This portfolio provides very similar benefit as portfolio 8. ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 543 MW (\$35,624 /MW)

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
9a)	3+4+17+51+53	NIPSCo	East LM	▪ Portfolio 9a = Portfolio 9 + NWI 138 kV Reconfiguration at Chicago Avenue, Dune Acres and Mitchell Substations ▪ APC savings: $3.2 million to ComEd, $1.7 million to NIPSCo, $0.2 million to WE ▪ $5.1 million total APC savings in LM area: 64% in ComEd, 33% in NIPSCo, 4% in WE ▪ Generation revenue increase: 0.0% within ComEd, 0.1% within WE, 3.8% within NIPSCo ▪ 0.4% total generation revenue increase in LM area ▪ As compared to Portfolio 9, Portfolio 9a provides improved benefit to PJM and diminished benefit to MISO. This is attributable to the NWI 138 kV Reconfiguration at Chicago Avenue, Dune Acres and Mitchell Substations. The generation revenue improves for NIPSCo. ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 865 MW ($27,186 /MW), the $/ MW is lower than portfolio 9 with over 300 MW of additional transfer capability thus proving value of the Northwest Reconfiguration Projects.
9b)	3+17+51+53	NIPSCo	East LM	▪ Portfolio 9b = Portfolio 9a–University Park–Olive looped into St. John ▪ APC savings: $1.8 million to NIPSCo ▪ $(2.6) million total APC savings in LM area: 64% in ComEd, 33% in NIPSCo, 4% in WE ▪ Generation revenue increase: -0.1% within ComEd, -0.7% within WE, 8.6% within NIPSCo ▪ 0.2% total generation revenue increase in LM area ▪ As compared to Portfolio 9, Portfolio 9b provides diminished benefit to both PJM and MISO. Further, the generation revenues for both ComEd and WE are relatively the same in Portfolio 9, 9a and 9b. Only NIPSCo will have increase generation revenues. ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 991 MW ($18,684 /MW)

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
9c)	3+4+17+51+53+Green Acre rating increase	NIPSCo+ComEd	East LM	▪ Portfolio 9c = Portfolio 9 + NWI 138 kV Reconfiguration at Chicago Avenue, Dune Acres and Mitchell Substations + Green Acre rating increase = Portfolio 9a + Green Acre rating increase ▪ APC savings: $3.2 million to ComEd; $1.65 million to NIPSCo ▪ Generation revenue increase: 3.8% within NIPSCo ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 865 MW ($27,446 /MW)
10)	3+16+17+51+52	NIPSCo	East LM	▪ APC savings: $3.2 million to ComEd, $9.1 million to NIPSCo, $1.4 million to WE ▪ $13.8 million total APC savings in LM area: 23% in ComEd, 66% in NIPSCo, 10% in WE ▪ $12 million total APC savings for MISO ▪ Generation revenue increase: 0.4% within ComEd, 0.5% within WE ▪ This portfolio provides best APC saving benefit to NIPSCo ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 883 MW (66,684/MW)
10a)	3+16+17+51+54+57	NIPSCo	East LM	▪ Portfolio 10a = Portfolio 10 + 2nd Babcock-Stillwell-Dumont 345 kV lines + Reynolds-East Winamac-Burr Oak-Hiple 345 kV lines ▪ APC savings: $35.1 million to ComEd, $3.5 million to NIPSCo, $3.5 million to WE ▪ $42.1 million total APC savings in LM area: 84% in ComEd, 8% in NIPSCo, 8% in WE ▪ 3.3% total generation revenue increase in LM area ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 926 MW ($193,825 /MW)

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
10b)	3+16+17+51+54+58	NIPSCo	East LM	▪ Portfolio 10b = Portfolio 10 + 2nd Babcock-Stillwell-Dumont 345 kV lines + Reynolds-East Winamac-Burr Oak-Stillwell 345 kV lines ▪ APC savings: $36.1 million to ComEd, $3.7 million to NIPSCo, $3.6 million to WE ▪ $43.5 million total APC savings in LM area: 84% in ComEd, 8% in NIPSCo, 8% in WE ▪ 3.3% total generation revenue increase in LM area ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 1,791 MW ($86,813 /MW)
11)	3+6+16+17+51+52+53	NIPSCo	East LM	▪ Portfolio 11 = Portfolio 10 + 2nd Bur Oak transformer ▪ APC savings: $20.1 million to ComEd, $0.3 million to NIPSCo, $3.2 million to WE ▪ $23.6 million total APC savings in LM area: 85% in ComEd, 1% in NIPSCo, 14% in WE ▪ Generation revenue increase: 1.9% within ComEd, 2.1% within WE ▪ 0.8% total generation revenue increase in LM area ▪ With all projects in portfolio 10 built, a 2nd Bur Oak transformer provides good APC savings and generation revenue increase to LM area, especially ComEd. ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 2,520 MW ($27,669 /MW)

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
11a)	3+6+16+17+51+53+54	NIPSCo	East LM	▪ Portfolio 11a = Portfolio 11 + 2nd Babcock to Stillwell to Dumont 345 kV lines–the new Luchtman Road 345 / 138 kV Substation and 345 kV line to Olive Substation ▪ APC savings: $35.0 million to ComEd, $3.8 million to NIPSCo, $3.1 million to WE ▪ $41.8 million total APC savings in LM area: 84% in ComEd, 9% in NIPSCo, 7% in WE ▪ Generation revenue increase: 3.0% within ComEd, 6.8% within NIPSCo, 2.8% within WE ▪ 3.4% total generation revenue increase in LM area ▪ As a comparison to Portfolio 11 that contained the new Luchtman Road 345 / 138 kV Substation and 345 kV line to Olive Substation, the 2nd Babcock-Stillwell-Dumont 345 kV lines provides considerably greater APC savings and generation revenue increase to LM area. ▪ The LM area, ComEd, NIPSCO and WE all benefit in APC savings ▪ LM area, ComEd and NIPSCO benefit in increased generation revenue. WE had marginally diminished generation revenues. ▪ Reliability Study results: – No-Harm Determination: To be performed in MTEP11 – Increase in incremental transfer capability: 2,570 MW ($26,197 /MW)
12)	1+3+10+16+17+18+51+52	NIPSCo/WE/ComEd	East+West LM	▪ Portfolio 12 = portfolio 1(East LM)+portfolio 3(West LM) ▪ APC savings: $34.9 million to ComEd, $6.3 million to NIPSCo, $22.1 million to WE ▪ $63.3 million total APC savings in LM area: 55% in ComEd, 10% in NIPSCo, 35% in WE ▪ Generation revenue increase by 16.8% in WE ▪ 1.9% total generation revenue increase in LM area
12a)	3+17+51+16+18+10+1+53	NIPSCo/WE/ComEd	East+West LM	▪ Portfolio 12a = Portfolio 12–Luchtman Road 345 / 138 kV Substation and 345 kV line to Olive Substation + 2nd Burr Oak 345 / 138 kV Transformer ▪ APC savings: $47.1 million to ComEd, $3.8 million to NIPSCo, $25.7 million to WE ▪ $76.6 million total APC savings in LM area: 62% in ComEd, 5% in NIPSCo, 33% in WE ▪ 4.1% total generation revenue increase in LM area

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Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
12b)	3+17+51+16+18+10+1+53+19	NIPSCo/WE/ComEd /MIDAM/AMIL	East+West LM	▪ Portfolio 12b = Portfolio 12a + Oakgrove-Fargo 345 kV line ▪ APC savings: $46.0 million to ComEd, $3.8 million to NIPSCo, $23.8 million to WE ▪ $73.6 million total APC savings in LM area: 63% in ComEd, 5% in NIPSCo, 32% in WE ▪ 3.0% total generation revenue increase in LM area
12c)	3+17+51+16+10+1+53	NIPSCo/WE/ComEd	East+West LM	▪ Portfolio 12c = Portfolio 12a–St John to Hiple 345 kV Line ▪ APC savings: $43.6 million to ComEd, $6.2 million to NIPSCo, $24.3 million to WE and $5.8 million to MidAmerican ▪ $74.1 million total APC savings in LM area: 59% in ComEd, 8% in NIPSCo, 33% in WE ▪ 2.6% total generation revenue increase in LM area
12d)	51+16+18+10+1+53+50	NIPSCo/WE/ComEd	East+West LM	▪ Portfolio 12d = Portfolio 12a + Reconductor East Frankfort–Crete–St. John 345 kV for Ratings Increase ▪ APC savings: $52.4 million to ComEd, $3.5 million to NIPSCo, $26.5 million to WE ▪ $82.3 million total APC savings in LM area: 64% in ComEd, 4% in NIPSCo, 32% in WE ▪ 4.4% total generation revenue increase in LM area
12e)	3+17+51+16+18+10+1+53+54	NIPSCo/WE/ComEd	East+West LM	▪ Portfolio 12e = Portfolio 12a + 2nd Babcock-Stillwell-Dumont 345 kV lines ▪ APC savings: $45.7 million to ComEd, $5.8 million to NIPSCo, $25.1 million to WE ▪ $76.5 million total APC savings in LM area: 60% in ComEd, 8% in NIPSCo, 33% in WE ▪ 4.5% total generation revenue increase in LM area
12f)	3+17+51+16+53+9+2	NIPSCo/WE/ComEd	East+West LM	▪ APC savings: $39.5 million to ComEd, $4.1 million to NIPSCo ▪ 1.86% total generation revenue increase in LM area
13)	10+19	WE/ComEd/AMIL	West LM	▪ APC savings: $5.4 million to ComEd, $19.7 million to WE, $5.1 million to MidAm ▪ $26 million total APC savings: 21% in ComEd, 4% in NIPSCo, 76% in WE ▪ Load cost savings: $157 million to ComEd, $34 million to AMIL, $20.2 million to NIPSCo ▪ Generation revenue increase: 13.2% within WE ▪ APC savings for WE mostly comes from Racine-Zion Energy Center 345kV line

Table 8.5-5: Mitigation Portfolios in Lake Michigan Area

Portfolio	Project Included	Control Areas	Geographic Area	Economic Study Highlights
13a)	10	WE/ComEd/AMIL	West LM	▪ APC savings: $3 million to ComEd, $21.86 million to WE ▪ Load cost savings: $104.44 million to ComEd, $16.29 million to AMIL, $11.87 million to NIPSCo ▪ Generation revenue increase: 14.2% within WE
13b)	19	WE/ComEd/AMIL	West LM	▪ APC savings: $2.53 million to ComEd; $4.78 million to MidAm ▪ Load cost savings: $54.59 million to ComEd, $19.19 million to AMIL, $8.47 million to NIPSCo
14)	14	WE/Michigan	East+West LM	▪ APC savings: $26.6 million to ComEd, $1.6 million to NIPSCo, $11.6 million to WE ▪ $39.8 million total APC savings in LM area: 67% in ComEd, 4% in NIPSCo, 29% in WE ▪ Generation revenue increase: 2.0% within ComEd, 13.6% within WE ▪ 3.9% total generation revenue increase in LM area
14a)	699367-243215-60 DC line	WE/Michigan	East+West LM	▪ APC savings: $30.2 million to ComEd, $2.2 million to NIPSCo, $25.3 million to WE ▪ $57.7 million total APC savings in LM area: 52% in ComEd, 4% in NIPSCo, 44% in WE ▪ Generation revenue increase: 1.9% within ComEd, 18.9% within WE ▪ 4.9% total generation revenue increase in LM area
14b)	699367-243215-60 DC line+ project 10	WE/Michigan	East+West LM	▪ APC savings: $33.6 million to ComEd, $2.3 million to NIPSCo, $33.8 million to WE ▪ $69.6 million total APC savings in LM area: 48% in ComEd, 3% in NIPSCo, 49% in WE ▪ Generation revenue increase: 1.2% within ComEd, 22.6% within WE ▪ 5.1% total generation revenue increase in LM area
15)	55	AMIL/MIDAM	West LM	▪ APC savings: $1.8 million to ComEd, $0.7 million to MidAm, $0.3 million to WE ▪ Generation revenue increase: 0.4% within MidAm, 0.1% within AMIL
15a)	55+10	AMIL/MIDAM/WE/ComEd	West LM	▪ APC savings: $5.2 million to ComEd, $21.6 million to WE ▪ Generation revenue increase: 13.8% within WE ▪ 0.9% total generation revenue increase in LM area

8.5.5 CBTCFS–Iowa-Nebraska Area

8.5.5.1 Flowgate Identification

Table 8.5-6 displays the congested flowgates for IA-NE area. Multiple sources were used to identify these flowgates.

Table 8.5-6: Congested flowgates for IA-NE Area

NERC ID	Constraint Name	Contingency Description
6007	Gerald Gentleman–Red Willow 345 kV	
6126	S1226-Tekamah 161 kV	S3451-Raun 345 kV
6009	Cooper South Interface	
6006	Gerald Gentleman Station	

Table 8.5-7 displays congested flowgates for the IA-NE area from the 2015 PROMOD case simulation. Some flowgates in this list are not in Table 8.5-7; these flowgates were new binding constraints in the 2015 simulation.

Table 8.5-7: Congested flowgates for IA-NE area (2015 PROMOD simulation results)

Monitored Element	Contingency Elements	2015 Total Binding Hours	2015 Total Shadow Price (k$/MWH)
INTERFACE WNE_WKS 13	No Outage	1119	64.40964
MIDWAY 5 541252 MIPU ST JOE 5 541253 MIPU	No Outage	420	23.751
INTERFACE FTCAL_S 18 16	No Outage	223	8.73045
TEKAMAH5 640377 MIDAM RAUN 5 635201 NPPD	RAUN 3 -S3451 3 1:	12	0.77172
S1226 5 646226 NPPD TEKAMAH5 640377 OPPD	RAUN 3 -S3451 3 1:	5	0.5033
INTERFACE GRIS_LNC 16 14	No Outage	12	0.33276
INTERFACE GGS 15 12	No Outage	15	0.1617

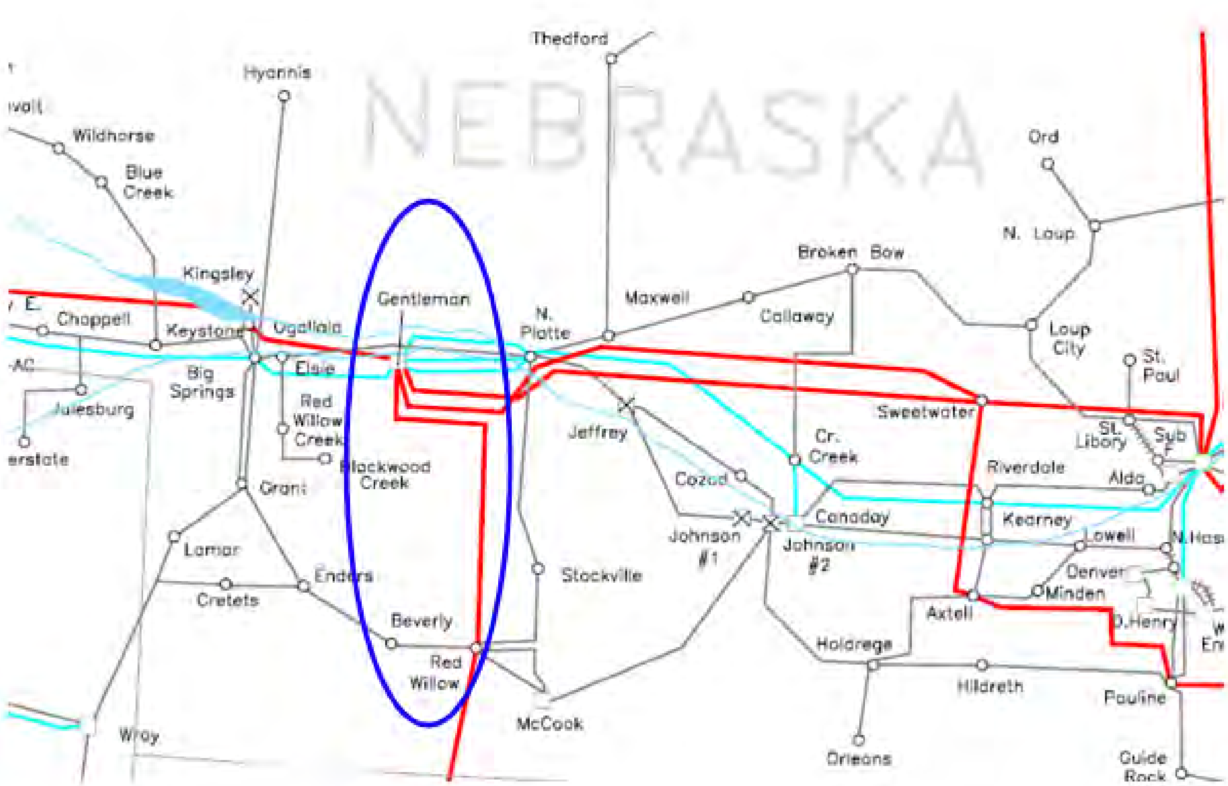

Figure 8.5-2: Flowgate 'Gerald Gentleman–Red Willow 345 kV'

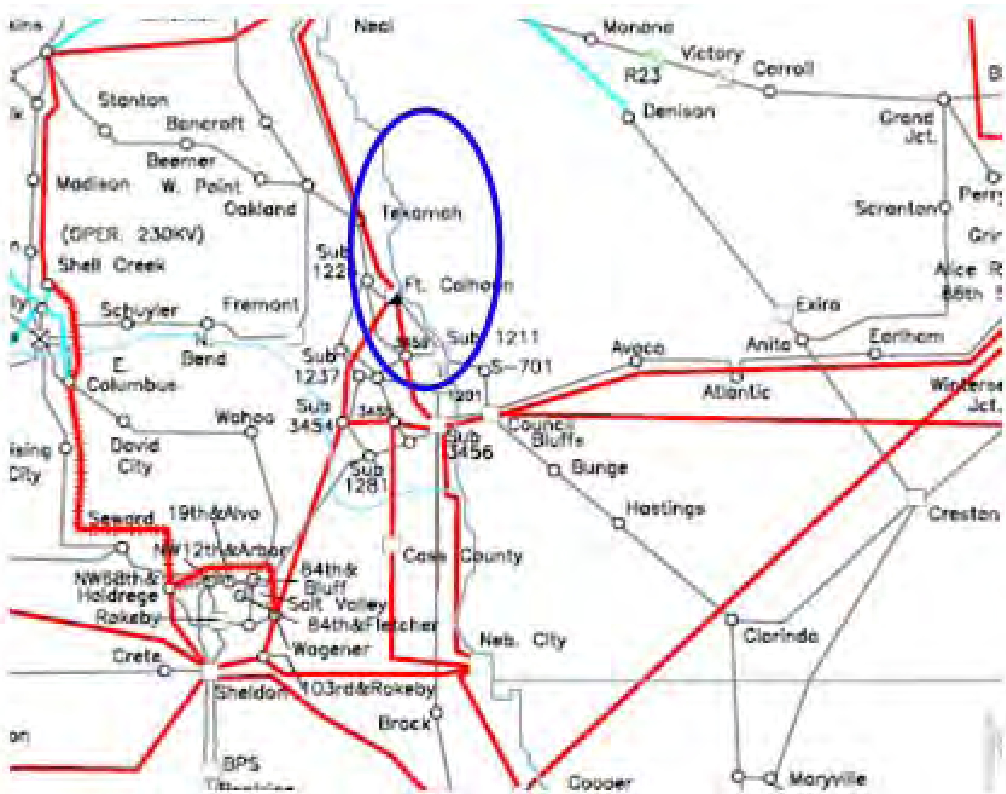

Figure 8.5-3: Flowgates 'S1226-Tekamah 161 kV' and 'FTCAL_S'

8.5.5.2 Mitigation Plans

Proposed mitigation plans are listed and described in Table 8.5-8, below.

Table 8.5-8: Mitigation Plan List

Run list	Description	Flowgate to Fix
1	Increase flowgate rating to 555 Winter and 505 Summer	Gerald Gentleman–Red Willow 345 kV
2	Build new GGS–Red Willow–Axtell 345 kV lines	Gerald Gentleman–Red Willow 345 kV
3	Intermediate: Rebuild S1226-Tekamah 161 kV line with bundled T2 Ibis with a 558 MVA rating and upgrade Tekamah 161 kV substation with at least 2000 Amp equipment	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV
4	Long Term: New 345 kV from Raun–Ft. Calhoun (Sub 3451)–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S
5	Long Term: New 345 kV from Raun–Council Bluffs	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S
6	Long Term: New 345 kV from Shell Creek–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S
7	Long Term: New 345 kV from Hoskins–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S

Mitigation plans in the IA-NE area were categorized as short-term, intermediate, or long-term fixes. Runs 1 and 3 serve as short-term/intermediate fixes while the other runs constitute long-term fixes.

8.5.5.3 Cost Estimation

The estimated cost for each mitigation plan is shown in Table 8.5-9, below.

Table 8.5-9: Cost Estimation

Run list	Description	Flowgate to Fix	Cost ($M) ± 20%
1	Increase flowgate rating to 555 Winter and 505 Summer	Gerald Gentleman–Red Willow 345 kV	20
2	Build new GGS–Red Willow–Axtell 345 kV lines	Gerald Gentleman–Red Willow 345 kV	260
3	Intermediate: Rebuild S1226-Tekamah 161 kV line with bundled T2 Ibis with a 558 MVA rating and upgrade Tekamah 161 kV substation with at least 2000 Amp equipment	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV	23.4
4	Long Term: New 345 kV from Raun–Ft. Calhoun (Sub 3451)–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	111.27
5	Long Term: New 345 kV from Raun–Council Bluffs	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	117.56
6	Long Term: New 345 kV from Shell Creek–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	92.88
7	Long Term: New 345 kV from Hoskins–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	138

8.5.5.4 Binding Constraints

Total binding hours, defined as hours when a loading limit was reached on a particular flowgate, and total shadow prices, defined as reductions to the cost of market dispatch from a small increase in the enforced loading limit, for relevant flowgates are listed in Tables 8.5-10, 8.5-11 and 8.5-12, which show the results for Runs 1–2, Runs 3–5, and Runs 6–7, respectively.

