MTEP 2009

Midwest ISO Transmission Expansion Plan

December 2009

MidwestISO
Energizing the Heartland

http://www.midwestmarket.org/page/Planning

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Appendices Included on CD-ROM

Section 1: Executive Summary

1.1 Overview

The Midwest ISO Transmission Expansion Plan 2009 (MTEP 09) recommends 274 new projects totaling $903 million of investment in transmission infrastructure for inclusion in Appendix A. Appendix A projects are those which have been approved by the Midwest ISO Board of Directors, creating an obligation on the part of the Transmission Owner to make a good faith effort to execute the project. These new projects, in combination with the existing portfolio of previously approved projects and the proposed projects in Appendix B[1] will enable reliable and efficient electricity expansion for the next ten years and comply with all relevant North American Electric Reliability Corporation (NERC) Transmission Planning Standards

The addition of these projects brings the total number of projects in Appendix A to 576 with total investment of $4.3 billion. Since the first MTEP cycle that closed in 2003, transmission investment totaling $7.2 billion has been approved, $2.7 billion of which is associated with projects already in-service. The recommended system enhancements, while primarily driven by reliability needs, are nonetheless expected to contribute significant economic benefits once they are placed into service. It is estimated that by 2014, the portfolio of projects in Appendices A and B, if constructed and put into service, will provide market efficiency savings of just under $1 billion annually. Additionally, these projects are forecasted to reduce CO_2 emissions in 2014 by more than 2 billion tons.

Of the projects recommended in the MTEP 2009 report cycle, 22 are identified as meeting the criteria for cost sharing eligibility under the provisions of the Midwest ISO tariff. Those projects represent a total investment of $302 million, $205 million of which is for projects (in excess of $5 million dollars) which are required to ensure compliance with NERC standards. Also included is a $6 million Regionally Beneficial Project (RBP). This project represents the first time a project's cost have been eligible for cost sharing based on economic benefits such as reduction in generation production cost and reduction in the Locational Marginal Prices (LMP) paid by load . The remaining $91 million of cost shared projects is associated with the 12 Generator Interconnection Projects (GIP) included in Appendix A which will serve to integrate over 1,100 MW of additional wind generation into the Midwest ISO footprint.

The continued identification of projects that improve system flexibility and enable additional generation capacity to connect to the grid is critical to maintaining long-term reliability. Although reserve margins are forecasted to decrease from 31.9% in 2009 to 25.5% by 2018, an analysis of load and generation projections indicates that ample supply, and the transmission capacity to move it, will exist to meet load expectations out through 2018 under nearly all base case conditions.[2] Conducted for 2013 and 2018, the analysis found that risk associated with loss of load expectations would exceed the industry standard of one day in ten years only in the relatively unlikely scenario that there is no additional generation build-out and very high load levels. This is an improvement over the results shown in the MTEP 08 report, which forecasted a shortfall beginning in 2014. The improved forecast in MTEP 2009 is largely due to an expectation by the load serving entities of the Midwest ISO of continued low load, driven by the recent impacts to the economy. In turn, the risk associated with loss of load expectation has also improved from a year ago. Additional sensitivities indicate an expectation of exceeding the

[1] Appendix B projects are those projects where a need has been identified, but the final business case assessment is not yet complete
[2] Base case conditions are characterized by a 50/50 load forecast and assumed levels of forced outages, generation imports during peak, and wind availability based on historical data.

benchmark primarily only in scenarios of high loads combined with an inability to access external energy sources.

To reduce the likelihood of this risk exceeding appropriate levels, the Midwest ISO must also focus on congestion management so that the transfer capability of the system, and thus the reserve margin, is not negatively impacted. For example, in the absence of additional transmission buildout, it is estimated that the planning reserve margin would need to increase from 0.6% in 2009 to 2.3% in 2018 to accommodate increased congestion. The annual review of historical congestion in MTEP 09 indicates that while the number of flowgates experiencing congestion in each post-market period is declining, chronic congestion remains. In 2009, the Midwest ISO executed the first Top Congested Flow Gate study. This study sought to identify, based on both historical and forward looking analyses, those areas where the cost of a transmission upgrade to reduce congestion was exceeded by the benefits of reduced production cost and lower LMPs paid by load. This study, which will be executed on an on-going basis, will continue to facilitate the development and evaluation of solutions for historical and future congestion, allowing mitigation to take place in some cases before the negative impacts from elevated levels of congestion are experienced.

Evolving energy policy has a significant impact on current planning activities. Within the Midwest ISO footprint, state Renewable Portfolio Standard (RPS) goals or mandates call for 23,000 MW of renewable generation to be installed in the next two decades, assuming a 35% capacity factor for wind units. Policy discussions at the federal level, while also including potential renewable energy mandates, encompass an even broader set of objectives. Clean energy, smart grid, and energy efficiency are all programs that will impact generation utilization and transmission planning. The level of uncertainty around the potential outcome of these many policy discussions continues to cause challenges for those who plan the transmission system and hesitancy for those who may wish to invest in it. Beginning in 2005, the Board of Directors of the Midwest ISO provided planning staff with guiding principles for the planning process. These principles, which focus on planning for reliability, economics and public policy objectives, led the Midwest ISO to create a value-based planning process which seeks to provide insight on a wide range of potential impacts under a large number of future policy scenarios.

These future policy scenarios each result in the design of a unique generation expansion and transmission plan that will enable the objectives to be met. Robustness testing is conducted to identify transmission projects or portfolios, from these unique plans, that would prove valuable under many, if not most, scenarios. At this point, transmission plans developed under this methodology reside in Appendix C of the MTEP, which reflects their relatively early stage of transmission design and justification. The ultimate goal is to create a single transmission plan, with the projects recommended for approval in Appendix A, which would result in the least future regrets – with respect to cost, right of way usage and benefits achieved - regardless of the ultimate energy policy decision.

The Midwest ISO's Regional Generation Outlet Study (RGOS) is currently underway to identify renewable energy zones and design transmission expansions that will connect those zones to states that will require the generation to achieve RPS mandates. The work done through this study will address the business case to assess the value of this type of transmission investment; however, the question of who will pay for this transmission continues to be an unanswered and critical question. The state regulators and governors in the Midwest ISO footprint have stepped forward to address this issue, as is evidenced by the efforts such as the Upper Midwest Transmission Development Initiative (UMTDI)[3], the Midwest Governor's Association and the Cost Allocation Regional Planning (CARP) initiative led by the full Organization of Midwest ISO States (OMS). These groups are focused on developing cost allocation recommendations, - evaluated within the context of potential transmission plans and enhanced by feedback from the entire Midwest ISO stakeholder community - that will enable meeting existing and potential future environmental policy requirements.

[3] North Dakota, South Dakota, Iowa, Minnesota and Wisconsin

Looking forward to 2010, Midwest ISO planning efforts will continue to focus on ensuring reliability, maximizing the market efficiency value that transmission can bring, collaborating with stakeholders across the Midwest ISO footprint and beyond, and supporting the ability of our members to meet their energy policy goals.

1.2 What is the Midwest ISO Transmission Expansion Plan?

The MTEP Report is produced on an annual basis to provide interested parties with an overview of the Midwest ISO's planning processes, an update on the transmission planning studies underway, and an understanding of the analyses used in the execution of those processes. The report is also the vehicle to communicate the projects that, as a result of those analyses, are recommended to the Midwest ISO Board of Directors for approval and subsequent implementation.

MTEP 09, the 6th edition of this publication, is the culmination of eighteen-plus months of collaboration between the Midwest ISO's planning staff and its many stakeholders. For each report cycle, efforts are focused on identifying issues and opportunities related to the strengthening of the transmission grid, developing alternatives to be considered, and evaluating those options to determine if there is an effective solution among them. The objective is to identify projects that:

- Ensure reliability of the transmission system
- Provide economic benefit, such as through allowing increased efficiency in market operations (i.e. reducing cost of energy production and/or the price paid by load)
- Enable public policy objectives, such as the integration of renewables, to be achieved
- Address other issues or goals identified through the stakeholder input process.

After thorough analysis, those projects that are determined to be the best solution for a particular issue or opportunity are included in Appendix A of the MTEP Report. Appendix A projects are then recommended for approval by the Midwest ISO Board of Directors. Upon the approval by the Midwest ISO Board, the Transmission Owner is required, under the Tariff, to make a good faith effort to complete the project, beginning with making the business case to state regulators. Projects that appear to meet a need, but require further analysis of alternatives, are assigned to Appendix B until it is determined that they will be either moved to Appendix A and recommended for approval or that they are not the best alternative to the issues they seek to address. Finally, Appendix C contains projects with a range of different statuses. This includes those that are at the conceptual stage and will require a fair amount of planning prior to being recommended for approval and, those projects entering late in the study process that not yet having been evaluated for need and effectiveness.

1.3 Investment in System Reliability

As a result of the analysis conducted during the MTEP 09 report cycle, 274 additional projects are included in Appendix A and recommended for implementation. Those projects represent an incremental $903 million transmission infrastructure investment in the Midwest ISO footprint. The distribution of those projects and their associated cost by type and across the Midwest ISO Planning Regions is shown in Figure 1.3-1.

The Appendix A projects fall into five categories:

- **Baseline Reliability –** Projects required to meet North American Electric Reliability Corporation (NERC) reliability standards. These standards impact projects of a voltage greater than 100kV and represent the minimum standard applied across the Midwest ISO's footprint.
- **Generator Interconnection –** Projects required to reliably connect new generation to the transmission grid.
- **Other –** Other incorporates a wide range of projects, from those that are designed to provide local economic or similar benefit – but do not meet the threshold requirements for qualification as a Regionally Beneficial Project (RBP) – to projects that are required on the lower voltage transmission system that is outside of the Midwest ISO's functional control
- **Regionally Beneficial Project (RBP) –** Projects having voltages of 345kV or higher that are determined to provide economic benefits, in the form of reduced production cost and load LMPs, to the region.
- **Transmission Service Delivery Projects -** Projects which are required to satisfy a Transmission Service Request. The costs of these projects are always direct assigned to the requestor.