Table 8.5-10: Binding Constraints Comparison For Run 1 through Run 2

Monitored Element|Contingency Elements	Total Binding Hours Base Case	Total Shadow Price (k$/MWH) Base Case	Total Binding Hours Run 1	Total Shadow Price (k$/MWH) Run 1	Total Binding Hours Run 2	Total Shadow Price (k$/MWH) Run 2
COOPER 3 640139 MIPU ST JOE 3 541199 NPPD | 7FAIRPT -COOPER 3 1: 7FAIRPT -ST JOE 3 1:	Not Binding	Not Binding	Not Binding	Not Binding	1	0.0
INTERFACE WNE_WKS 13 |No Outage	1119	64.4	634	33.9	Fixed	Fixed
MIDWAY 5 541252 MIPU ST JOE 5 541253 MIPU |No Outage	420	23.8	433	24.1	449	24.9
INTERFACE FTCAL_S 18 16 |No Outage	223	8.7	236	9.5	245	10.4
TEKAMAH5 640377 MIDAM RAUN 5 635201 NPPD | RAUN 3 -S3451 3 1:	12	0.8	13	0.8	12	0.8
S1226 5 646226 NPPD TEKAMAH5 640377 OPPD | RAUN 3 -S3451 3 1:	5	0.5	5	0.5	6	0.5
INTERFACE GRIS_LNC 16 14 |No Outage	12	0.3	12	0.3	16	0.4
INTERFACE GGS 15 12 |No Outage	15	0.2	25	0.3	Fixed	Fixed

Table 8.5-11: Binding Constraints Comparison For Run 3 through Run 5

Monitored Element|Contingency Elements	Total Binding Hours Base Case	Total Shadow Price (k$/MWH) Base Case	Total Binding Hours Run 3	Total Shadow Price (k$/MWH) Run 3	Total Binding Hours Run 4	Total Shadow Price (k$/MWH) Run 4	Total Binding Hours Run 5	Total Shadow Price (k$/MWH) Run 5
70&BLUFF 650169 LES YBUS1664 98334 LES | S3454 3 -WAGENER 1:	Not Binding	Not Binding	Not Binding	Not Binding	3	0.1	1	0.0
INTERFACE WNE_WKS 13 |No Outage	1119	64.4	1117	64.2	1126	65.7	1128	66.3
MIDWAY 5 541252 MIPU ST JOE 5 541253 MIPU |No Outage	420	23.8	425	23.9	422	23.3	431	23.6
INTERFACE FTCAL_S 18 16 |No Outage	223	8.7	223	8.9	Fixed	Fixed	73	3.0
TEKAMAH5 640377 MIDAM RAUN 5 635201 NPPD | RAUN 3 -S3451 3 1:	12	0.8	25	1.2	Fixed	Fixed	Fixed	Fixed
S1226 5 646226 NPPD TEKAMAH5 640377 OPPD | RAUN 3 -S3451 3 1:	5	0.5	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
INTERFACE GRIS_LNC 16 14 |No Outage	12	0.3	11	0.3	12	0.3	11	0.3
INTERFACE GGS 15 12 |No Outage	15	0.2	15	0.2	14	0.1	12	0.1

Table 8.5-12: Binding Constraints Comparison For Run 6 through Run 7

Monitored Element|Contingency Elements	Total Binding Hours Base Case	Total Shadow Price (k$/MWH) Base Case	Total Binding Hours Run 6	Total Shadow Price (k$/MWH) Run 6	Total Binding Hours Run 7	Total Shadow Price (k$/MWH) Run 7
INTERFACE WNE_WKS 13 |No Outage	1119	64.4	1135	66.5	1134	66.6
MIDWAY 5 541252 MIPU ST JOE 5 541253 MIPU |No Outage	420	23.8	427	23.3	426	23.6
INTERFACE FTCAL_S 18 16 |No Outage	223	8.7	Fixed	Fixed	Fixed	Fixed
TEKAMAH5 640377 MIDAM RAUN 5 635201 NPPD | RAUN 3 -S3451 3 1:	12	0.8	13	1.3	5	0.5
S1226 5 646226 NPPD TEKAMAH5 640377 OPPD | RAUN 3 -S3451 3 1:	5	0.5	Fixed	Fixed	Fixed	Fixed
INTERFACE GRIS_LNC 16 14 |No Outage	12	0.3	11	0.3	11	0.3
INTERFACE GGS 15 12 |No Outage	15	0.2	14	0.1	14	0.1

8.5.5.5 Economic Benefits

The Adjusted Production Cost savings and the corresponding B/C ratio for all seven (7) runs are listed in Table 8.5-13 and Table 8.5-14, respectively. Table 8.5-15 and Table 8.5-16 show Load Cost savings and the corresponding B/C ratio for all seven (7) runs. Note values in black font denote positive savings and red font numbers within parenthesis indicate negative savings. Please note the B/C ratio for IA-NE area was calculated using an annualized project cost. 15% Annual RR and 3% inflation rate were used. All dollar values were converted to estimated 2015 USD values.

Table 8.5-13: Adjusted Production Cost Savings for All Runs

Company	Adj Production Cost Savings ($)						
	RUN_1	RUN_2	RUN_3	RUN_4	RUN_5	RUN_6	RUN_7
MIDAM	378,031	817,723	(139,743)	743,308	380,037	473,962	636,399
NPPD	1,359,168	3,154,896	31,570	(167,370)	(217,497)	(127,334)	(104,136)
OPPD	216,245	412,438	(22,528)	550,878	401,421	596,915	637,384
Total MISO	1,007,853	1,132,852	155,841	1,675,652	590,891	1,181,613	1,335,905
Total SPP	5,726,409	10,325,523	(35,134)	330,358	1,252,055	1,916,908	1,308,642

Table 8.5-14: APC Savings Versus Cost Ratio for All Runs

Company	B/C ratio for APC Savings						
	RUN_1	RUN_2	RUN_3	RUN_4	RUN_5	RUN_6	RUN_7
MIDAM	0.109	0.018	(0.034)	0.038	0.019	0.029	0.027
NPPD	0.391	0.070	0.008	(0.009)	(0.011)	(0.008)	(0.004)
OPPD	0.062	0.009	(0.006)	0.028	0.020	0.037	0.027
Total MISO	0.290	0.025	0.038	0.087	0.029	0.073	0.056
Total SPP	1.647	0.228	(0.009)	0.017	0.061	0.119	0.055

Table 8.5-15: Load Cost Savings for All Runs

Company	Load Cost Savings ($)						
	RUN_1	RUN_2	RUN_3	RUN_4	RUN_5	RUN_6	RUN_7
MIDAM	(1,005,097)	(1,963,841)	64,233	(32,949)	539,376	331,550	102,558
NPPD	(1,409,069)	(3,409,090)	110,164	(40,146)	134,097	409,894	204,992
OPPD	(738,501)	(1,480,894)	(95,373)	1,718,692	1,478,962	1,167,948	1,270,725
Total MISO	(7,163,112)	(10,862,166)	2,070,459	(2,425,729)	3,239,033	(1,692,490)	(6,009,682)
Total SPP	13,455,330	28,168,927	1,872,452	9,099,974	6,575,757	7,867,499	6,591,171

Table 8.5-16: Load Cost Savings versus Cost Ratio for All Runs

Company	B/C ratio for Load Cost Savings						
	RUN_1	RUN_2	RUN_3	RUN_4	RUN_5	RUN_6	RUN_7
MIDAM	(0.289)	(0.043)	0.016	(0.002)	0.026	0.021	0.004
NPPD	(0.405)	(0.075)	0.027	(0.002)	0.007	0.025	0.009
OPPD	(0.212)	(0.033)	(0.023)	0.089	0.072	0.072	0.053
Total MISO	(2.060)	(0.240)	0.509	(0.125)	0.158	(0.105)	(0.250)
Total SPP	3.869	0.623	0.460	0.470	0.322	0.487	0.275

8.5.5.6 Summary

The following bulleted items provide a summary of benefits:

- The transmission modeled in run 2 alleviated the targeted congestion on 'Gerald Gentleman–Red Willow 345 kV' while the transmission modeled in run 1 relieved this congestion.
- The transmission modeled in runs 3-7 alleviated the 'S1226-Tekamah 161 kV' congestion.
- The transmission modeled in runs 4, 6 and 7 alleviated the congestion on the 'FTCAL_S' interface, while the transmission modeled for run 5 relieved the congestion on this interface.
- None of the transmission projects investigated in the seven (7) runs described below has a B/C ratio larger than 0.6 for any individual company, such as MIDAM, NPPD, and OPPD.

Refer to Table 8.5-17, which summarizes the effect of each proposed project on the targeted flowgate.

Table 8.5-17: Effect of Each Proposed Project on the Targeted Flowgate

Run List	Description	Flowgate to Fix	Flowgate Fixed?
1	Increase flowgate rating to 555 Winter and 505 Summer	Gerald Gentleman–Red Willow 345 kV	Relieved
2	Build new GGS–Red Willow–Axtell 345 kV lines	Gerald Gentleman–Red Willow 345 kV	Fixed
3	Intermediate: Rebuild S1226-Tekamah 161 kV line with bundled T2 Ibis with a 558 MVA rating and upgrade Tekamah 161 kV substation with at least 2000 Amp equipment	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	S1126: Fixed FTCAL_S: Not Fixed
4	Long Term: New 345 kV from Raun–Ft. Calhoun (Sub 3451)–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	S1126: Fixed FTCAL_S: Fixed
5	Long Term: New 345 kV from Raun–Council Bluffs	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	S1126: Fixed FTCAL_S: Relieved
6	Long Term: New 345 kV from Shell Creek–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	S1126: Fixed FTCAL_S: Fixed
7	Long Term: New 345 kV from Hoskins–Omaha (new Sub 3452)	S1226-Tekamah 161 kV (flo) S3451-Raun 345 kV and FTCAL_S	S1126: Fixed FTCAL_S: Fixed

8.5.6 CBTCFS–Indiana-Kentucky Area

8.5.6.1 Flowgate Identification

Table 8.5-18 displays the congested flowgates for IN-KY area, which were identified using multiple sources.

Table 8.5-18: Congested flowgates for IN-KY Area

NERC ID	Constraint Name	Contingency Description
2245	Blue Lick–Bullitt Co. 161 kV (flo) Baker–Broadford 765 kV	
2872	Frankfort East–Tyrone 138 kV (flo) Ghent–West Lexington 345 kV	
1649	Avon 345/138 kV XFMR	
2557	Northeast Kentucky Interface	
2422	4N.HARD 340615 BREC 5N.HARD 340616 BREC 521	5COLEMAN -5NATAL 1:
2884	4GR STL 324256 LG&E 4CLVRPRT 324231 LG&E 448	7DAVIESS -7HARDIN 1:
2268	4SMITH 324309 LG&E 4GR STL 324256 LG&E 567	7SMITH -4SMITH 1:
1628	5WOLF EK 342790 EKPC 5RUSSCOJ 342370 EKPC 142	8VOLUNTE -8PHIPPS 1:
1659	5MCRACK 340620 BREC 5BRYAN 340568 BREC 131	8SHAWNEE -8MARSHAL 1:
1658	C33-Marshall 161 kV (flo) Shawnee-Marshall 500 kV	
	C33-Grahamville 161 kV (flo) Shawnee-Marshall 500 kV	

Table 8.5-19 displays the congested flowgates in the IN-KY area, as determined through the 2015 PROMOD case simulation. Some flowgates in this list are not in Table 8.5-43 because they were new binding constraints in the 2015 simulation. The Duff–Dubois 138kV flowgate (10DUFF13 253543 SIGE to 10DUBS13 253522 SIGE l/o 07VIC161–07RATTS 1) was also ranked as a congested flowgate in the Top Congested Flowgates Study.

Table 8.5-19: Congested flowgates for IN-KY area (2015 PROMOD simulation results)

Monitored element | Contingency Elements	Total Binding Hours	Total Shadow Price (k$/MWH)
05BREED 243213 AEP 16WHEAT 254539 IPL | 05JEFRSO -05ROCKPT 1:	3930	134.1
5MCRACK 340620 BREC 5BRYAN 340568 BREC | 8SHAWNEE -8MARSHAL 1:	1302	73.4
5BLUE LK 324134 LG&E 5CEDARIT 341306 EKPC |No Outage	67	11.2
10DUFF13 253543 SIGE 10DUBS13 253522 SIGE | 07VIC161 -07RATTS 1:	52	4.2
7TRIMBLE 324114 AEP 06CLIFTY 248000 LG&E | 05JEFRSO -05ROCKPT 1:	115	1.9
4N.HARD 340615 BREC 5N.HARD 340616 BREC | 5COLEMAN -5NATAL 1:	19	1.6
08GALAGH 249730 DEM 4P WEST 324294 LG&E | 05JEFRSO -05ROCKPT 1:	155	1.3
4P WEST 324294 LG&E 4PADDYSR 324295 LG&E |No Outage	69	0.4
5LIVNG C 324151 LG&E 5KMPAPNT 324170 LG&E | 5CRITTEN -5LIVNG C 1:	1	0.1
06CLIFTY 248009 AEP 4NORTHSD 324289 LG&E | 06CLIFTY -7TRIMBLE 1:	2	0.0
5ALCALDE 324130 LG&E 5ELIHU 324141 LG&E |No Outage	7	0.0
4SMITH 324309 LG&E 4GR STL 324256 LG&E | 7DAVIESS -7HARDIN 1:	1	0.0
5PINEVIL 360452 LG&E 5PINEVL1 324155 TVA | 8POCKETN -8PHIPPS 1:	1	0.0
4SMITH 324309 LG&E 4GR STL 324256 LG&E | 7SMITH -4SMITH 1:	1	0.0

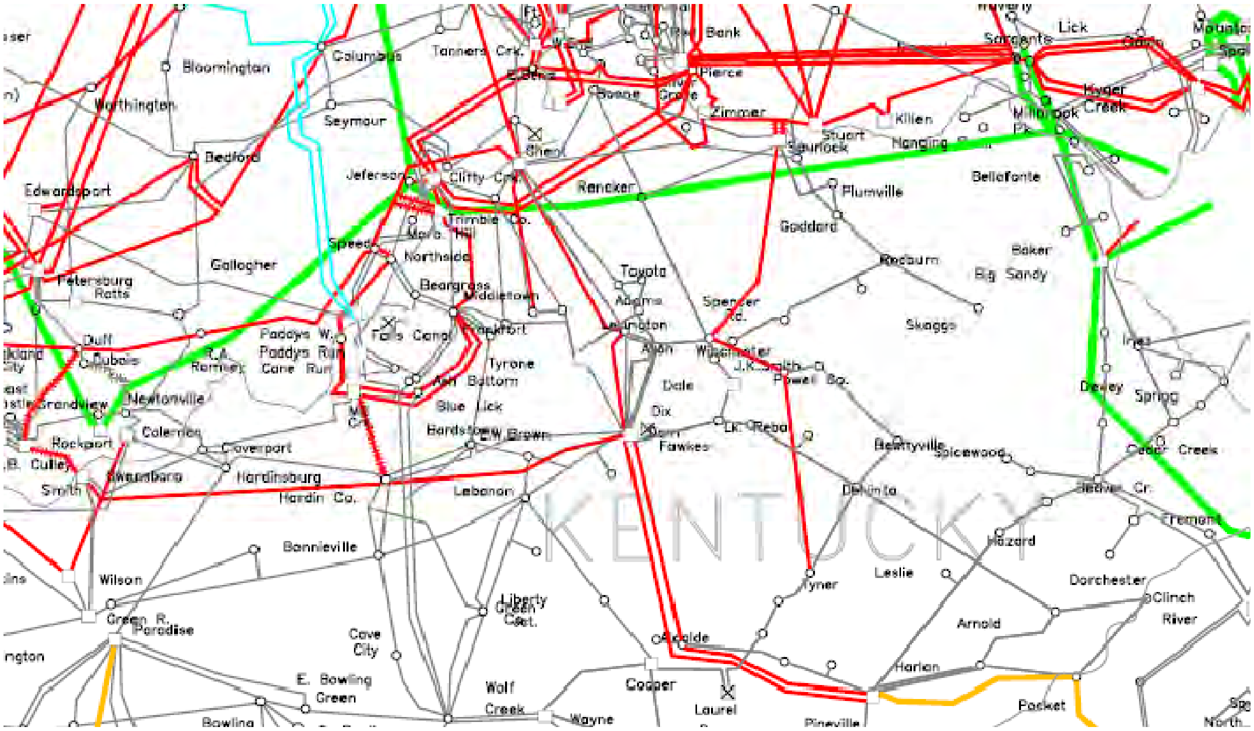

Figure 8.5-4: IN-KY Area

8.5.6.2 Mitigation Plans

LGEE proposed two (2) projects as mitigation to Duff-Dubois 138kV and Paddy West to Gallagher constraints: These two (2) projects include upgrading the New Albany station and the Paddy West to Speed 345kV line, respectively. Note that since these projects would help mitigate other flowgates in the IN-KY seam area, the projects were included in the Cross Border Top Congested Flowgate Study rather than in the Top Congested Flowgate Study.

New Albany Station

The estimated cost for this portfolio was $15 million. Its estimated in-service date was not known at the time of the CBTCFS, but, due to the minimal right of way required, it could be accomplished in a relatively short time.

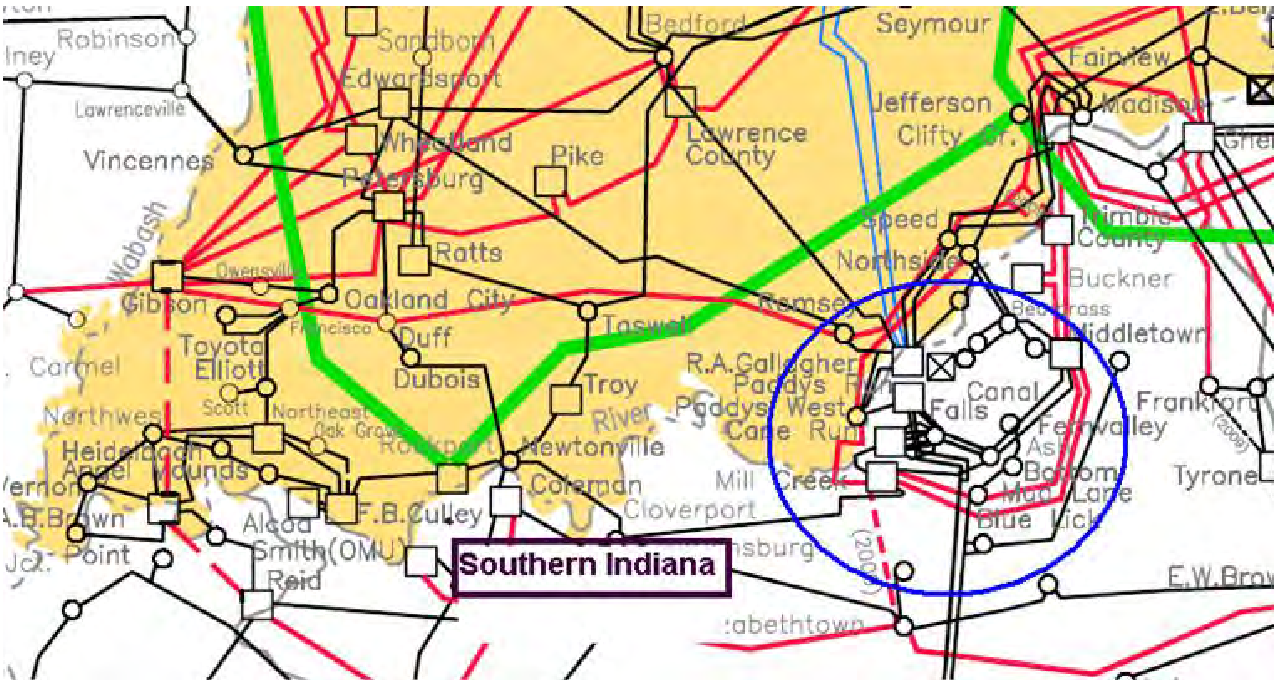

Figure 8.5-5: IN-KY Mitigation Plans

The CBTCFS determined the following potential economic benefits would be created by the New Albany project:

- APC savings: $0.43 million for LG&E
- Load Cost Savings: $1.62 million for LG&E

A reliability analysis, including a non-harm determination and an evaluation of the increase in incremental transfer capacity created by this project, was not performed during the MTEP10 study process.

Table 8.5-20 compares the total binding hours and total shadow prices for the base case run and the New Albany station project run.

Table 8.5-20: Binding Constraints Comparison

Monitored Element	Contingency Elements	Total binding Hours Base Case	Total Shadow Price (k$/MWH) Base Case	Total binding hours Project Case	Total Shadow Price (k$/MWH) Project Case
08GALAGH 249730 DEM 4P WEST 324294 LG&E	05JEFRSO -05ROCKPT 1:	155	1.3	Fixed	Fixed
7TRIMBLE 324114 AEP 06CLIFTY 248000 LG&E	05JEFRSO -05ROCKPT 1:	115	1.9	115	1.8
10DUFF13 253543 SIGE 10DUBS13 253522 SIGE	07VIC161 -07RATTS 1:	52	4.2	20	1.3

In comparison to the base case run results, the congestion on the Gallagher to Paddys West flowgate was reduced. The Duff-Dubois 138kV constraint bound for 52 hours with a shadow price of 4.2k$/MWh in base case and it bound for 20 hours with a shadow price of 1.3k$/MWh in the project run.

Paddy West to Speed 345kV Project

The estimated cost for this portfolio is $15 million; its estimated in-service date was not known at the time the CBTCFS report summary was written.

The CBTCFS determined the following potential economic benefits would be created by the Paddys West to Speed project:

- APC savings: $0.35 million for LG&E
- Load Cost Savings: $1.41 million for LG&E

Table 8.5-21 compares the total binding hours and total shadow prices for the base case run and New Albany station project run.

Table 8.5-21: Binding Constraints Comparison

Monitored Element	Contingency Elements	Total binding Hours Base Case	Total Shadow Price (k$/MWH) Base Case	Total binding hours Project Case	Total Shadow Price (k$/MWH) Project Case
08GALAGH 249730 DEM 4P WEST 324294 LG&E	05JEFRSO -05ROCKPT 1:	155	1.3	4	0
7TRIMBLE 324114 AEP 06CLIFTY 248000 LG&E	05JEFRSO -05ROCKPT 1:	115	1.9	113	198
10DUFF13 253543 SIGE 10DUBS13 253522 SIGE	07VIC161 -07RATTS 1:	52	4.2	31	1.9

In comparison to base case run results, the Gallagher to Paddys West constraint was largely relieved. The Duff-Dubois 138kV constraint bound for 52 hours with a shadow price of 4.2k$/MWh in the base case and it bound for 31 hours with a shadow price of 1.9k$/MWh in the project run.