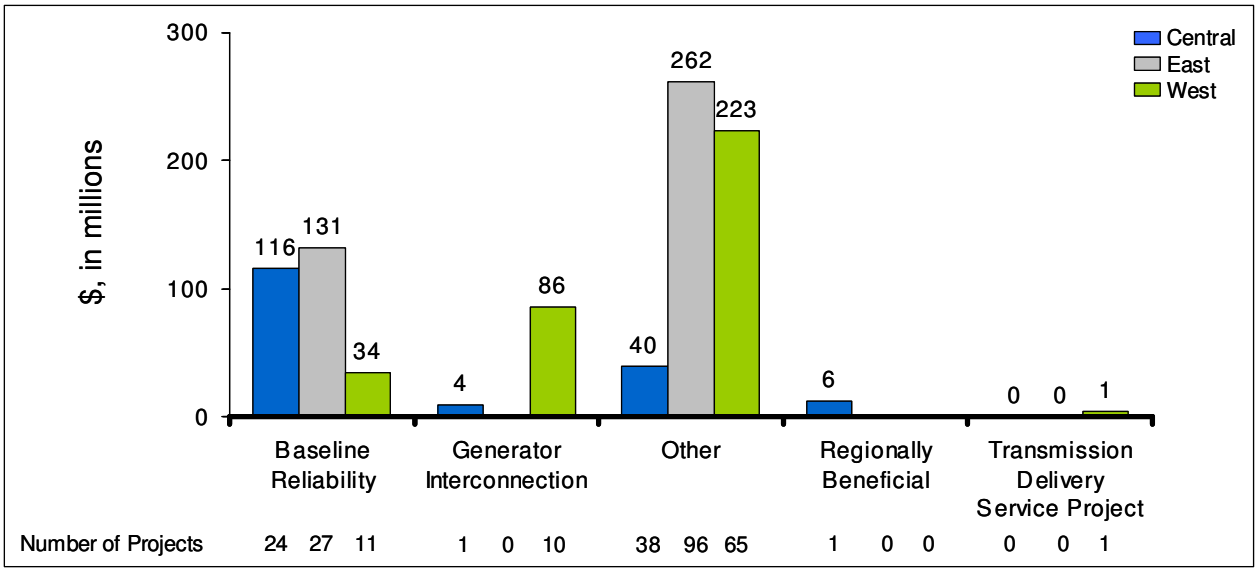


Figure 1.3-1 MTEP 09 Appendix A Projects and Costs

The eleven Generator Interconnection projects in Appendix A support the connection of 1,294 MW of capacity to the transmission grid, of which 1,102 MW is wind and the remainder for coal and a Waste

Heat Recovery site. In addition, 12 interconnection requests representing 822 MW of capacity are able to connect with limited transmission upgrades; 412 MW of this are for wind generation.

Appendix A projects represent approximately 3,350 miles of new or upgraded transmission lines in the 2009 through 2019 timeframe. The distribution of those lines by state and by voltage is shown in Figure 1.3-2

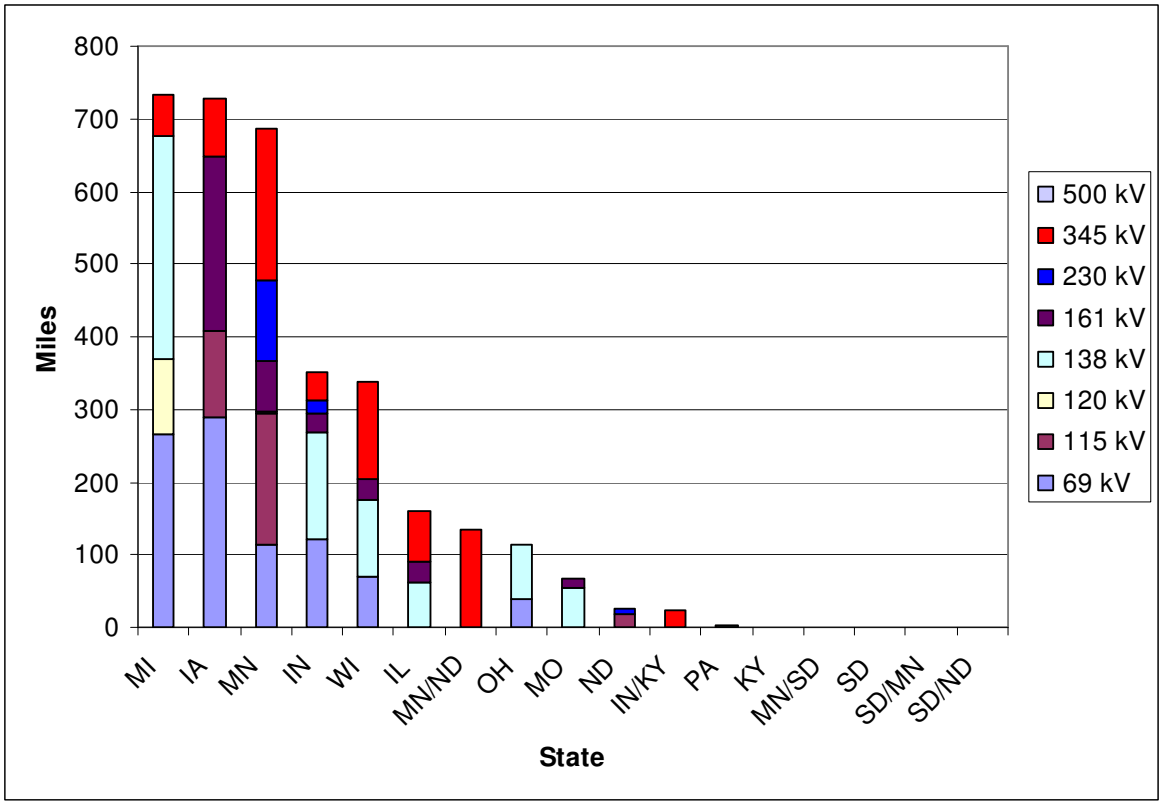


Figure 1.3-2 New or Upgraded Line Miles in Appendix A by State

Those line miles correspond to a substantial investment in transmission infrastructure in the Midwest ISO region. The total estimated investment of the projects in MTEP 09 Appendix A and Appendix B for the period 2009 to 2014 is $5.20 billion. Appendix A on its own contains $3.90 billion in investment through 2014. Although most projects needed for reliability fall within the 5 year timeframe, some projects driven by reliability, as well as economic or other criteria, may require a longer lead time. The addition of projects in MTEP 09 brings the total number of projects in Appendix A to 576, representing an expected investment of $4.3 billion through 2019. Appendix B contains an additional $1.5 billion in investment. Once completed, the projects in Appendix A and B will provide reliable and efficient transmission service for existing and new load growth through the 10-year planning horizon and comply with all relevant NERC Transmission Planning Standards.

In addition, there is $22.8 billion of potential investment associated with projects in Appendix C. These projects generally are longer-term solutions that are at the conceptual stage and will require much more planning in order to evaluate the need and effectiveness of the proposed solution.. A large portion of the investment in Appendix C is associated with a $14 billion Extra High Voltage (EHV) conceptual transmission overlay that was designed to address the energy policy future which reflects future energy policies being similar to today.

Since the first MTEP cycle that closed in 2003, projects recommended for approval total $7.2 billion, $2.7 billion of which is associated with projects that are already in-service. The continued growth of Appendix A is a testament to the coordinated efforts of the Midwest ISO and its stakeholders on developing solutions to ensure transmission system reliability and efficient system operation into the future.

21 Appendix A projects were identified as meeting the criteria for cost sharing eligibility under the RECB I provisions of the Midwest ISO tariff and one was determined to be the first project proposed since the advent of cost sharing which met the criteria associated with the RECB II cost sharing methodology. Those 22 projects represent total investment of $302 million. 10 of these projects, totaling $205 million are Baseline Reliability Projects (BRP) that are driven by NERC standards, are 100kV or higher in voltage, and have an estimated direct cost of $5 million or 5% of Transmission Owner Net Plant.[4] One project, with a cost of $6 million, will provide economic benefits in the form of reduction in adjusted generation production costs and Locational Marginal Prices paid by load is defined as a Regionally Beneficial Project (RBP).[5] The remaining 12 projects are to enable Generator Interconnection. The distribution of those projects and their associated cost by type and across Midwest ISO Planning Region is shown in Figure 1.3-3.

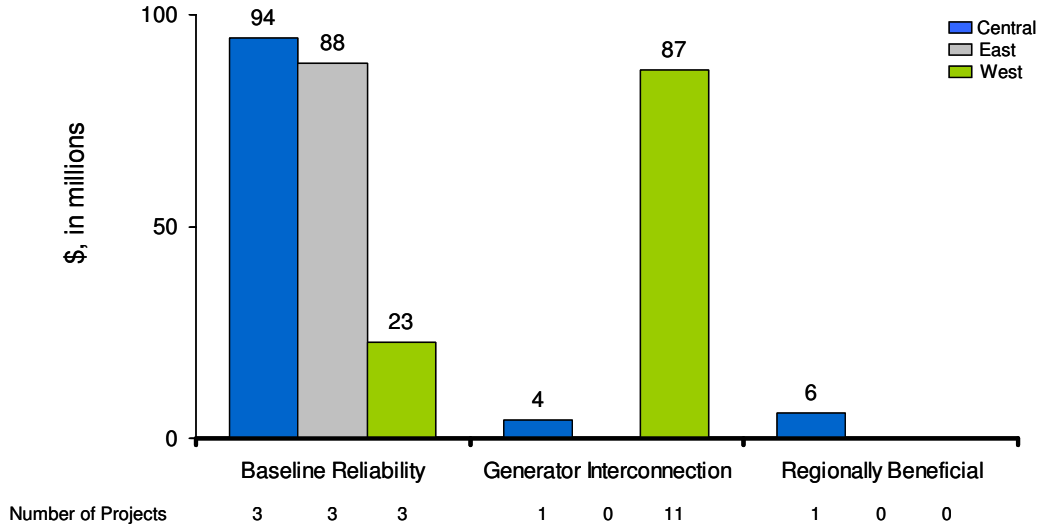


Figure 1.3-3: Projects Eligble for Cost Sharing

[4] The cost of Baseline Reliability Projects 345 kV and above are shared 20% to the entire footprint on a load ratio share basis; the remainding 80% of costs for eligible projects 345 kV and above, and all costs for eligible projects between 100 kV and 345 kV are shared using the Line Outage Distribution Factor Methodology.

[5] The cost of Regionally Beneficial Projects is shared 20% to the entire footprint on a load ratio share basis, with the remainder divided between the three planning subregions proportional to the benefits received. Within a subregion, costs are allocated on a load ratio share basis.

1.3.1 Economic Assessment of Planned and Proposed Projects

As previously described, the projects currently contained in Appendices A and B are primarily meant to address a reliability issue or need on the transmission system. However, those projects also have the potential to create additional value, including adjusted production cost savings, load cost savings, and reduced energy and capacity losses.

Each MTEP cycle the Midwest ISO performs an economic assessment of the portfolio of all Appendix A and B projects. Table 1.3-1 shows an estimated Market Congestion benefit of $965 million against a modeled transmission portfolio cost of $4 billion. Note that approximately $1.8 billion of Appendix A and B projects, such as rebuilds of existing lines, were excluded from the model due to their inability to provide incremental economic benefits.[6] The Market congestion benefits calculation uses a 70% weighting on adjusted production cost savings plus a 30% contribution of load cost savings. This methodology is similar to that used in the tariff to describe benefits when evaluating projects for eligibility as a Regionally Beneficial Project (RBP).

2014 Economic Benefits			
	Load Cost Savings	Adjusted Production Cost Savings	Market Congestion Benefits
Midwest ISO East	$598 million	$173 million	$300 million
Midwest ISO Central	$469 million	$222 million	$296 million
Midwest ISO West	$747 million	$207 million	$ 369 million
Midwest ISO	$1,813 billion	$602 million	$965 million

Table 1.3-1: 2014 Economic Benefits of Appendix A/B Projects

In addition to the economic benefits outlined above, the projects in Appendices A and B are also expected to enable a reduction in losses. Table 1.3-2 shows the expected benefits associated with the more efficient delivery of energy created by the implementation of this portfolio of projects. The $65 million associated with reduced losses is not an incremental benefit, but rather is a partial driver for the $602 million in adjusted production cost savings overall. The expected capacity loss benefit of $90 – 166 million represents the one year deferral of costs associated with additional capacity that would have been needed, but for the reduction in losses. Finally, this portfolio of projects will result in a lower level of generation by coal units. This will allow for a reduction in CO_2 emissions by more than 2 millions tons annually. Section 2.6 includes a more detailed discussion of the economic benefits associated with planned and proposed expansions.