8.5.7 Benefit to Cost Ratio Test for Selected Portfolios

Among the total of 38 portfolios tested for Lake Michigan area, only four (4) portfolios (portfolios 1, 8, 9, and 10) showed positive RECB II benefit to Midwest ISO for the 2015 PROMOD simulation. The following is a summary of the projects included in these portfolios:

- **Portfolio 1:** Re-sag St. John-Crete-E. Frankfort line; rating changes on Michigan-Laporte, Burnham-Munster; Northwest Circuit reconfiguration at Dune Acres and D. H. Mitchell 138kV Substations; loop in Michigan City to Babcock 345 kV line into Lutchman Road 138 kV station creating a new 345/138 kV station; new 345 kV circuit from Lutchman Road 345 kV station to Olive 345 kV station; new 2nd 345kV circuit from St. John to Schahfer to Hiple.
- **Portfolio 8:** Loop in University Park to Olive 345 kV line into St. John 345 kV Station, plus rating change on St. John-Crete-E. Frankfort.
- **Portfolio 9:** Loop in University Park to Olive 345 kV line into St. John 345 kV Station, plus rating change on St. John-Crete-E. Frankfort, and Burr Oak 2nd transformer.
- **Portfolio 10:** Re-sag St. John-Crete-E. Frankfort line; rating changes on Michigan-Laporte, Burnham-Munster; Northwest Circuit reconfiguration at Dune Acres and D. H. Mitchell 138kV Substations; loop in Michigan City to Babcock 345 kV line into Lutchman Road 138 kV station creating a new 345/138 kV station; new 345 kV circuit from Lutchman Road 345 kV station to Olive 345 kV station.

The in-service date for portfolios 8 and 9 were estimated as 2013, and portfolios 1 and 10 have an estimated 2015 in-service date. Based on these in-service dates, the B/C ratio threshold for RECB II cost allocation eligibility is equal to 1.6 for portfolios 8 and 9 and 2.0 for portfolios 1 and 10. The benefits and costs applied in the benefit to cost (B/C) ratio calculations were the present value for the first ten (10) years of the project life after the in-service year. Three (3) years of PROMOD production cost simulations—2015, 2020, and 2025—were performed to calculate benefits spanning across an eleven (11) year timeframe. Benefit savings for years between the three simulated years were derived using linear interpolation. The eleven (11) year net present value (NPV) RECB II benefit savings from 2015 to 2025 were calculated using an 8.39% discount rate. A 15% leveled fixed charge rate (LFCR) was utilized to determine annual costs for the preliminary stages of planning. B/C ratios of the four (4) portfolios are shown in Table 8.5-22 below. B/C ratios were based on a 70/30% weighting of Adjusted Production Cost and Load Cost savings for the Midwest ISO footprint. The aggregated cost shown below was the initial capital investment for each portfolio, presented as an 11-year aggregated cost from 2015 to 2025.

Table 8.5-22: Midwest ISO Selected Portfolios B/C ratio

Portfolio ID	Aggregated Cost (2015-$)	Load Cost Savings (2015-$)	Adjusted Production Cost Savings (2015-$)	RECB II (2015-$)	B/C ratio
1	172,442,880	(251,200,387)	559,286	(74,968,616)	(0.43)
8	10,795,887	(112,721,999)	56,851,795	5,979,657	0.55
9	23,203,961	(74,226,958)	59,437,806	19,338,377	0.83
10	73,110,854	(115,704,227)	108,591,470	41,302,761	0.56

Under these configurations and assumptions, none of the four (4) portfolios above were RECB II-eligible. Although some of the projects demonstrated significant Adjusted Projection Cost Savings, negative Load Cost Savings contributed to a reduction of the overall RECB II B/C ratio.

8.5.8 Conclusions and Next Steps

Performed in conjunction with the Top Congested Flowgate Study, the Cross Border Top Congested Flowgate Study is expected to be an ongoing effort, not an ad-hoc study. Together, these two studies address market congestion inside and along the seams of the Midwest ISO footprint. Over the course of the study process, projects or portfolios demonstrating value in the reduction of chronic congestion will be recommended to move to MTEP Appendix B or Appendix A (as applicable). Within the MTEP10 study process and in accordance with stakeholder input based upon the study findings, Midwest ISO recommends the following projects be moved to MTEP Appendix B:

- Racine-Zion Energy Center 345kV project
  - Based on the results of portfolios 13) and 13a).
- Oak Grove to Galesburg to Fargo 345kV project
  - Based on the results of portfolios 13) and 13b).
- Reynolds to East Winamac to Burr Oak to Hiple 345kV project
  - Based on the results from portfolios 10) and 10a).

Midwest ISO will continue conducting reliability-based, no-harm analysis, working with adjacent RTOs in further refinement of study models and testing cross-border market efficiency projects. The 2010 CBTCFS results described in this report are a snapshot of the study's progress as of August 16, 2010. Additional work is required to fully complete the Cross Border analysis and to recommend any applicable projects to Appendix A.

9 Regional Energy Policy Studies

9.1 Regional Generation Outlet Study (RGOS)

Renewable Portfolio Standards (RPS) passed by most Midwest ISO member states mandate meeting significant percentages of total electrical energy with renewable energy resources. To develop transmission portfolios fulfilling these requirements and meeting the objective function of achieving the lowest delivered dollar per MWh cost, Midwest ISO, with the assistance of state regulators and industry stakeholders, conducted the Regional Generator Outlet Study (RGOS).

9.1.1 RGOS Results Summary

During initial RGOS phases, analysis showed locating wind zones in a distributed manner throughout the system—as opposed to only locating the wind local to load or regionally where the best wind resources are located—results in a set of least-cost wind zones that help to reduce the delivered dollar per MWh cost needed to meet renewable energy requirements. From this earlier work, a combination of local and regional wind zones were identified and approved by the Upper Midwest Transmission Development Initiative (UMTDI). Further solidifying the validity of this methodology, the Midwest Governors' Association affirmed the method employed selecting these wind zones as the best approach to wind zone selection.

- RGOS determined the best fit solution to be a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

RGOS narrowed its focus to the development of three (3) transmission expansion scenarios to integrate wind from the designated zones: (1) a **Native Voltage** overlay that does *not* introduce new voltages such as 765kV in areas where they do not currently exist; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint.

- All three (3) transmission expansion scenarios meet respective state Renewable Portfolio Standards (RPS) requirements within the Midwest ISO footprint.
- The addition of renewable energy zones with the transmission overlays reduced the Midwest ISO load-weighted LMP between $4.30 to $4.90/MWh (2010 USD).
- The three (3) transmission overlay plans represent potential investment of $16B to $22B in 2010 USD in transmission over the next 20 years and consist of new transmission mileage of 6,400–8,000 miles.
- Total cost for the transmission overlays ranges from $19/MWh to $25/MWh. The cost of the wind generation is an additional $72/MWh. However, the overlays and generation also produce Adjusted Production Cost (APC) savings of $41/MWh to $43/MWh within the Midwest ISO footprint, creating a net cost of $49/MWh to $54/MWh. This cost does not include the value associated with an additional $20/MWh to $22/MWh of APC savings which would accrue to the rest of the Eastern Interconnect as the result of the RGOS transmission overlays and generation.
- Analyses of these three (3) transmission plan alternatives through the RGOS study, along with additional analytics performed within Midwest ISO planning processes, have identified a sub-set qualifying as inputs into the 2011 Candidate Multi-Value Project (MVP) portfolio analysis.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate MVPs designed to address current renewable energy mandates and the regional reliability needs of its members. Viable for near-term development, these projects represent $5.8B (2010 USD) of capital investment, approximately $4.4 billion in the Midwest ISO footprint with the remainder in PJM. These Candidate MVPs will serve as inputs into the 2011 Candidate MVP Portfolio analysis, the first of a cyclical set of MVP Portfolio analyses which will propose and evaluate transmission to meet a changing policy landscape. While none of the overlay scenarios—Native Voltage, 765 kV, Native Voltage with DC—has emerged as the definitive renewable energy transmission solution, it is important to note all selected Candidate MVPs are compatible with all three (3) transmission plans.

9.1.2 Long-term Transmission Strategies

All three (3) transmission plans were developed to provide reliable delivery of the RPS-identified levels of renewable energy. The study focused on monitoring and mitigating transmission system constraints 200 kV and higher. Refer to Figure 9.1-1. The study region consists of Midwest ISO and neighboring facilities including MAPP, Commonwealth Edison, and American Electric Power.

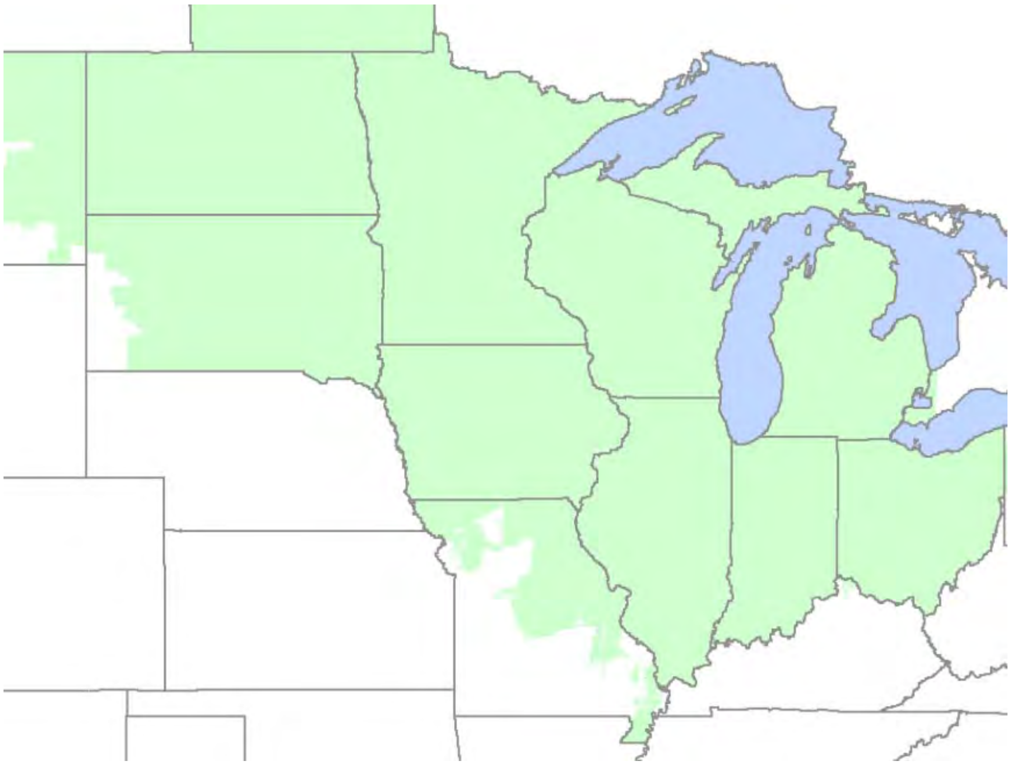

Figure 9.1-1: RGOS Study Footprint

Because RGOS transmission plans impact MAPP and PJM systems, references to these neighboring systems are made whenever RGOS is discussed, as the result of necessary assumptions regarding planning practices and strategic assessment. For example, a 765 kV grid logically connects into an already existing 765 backbone on the PJM system, but PJM references are not yet indicative of any projects in the PJM Regional Transmission Expansion Plan. Evaluation of overlays moving forward will continue to require coordination between impacted neighboring entities, including PJM, MAPP, SPP, and TVA.

9.1.2.1 The Study Footprint

The Midwest ISO region observed two (2) significant drivers for transmission expansion: (1) state RPS mandates; and (2) associated generation in the Midwest ISO Generation Interconnection Queue (GIQ).

Some states within the Midwest ISO purview; i.e., Montana, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Michigan, Ohio, and Pennsylvania, currently have RPS mandates that require varying percentages of electrical energy be met from renewable energy resources. North Dakota and South Dakota do not have an RPS but do have renewable goals. Kentucky and Indiana currently have neither RPS mandates nor goals. RPS mandates vary from state to state in specific requirements and implementation timing but generally start at or around 2010 and continue into the next decade. Refer to Figure 9.1-2.

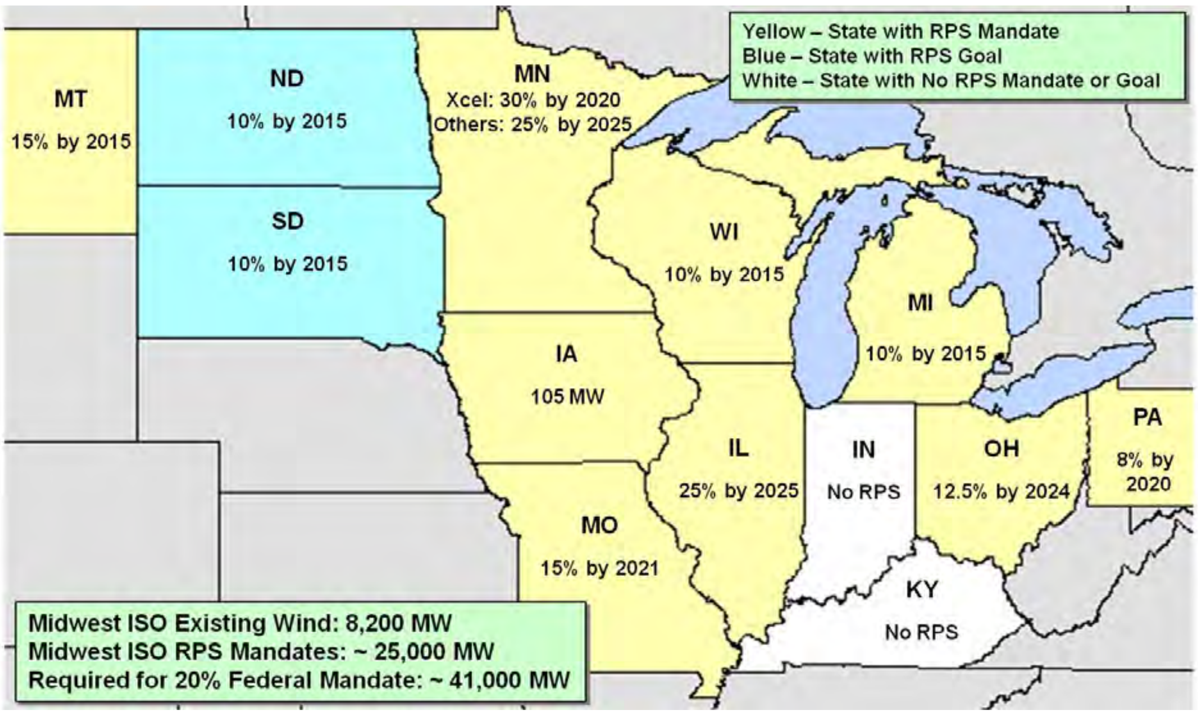

Figure 9.1-2: RPS Requirements within Midwest ISO Footprint

The second major driver for transmission expansion is the Midwest ISO Generation Interconnection Queue (GIQ), which—as of the end of July 2010—held approximately 64,500 MWs of wind requests. After careful examination of the inherently complex issues involved, Midwest ISO staff and stakeholders determined the GIQ process would not be an efficient means for building a cost-effective transmission system over the next 5–10 year period or in the foreseeable future beyond that time-frame.

9.1.2.2 Comparative Analysis

During the study process, the RGOS group focused on the development of three transmission expansion scenarios mentioned in the previous section: (1) a **Native Voltage** overlay that does *not* introduce new technology or voltages in the area; (2) a **765 kV** overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) **Native Voltage with DC** transmission that allows for the expansion of DC technology within the study footprint. Refer to Table 9.1-1, which describes the physical characteristics of the three (3) overlay scenarios. It shows how the number of new lines, total line miles, acres of right of way, river crossings, and substations differ between scenarios. It also breaks down each scenario geographically between Midwest ISO, PJM, and Total study footprint. Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM.

The data reveals, for example, that the Native Voltage scenario has more new lines, more line miles, and more substations than the 765 kV overlay for the total study footprint but does, however, require less acres of right-of-way.

Table 9.1-1: Summary of RGOS Overlay Physical Infrastructure

Overlay	Purview	# of New Lines	Line Miles	Acres of Right of Way	River Crossings	Substations
Native	**Total**	**122**	**6,795**	**126,637**	**7**	**139**
	Midwest ISO	107	5,938	109,248	7	119
	PJM	13	685	13,197	0	20
	Joint/DC	2	173	4,192	0	0
765	**Total**	**90**	**6,412**	**136,612**	**7**	**124**
	Midwest ISO	69	5,029	104582	7	94
	PJM	17	1,047	23,891	0	30
	Joint/DC	4	336	8,139	0	0
Native DC	**Total**	**113**	**8,033**	**150,094**	**7**	**132**
	Midwest ISO	95	5,340	100,917	7	101
	PJM	17	836	16,289	0	21
	Joint/DC	1	1,857	32,887	0	10

*** Right of Way widths used in Calculation: 230 kV–100ft ; 345 kV–150ft; Dbl Ckt 345 kV–160ft; 765 kV–200 ft**

Refer to Table 9.1-2, which describes the costs to build new transmission and generation for the three (3) scenarios. Transmission costs were calculated by multiplying line mileage by cost per mile, with cost per mile differentiated by state. The calculations also included substations, transformers, and related infrastructure. Construction cost estimates also attempted to include costs associated with the regulatory permitting process. The table categorizes these factors by Native, 765 kW, and native scenarios, and Midwest ISO, PJM, and Joint/DC geographies. Based on these factors, RGOS produced total overlay costs estimate range from $16.3 billion (2010 USD) for the Native system, $20.2 billion for 765 kW, and $21.9 billion for the Native/DC scenario for the RGOS study footprint. Generation costs were calculated by multiplying the total amount of RPS required MW by construction cost estimates of $2 million per MW. This cost, at $58.1 billion (2010 USD), does not vary between scenarios.

Table 9.1-2: 2010 Cost Summary - Construction (2010 USD in Millions)

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	$16,301	$20,249	$21,544
	Midwest ISO	$13,865	$15,099	$12,662
	PJM	$1,952	$4,196	$2,138
	Joint/DC*	$484	$955	6,744
Generation	**Total**	$58,100	$58,100	$58,100
	Midwest ISO	$44,737	$44,737	$44,737
	PJM	$13,363	$13,363	$13,363
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	$74,401	$78,349	$79,644
	Midwest ISO	$58,602	$59,836	$57,399
	PJM	$15,315	$17,559	$15,501
	Joint/DC*	$484	$955	$6,744

Table 9.1-3 describes 2010 Levelized Annual Costs, which are the total revenue requirements (2010 USD) for the three scenarios. Revenue requirements refer to the total annualized costs for the new transmission and generation. These levelized annual costs are determined through application of proxy Attachment O of the Midwest ISO FERC tariff. The table breaks these factors down by Native, 765 kW, and native scenarios, and Midwest ISO, PJM, and Joint/DC geographies.

RGOS found total study footprint annual levelized costs vary between $1.7 billion per year for Native Voltage, to $2.1 for 765 kV, to $2.2 for Native Voltage with DC (Native DC), with generation annual costs at $4.9 billion.

Table 9.1-3: Cost Summary - 2010 Levelized Annual Costs (2010 USD in Millions)***

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$1,686**	**$2,064**	**$2,188**
	Midwest ISO	$1,419	$1,537	$1,304
	PJM	$209	$424	$227
	Joint/DC*	$57	$102	$656
Generation	**Total**	**$6,334**	**$6,334**	**$6,334**
	Midwest ISO	$4,931	$4,931	$4,931
	PJM	$1,402	$1,402	$1,402
	Joint/DC*	$ -	$ -	$ -
Total	**Total**	**$8,019**	**$8,397**	**$8,521**
	Midwest ISO	$6,351	$6,469	$6,236
	PJM	$1,612	$1,826	$1,630
	Joint/DC*	$57	$102	$656

Table 9.1-4 describes 2010 Annual Costs $/MWh, which takes the total costs from Table 9.1-3 and presents it as a per MWh value. This calculation is based on 88.6 TWh of energy delivered from renewable energy zones. Table 9.1-4 describes transmission and generation costs for the modeled RGOS renewable wind zone energy.This table indicates transmission costs for the modeled RGOS renewable energy wind zone delivered would be $19, $23, or $25 per MWh based on the addition of the various RGOS transmission overlays in the Midwest ISO footprint. On the generation side, MWh cost would increase to $72/MWh for all scenarios.

Table 9.1-4: Cost Summary – 2010 Annual Costs ($/MWh*)**

Category	Geographic Purview	Native Voltage	765 kV	Native DC
Transmission	**Total**	**$19**	**$23**	**$25**
	Midwest ISO	$16	$17	$15
	PJM	$2	$5	$3
	Joint/DC*	$1	$1	$7
Generation	**Total**	**$72**	**$72**	**$72**
	Midwest ISO	$56	$56	$56
	PJM	$16	$16	$16
	Joint/DC*	$0	$0	$0
Total	**Total**	**$91**	**$95**	**$96**
	Midwest ISO	$72	$73	$70
	PJM	$18	$21	$18
	Joint/DC*	$1	$1	$7

* Joint/DC represents AC and DC transmission projects that may constitute shared costs between Midwest ISO and PJM. Note, too, there is one AC project: the Pioneer 765 kV project in Indiana. The rest represent DC projects.

** Transmission costs include line and substation cost estimates

*** Levelized annual costs determined through application of proxy Attachment O calculation to determine annual revenue requirements

**** Calculation based on energy delivered from renewable energy zones: 88.6 TWh (each overlay effectively delivered the same amount of energy)

Adding wind to the system reduces the total energy costs. This benefit is captured through the Adjusted Production Cost (APC) calculated by dividing total production cost savings by total MWh. Refer to Table 9.1-5, which describes regional per MWh adjusted production savings based on 88.6 TWh of RGOS wind zone delivered energy. Adjusted cost savings within the Midwest ISO footprint for Native Voltage, 765 kW, and Native Voltage with DC (Native DC) scenarios would be $41/MWh, $43/MWh, and $43/MWh (2010 USD), respectively.

Table 9.1-5: 2010 Adjusted Production Cost (APC) Savings ($/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	$41	$43	$42
Midwest ISO/MAPP	$56	$57	$57
Midwest ISO/MAPP/PJM	$62	$63	$63
Eastern Interconnect	$62	$63	$63

Table 9.1-6 summarizes net cost. The net cost, per MWh of delivered RGOS wind energy, is calculated by subtracting 2010 MWh Adjusted Production Cost (APC) benefits from 2010 installed costs.