2014 MIDWEST ISO Loss and Environmental Benefits with Appendix A/B Projects						
	Energy Loss Benefit	Value of Energy Loss Benefit	Capacity of Loss Benefit	Value of Capacity Loss Benefit	Maximum Hourly Loss Decrease	CO_2 Emission Decrease
Midwest ISO	579,030 MWH	$65 million	123 MW	$90~166 million	676 MW	2,112,535 Ton

Table 1.3-2: 2014 Loss Benefits of Appendix A/B Projects

1.3.2 Resource Adequacy

In addition to transmission planning, the MTEP 09 includes an analysis of total load and generation, found in Section 5.2. The results of a study of the period from 2009 to 2018 indicate that the Midwest ISO will have ample generating capacity to meet demand. Based on load projections reported by Network Customers, which are reduced from the prior year's analysis driven by the current economic climate, the forecasted peak demand is 95,890 MW in 2009. The forecasted peak is expected to grow slowly but consistently over the ten year period to 105,265 MW in 2018. Nameplate capacity of 131,308 MW is expected to be available in 2009 for the Midwest ISO Region, increasing to 137,119 MW in 2018[7].

The reduction in projected load levels results in higher reserve margins, with an expectation of a 25.5% reserve margin in 2018. In turn, the risk associated with loss of load expectations (LOLE), or the expected ability of forecasted resources to meet demand projections, is expected to be below the accepted industry standard of 1 day in ten years under nearly all base case conditions in both 2013 and 2018. Put another way, the expected reliability of the system is projected to be greater than the requirement. Only when no additional capacity and high load are assumed in 2018 does the risk level exceed the benchmark.

Additional sensitivity analyses were conducted to determine the impact on LOLE of varying assumptions. During the year 2013 analysis it was determined that the one-day-in-ten LOLE benchmark would only be exceeded during the extreme scenario of high load conditions combined with a complete lack of external support. Results are shown in Table 1.3-3. The elevated risk is not fully mitigated when additional capacity is assumed.

2013 Loss of Load Expectations Under Various Sensitivity						
	2013 – No New Units			2013 – 20% of Queued Units		
SCENARIO	High Load	Base Load	Low Load	High Load	Base Load	Low Load
Base Case	0.047	0.001	0.000	0.017	0.000	0.000
Increased Forced Outage Rate	0.099	0.003	0.000	0.040	0.001	0.000
No External Support	0.284	0.014	0.000	0.131	0.004	0.000
No Wind Availability	0.074	0.001	0.000	0.025	0.000	0.000

Table 1.3-3: 2013 Loss of Load Expectations

Similar to the 2013 results, it was only during high load conditions that any of the 2018 cases exceeded the one-day-in-ten benchmark. As shown in Table 1.3-4 it should be noted that without any generation expansion, even with the present load growth values, the system exceeds the industry standard LOLE benchmark for all sensitivities in this analysis, reflecting increased risk. That risk expectation is minimized in all scenarios - except where external support continues to be unavailable – if one assumes that 20% of the currently queued generation proceeds to operation. The LOLE analysis is covered in greater detail in Section 5.4.

[7] Future statistics reflect Midwest ISO membership as it existed in September 2008.

2018 Loss of Load Expectation Under Various Sensitivities						
	2018 – No New Units			2018 – 20% of Queued Units		
SCENARIO	High Load	Base Load	Low Load	High Load	Base Load	Low Load
Base Case	0.228	0.005	0.000	0.012	0.000	0.000
Increased Forced Outage Rate	0.467	0.021	0.000	0.038	0.000	0.000
No External Support	1.177	0.087	0.001	0.137	0.002	0.000
No Wind Availability	0.325	0.009	0.000	0.020	0.000	0.000

Table 1.3-4: 2018 Loss of Load Expectations

The LOLE analysis results, while revealing some clear drivers of increased risk, are improved from the prior year. The 2008 analysis results showed an expectation for the industry benchmark to be exceeded, under base case conditions, in 2014. However, the LOLE analysis also revealed that maintaining system reliability to achieve the improved risk levels requires an increase in the Planning Reserve Margin (PRM) over the period of this analysis in the absence of transmission or generation solutions to reduce congestion. (See Section 8.3) The expectations of an increasing impact from system congestion results in the congestion component of the PRM rising from 0.6% in 2009 to 2.3% in 2018 and the overall PRM rising from 15.4% for the current planning year to 17% by the end of the ten year period. Mitigating sources of chronic congestion in coming years will be critical to maintaining reliability.

1.4 Enabling Economic and Policy Driven Investment

While near-term planning will continue to ensure necessary reliability upgrades and enhancements are made, the Midwest ISO continues to evolve its planning process to ensure that longer-term system upgrades that create economic benefits through improved market efficiencies are identified and evaluated as well. Current energy policy discussions are also drive the need for a process that looks out over a longer time horizon and across many scenarios to identify projects that will enable public policy goals to be met. The Midwest ISO has created a planning process that provides the framework for the realization of these objectives and is continuing to develop and implement the steps involved in that process.

1.4.1 Value Based Planning Process

At the outset, the seven-step value-based planning process aligns itself with potential energy policy outcomes to ensure that planning is reflective of, not counter to, those possibilities. In the first step of the process a set of such outcomes, or future scenarios are defined to provide ranges of key policy objectives to be planned for. The process then moves to the identification of capacity expansions that must occur in order for the objectives under each future to be met. This creates the basis for the design of a conceptual transmission plan under each future that will connect this capacity to load centers. These three steps have been previously implemented in prior MTEP cycles, with futures definition and capacity expansion being refreshed for MTEP 09.

The introduction of the fourth step in the process, robustness testing, is a focus of the MTEP 09 planning cycle, with development continuing into the next cycle. Robustness testing is a means for identifying projects that perform well under most, if not all, future scenarios. Combining such projects into a transmission plan is intended to result in the least regrets regardless of policy decisions, mitigating the risk involved with planning in an uncertain environment. With limited public support for creating new transmission right of way, and potential transmission costs in the billions, it is important that the transmission developed will serve, in an appropriate way, any variety of future outcomes.