Table 9.1-6: 2010 Net Total Cost Summary ($/MWh)

Entity	Native Voltage	765 kV	Native DC
Midwest ISO	$49	$52	$54
Midwest ISO/MAPP	$35	$37	$39
Midwest ISO/MAPP/PJM	$29	$32	$33
Eastern Interconnect	$29	$32	$33

When analyzing the information presented in Tables 9.1-1–9.1-6, it is important to note while overall metrics show some disparity among plans, the Native Voltage and 765 kV overlays are very similar when looking solely at Midwest ISO impacts. It is more problematic, however, to conduct a comparison of the Native Voltage with DC option with the other overlays since DC transmission costs are not categorized solely by Midwest ISO or PJM because the lines start in one system and terminate in the other.

9.1.2.3 Native Voltage Overlay

The Native Voltage solution focuses on the development of transmission that does **not** introduce a new voltage class within areas. This means areas with 345 kV transmission since the native Extra High Voltage (EHV) must be limited to a maximum of 345 kV transmission for new infrastructure expansion. However, those areas with existing 765 kV transmission would be allowed to expand 765 kV infrastructure. Refer to Figure 9.1-3, which depicts the Native Voltage transmission solution meeting RGOS design criteria.

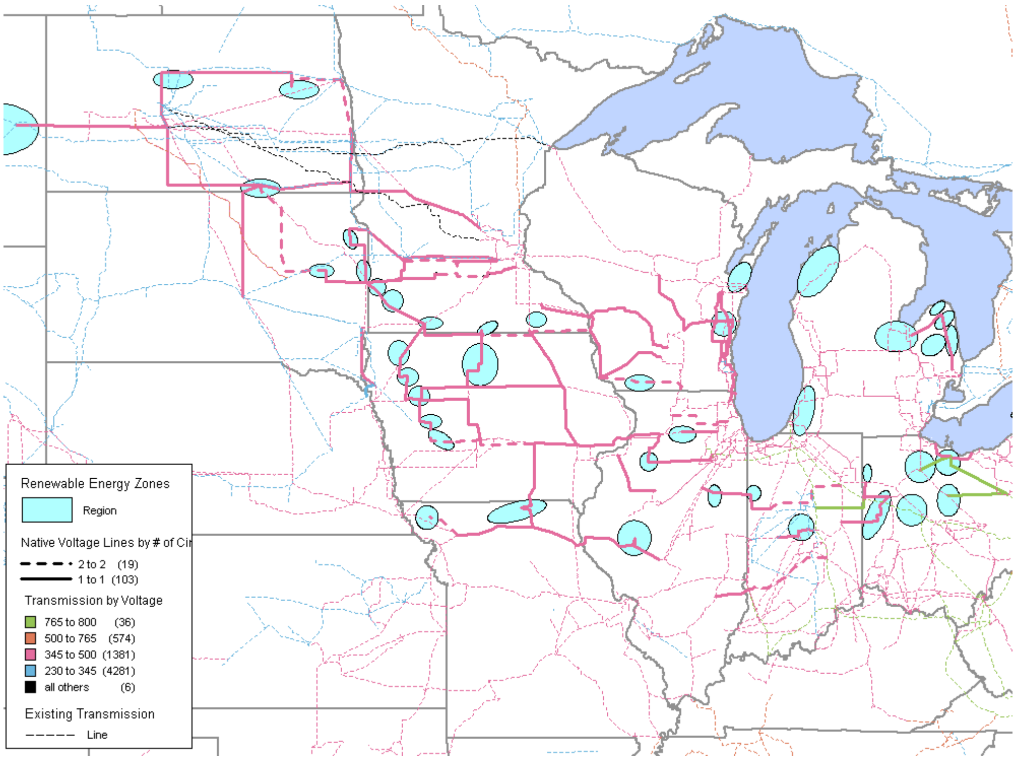

Figure 9.1-3: Native Voltage Transmission Overlay Strategy

As currently designed, the Native Voltage transmission overlay has the lowest construction cost, requiring about $1,200M less in capital investment to construct. Although Native Voltage has more line miles than the 765 kV overlay, it requires fewer acres of right-of-way. The Native Voltage plan, like the two other transmission overlays, achieves the reliability objectives of the study. However, this plan does not extend as far south as the other two plans. This is part of the reason the other plans have higher construction/capital costs.

The Native Voltage strategy does have some risks and benefits. If renewable energy mandates are increased within the study footprint, or if there is an increased need for exports, additional transmission may need to be constructed. This would likely require additional right-of-way and more miles of transmission line when compared to the 765 kV and Native Voltage with DC overlays. In the long-term, this may result in escalating costs and environmental impacts that are not accounted for in this study. However, the Native Voltage Overlay has less dependence on the future transmission expansion plans of neighbors. By not introducing new voltages, the Native Voltage strategy readily integrates into the existing Midwest ISO system and may allow for quicker construction and better sequencing with other overlay components compared with the 765 kV overlays. Additionally, this strategy possibly puts less cost at risk if actual wind requirements of the Midwest ISO states are determined to be lower than the amount of wind included in the RGOS study—a determination not yet made. This risk will be minimized by carefully sequencing the construction of whichever overlay is chosen.

9.1.2.4 765 kV Overlay

The 765 kV solution emphasizes the development of transmission that introduces a new voltage class to much of the RGOS footprint. Figure 9.1-4 depicts the 765 kV transmission solution meeting RGOS design criteria.

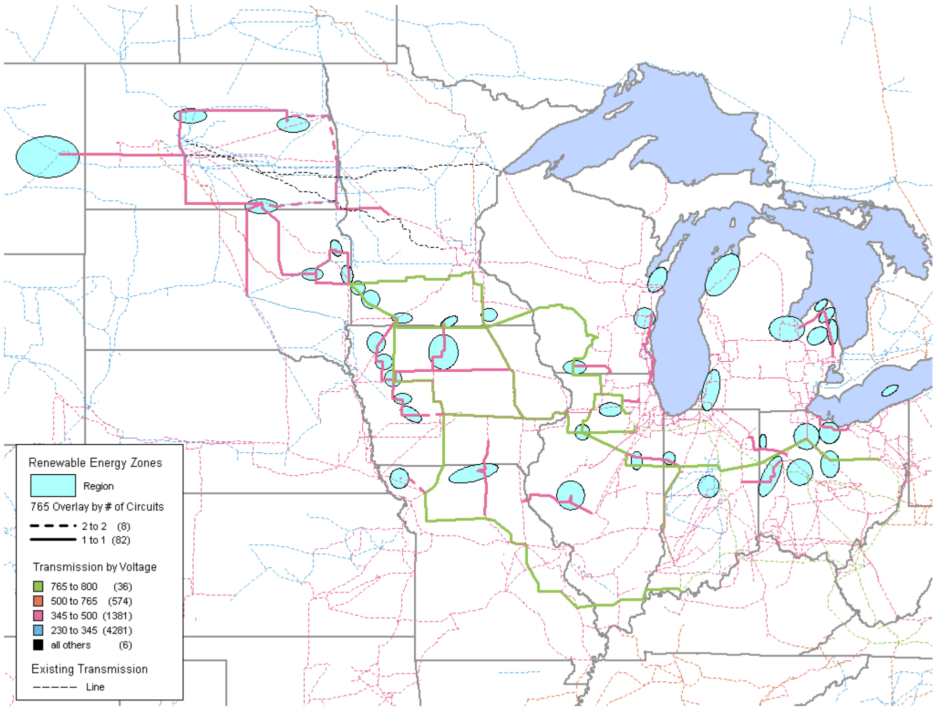

Figure 9.1-4: 765 kV Transmission Overlay Strategy

The 765 kV overlay results in Adjusted Production Cost (APC) savings greater than the Native Voltage overlay. The 765 kV overlay also uses less line miles of transmission lines than the Native Voltage overlay, although the 765 kV overlay does require more acres of right-of-way due to the wider right-of-way needed for 765 kV transmission. However, in the Midwest ISO portion of the overlay, the comparison of transmission costs, mileage, and acreage may favor the 765 kV plan.

Selecting 765 kV as an overall strategy also holds risks. For example, system development may not be achievable without cooperation among the transmission expansion strategies of two RTO regions; e.g., investment in 765 kV construction within Midwest ISO may be more heavily dependent upon the investment of the 765 kV grid within the western PJM region than the Native Voltage overlay. Proper coordination of development within Midwest ISO is also an important consideration. Transmission built in the western portion of the footprint to 765 kV standards may default to 345 kV transmission operation if eastern portions of the Midwest ISO footprint do not commit to the same 765 kV development in the same time-frame, resulting in potential cost risk. Finally, introducing 765 kV into new portions of the footprint will require costs associated with the learning curve required for the development and management necessitated by a new voltage type in the system.

Adopting a 765 kV strategy does, however, offer a number of benefits. For example, the 765 kV overlay demonstrates the need for less miles of transmission than the miles of transmission required by Native Voltage to deliver the same amount of renewable energy. If wind development in the region continues to increase over the future—and it is reasonable to expect this would be a continuing trend—the 765 kV overlay will reduce the amount of environmental impact caused by transmission construction. Although the current 765 kV plan has the potential to create better interconnection access to areas to the south and Southeast of Midwest ISO, additional refinement of the 765 kV plan that results in the same geographical footprint access as the current Native Voltage design could further reduce the line mileage of the strategy while also reducing total costs.

9.1.2.5 Native Voltage with DC Overlay

The Native Voltage with DC solution reflects the Technical Review Group (TRG) desire to develop an overlay with a dual +/- 800kV and HVDC strategy within RGOS study footprint. Figure 9.1-5 shows the Native Voltage with DC transmission solution that meets RGOS design criteria.

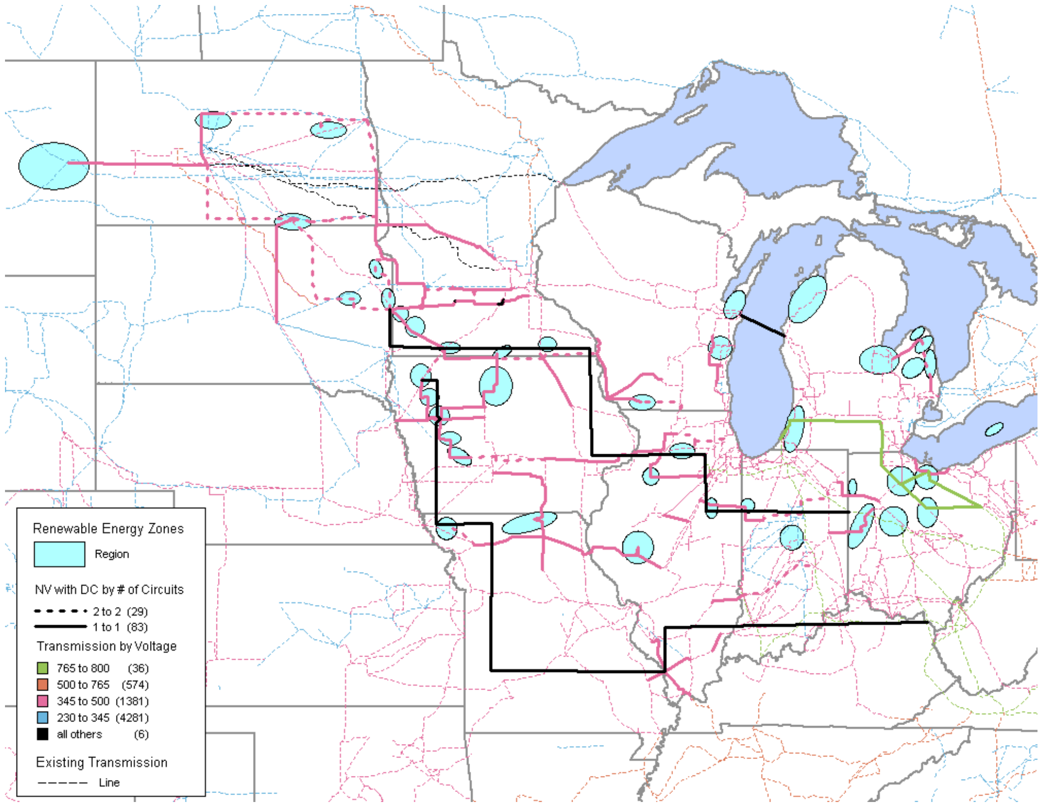

Figure 9.1-5: Native Voltage with DC Transmission Overlay Strategy

The Native Voltage with DC overlay provides benefits to the system—reducing, for example, the amount of AC transmission needed by allowing energy to be gathered in the western region of the study footprint and delivered to points to the east while avoiding potential impacts on the underlying systems. This scenario demonstrates that the crossing under Lake Michigan has the potential to reduce land-based transmission within Wisconsin and along the southern shores of Lake Michigan. Like 765 kV, Native Voltage with DC accesses part of the footprint that the Native Voltage strategy would not.

Land-based High Voltage Direct Current (HVDC) transmission was modeled as conventional HVDC. However, there are other options for the DC design available for future analysis that may provide for operational benefit that could not be captured through this study. For example, HVDC–Voltage Source Control (VSC) provides real Power Flow control beyond generator dispatch at full range of capability where conventional has limitations at lightly loaded schedules. In addition, HVDC–VSC has voltage control capability independent of the real Power Flow on the line, whereas conventional design reactive support is dependent on the real Power Flow.

Unfortunately the costs of adding DC to the system are rather high compared to the AC alternatives at shorter distance needs, and the entries to tap the lines are much more expensive and less integrated than providing AC paths across the system. However, it is difficult to eliminate DC transmission as an option for bulk energy delivery from renewable energy areas across long distances because of not-yet-evaluated option values. Proper evaluation of these other metrics along with improved design of what type of HVDC as well as interconnection locations could improve the case for long-distance DC energy delivery.

9.1.3 RGOS Candidate Multi-Value Projects

Although RGOS focused on the development of holistic system solutions meeting long-term needs for the integration of renewable resources into the transmission system, it is important to identify an initial group of projects, or Candidate Multi-Value Projects (MVPs), that are compatible with the three overlays that provide a practical first step towards meeting the renewable resource requirements. These RGOS-identified projects will require additional, more detailed analysis. Because a Midwest ISO long-range transmission expansion strategy has not yet been determined and was not within the scope of RGOS analysis, it is important Candidate MVPs not pre-determine Midwest ISO long-range strategic aims and equally important Candidate MVPs prove compatible with all potential strategies.

Refer to the Venn diagram in Figure 9.1-6, which encapsulates RGOS Candidate MVP selection.

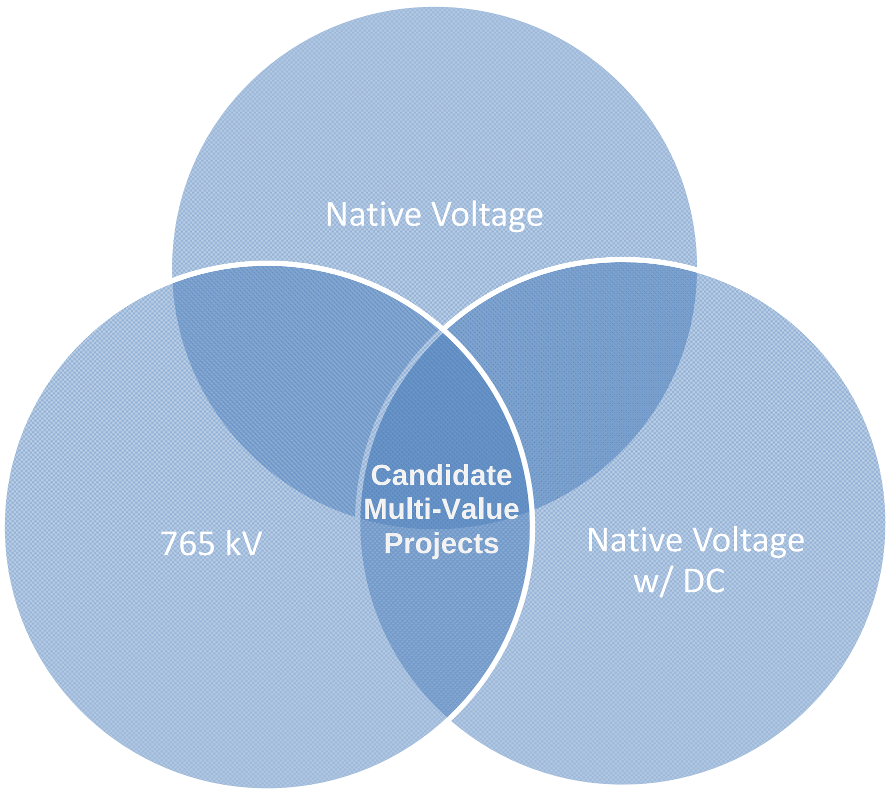

Figure 9.1-6: Candidate MVP Strategy Development Venn Diagram

9.1.3.1 Identifying RGOS Candidate Multi-Value Projects

The RGOS inputs into the Candidate Multi-Value Projects (MVPs) portfolio were identified by means of the process outlined below. Please note that other studies were considered in collecting the Candidate MVP portfolio; not all of the projects in the 2011 Candidate MVP portfolio are from the RGOS study effort.

Step 1: Identify useful corridors common to multiple Midwest ISO studies.

Corridors represent general paths for transmission that do not discriminate between voltages or potential intermediate connection points. Studies to be considered when identifying corridors include the following:

- Regional Generation Outlet Study overlay development results
- Generation Interconnection studies:
  - Definitive Planning Phase (DPP)
  - System Planning and Analysis (SPA)
- MTEP related studies:
  - Appendix B and C projects, which address future reliability concerns
  - Top congested flowgate studies
  - Cross-border top congested flowgate studies
  - Narrowly constrained areas

Step 2: Identify RPS timing needs and synchronize with generation interconnection queue locations.

Refer to Table 9.1-7, which shows renewable portfolio requirements starting in 2015. All states within the Midwest ISO with RPS mandates or load-serving entity goals are listed. States within the Midwest ISO purview; i.e., Montana, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Michigan, Ohio and Pennsylvania, currently have RPS mandates in place requiring that significant percentages of electrical demand be met with renewable energy resources. North Dakota and South Dakota do not have RPS but *do* have renewable goals to be met by their load serving entities. Kentucky and Indiana currently have neither RPS mandates nor load serving entity goals.

Table 9.1-7: Renewable Portfolio Standard Requirements

Year	WI	MN (w/o Xcel)	Xcel MN	IL	MI	OH	MO	MT	PA	SD	ND	IA
	(Of energy served)											(MW)
2015	10.0%	12.0%	18.0%	10.0%	10.0%	3.5%	5.0%	15.0%	5.5%	10.0%	10.0%	105
2016	10.0%	17.0%	25.0%	11.5%	10.0%	4.5%	5.0%	15.0%	6.0%	10.0%	10.0%	105
2017	10.0%	17.0%	25.0%	13.0%	10.0%	5.5%	5.0%	15.0%	6.5%	10.0%	10.0%	105
2018	10.0%	17.0%	25.0%	14.5%	10.0%	6.5%	10.0%	15.0%	7.0%	10.0%	10.0%	105
2019	10.0%	17.0%	25.0%	16.0%	10.0%	7.5%	10.0%	15.0%	7.5%	10.0%	10.0%	105
2020	10.0%	20.0%	30.0%	17.5%	10.0%	8.5%	10.0%	15.0%	8.0%	10.0%	10.0%	105
2021	10.0%	20.0%	30.0%	19.0%	10.0%	9.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2022	10.0%	20.0%	30.0%	20.5%	10.0%	10.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2023	10.0%	20.0%	30.0%	22.0%	10.0%	11.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2024	10.0%	20.0%	30.0%	23.5%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105
2025	10.0%	25.0%	30.0%	25.0%	10.0%	12.5%	15.0%	15.0%	8.0%	10.0%	10.0%	105

Locations of generation interconnection queue requests can be seen in Figure 9.1-7. This map represents wind queue locations as of the end of July, 2010.

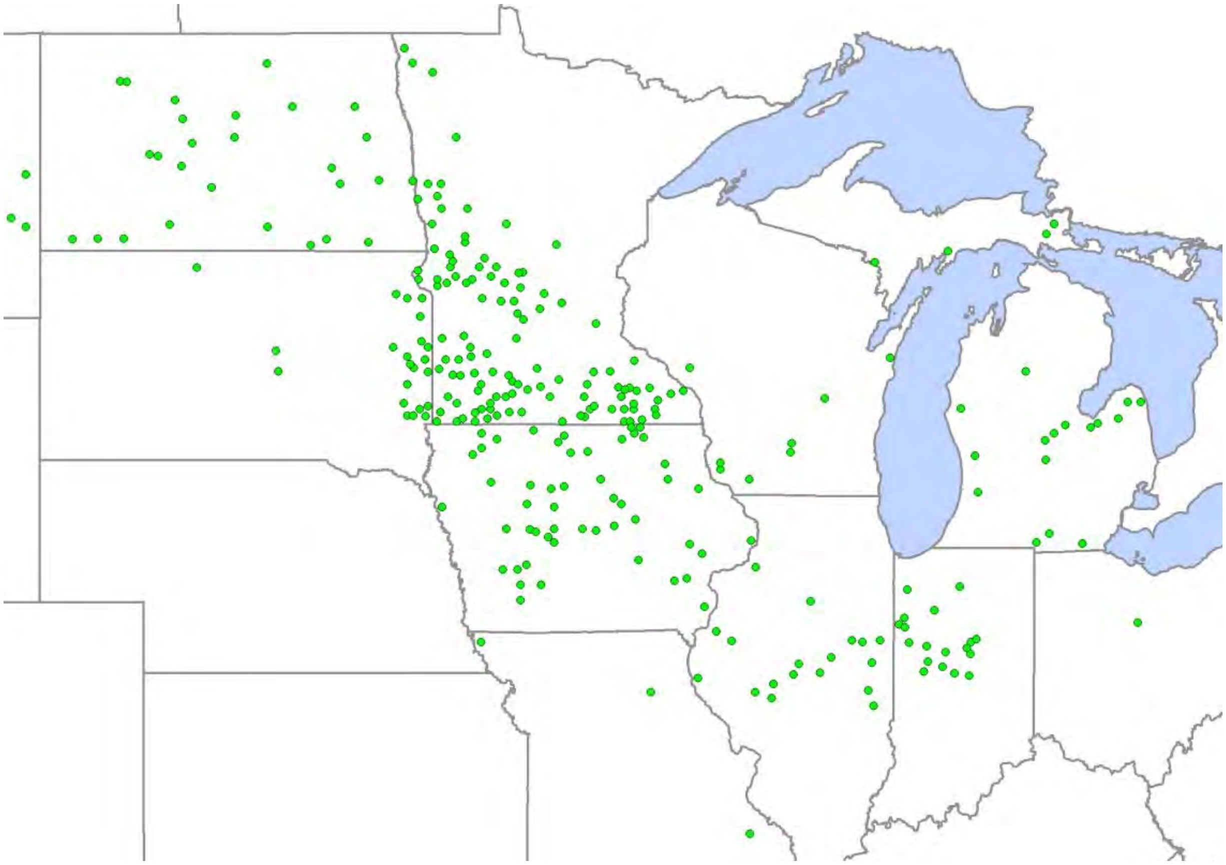

Figure 9.1-7: Location of Generation Interconnection Queue Requests

Step 3: Evaluate constructability of transmission.

Construction dynamics possibly requiring longer lead times for projects include the following:

- Interstate transmission coordination
- River crossings
- Commonsense coordination of projects; i.e., a group of lines may not make sense until another group is constructed first
- Midwest ISO/PJM cross-border projects

Certain projects may have shorter lead times; for example, when stringing second circuits on "existing" double circuit capable transmission structures.

9.1.3.2 RGOS-identified Candidate Multi-Value Projects

An initial set of transmission projects was identified using the inspection steps listed above. These transmission projects served as an input into the overall Candidate MVP portfolio described in section 4.4.9. The selected Candidate MVPs are compatible with RGOS-developed overlays and provide potential value for other needs identified within the transmission system. Refer to Figure 9.1-8 which depicts Candidate MVPs from the RGOS analysis. Estimated cost for this RGOS Candidate MVP set is approximately $5.8 Billion, $4.4 billion of which is within the Midwest ISO borders.

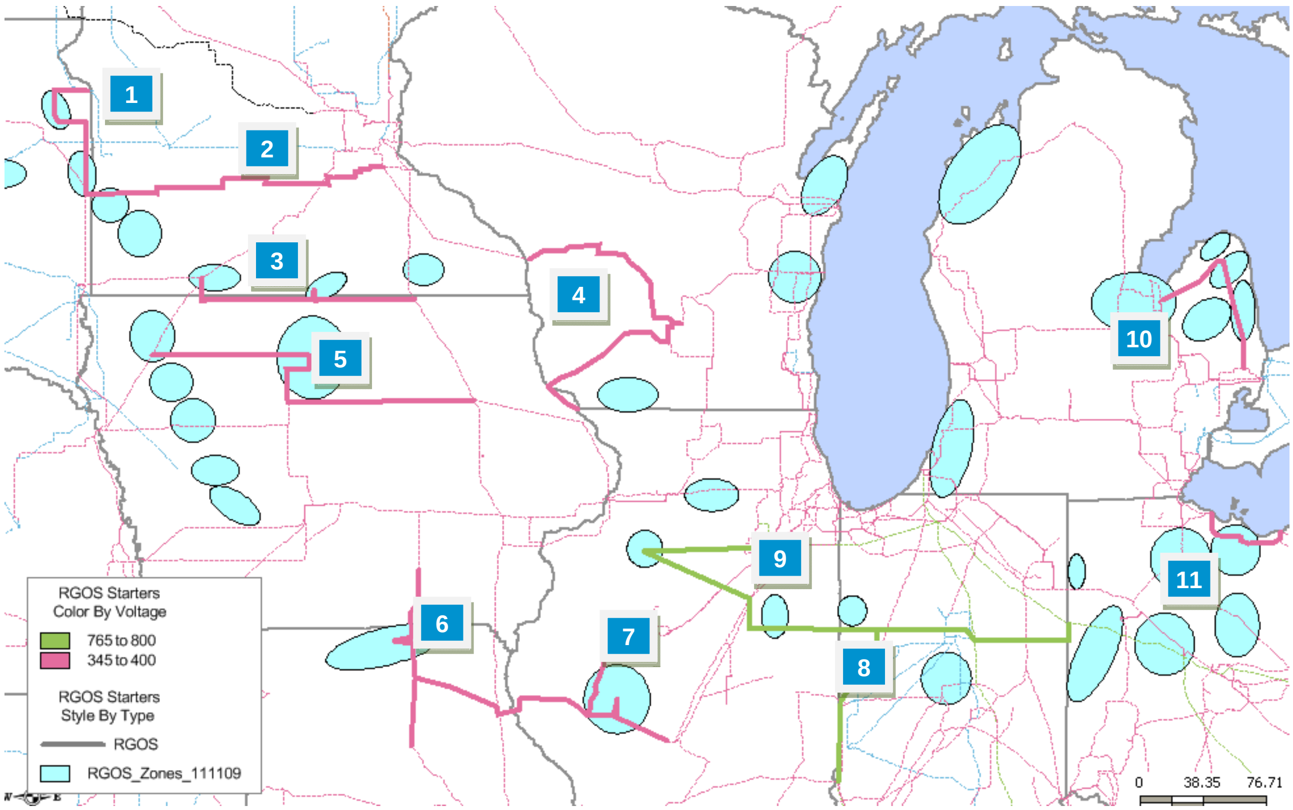

Figure 9.1-8: RGOS-identified Candidate Multi-Value Projects (Midwest ISO and PJM Lines Shown)

The following numbered list corresponds to the numbered identifiers in Figure 9.1-8 and furnishes additional details on the rationale guiding specific Candidate MVP selection.

1. **Big Stone to Brookings 345 kV line (2010 estimated installed cost: $150M):** This line provides access to and collection from renewable energy areas located in the eastern South Dakota portion of the Buffalo Ridge area. This corridor is identified in all RGOS overlays at the 345 kV construction. The corridor is also compatible with current Generation Interconnection Queue (GIQ) locations.

2. **Brookings to Twin Cities 345 kV line (2010 estimated installed cost: $700M):** This line, as approved the Minnesota Public Utilities Commission, delivers energy from the Buffalo Ridge area to a major load center in the Twin Cities and beyond. This 345 kV project also provides collection points for renewable energy, as well as reliability benefits. This corridor is identified in all RGOS overlay scenarios, although at different voltage levels. Proceeding with 345 kV construction does not negate a long-range 765 kV transmission expansion strategy. The 765 kV strategy can be adjusted to accommodate this selection.

3. **Lakefield Junction to Mitchell County 345 kV line constructed at 765 kV specifications (2010 estimated installed cost: $600M).** This line provides for an additional West to East path for energy delivery from the Buffalo Ridge area. This corridor has been identified in all of the RGOS overlays, as well as in other studies such as the Top Congested Flowgate analysis in the 2009 MTEP process and recent GIQ SPA analysis. This corridor is also compatible to collect resources associated with current GIQ locations. By developing this corridor using 765 kV construction, all potential long-term strategies remain viable.

4. **North LaCrosse to North Madison to Cardinal, Dubuque to Spring Green to Cardinal 345 kV lines (2010 estimated installed cost: $811M).** The development of these corridors will provide for the continuation and extension of the west to east transmission path to and provide more areas with greater access to the high wind areas within of the Buffalo Ridge and beyond area. These corridors are compatible with the RGOS overlays as well as other initiatives such as the GIQ SPA and DPP studies. These projects can be well-integrated regardless of the long-range transmission expansion strategy adopted by Midwest ISO; e.g., Native Voltage, 765 kV, and 765 kV plus DC.

5. **Sheldon to Webster to Hazleton 345 kV line (2010 estimated installed cost: $458M).** This set of transmission projects provides both a collection of renewable energy in the area and an additional west to east transmission path for delivery of energy to other parts of the study footprint. This combination of collection and delivery is compatible with the RGOS overlays (with proper adjustments made) and has shown to be compatible with corridors identified within the GIQ SPA studies.

6. **Ottumwa to Adair to Thomas Hill, Adair to Palmyra 345 kV lines (2010 estimated installed cost: $295M).** This set of transmission is compatible with the all RGOS overlays and provides access to quality wind resources within the Midwest ISO footprint in Missouri. This corridor development provides an additional north to south path and begins a new west to east transmission path for energy delivery across the footprint.

7. **Palmyra to Meredosia to Pawnee, Ipava to Meredosia 345 kV lines (2010 estimated installed cost: $345M).** This transmission is compatible with the RGOS overlays and provides access to quality Illinois wind potential located within the Midwest ISO footprint. These lines provide reliability support to the Ipava area with the new 345 kV connections. It also continues the new west to east path that will help bridge some of the market constraints across Illinois.

8. **Sullivan to Meadow Lake to Greentown to Blue Creek 765 kV line (2010 estimated installed cost: $908M).** 765 kV transmission is native to Indiana. This transmission plan is part of the 765 kV overlay but can also be compatible with the other overlays such as the 345 kV lines discussed previously. This transmission provides access to the wind potential in the Benton County area of Indiana and provides an additional west to east energy delivery route. Both Midwest ISO and PJM generation interconnection queues include potential resources in this area. It will also provide the completion of a 765 kV loop within Indiana to help mitigate some of the market constraints associated with the existing Rockport to Jefferson 765 kV line. A similar line was identified as a potential solution to constraints associated with the Southwest Indiana generation energy delivery. Note a version of this project was previously proposed as a joint project between PJM and Midwest ISO. Because of this, costs may be split between Midwest ISO and PJM and would—in the event of a joint project undertaking—also require a coincident PJM analysis.

9. **Collins to Kewanee to Pontiac to Meadow Lake 765 kV line (2010 estimated installed cost: $964M).** 765 kV transmission is native to the PJM system in northern Illinois and Indiana. This corridor is identified primarily within the 765 kV overlay. However, it does have corridor compatibility within the other overlays. This line provides a second EHV path from the Chicago area to the east. It also provides a potential solution to the Wilton to Dumont related constraints that provides three (3) of the top 20 historical top congested flowgates within the Midwest ISO market. With the increasing pressure of wind within the Midwest ISO and the PJM portion of Illinois, specifically the Kewanee area, this transmission line will help release known and projected congestion associated with the transmission systems along Lake Michigan's southern shore.
10. **Michigan Thumb 345 kV transmission loop (2010 estimated installed cost: $510M).** This loop was evaluated under an Out-of-Cycle process for inclusion in MTEP10 Appendix A and approved by the Midwest ISO Board of Directors (BOD) in its August meeting. This accelerated review was required to meet the near-time needs of the Michigan renewable energy mandate. This transmission is compatible with the all of the strategies within the RGOS analysis and gives access to a high wind potential area within Michigan.
11. **Davis Besse to Beaver 345 kV line (2010 estimated installed cost: $71M).** This transmission provides access to and delivery of wind energy potential located around the shores of Lake Erie within Ohio. There is GIQ generation in the area and the transmission is identified within all of the RGOS-developed transmission strategies.

The RGOS effort encompassed not only Midwest ISO but also immediate neighbors in PJM. This broadening of the study footprint resulted in development of transmission overlays that include transmission within Midwest ISO and PJM footprints. Thus, projects from both areas were considered when identifying Candidate MVPs useful to an RGOS solution.

However, focus must be placed exclusively on Midwest ISO-related projects when referencing RGOS and Midwest ISO projects and measuring the impact for future Candidate Multi Value Project (MVP) evaluations. Therefore, the already identified RGOS Candidate MVP portfolio was filtered of expected PJM-only projects before its submission into the full Midwest ISO Candidate MVP portfolio for analysis in 2011.

Figure 9.1-9 shows RGOS Candidate MVPs within Midwest ISO. Projects removed from this set of transmission include Collins to Kewanee to Pontiac to Meadow Lake 765 kV line (9) as well as Greentown to Blue Creek 765 kV line, part of the Sullivan to Meadow Lake to Greentown to Blue Lake project (8). For the MTEP11 Candidate MVP portfolio analysis, other Candidate MVP projects were added to this list, from studies such as the Cross Border Top Congested Flowgate Study.

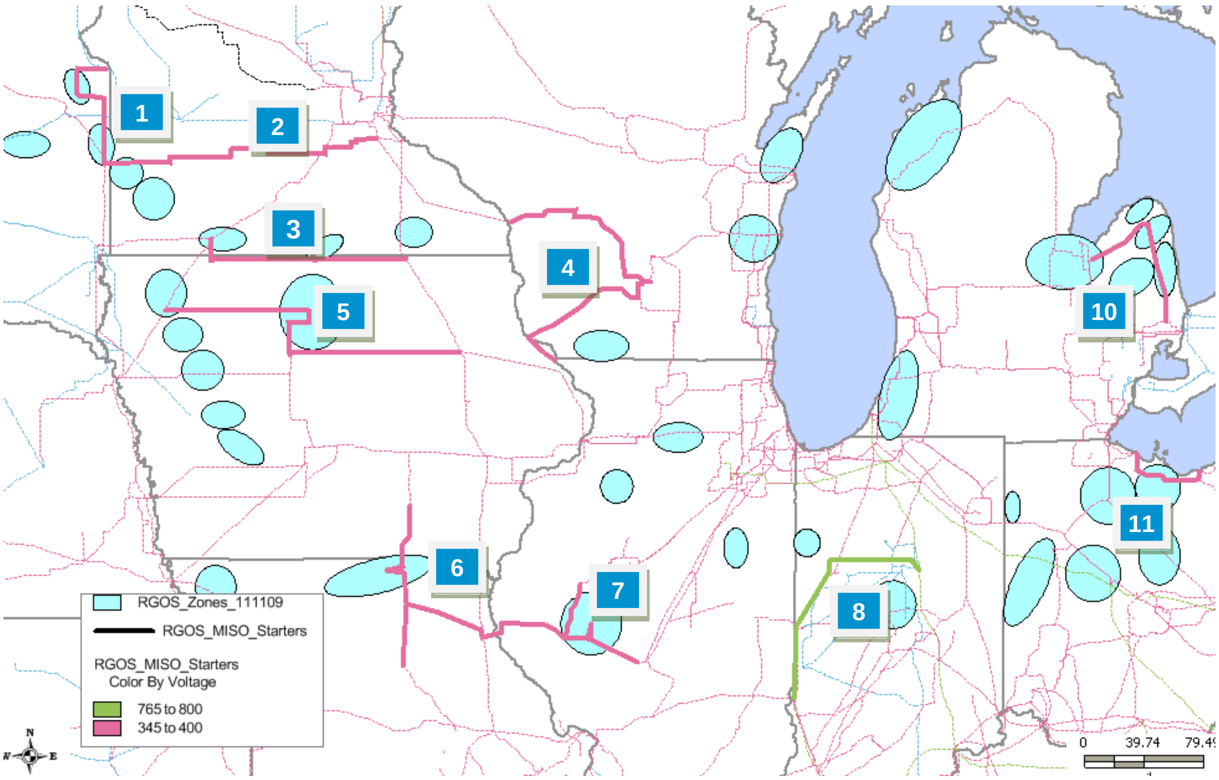

Figure 9.1-9: RGOS Midwest ISO Candidate Multi-Value Projects (Midwest ISO Lines Only)

Candidate MVP analyses will determine the ability of these projects in the Candidate MVP portfolio to move to Appendix A of the MTEP report. This MTEP11 evaluation is expected to include economic, reliability, and dynamic model analysis. Once the Candidate MVP portfolio analysis has been completed, it is expected another cycle of system overlay analysis will commence. This process will possibly entail updating many of the assumptions driving the design of the current RGOS transmission strategies. These changes may be driven by change in policy objectives, impacts of the Candidate MVPs on the system, new generation, demand and energy growth, and any number of additional external impacts that could materially affect the future of the electric transmission grid. During this analysis, a Midwest ISO-preferred strategy may be adopted.

9.1.4 RGOS Conclusions

RGOS provides industry stakeholders and policy makers with a regional planning perspective identifying potential investment opportunities and demonstrating the integration of renewable energy policies into electrical system development. The purpose of RGOS is to explore long-term transmission strategies ensuring study defined reliability objectives in delivery of renewable energy as well as RPS compliance. Aside from developmental considerations and regulatory concerns, determining a long-term transmission expansion strategy also serves to frame and define near-term needs. With these factors in mind, RGOS contributors considered the following when formulating viable long-term transmission strategies:

- **Performance:** Does the proposed strategy perform well under a variety of future scenarios?
- **Developmental Considerations:** As many of the more reliable wind resources reside far from large electrical load centers and lack adequate long-distance transmission lines, what is the expectation for further long-term development of wind resources within Midwest ISO?
- **Time Constraints:** Can finalizing a single, long-term strategy decision be deferred long enough to allow continued testing of important assumptions without jeopardizing legal requirements and renewable investment or risking the potential for stranded investment?

The best fit solution has been determined to be a transmission overlay encompassing all Midwest ISO states, premised on a distributed set of wind zones, each with varying capacity factors and distances from load.

Midwest ISO cannot currently recommend a long-term transmission development strategy employing Native Voltage, 765 kV, or Native Voltage with DC. All three plans meet study objectives. Costs and benefits vary between scenarios, but not significantly. Methodologies for analyzing performance under a variety of possible futures require continued development along with determining ‘options value’ for each strategy. Detailed construction design analysis is still required.

No consensus exists regarding the amount of renewable generation ultimately needed to comply with current and future RPS mandates. Some assert a much higher level of wind generation will be required than those included in RGOS analyses while others, equally confident, claim a lower amount. Regardless of the long-term uncertainty engendered by expansion or reduction of renewable energy standards, states within the Midwest ISO system will need new transmission to meet current and near-term renewable energy requirements, ensure reliable operation of the transmission grid, and facilitate the generation interconnection queue process. Midwest ISO will continue to work with policy makers and industry stakeholders to determine a strategy for transmission development within the footprint.

Because of RGOS, Midwest ISO has identified the next, most immediate step to transmission investment: a set of robust Candidate Multi-Value Projects (MVPs) meeting current renewable energy mandates and the regional reliability needs of its members.

9.1.5 RGOS Process & Methodology

9.1.5.1 Stakeholder Study Participation

Stakeholders reviewed and contributed to RGOS throughout the study process. A Technical Review Group (TRG), composed of regulators, transmission owners, renewable energy developers, and market participants, met monthly with Midwest ISO engineers to provide input, feedback, and guidance. A Design Subteam (DST), composed of a smaller group of experienced transmission engineers, met bi-weekly to review detailed results. RGOS reported regularly to the Midwest ISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). RGOS transmission planners also conferred with the Upper Midwest Transmission Development Initiative (UMTDI), a group of Governor-appointed representatives from Wisconsin, Iowa, Minnesota, South Dakota, and North Dakota.

9.1.5.2 Wind Zone Development

A key assumption of the RGOS study has been the amount and location of wind energy zones modeled within the study footprint. Wind energy zone development is based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During RGOS I and RGOS II wind zone development, Midwest ISO staff provided multiple energy zone configurations to be considered that met renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. In both RGOS I and II efforts, the most expensive energy delivery options were those options relying solely on the best regional wind source areas (with higher amounts of transmission needed) or those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

As a result of RGOS I and RGOS II zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within the Midwest ISO, a set of renewable energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the Midwest ISO market footprint. Zone selection was based on a number of potential locations developed by the Midwest ISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. Wind zones distributed across the region (1) reflecting local development trends and requirements; or (2) occupying the best regional wind locations results in a set of distributed wind zones best balancing renewable energy requirements and overall system costs.

Refer to Figure 9.1-10, which depicts this selected set of renewable energy zones, and to Table 9.1-8 and Table 9.1–9 (on the following page), which furnish zone-by-zone UMTDI and non-UMTDI selections, respectively.

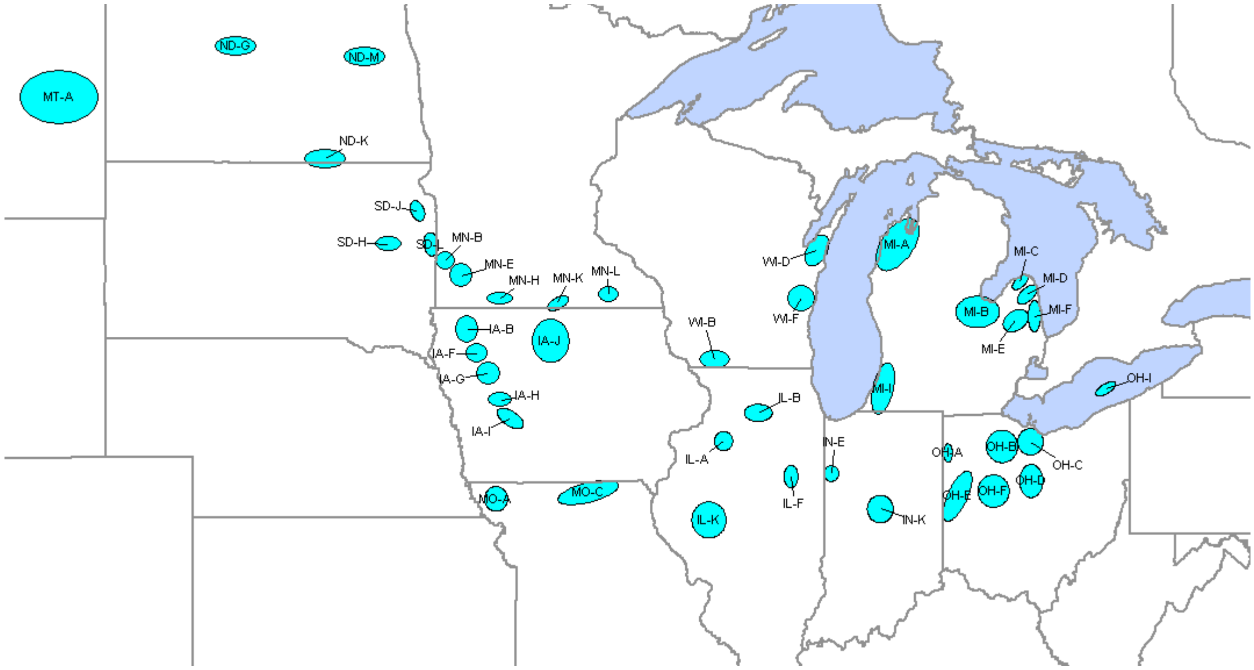

Figure 9.1-10: Renewable Energy Zone Locations

Table 9.1-8: Renewable Energy Zone Information (UMTDI Zone Selection B)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IA-B	IA	0.366	775	2485	MN-L	MN	0.349	775	2369
IA-F	IA	0.362	775	2458	ND-G	ND	0.424	775	2879
IA-G	IA	0.354	775	2403	ND-K	ND	0.373	775	2532
IA-H	IA	0.367	775	2492	ND-M	ND	0.359	775	2437
IA-I	IA	0.356	775	2417	SD-H	SD	0.384	775	2607
IA-J	IA	0.327	775	2220	SD-J	SD	0.407	775	2763
MN-B	MN	0.393	775	2668	SD-L	SD	0.399	775	2709
MN-E	MN	0.382	775	2593	WI-B	WI	0.266	775	1806
MN-H	MN	0.368	775	2498	WI-D	WI	0.283	775	1921
MN-K	MN	0.334	775	2268	WI-F	WI	0.276	775	1874

Table 9.1-9: Renewable Energy Zone Information (non-UMTDI Zone Selections)

Zone	State	CF	Nameplate (MW)	Energy Output (GWh)	Zone	State	CF	Nameplate(MW)	Energy Output (GWh)
IL-A	IL	0.310	550	1494	MI-I	MI	0.259	350	794
IL-B	IL	0.298	550	1436	MO-A	MO	0.358	500	1568
IL-F	IL	0.300	550	1445	MO-C	MO	0.330	500	1445
IL-K	IL	0.252	550	1214	MT-A	MT	0.432	400	1514
IN-E	IN	0.311	500	1362	OH-A	OH	0.272	725	1727
IN-K	IN	0.291	500	1275	OH-B	OH	0.271	725	1721
MI-A	MI	0.264	300	694	OH-C	OH	0.280	725	1778
MI-B	MI	0.274	500	1200	OH-D	OH	0.252	725	1600
MI-C	MI	0.298	500	1305	OH-E	OH	0.255	725	1620
MI-D	MI	0.281	500	1231	OH-F	OH	0.281	725	1785
MI-E	MI	0.272	500	1191	OH-I	OH	0.407	725	2585
MI-F	MI	0.270	500	1183					

The capacity factors used in Table 9.1-8 and Table 9.1-9 are weighted capacity factors (CFs) developed as part of RGOS Phase I analysis. For further information regarding CF calculations, refer to section 9 of MTEP09 and the RGOS Phase I Executive Summary Report. A general methodology was employed in the selection of renewable energy zones:

1. UMTDI B zones from the RGOS Phase I were used for the western footprint to meet local needs.
2. Michigan would meet all of its energy needs within the state of Michigan in accordance with state legislation.
3. Ohio, Missouri, and Illinois would meet 50% of their needs with respective in-state resources to reflect state legislation and the desire for local development.
4. UMTDI group B zones, Montana, and Indiana were used to meet the remaining renewable energy needs of Ohio, Missouri, and Illinois.
5. The target energy from the renewable energy zones was 81,406 GWh.