Robustness testing will involve the evaluation of project and / or portfolio alternatives with the initial screening being conducted using a screening tool to identify projects that warrant a more complete value assessment. Performing an initial screen, for a subset of hours, allows significantly increased efficiency by permitting the evaluation of a large number of portfolios in a short time. The challenge is picking the correct subset of hours to evaluate. This methodology continues to be refined with input from the Midwest ISO Stakeholder community. Ultimately, the projects or portfolios recommended to move forward will be those that are impacted least by variations in objectives, or – put another way- those that are the most robust. To accomplish this, refinement to a set of metrics developed to measure a more complete set of values is in progress.

Remaining steps in the process are focused on testing the transmission plan against reliability criteria and determining the allocation of costs for those projects that are eligible for cost sharing. Once fully implemented, this process will provide the framework for all projects, regardless of driver, to be considered as solutions to system issues. This includes those projects that are determined to improve market efficiency through congestion mitigation.

1.4.2 Congestion Management

As part of the MTEP cycle the Midwest ISO conducts and annual assessment of market congestion. This effort includes a review of historical congestion as well as a determination of forecasted congestion, both of which are discussed thoroughly in Section 8.2. The review of historical congestion provides visibility into chronic congestion where mitigation steps are more likely to be warranted. As those congested flowgates are relieved over time the analysis is able to determine the location of future

congestion so that solutions can potentially be implemented even prior to the congestion reaching forecasted levels.

The analysis for MTEP 09 has found that while the number of flowgates experiencing congestion in each post-market period has fallen, opportunities exist for further mitigation. Total hours of congestion during the period from April 2008 to April 2009 were higher than the two previous periods and were the second highest since market start in April 2005. In addition, the average hours of congestion per flowgate were the highest since market start. Relieving this congestion is important to avoid negative impacts on the required reserve margin.

Consider Figure 1.4-1, which provides an illustration of the theoretical relationship between congestion and the reserve margin. Congestion necessitates the flow of energy to be altered, negatively impacting the transfer capability of the system. Conversely, a high level of transfer capability in all areas of the footprint would require a reduced reserve margin due to the increased ability of generation anywhere in the footprint to access loads. Thus, the analysis of congestion must weigh the cost of addressing the congestion through the increased transfer capability, in the form of additional transmission construction, against the costs of incremental generation that would be required to support an increased reserve margin. As shown in Figure 1.4-1, there is a balance point where the right balance of transfer capability and reserve margin meet to provide the most economic outcome.

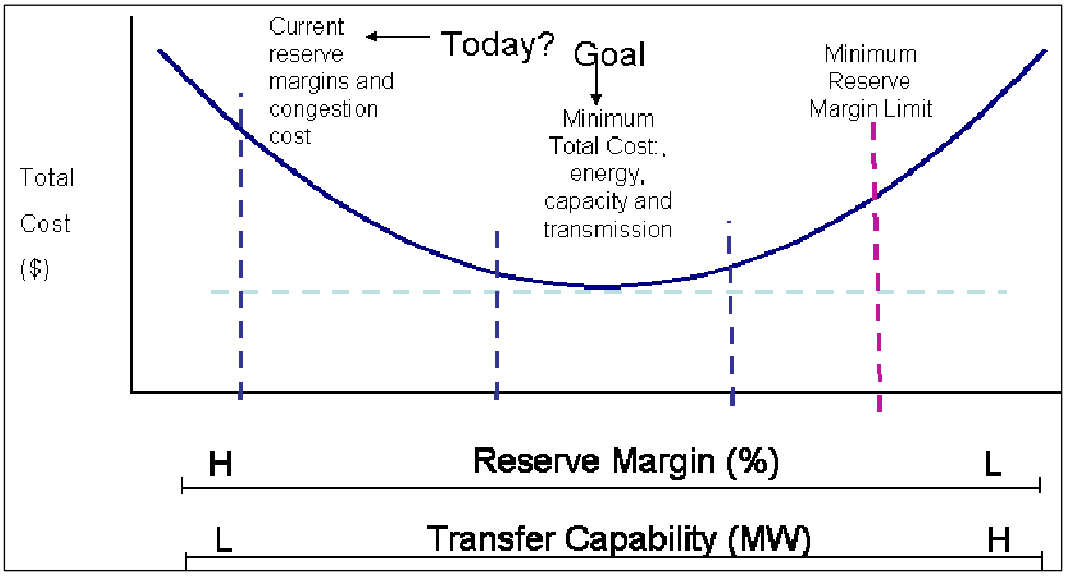


Figure 1.4-1: Relationship Between Reserve Margin and Transfer Capability

As discussed in Section 1.3.2, the Midwest ISO expects that reserve margins will exceed the minimum reserve requirement, or Planning Reserve Margin (PRM), at least through 2018. However, the impact of congestion will account for a larger percentage of an increasing margin over that time period. It is expected that the congestion adder to the PRM will rise from 0.6% in 2009 to 2.3% by 2018 with no further refinements to transmission plans. This will cause the overall PRM to rise from 15.4% in 2009 to 17% by 2018. Given that the LOLE analysis incorporates currently planned transmission upgrades and expansions, the need to develop additional solutions that provide relief for future congestion is reflected by this analysis.

In order to limit the impact of congestion on the reserve margin, the planning process must allow for identification of projects that provide relief to congested flowgates and those projects must be considered

as alternatives to other solutions, including those with a reliability driver. The value-based process discussed in Section 1.3.1 provides the framework for these projects to be considered as potential solutions and the identification of projects positively impacting congestion now occurs under two different efforts.

As part of the historical congestion review, the top 44 congested flowgates are analyzed. One step is to determine if a currently proposed reliability project will mitigate the constraint. In addition, the Top Congested Flowgate Study, an annual study initially conducted for MTEP 08, takes a deeper look at those same 44 flowgates. Under this study, covered in Section 8.3, simulations are run whereas the flowgates are relieved via increased ratings of monitored elements. The economic benefits realized in the analysis then are considered the design budget for a mitigation plan.

For the MTEP 09 cycle, the Midwest ISO and the Technical Review Group (TRG) associated with this study, focused only on the top 14 congested flowgates. Mitigation plans were developed for each flowgate and the expected benefits of each was determined. The objective is to identify mitigation plans that pass RECB II thresholds, and are thus eligible for cost sharing. Projects passing this test will be recommended for Appendix B. A methodology is also being refined that would enable the combination of mitigation plans into portfolios to be tested for RECB II eligibility.

Of the top 44 historically congested flowgates, thirteen are non-Midwest ISO facilities. 20 of the remaining 31 flowgates are either under review in the Top Congested Flowgate Study or are expected to be relieved by a planned reliability upgrade. The remainder were projected to have lower levels of future congestion, and thus were kept out of scope of the Top Congested Flowgate Study at this time. The combination of these efforts will continue to focus future efforts on identifying congestion points where mitigation steps are warranted and can have a beneficial impact on market efficiency.

1.4.3 Planning to Meet Policy Objectives

Planning to meet the goals and objectives of public policy, such as State Renewable Portfolio Standards, is increasingly critical and requires the use of new and unique planning processes. The variations in the potential outcomes of policy decisions introduce a fair amount of uncertainty into the planning process.

The Midwest ISO footprint includes eleven states that currently have either a Renewable Portfolio Standard (RPS) goal or mandate. As of July 1st, 2009 these requirements represent approximately 23,000 MW of generation. That number has increased from 15,000 MW a year ago as additional states have enacted legislation to demonstrate their commitment to promoting renewable energy policies. The state requirements are diverse in the amount, location, and, type of generation required, as well as in the time given to achieve the mandates, adding additional complexity to enabling the meeting of the standards.

Discussions at the federal level encompass a broader set of objectives including carbon reduction, development of a smart grid and energy efficiency along with integration of renewable generation. Any federal renewable mandate would likely have a much larger impact on the Midwest ISO planning efforts as it is expected that at least a portion of other regions' renewable energy requirements would be fulfilled by generation within the Midwest ISO footprint, requiring incremental build out of the transmission system beyond that already needed under the current state standards to facilitate an increased level of exports.

The Regional Generation Outlet Study (RGOS), discussed further in Section 9.1, was initiated in response to the growing focus on the use of renewable sources of energy. Phase I of RGOS focuses on meeting those objectives in the states of Illinois, Iowa, Minnesota, and Wisconsin. Phase II focuses on the states of Illinois, Missouri, Ohio, Indiana, Michigan, Pennsylvania, in addition to any increases in

RGOS I states since that phase began. In combination, the two phases of study will result in an appropriate transmission plans to enable our members to meet their Renewable Portfolio requirements.

An effort that has interfaced with RGOS to meet its objectives is that of the Upper Midwest Transmission Development Initiative (UMTDI), which is comprised of the governors and regulators of North and South Dakota, Iowa, Minnesota, and Wisconsin. One goal of the group is the development of regional transmission plans that would enable the RPSs in their states to be met. The UMTDI has provided guidance and direction to RGOS based on parameters associated with the indicative transmission plans developed under that initiative. However, the lack of a widely accepted methodology for identifying the beneficiaries of transmission expansion projects driven largely by renewable integration, and subsequently allocating the costs to those beneficiaries has the potential to reduce the amount of transmission being built, introducing risk into satisfying the mandates. Thus, the UMTDI has a second goal of developing a methodology for allocating the costs of the transmission plans that are required to meet the RPS. The UMTDI will use the detailed transmission plans and analyses from the RGOS work to develop cost allocation recommendations for the UMTDI states.

The full Organization of Midwest ISO States (OMS) also recognizes the lack of an appropriate cost allocation mechanism as a potential barrier to achieving energy related policy goals. The Cost Allocation Regional Planning (CARP) Initiative is focused on developing recommendations for improvements to cost allocation that will enable meeting existing and potential future energy and environmental policies. The cost allocation discussion is being held within the context of evaluating a number of potential future scenarios developed by the group. These scenarios address a wide variety of energy policies such as renewable integration, carbon reduction and smart grid.

The objectives of these initiatives, their points of interaction, and the role of the Midwest ISO in each are detailed further in Section 4.4.

Addressing Uncertainty through Planning

The efforts that have been initiated in response to potential energy policy outcomes is an expansion on the planning that the Midwest ISO already conducts as part of the value-based planning approach. The lack of clarity and consensus around energy policy results in vast variation across outcomes. The level of uncertainty that exists around future policy decisions, in particular, creates difficulty for those involved in the planning function and causes hesitancy for those with the resources to undertake transmission expansion projects. To minimize the risk involved with planning a system under such conditions, the process must consider projects in the context of potential outcomes. The work of the Midwest ISO and its stakeholders to identify transmission plans that result in the least regrets regardless of policy decisions will help to alleviate the impacts of those future outcomes.

The primary futures defined and analyzed in MTEP 09, and discussed in detail in Section 10.2 are:

- Reference Future - assumes future looks like recent past; reflects current laws including Renewable Portfolio Standards
- Renewable Future (20% Federal Wind Energy Future) – assumes 20% nationwide Renewable Portfolio Standard
- Environmental Future – assumes $25/ton carbon cost and reduced demand
- Gas-only Expansion Future – assumes only gas and wind generation are constructed

RGOS is closely aligned with the Reference Future, as that scenario includes the renewable energy mandates and goals that currently exist in the Midwest ISO footprint. The scenarios being developed for the CARP initiative are variation of those developed for prior or current MTEP cycles or seek to address different policy related questions. The planning framework in place and utilized by the Midwest ISO has enabled a more efficient response to the policy discussions that are shaping the future of our industry.

Impact of Future Scenarios

Each of the future scenarios results in a different requirement for capacity expansion which in turn drives a unique transmission plan to connect the capacity to load centers. Therefore, the impact on consumer rates can vary significantly across the futures. Figure 1.4-2 provides the current rate along with the estimated rates under the analyzed futures.