9.1.5.3 Study Methodology

Three (3) primary steps were utilized in the development of the transmission overlays. These steps include both production cost and Power Flow analysis, with each technique providing its own value to the process. The starting point of this analysis was the indicative transmission developed during RGOS Phase I and Phase II studies in 2008 and 2009. For more information regarding this development process, again refer to MTEP 09 report, Section 9.

9.1.5.3.1 Production Cost Analysis

A production cost model was used to create a starting point for Power Flow reliability analysis. This starting point analyzed the energy flow on the system and reduced the indicative transmission to a limited level of transmission to achieve economic energy flow. Production cost modeling uses a limited list of reliability constraints for analysis, and therefore should not be considered an optimal solution without reliability model analysis.

The production cost model included the transmission infrastructure contained within the RGOS peer-reviewed 2019 Power Flow model. The initial production cost analysis was based on the Organization of Midwest ISO States (OMS) Cost Allocation and Regional Planning (CARP) developed Business as Usual with High Demand and Energy Case. Refer to Table 9.1-10, which posits the primary assumptions associated with the development of this case.

Table 9.1-10: Key Assumptions for Economic Model Development

Uncertainty	Value
Demand Source	Module E 2009 Submittal
Demand Growth	1.6% Annual Escalation
Energy Growth	2.19% Annual Escalation
Natural Gas Cost (2010 Henry Hub)	$6.22/MBtu
Carbon Cost/Cap	No Cap nor Cost applied
Reserve Target	15% of Midwest ISO Coincident Peak Demand

Note each overlay was compared to a base run that included new wind zone generation without additional transmission beyond the 2019 base case assumptions. The base run included typical flowgates, and was not screened for additional flowgates that might have the potential to severely restrict RPS wind injections resulting in 'dump' energy.

The production cost model uses an event file to perform contingencies and system monitoring. This event file was updated with 'local' contingencies to capture wind effects, and contains Midwest ISO and NERC flowgates. These flowgates will not show the outlet issues associated with the zones. To add relevant constraints to the modeling, Midwest ISO staff utilized the Power Flow Analysis Tool (PAT).

9.1.5.3.2 Linear Power Flow Analysis

The reduced amount of transmission developed through the production cost analysis of the indicative transmission designs was then added to the off-peak, shoulder Power Flow model. Linear analysis on the off-peak, shoulder model identified additional reliability constraints, which were addressed. The bulk of the reliability analysis fell within the off-peak, shoulder case work effort.

Once all selected criteria violations were identified and solutions proposed, plans were analyzed using an on-peak model as well as a light load model.

MTEP 09 Power Flow models were used to conduct this study in the development of the 2019 peak and off-peak models. These models were created within the Midwest ISO Model On Demand database and include 2019 summer peak load cases, which were then modified to produce the 2019 off-peak model used in the analysis. The MTEP10 Power Flow model was used to create the light load model employed in analysis. The external representation used for the MTEP models are the ERAG MMWG models. The latest MRO models were used to update non-Midwest ISO MRO data. Midwest ISO system updates were added through the stakeholder process. Neighboring utility updates were provided by SPP, TVA, and PJM.

The 2019 model contains all projects moving to MTEP Appendix A as well as those MTEP Appendix B projects identified with a “Planned” status designation. Given the uncertainty of their status, those projects in MTEP Appendices B and C **not** moving to MTEP Appendix A in the current planning cycle will be removed or not incorporated in RGOS models. Designing RGOS (or any) transmission system dependent on projects not confirmed for development or potentially destined for replacement by an alternative project would adversely impact the final set of transmission projects.

NERC Category A, B and C events were used in Power Flow analysis. A comprehensive Category C evaluation was not performed. Category C events were limited to select events greater than 230 kV supplied by stakeholders, and double branch contingencies within a bus of each zone’s outlet facilities will be used. Category C events tested for energy zone outlet restriction and for potential cascading events. These cascading events were defined as situations in which transmission facilities experience a maximum loading of 125% or higher, as compared to the facility's emergency ratings. All elements greater than 100 kV were monitored during analysis. However, only elements greater than 200 kV in violation were addressed for solutions. All other elements were identified and included within the evaluation of the overlays.

9.1.5.3.3 AC Power Flow Analysis

AC Power Flow analysis was performed on the same peak, off-peak, and light load models used in linear flow analysis by employing an AC Power Flow solution with the same contingency files used in the linear Power Flow work. This analysis helped identify an approximation for reactive and capacitive support on the system, improving the accuracy of cost estimates and providing a more holistic solution to stated RGOS objectives.

9.1.6 Cost Assumptions

During the RGOS study process, Midwest ISO staff and stakeholders developed a set of cost assumptions that applied to the cost of new generation, transmission, and substations. These numbers are the basis for the comparison of the costs of the overlays. Tables 9.1-11–9.1-14 represent these costs.

Table 9.1-11: Transmission Line Costs ($M)

Type	IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI
345	$1.6	$1.5	$2.0	$1.8	$1.8	$0.9	$1.4	$1.4	$2.0	$1.4	$2.1
2-345	$2.3	$2.0	$2.0	$2.7	$2.5	$2.3	$1.9	$1.9	$2.0	$1.9	$2.7
500	$2.1	$1.8	$1.8	$0.0	$2.4	$1.8	$1.8	$1.8	$1.8	$1.8	$2.8

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Table 9.1-11: Transmission Line Costs ($M)

Type	IA	IL	IN	MI	MN	MO	MT	ND	OH	SD	WI
765	$3.2	$2.8	$2.8	$3.6	$3.5	$3.2	$2.8	$2.8	$2.8	$2.8	$4.0
DC(OH)	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2
DC(Marine)	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0

Table 9.1-12: Transformer Costs

kV	($M)
765/345	$28.2
765/161	$20.7
765/138	$20.7
765/115	$20.7
345/230	$6.5
345/161	$5.7
345/138	$5.7
345/115	$5.7

Table 9.1-13: Substation Costs

Substation Type	($M)
115 kV	$9.0
138 kV	$9.0
161 kV	$9.0
230 kV	$9.0
345 kV	$11.8
765 kV	$25.1
DC–6400 MW	$549.0
DC–1000 MW	$340.0

Tale 9.1-14: Other Cost Assumptions

Assumption	Estimate
Wind Turbine Cost	$2M/MW
Inflation Rate	3.00%
Discount Rate	7.00%
Capitalization Rate	9.69%

9.2 Wind Integration and Operational Impacts

The past decade has seen several factors shaping utility industry policies. Societal pressures related to the environment and competitive pressures within the industry, along with a decline in the cost of renewable energy, have led to the recent adoption of Renewable Portfolio Standards (RPS) and goals in several states across the United States and specifically in the Midwest. Midwest ISO is observing a significant increase in the amount of renewable energy installed in the Midwest ISO footprint (namely wind) due to state Renewable Portfolio Standards. Although requirements in each state differ, they usually focus on Load Serving Entities (LSE) consuming a specified amount of energy (usually a percentage of total generation) from renewable resources with the option to purchase Renewable Energy Credits (REC).

Wind generation is more volatile than other fuel types because of the volatile nature of weather patterns. Today, as of July 2010, approximately 8,000 MW of wind generation is installed in the Midwest ISO footprint. With this penetration, existing tools and processes are sufficient to ensure reliability and to operate the Energy and Ancillary services markets. The expected increased penetration of wind generation creates the need for new tools and processes to manage the expected increase in volatility.

The Midwest, including a large part of the Midwest ISO footprint, possesses an abundance of potential wind energy; and the current Midwest ISO generation queue has over 60,000 MWs of wind requests. Midwest ISO expects wind to be the main source of renewable energy to comply with state RPS mandates in and outside its footprint. The Midwest ISO also expects that wind within its footprint will be a source of renewable energy should a Federal RPS mandate become law. Therefore, based on the growing wind impacts and implications the Midwest ISO Management authorized and kicked off the Wind Integration Initiative (WII) Project in the fall of 2008. The Wind Integration Initiative (WII) will enable Midwest ISO to formalize various solutions for the growing wind capacity to be absorbed in an efficient and reliable manner. This investigation is multifaceted, with the core objectives being to enable integration of wind resources in a manner that will:

- Ensure Reliability.
- Ensure an Efficient and Effective Market.
- Ensure a Level Playing Field for all Market Participants.
- File necessary FERC tariff changes to codify these solutions.

The deliverables for this initiative are related to the following:

1. Creation of a Dispatchable Intermittent Resource (DIR) product
2. Identification of additional Load Following Products
3. Evaluation of enhancements for Minimum Generation scenarios
4. Enhancement of Wind Forecast capabilities
5. Impact of high wind penetration on frequency response
6. Evaluation of need for additional wind generation planning studies

An overview of the initiative's work to date, along with their future deliverables, may be found in the WII work plan at the link below. This initiative will continue their work through 2011, and an update on their deliverables will be provided in the MTEP11 report.

https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/RSC/2010/20101122-23/20101122-23%20RSC%20Item%2011a%20Wind%20Integration%20Work%20Plan%2020101117.pdf

9.2.1 Dispatchable Intermittent Resource

Wind capacity in the Midwest ISO has grown from 1000 MW in 2006 to more than 8000 MW in 2010. The increase in capacity has naturally caused an increase in the amount of wind energy available on the Midwest ISO system, with the wind energy reaching as high as 4.5% of all energy served. Wind and other renewable sources of energy have reached a point where their operating characteristics are beginning to significantly influence the operation of the bulk electric system. Midwest ISO and its stakeholders have identified and created Dispatchable Intermittent Resource (DIR), a new type of resource that allows resources traditionally classified as “Intermittent Resources” to be incorporated into the Midwest ISO Energy market.

Traditionally, Intermittent Resources in Midwest ISO have Energy Resource Interconnection Service. An energy resource is a resource that can interconnect to the Midwest ISO transmission system under less strenuous deliverability and transmission upgrade requirements, with the idea that the transmission system can be used by the energy resource as capacity is available. Implementation of the energy resource construct for Intermittent Resources has resulted in two issues. First, when Intermittent Resources interconnect as energy resources, the potential exists where the market is unable to manage congestion because:

- The Intermittent Resource cannot be dispatched.
- Insufficient transmission capacity exists to deliver Intermittent Energy Resource (IER) output.

Generator resources with network resources that have funded network upgrades may be unable to utilize the transmission capacity they funded due to the output of Intermittent Resources; i.e., the market will dispatch a network resource to manage congestion since there is no way to dispatch the intermittent energy resource.

DIR allows wind resources to act like other generation resources by allowing wind resources to submit economic offers for energy generation and receive a dispatch target from the Security Constrained Economic Dispatch system. Increasing the number of wind units participating in normal market operations allows Midwest ISO to reduce its reliance on out-of-market actions to curtail wind resources. More wind resources in normal market operations also improve Midwest ISO’s efficiency when implementing congestion management actions. Congestion can then be relieved based upon economics, allowing the least costly units to be run. DIR leverages current and anticipated wind turbine control technologies that most of the wind units in the footprint use to control their output. .DIR deliverables include the following:

- Revised Tariff Sheet Filed with FERC
- BPM Revisions
- Implementation Plan

9.2.2 Load Following Product–Amplified Ramp Requirement/Net Load Following

Load Following refers to the ability of resources to be dispatched in a manner to follow changes in the short-term load forecast and net scheduled interchange (NSI) on a five-minute basis. It represents a solution to the anticipated increase in ramp requirements due to the variability of a large penetration of wind generation in Midwest ISO. A significant increase in the number of intermittent resources will impact Midwest ISO's ability to follow load in two ways:

- The displacement of Dispatchable Resources with Intermittent Resources in the unit commitment process will reduce the amount of committed resources that can follow load.
- Intermittent Resources will at times introduce additional load following burden by being another source of volatility.

With a significant percentage of intermittent resources in the resource mix, load following can be thought of as the need for dispatchable resources to follow an effective load where the effective load is equal to the short-term load forecast plus the net scheduled interchange less the forecasted output of intermittent resources. Therefore, load following becomes *effective* load following. To mitigate effective load following issues, it may be necessary to significantly expand incentives for resources to maximize the offered load following capability; i.e., ramp and dispatch flexibility. These incentives could be in the form of:

- A new load following product such as load following reserve;
- Additional offer parameters; and/or
- Changes to existing penalty mechanisms to reduce the risk of the offering load following capability such as the alternative dynamic tolerance band currently on the ASM parking lot issues list. Load following deliverables include:
  - **A white paper** providing issue description, conceptual design framework, modification in optimization formulations, operation and market implications and illustrative examples
  - **Business rules document** providing required changes in registration, bid and offer, settlement process, etc.
  - **Series of stakeholder presentations** providing operational assessment, potential alternatives and recommended solutions, and technical discussions
  - **Modifications in Tariff (June 2011) and Energy and Operating Reserves Business Practice Manual** consistent with the white paper and business rules document

9.2.3 Evaluation of Enhancements for Minimum Generation Scenarios

Throughout 2009, the Minimum Generation Task Force (MGTF) investigated the root causes of Minimum Generation events and some of those were attributed to wind generators. The MGTF drafted a set of recommendations for Midwest ISO to consider. The motions focused on two broad areas: Administrative Pricing and new Market Functionalities. In March, the Market Subcommittee (MSC) approved a motion for the Midwest ISO to review each of the following proposed recommendations and provide an update to the MSC to inform Stakeholders of the merit and feasibility of each recommendation and to outline next steps. Midwest ISO will continue to consider the recommendations presented by the MSC and will respond to the MSC after the merits of each recommendation has been considered.

9.2.4 Wind Forecast Enhancements

Accurate wind forecasts are critical to successful wind integration. Wind forecasts are used in several tools by different business areas within Midwest ISO. The development of the Dispatchable Intermittent Resource (DIR) has also created the need for a 5-minute interval wind forecast for each wind farm. Midwest ISO has been working with stakeholders to increase the accuracy of the wind forecast. Midwest ISO has presented to the Market Subcommittee and Reliability Subcommittee where the wind forecast is used. There was also a specific wind forecast workshop in July 2010, where stakeholders and Midwest ISO discussed information required to increase the wind forecast accuracy. Deliverables include the following:

- Wind Forecast Vendor to provide a 5-minute interval forecast for each wind farm, updated every five (5) minutes for the next six (6) hours
- A commitment to continue working with stakeholders to identify ways to improve wind forecast accuracy

9.2.5 RTO Frequency Response

Frequency response is required to help rebalance a system after an unplanned loss of supply resulting from a unit trip or other causal factors. When a resource is lost, there is an immediate drop in frequency due to imbalance. The load frequency response; i.e., motors, results in immediate rebalance, although at a lower frequency. Several seconds later, governor response from generation resources and/or regulating reserve deployment temporarily increase supply and frequency (although not to pre-disturbance levels) until the deployment of the contingency reserve, which typically takes 5–15 minutes to replace the lost supply and fully restore the frequency.

There is an industry-wide decreasing level of frequency responsive generation and load. An increasing penetration of wind units could equate to a high number of generation resources with some output uncertainty regarding their ability to respond to frequency. Regarding wind, the problem could be aggravated particularly at night when there is:

- Less load frequency response
- Fewer units committed
- More steam units operating on sliding pressure
- The largest generation contingency likely still applies

Historical data suggests wind output is frequently high during nighttime hours, meaning large amounts of wind could pose a problem if wind turbines do not have the ability to increase output; i.e., are operating at full output and do not have governors in place to facilitate frequency response. Potential solutions might be found by exploring ways in which a subset of the wind resources could be frequency responsive or providing incentives for other resources to operate in a frequency responsive mode.

Frequency response is a Midwest ISO-wide issue. A committee and process outside the WII is currently working on this issue. Increasing wind generation is only one contributing factor to this issue; as such, the scope of WII frequency response work will be limited to participating in the larger effort.

9.2.6 Wind Planning Analysis Task Team Recommendations

Generally, wind resources are located far from load centers. Having substantial amount of generation a large distance from load has the potential to stress the bulk electric system due to less system inertia, increased angular displacement, and increased potential for short circuit faults. System conditions include such factors as system or area load levels, dispatch level of renewable resources at specific load levels, and associated dispatch of non-renewable resources. All of these factors could lead to a reduction in grid stability. A team, which includes stakeholders, has been formed to determine if there is need for new or revised studies required for wind generation in the MTEP process.

- The Wind Planning Analysis Task Team has been tasked to recommend and achieve concurrence from the Planning Subcommittee and Planning Advisory Committee on the proposed critical system conditions to be analyzed with renewable generators in MTEP and Transmission Access Planning processes. Deliverable may include updates to Business Process Manual (BPM) with proposal for conditions appropriate for testing system performance associated with integration of wind resources. This task is scheduled to be complete by the end of 2010; recommendations will be provided to the Planning Subcommittee once the Task Team has completed their work.

9.2.7 Plexos™ Software Model Implementation

One additional item not specifically mentioned in the Wind Integration Initiative but tied closely to the objectives is the implementation of the Plexos software model.

Production cost and Power Flow models have been used to develop an understanding of the economic and reliability impacts in future years based upon changes load growth and system topology changes. Production cost models used in RECB and RGOS have been very useful due to their ability to simulate every hour within a given year to enable energy based planning to be incorporated into the analysis framework. However, due to the hourly dispatch nature of these models the operational reserve requirement impacts from system topology changes are not available within the traditional production cost models. Historically, the inability to forecast operational reserve impacts has not been a major disability; however, the need to forecast operational reserve impacts and costs have increased with more wind coming onto the Midwest ISO system.

To accomplish this operational impact analysis, Midwest ISO evaluated Plexos production costing software for its ability to perform intra-hour dispatches; i.e., every five (5) minutes), on a forecast basis. This intra-hour dispatch capability allows for potential new operating reserve requirements and products to be determined based upon future changes in system generation and transmission topology. Major topology changes forecasted are driven by the state RPS requirements and the need to deliver renewable energy, mainly from wind resources located throughout the Midwest ISO footprint. The load following product development discussed in section 9.2.2 is an area where Plexos would provide insight into the anticipated increase in ramp requirements due to the variability of a large future penetration of wind generation in the Midwest ISO. The Plexos model was purchased by Midwest ISO in May 2010Midwest ISO. Utilization of the Plexos model will be further incorporated into MTEP11 reporting.

9.3 Carbon Impacts and Futures Elaboration

Midwest ISO faces significant changes to the generation resource mix within its footprint with the implementation of carbon reduction legislation. Carbon reductions on the order of 83% by 2050, as proposed in the Waxman-Markey legislation, have huge impacts on the future resource mix. The Midwest ISO had approximately 500 million tons of carbon emissions in 2005, which is used as the baseline in the Waxman-Markey legislation. This would result in a required reduction of 400 million tons of carbon by the year 2050[60]. Achieving this level of reduction will require a combination of regulatory and policy strategies. For this report, four of these strategies were evaluated to understand the reductions and associated costs of the strategies. These strategies include demand response and energy efficiency, renewable portfolio standards, carbon costs and the retirement of existing carbon emitting resources.

The EGEAS model was used to evaluate regulatory and policy strategies. Five (5) modeling inputs were introduced into the model to address the range of sensitivities to the regulatory and policy strategies. These modeling inputs are the following:

- Demand and energy growth rates of 0.3%, 1% and 3%
- Renewable portfolio standard levels of 10%,15% and 20%
- Gas to coal price delta of $4, $6 and $8 per MMBTU
- Nuclear to coal capital cost delta of 1,600 $/kw and 3,600 $/kw
- Carbon cost of $0, $25, $50, $75, $100 and $125
- Retirement of existing coal fleet 0%, 20%, 40%, 45%, 80% and 95%

330 cases were run and evaluated with the ranges of modeling inputs. Eight (8) reduction ranges fell out of the model runs. These eight "Carbon Bands of Reduction" show the compliance strategies and the range of costs required to achieve the desired carbon reduction. Refer to Figure 9.3-1.

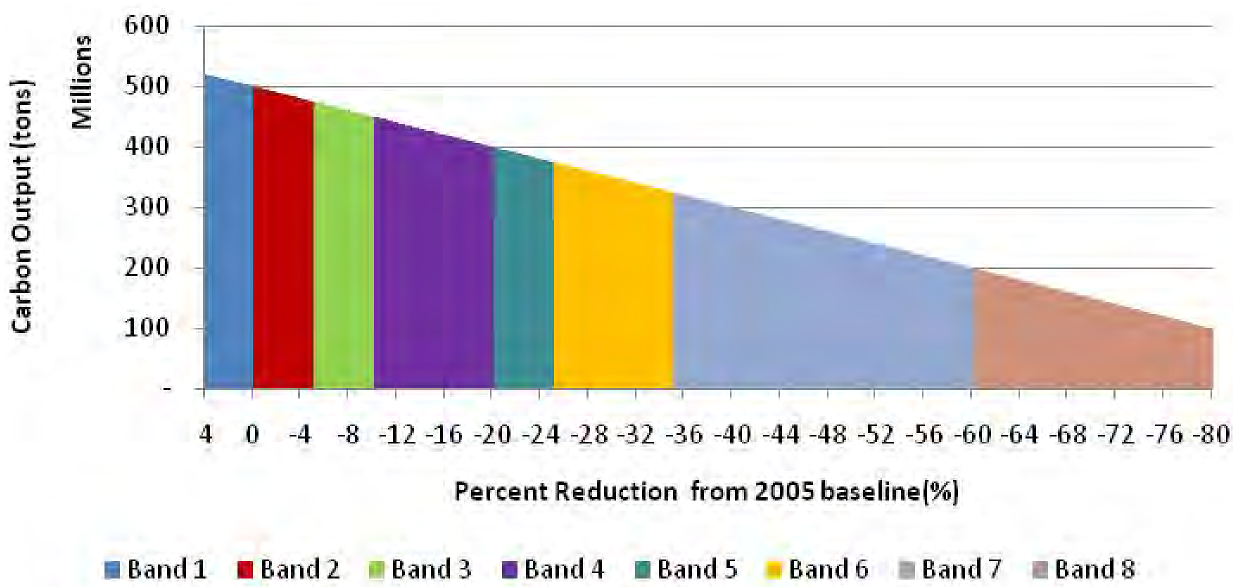

Figure 9.3-1: Midwest ISO Bands of Carbon Reduction

60 All carbon reduction values are based on Waxman-Markey legislation requirements.

Each band can employ multiple compliance strategies to achieve desired carbon reduction:

- Band 1: 10% Renewable Portfolio Standard(RPS)
- Band 2: 15% RPS and $25/Ton carbon cost or less
- Band 3: 20% RPS and $25/Ton carbon cost or less
- Band 4: 10% RPS with $50-$75 carbon cost; OR 20% RPS with 20% to 45% coal retirement and $25/ton carbon cost or less
- Band 5
  - 15% RPS with $50-$75 carbon cost; or
  - 10% RPS with $75-$125 carbon cost; or
  - 20% RPS with 80%-95% coal retirements
- Band 6: 20% RPS with $100/Ton or greater carbon cost
- Band 7: 20% RPS with $50/Ton or greater carbon cost and 20% to 45% coal retirements
- Band 8: 20% RPS with $50/Ton or greater carbon cost and 45% to 95% coal retirements

The bands represent different compliance strategies that would have to be implemented to achieve the band's level of carbon reduction. There are many different cases within the bands that all fall within the min and max reduction target. The goal would be to choose the least-cost case within the band. Refer to Table 9.3-1, which shows the varying costs for each band's level of reduction.

Table 9.3-1: Range of Carbon Reduction and Total 20 Year Cost (Present Value)

Band #	Min Carbon Reduction	Max Carbon Reduction	Min 20 year PV Cost (billions of dollars)	Max 20 year PV cost (billions of dollars)
Band 1	4%	0%	27.9	49.7
Band 2	0%	-5%	29.2	50.1
Band 3	-5%	-10%	29.8	50.2
Band 4	-10%	-20%	36.2	69.6
Band 5	-20%	-25%	41.0	80.7
Band 6	-25%	-35%	51.4	80.2
Band 7	-35%	-60%	59.0	106.9
Band 8	-60%	-90%	61.6	105.3

Using Band 5 as an example, it can be seen a 5% range in carbon reduction results in PVC costs in the $40 billion range. A better way to view carbon reduction and associated cost for the cases is to plot carbon reduction from lowest to highest and then plot the resulting cost associated with that case.

Refer to Figure 9.3-2. If a carbon reduction of -20% to -25% is desired from Band 5, one would choose between the three (3) cases highlighted in Band 5. Case A is the most attractive because its $50.4 billion cost is lower than Cases B and C, $78.5 billion and $80.3 billion, respectively.

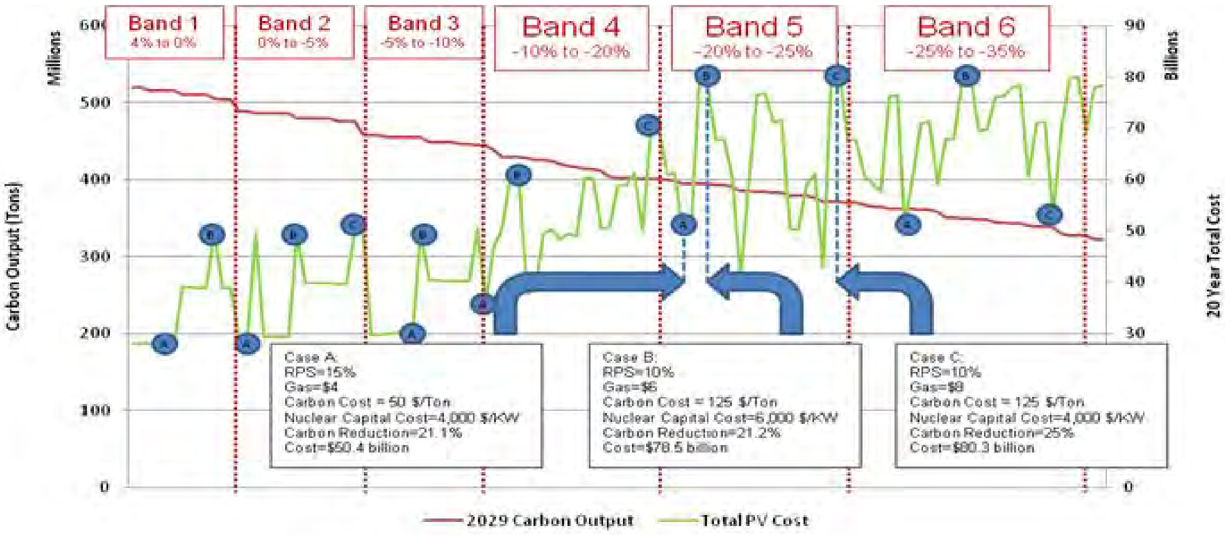

Figure 9.3-2: 2029 Midwest ISO Carbon Output versus 20-Year Total Cost (Present Value)

Refer to Table 9.3-2, below, which provides case definitions to the highlighted cases in Figure 9.3-2, above.

Table 9.3-2: Case Definitions for 2029 Carbon Output versus 20 Year PV Total Cost (Present Value)

Case	RPS (%)	Gas Cost (Δ$)	Carbon Cost ($/Ton)	Nuclear Capital Cost ($/KW)	Retirements (%)	Carbon Reduction (%)	20 Year PV Cost ($billion)
Band 1: A	10	8	0	6000	0	3.12	28.2
Band 1: B	10	8	50	6000	0	1.05	49.7
Band 2: A	15	4	0	4000	0	-2.25	29.2
Band 2: B	10	6	50	4000	0	-4.00	49.7
Band 2: C	15	8	50	6000	0	-5.00	50.1
Band 3: A	20	6	0	4000	0	-9.05	30
Band 3: B	10	8	50	4000	0	-9.10	49.8
Band 4: A	20	6	0	4000	20	-11.12	36.2
Band 4: B	10	8	75	6000	0	-14.12	61.1
Band 4: C	10	6	100	4000	0	-19.88	69.5
Band 5: A	15	4	50	4000	0	-21.10	50.4
Band 5: B	10	6	125	6000	0	-21.20	78.5
Band 5: C	10	8	125	4000	0	-25.00	80.3

Table 9.3-2: Case Definitions for 2029 Carbon Output versus 20 Year PV Total Cost (Present Value)

Case	RPS (%)	Gas Cost (Δ$)	Carbon Cost ($/Ton)	Nuclear Capital Cost ($/KW)	Retirements (%)	Carbon Reduction (%)	20 Year PV Cost ($billion)
Band 6: A	20	6	25	4000	80	-27.56	51.4
Band 6: B	15	8	125	6000	0	-30.19	80.2
Band 6: C	20	6	25	4000	95	-32.52	53.3

All information gathered thus far has shown total costs for only the first twenty years of the study for Bands 1–6, and is missing the costs associated with the last twenty years of the study. Bands 1–6 have carbon reductions less than half of the Waxman-Markey legislation reductions. If the assumption is made that the actions required to achieve Band 6 could be implemented within the twenty years, then costs required for the type of reductions for Bands 1–6 have been appropriately defined. For Bands 7 and 8, it would be faulty, however, to assume the actions required could be implemented by 2020; thus, 2050 total system costs for those bands is more appropriate. To get those costs, some special modeling techniques were employed on one specific case in Band 8. Refer to Figure 9.3-3.

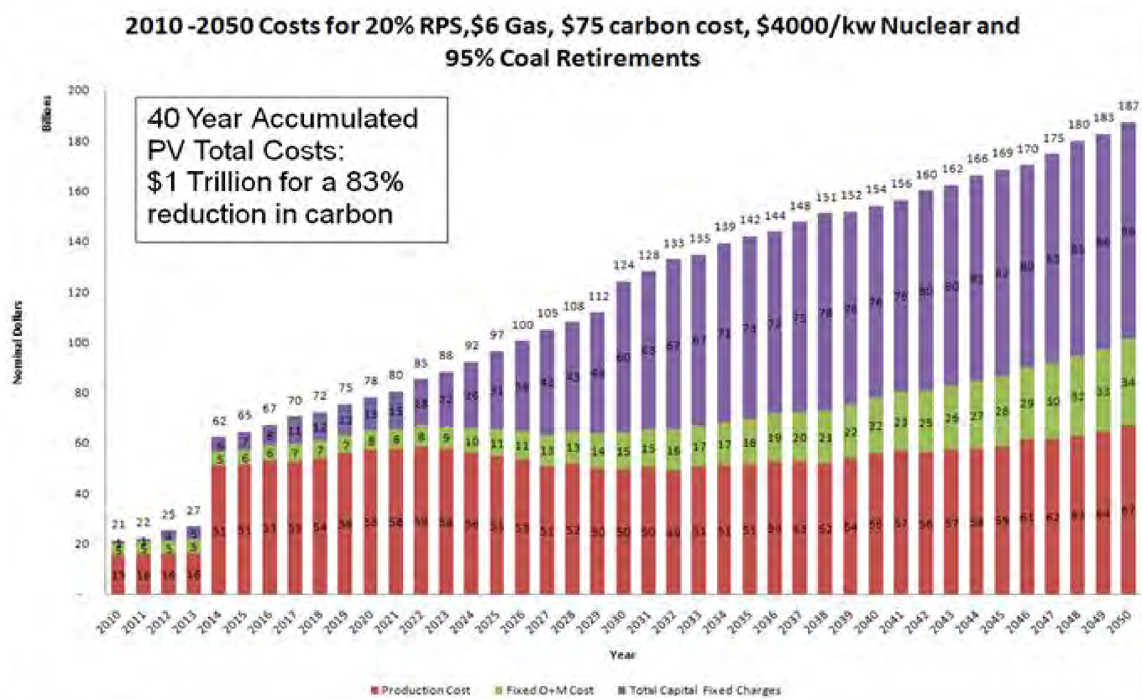

Figure 9.3-3: 40-Year Total Cost for a Case in Band 8

Calculating present value of 40-year costs results in a total 40-year present valued cost of $1 trillion. To achieve 83% carbon reduction by 2050 would cost $1 trillion. One carbon reduction compliance strategy alone cannot achieve Waxman-Markey level reductions. A combination of all strategies is required to achieve high carbon reductions. Costs vary widely depending on the compliance strategy employed. To reach reductions higher than 35%, retirements of existing coal resources are needed. What Midwest ISO can do is to be proactive in transmission planning, enabling not only integration of renewable and other new generation resources but also providing increased transfer capability to better optimize generation resources, demand response, and energy efficiency programs.

9.4 Demand Response and Energy Efficiency Potential

9.4.1 Overview

In previous studies, demand response and energy efficiency programs and their impacts were reflected in cumulative demand and energy growth rates. A simplified approach to model demand response and energy efficiency across a system cannot be justified because there is a wide range of Demand Side Management (DSM) penetration varying over a period of time across regions. Thus, it is essential to capture all different program types at different costs and their comparison to conventional thermal generating units. Currently, various utilities implement DSM at different levels. The best method to obtain an accurate estimation of traditional utility-sponsored programs and their penetration levels is to survey individual utilities and obtain their current and planned forecast data.

Midwest ISO has consulted with Global Energy Partners LLC (Global) to perform an evaluation of Demand Response (DR) and Energy Efficiency (EE) potential in the Midwest ISO footprint and develop a twenty year forecast for Midwest ISO region and rest of the Eastern Interconnection. This study demonstrated the enhanced modeling capabilities of DSM programs in 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. An accurate understanding and effective modeling of demand side programs is of high value as these programs significantly impact the load growth and future generation needs of the system. A comprehensive model that includes both the supply side and demand side resources as possible options in the regional resource forecasting is needed.

EGEAS gives the least cost system expansion plan with a combination of resources needed to reliably meet the system peak demand with a certain system planning reserve margin determined based on Loss of Load Expectation (LOLE) studies. With the Global project the options that are considered as part of regional resource plans would include new generation, renewable portfolio standards, thermal generation, demand response, and energy efficiency. This study also assesses the cost effectiveness of the DSM programs at addressing peak demand requirements, as compared to using natural gas-fired generation. Hence, the least cost generation portfolio would propose those DSM programs that lower the overall system production and capital costs.

9.4.2 Stakeholder Survey

Global sent out a survey to several utilities in the Midwest ISO footprint requesting data on their current demand-side management programs and a 20 year forecast for different programs. Global developed a baseline forecast as part of the study and used the program information received to develop estimates of DR and EE demand and energy savings by program type in a format that can be used in the EGEAS resource expansion planning model. The estimate of demand response potential for the Midwest ISO region includes five program types: Commercial and Industrial (C&I) Curtailable/Interruptible tariffs, C&I Direct Load Control (DLC), C&I Dynamic Pricing, Residential DLC, and Residential Dynamic Pricing. Residential and C&I Energy Efficiency (EE) programs are considered in this study and are broken down based on the cost of implementation of the EE program on a $/kW basis. The programs that cost more than $1000 per achieved kW savings are categorized under the high cost programs and the others under low cost EE programs. Programs ranging from appliance incentives/ rebates, appliance recycling, lighting initiatives, low income programs to multi-family, new construction, home audit programs were considered for the residential EE programs. Lighting programs, prescriptive rebates, custom incentives, new construction programs, retro-commissioning and all other C&I programs were considered for C&I EE programs. Assumptions on participation factors, growth rates and program impacts were at the program level and a thorough analysis was performed for each program class.

Estimates were also developed for Midwest ISO East, West, and Central planning regions in addition to Midwest ISO as a whole. The DR and EE estimates for other regions in the Eastern Interconnection will also be calculated on a state-by-state level and then mapped to the regions based on the utilities' load share by state.

9.4.3 Scenario Analysis

Global's baseline demand and energy forecast for the Midwest ISO region is similar to the values assumed for the Planning Advisory Committee (PAC) Business as Usual ("BAU") with Mid-Low Demand and Energy Growth (S8: PAC BAU MLDE) future. Similar DR and EE forecasts for four other scenarios as selected by PAC will be developed and the results will feed into EGEAS modeling and the most economical resource plan will be determined for those futures. DSM under various scenarios will be defined and their potential estimated for our study by Global. Scenario analysis is a key step of the project as the available DSM potential, cost estimates and peak load impacts vary by future; hence, a baseline DSM forecast cannot be used across different scenarios.

9.4.4 Results

Figure 9.4-1 shows the total peak demand (MW) and energy (GWh) savings potential available in the Midwest ISO region for the PAC BAU MLDE future (S8). The current year's (2010) demand response and energy efficiency potential peak MW savings is about 4.4% of the baseline peak forecast that increases to about 17.3% of the baseline peak forecast at the end of the study period (2030). In terms of energy savings, the current year's energy savings from both DR and EE is 0.6% of the baseline energy forecast that increases to about 10.3% of the baseline energy forecast at the end of the study period.

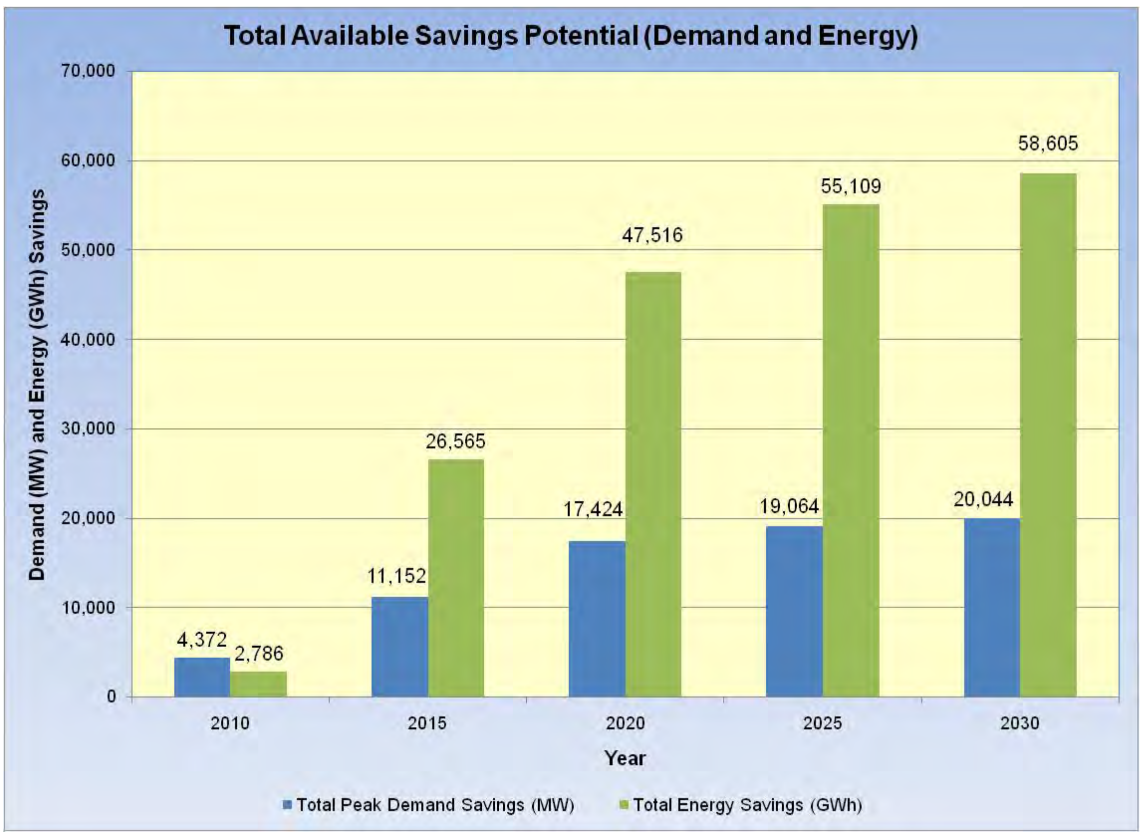

Figure 9.4-1: Total Midwest ISO Savings Potential for both Demand (MW) and Energy (GWh)

The baseline demand forecast developed using the utility provided data was compared against the 2009 Module E forecast. On average, the baseline forecast is lower than the 2009 Module E data. This difference can be attributed to transmission and distribution losses and data from other smaller cooperatives not being considered for this round of the study.

Figure 9.4-2 shows, by program type for Midwest ISO, demand response peak MW savings/impacts in MW and the cumulative energy efficiency savings in GWh. Figure 9.5-2 shows a very large penetration capability of demand reduction from DR programs and very large energy savings using energy efficiency programs. The costs and penetration levels are different for various DSM programs. All of these program options will be competing against supply side options, and from these, EGEAS will determine the least cost/most economical option to meet the peak load demand reliably.

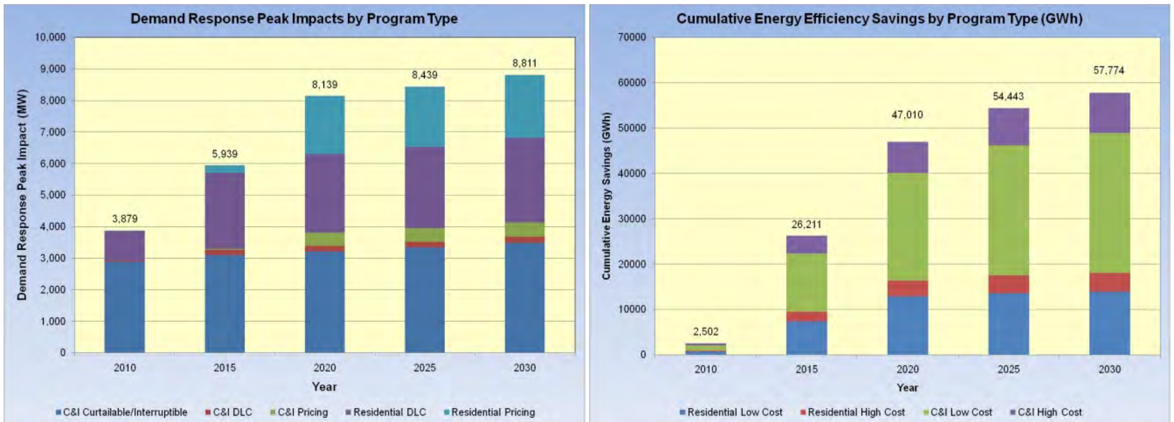

Figure 9.4-2: Demand Response Peak Impacts and Cumulative Energy Efficiency Savings Impact

9.4.5 Next Steps and Conclusions

DSM programs have a significant impact to defer the need for additional capacity while meeting the system planning reserve margin without the build out of additional supply side resources. The DR and EE programs also have an impact on the carbon emissions as the conventional supply side units have to produce less to meet the demand and their effect on carbon emissions will need to be studied.

EGEAS resource expansion plans will feed into the second step of the 7-step MTEP process. If a particular combination of DSM programs is economically viable, then those programs will be in the resource mix and will be sited in the Power Flow as future units that will be fed into economic production cost models such as PROMOD IV. This in turn will have an impact on preliminary transmission portfolio design and affect—to greater or lesser degrees—the overall robust transmission overlay that will be proposed. An accurate DSM estimation and representation not only allows for deferred capacity savings but also influences the robust transmission overlay proposals. Since this is an important step in the MTEP process, a revised survey, estimation, and forecasting approach will need to be used in MTEP11.

9.5 Energy Storage

9.5.1 Overview

With the addition of significant amounts of renewable resources to Midwest ISO, the ability to store large amounts of off-peak energy and cycle that energy back during high demand periods is becoming an even greater necessity. Many states within the Midwest ISO footprint have already implemented renewable portfolio standards (RPS) requiring as much as 25% renewable resources by 2025, with some individual utilities setting even loftier goals as high as 30% by 2020. Midwest ISO recognizes the need to be able to efficiently utilize this intermittent power at times when it is most needed.

Refer to Figure 9.5-1. One potential bulk energy storage solution is Compressed-Air Energy Storage (CAES). CAES facilities utilize large underground caverns to store air which is compressed during off-peak hours. The compressed air is then fed into a natural gas combustion turbine (CT) to provide power back to the grid during peak demand periods. It should be noted that, although CAES is the focus of this report, many different types of energy storage are available. An analysis for various energy storage technologies will be included in the MTEP11 scope.

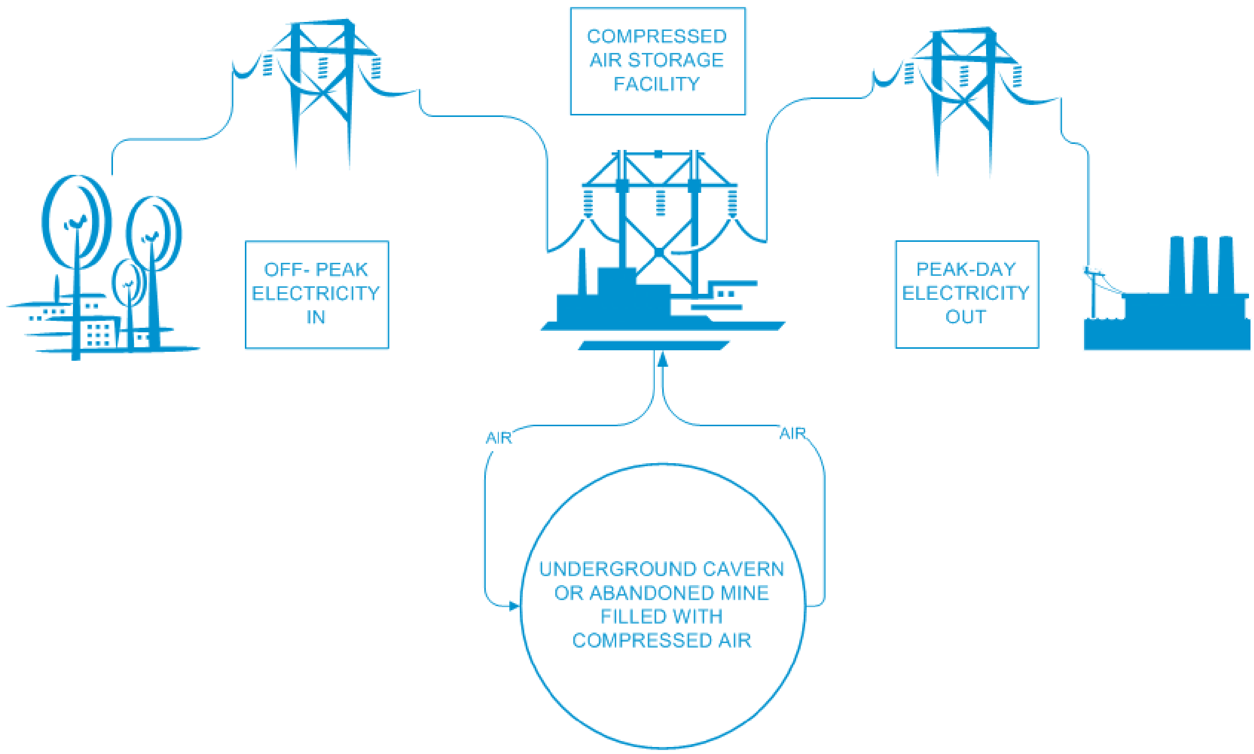

Figure 9.5-1: Compressed-Air Energy Storage Concept

Preliminary screening by Midwest ISO has shown that CAES fits best into the resource mix with higher gas prices. Further, if off-peak LMP prices are driven down by large quantities of renewable generation on the system, a CAES facility is able to compress air with this cheaper energy and provide it back during on-peak periods, adding to the potential value CAES can provide. A full-scale evaluation of energy storage, including an analysis of other energy storage technologies, is anticipated for the MTEP11 planning cycle.

9.5.2 Screening Results

The following three (3) figures are screening curves used to illustrate where different generation types fit into the resource mix. The point where the lines cross the vertical axis is determined by the fixed cost of each unit, which are annual carrying costs and fixed operating & maintenance (O&M). The slope of each line is determined by variable costs such as variable O&M and fuel. A CAES unit has been plotted on each curve using off-peak charging prices ranging from $5.00 per MWh to $40.00 per MWh. The three (3) figures show gas prices ranging from $4.00 per MBtu (Figure 9.5.1) to $8.00 per MBtu (Figure 9.5.3). The unit with the least total cost per MW at any given hour is typically seen as the best choice for generation.

Refer to Figure 9.5-2. At $4/MBtu gas, CAES competes heavily with CTs at off-peak LMPs below $25/MWh and—for higher prices—a Combined Cycle (CC) would be the better choice.

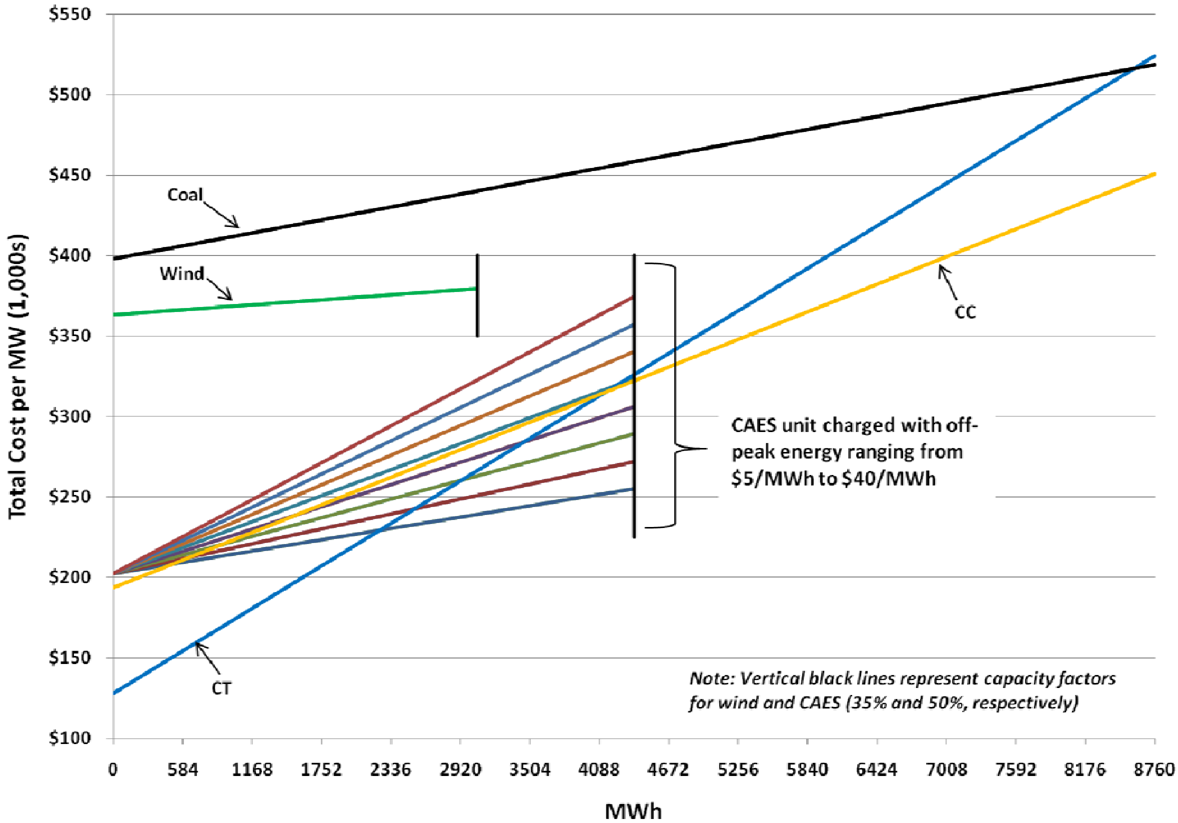

Figure 9.5-2: CAES Unit Charged with Varying Off-peak Energy Prices and $4.00 per MBtu Gas

In Figure 9.5-3 below, gas prices were raised to $6/MBTu. In this situation, CAES looks highly favorable, with LMPs below $35/MWh and with a much larger time window available to provide stored power back to the grid.

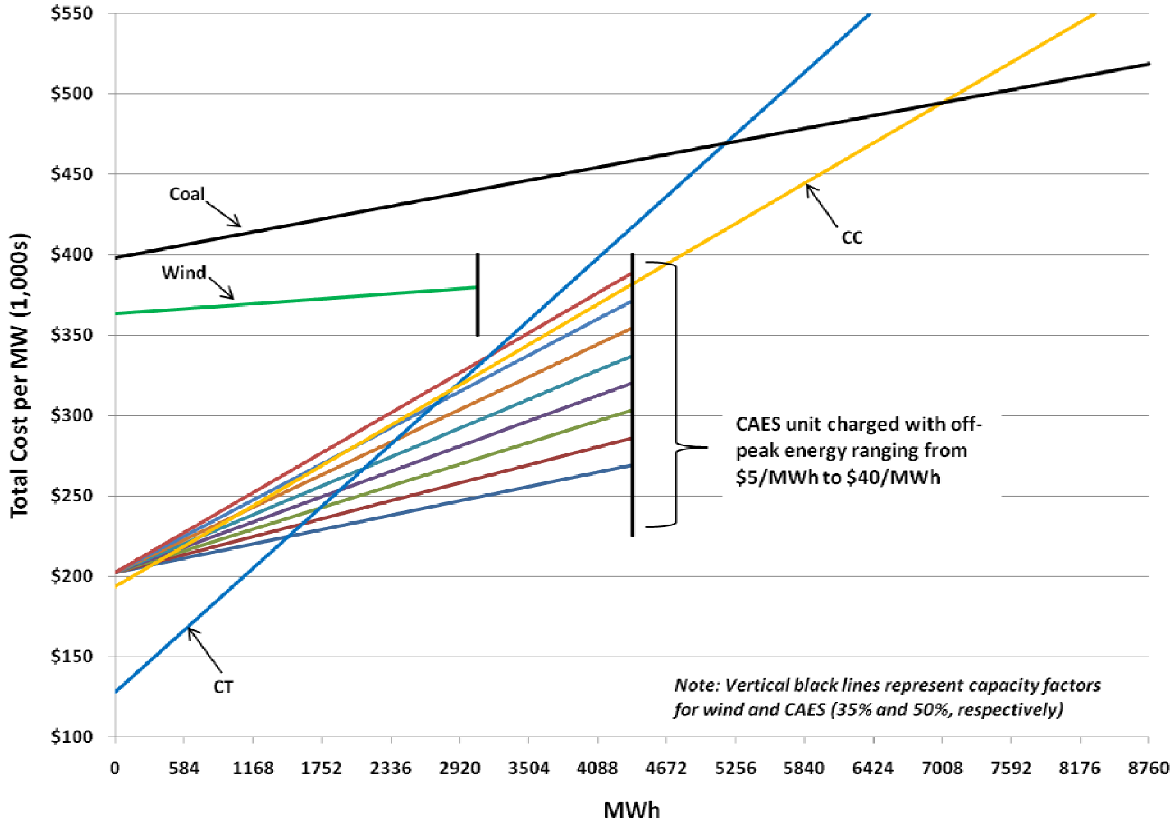

Figure 9.5-3: CAES Unit Charged with Varying Off-peak Energy Prices and $6.00 per MBtu Gas

Refer to Figure 9.5-4, below. If gas prices were to rise to $8/MBtu, CTs and CCs would become too costly to operate for long periods of time. The potential for bulk storage units like CAES would be very great.

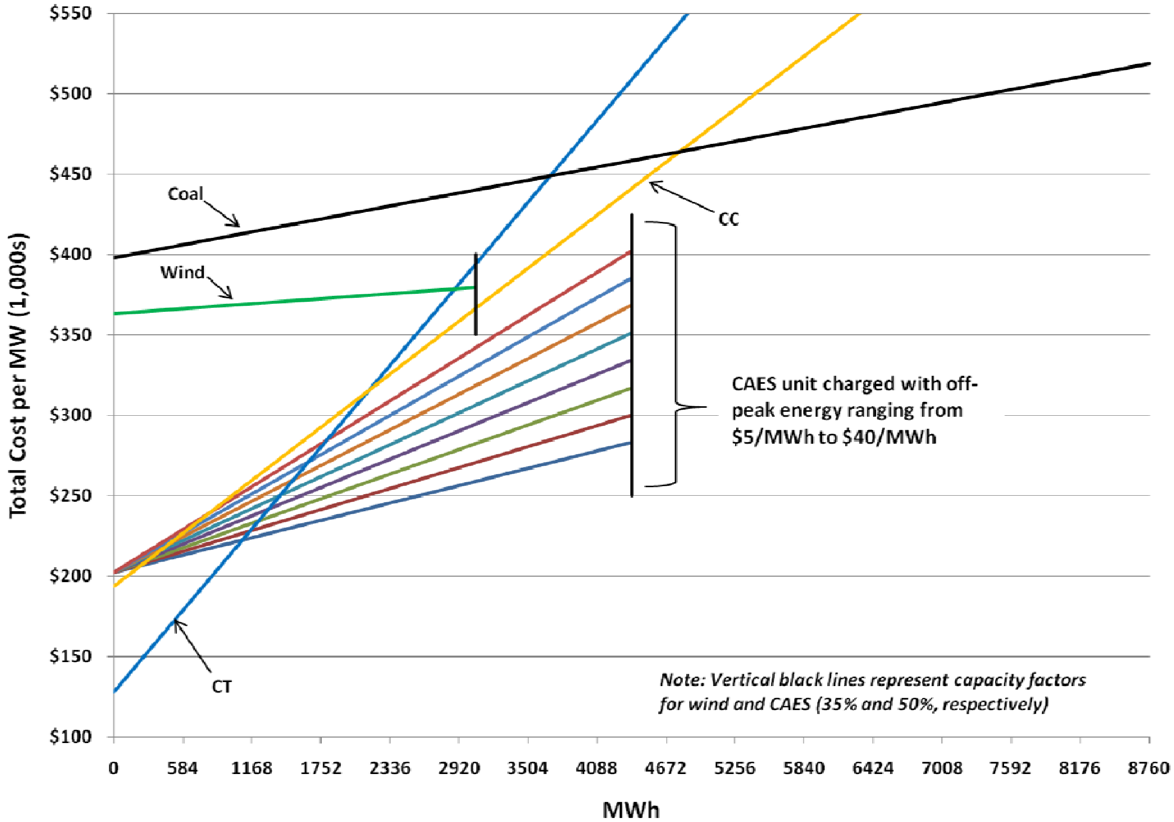

Figure 9.5-4: CAES Unit Charged with Varying Off-peak Energy Prices and $8.00 per MBtu Gas

9.5.3 Conclusion and Next Steps

It is important to note many other factors and variables must be considered when choosing any type of new generation. Electric Generation Expansion Analysis System (EGEAS) software simulation results have shown some potential for this type of storage capacity.

Midwest ISO recognizes the impending need for grid-scale energy storage. Preliminary screening of CAES units has shown two (2) main drivers for implementation: gas prices and off-peak LMP prices. As many states continue to enact Renewable Portfolio Standards, off-peak energy prices may be reduced to levels that allow storage resources such as CAES to be competitive.

In MTEP11, Midwest ISO plans to more fully explore the potential benefits of a variety of energy storage technologies. Midwest ISO also plans to consider energy storage as a resource option in planning models and future-based scenarios. If enough interest is expressed, an entirely new scenario may be developed and evaluated in the MTEP11 planning cycle.

9.6 Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative (EIPC) was formed among planning entities to address Eastern Interconnection efforts to prepare analyses of transmission requirements under a broad range of alternative futures and to develop long-term interconnection-wide transmission expansion plans in response to alternative resource scenarios selected through the stakeholder process.

The current EIPC project will aggregate modeling and regional expansion plans developed in the annual regional processes for 2010, and will entail conducting base plan and scenario analysis to identify potential impacts and interregional transmission expansion options. The resulting Eastern Interconnection transmission model developed by integrating regional plans will be analyzed to identify opportunities for potential transmission enhancements to regional expansion plans in order to increase the ability to move power or reduce costs. In Phase II, the EIPC will provide the results of the reliability and production cost analyses performed for the resource expansion scenario(s) selected for further study, including the interregional transmission expansion options identified and the associated cost estimates.

Funding for the project will come from a U.S. Department of Energy (DOE) grant that was recently awarded to the EIPC for these purposes. The project is expected to be completed in 2013, although the DOE will decide whether to continue the project after Phase I of the study is completed. The final schedule for completion is being finalized. Project kick-off is scheduled for late August 2010.

10 Commonly Used Acronyms

AEO	Annual Energy Outlook
AEP	American Electric Power
ALTE	Alliant East
AMIL	Ameren Illinois
AMMO	Ameren Missouri
BA	Balancing Authority
BES	Bulk Electrical System
BRP	Baseline Reliability Project
BTM	Behind The Meter
CapX	Capacity Expansion
CARP	Cost Allocation and Regional Planning
CC	Combined Cycle
CE	Commonwealth Edison
CR	Contingency Reserves
CRSG	Contingency Reserve Sharing Group
CT	Combustion Turbine
CWLD	City of Columbia, MO
CWLP	City Water Light & Power–Springfield, IL
DA	Day Ahead
DCLM	Direct Controlled Load Management
DEM	Duke Energy Midwest
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
EGEAS	Electric Generation & Expansion Analysis System
EHV	Extreme High Voltage
EI	Eastern Interconnect
EIA	Energy Information Administration
EMT	Energy Markets Tariff
ERAG	Eastern Interconnection Regional Reliability Organization
EWITS	Eastern Wind Integration Transmission Study
FE	First Energy
FERC	Federal Energy Regulatory Commission
FG	Flow Gate

FOR	Forced Outage Rate
GADS	General Availability Data System
GIP	Generator Interconnection Project
GRE	Great River Energy
GW	Gigawatt = 1,000,000,000 watts
HE	Hoosier Energy
HVDC	High Voltage Direct Current
IA	Interconnection Agreement
IGCC	Integrated Coal Gasification Comined Cycle
IL	Interruptible Load
IMM	Independent Market Monitor
IMPA	Indiana Municipal Power Agency
IPL	Indianapolis Power & Light
ISD	In Service Date
ISO	Independent System Operator
ITC	ITC Transmission Co. (ITC Holding)
JCSP	Joint Coordinated System Planning
kW	Kilowatt = 1,000 watts
kWh	Kilowatt Hours
LFCR	Levelized Fixed Charge Rate
LFU	Load Forecast Uncertainty
LMP	Locational Marginal Pricing
LODF	Line Outage Distribution Factor
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LOLH	Loss of Load Hours
LOLP	Loss of Load Probablility
LSE	Load Serving Entities
LSE	Load Serving Entities
LTC	Load Tap Changing Transformers
MAIN	Mid-America Internconnected Network
MAPP	Mid-Continent Area Power Pool
MCC	Marginal Congestion Component
MEC	Midamerican Energy Company
METC	Michigan Electric Transmission Co. (ITC Holding)
MOD	Model on Demand
MP	Minnesota Power (& Light Co.)

MidwestISO
Energizing the Heartland

MPPA	Michigan Public Power Agency
MPRSG	Midwest Planning Reserve Sharing Group
MRES	Missouri river Energy Group
MRO	Midwest Reliability Organization
MSCPA	Michigan South Central Power Agency
MVP	Multi-Value Project
MW	Megawatt = 1,000,000 watts
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corp.
NIPSCO	Northern Indiana Public Service Company
NPV	Net Present Value
NR	Network Resources
NREL	National Renewable Energy Labs
NWEC	Northern Wisconsin Electric Company
O&M	Operations and Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	Organization of Midwest ISO States
OTP	Otter Tail Power Co.
PA	Planning Authority
PAC	Planning Advisory Committee
PAT	PROMOD® Analysis Tool
PJM	Maryland Interconnect
PMU	Phasor Measurement Unit
PrjID	Project ID
PRM	Planning Reserve Margin
PS	Planning Subcommittee
RA	Reliability Authority
RAR	Resource Adequacy Requirements
RECB II	Regional Expansion Criteria & Benefits
RGOS	Regional Generation Outlet Study
ROW	Rights of Way
RPF	Regional Resource Forecasting
RPS	Renewable Portfolio Standards
RT	Real Time
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization

SCED	Security Constrained Economic Dispatch
SIPC	Southern Illinois Power Cooperative
SPM	Subregional Planning Meetings
SPP	Southwest Power Pool
TDSP	Transmission Service Delivery Project
TLR	Transmission Loading Relief
TO	Transmission Owners
TPL	NERC Transmission Planning
TRG	Technical Review Group
TVA	Tennessee Valley Authority
UMTDI	Upper Midwest Transmission Development Initiative
Vectren	Southern Indiana Gas & Electric
Vectren	Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana
WECC	Western Electricity Coordinating Council
WPSC	Wolverine Power Supply Cooperative
WUMS	Wisconsin Upper Michigan System
WVPA	Wabash Valley Power Association
XEL	Xcel Energy

11 Appendices

The following MTEP10 Appendices are available and accessible on the Midwest ISO public webpage. All confidential Appendices, such as D.3-D.6, are available on the Midwest ISO MTEP10 FTP site.

- Appendix A: Projects Recommended for Approval
  - Sections A.1, A.2, A.3: Cost Allocations
- Appendix B: Projects with Documented Need & Effectiveness
- Appendix C: Projects in Review and Conceptual Projects
- Appendix D: Reliability Studies Analytical Details with Mitigation Plan
  - Section D.1: Project Justification
  - Section D.2: Modeling Documentation
- Appendix E: Long-term Reliability Planning
- Appendix F: Long-term Value-based Planning
- Appendix G: Congestion History and Analyses
- Appendix H: Stakeholder Substantive Comments

A link to the MTEP10 report and Appendices, on the Midwest ISO public website, is below:

https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan2010.aspx