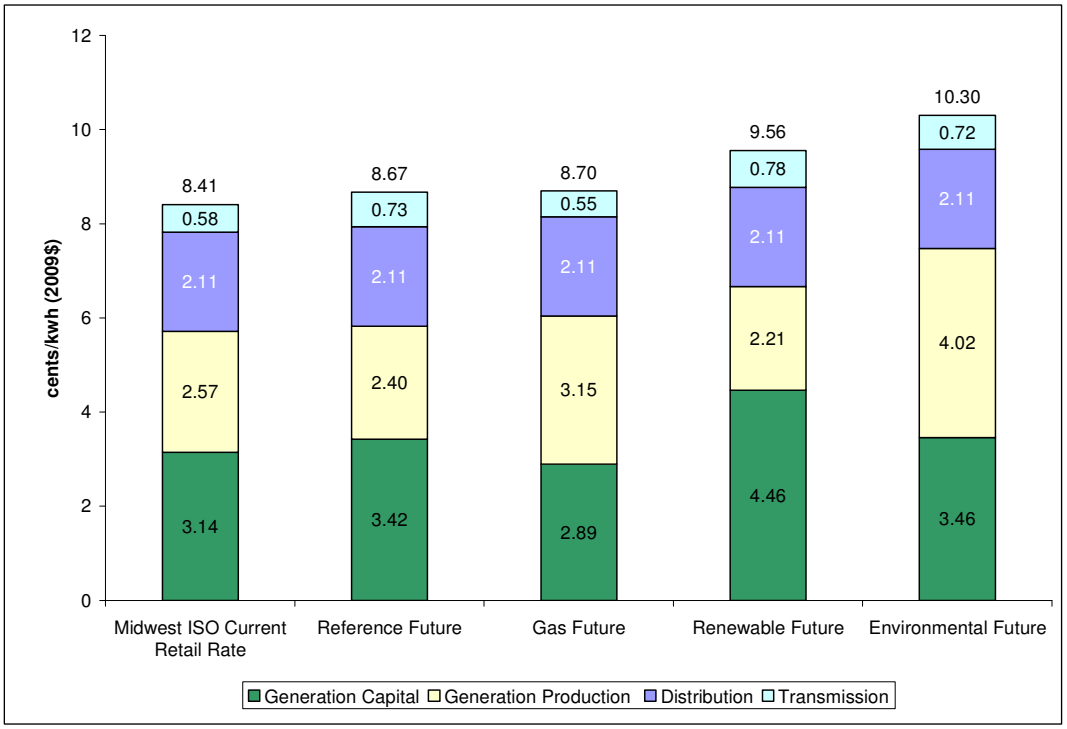


Figure 1.4-2: Estimated Retail Rates Under Future Scenarios

Increases to the rate over current levels range from 3% to 23%, over and above the cost of inflation. While all scenarios result in rate increases that are higher than expected inflation, the primary driver is not consistent across the futures. In general, the scenarios reflect the differences between the type of generation and the associated transmission needed to integrate the generation in the various scenarios. For example, the Renewable Future reflects the high capital cost of the large quantity of wind turbines and associated transmission facilities which must be installed to meet a 20% Midwest ISO renewable portfolio standard requirement, as well as the additional generation needed to meet reserve requirments. The increased production cost under the Environmental future is driven by the addition of a relatively modest (compared to current proposed legislation) $25/ton carbon cost based on the expectation of future policies to limit carbon output. The major drivers to rate increases under each future are described in detail in Section 4.5

1.5 MTEP 10 and Beyond

1.5.1 Advancing the Value-Based Planning Approach

A focus of MTEP 10 will be on the continued implementation of the value-based planning process that the Midwest ISO has been evolving to over the last couple of years. The Midwest ISO will be refining the robustness testing methodology with stakeholders and will seek to further the amalgamation of its planning functions. As these functions - short term reliability, long-term value based and targeted studies - become fully integrated, longer-term solutions that provide greater benefits will become alternative solutions to address issues that are today solved through a series of shorter-term, and many times less valuable, mitigation steps. That is not to say, however, that the discrete analyses will disappear. Studies over each of the timeframes are still required to meet the planning needs of the region in the most expedient and efficient standpoint. In fact, with continued experience the Midwest ISO has recognized the value of having the combination of plans. As the Midwest ISO seeks to implement nearer term reliability upgrades through the generation interconnection queue and the NERC reliability analyses, results from targeted studies provide insight into potentially more efficient alternative solutions based on the larger-scale transmission developed therein. Similarly, targeted studies such as the Regional Generation Outlet Study are informed by the long-term transmission roadmaps created through efforts such as the MTEP long-term value-based planning and the Joint Coordinated System Plan. By planning in the reverse order from which transmission is actually built, the nearer term transmission solutions can be developed in such a way to support future goals through more efficient plan development, including such considerations as preserving future right of way requirements.

1.5.2 Completion of Key Studies

A number of major studies will be completed in the coming months and reflected in the MTEP10 report. The Regional Generation Outlet study will provide important insight into the requirement for high voltage transmission to enable renewable integration. Additionally, the Midwest ISO will continue to focus on the question of market efficiency through continued analysis of congested flowgates and the feasibility of Long Term Financial Transmission Rights. Finally, the results of the regional scenario planning currently underway by the Organization of MISO States Cost Allocation and Regional Planning group will be available to inform decision making around long-term transmission needed to address public policy in the 10 to 20 year timeframe. Results of all of these efforts will be made available as they are completed, as well as included in the MTEP 2010 report.

1.5.3 Eastern Interconnection Planning Cooperative (EIPC)

The Eastern Interconnection Planning Collaborative (EIPC) is comprised of 28 Planning Authorities in the Eastern Interconnection. It was formed as a follow-on function to the Joint Coordinated System Plan work that was completed in February 2009 and is discussed in Section 11 of this report. The EIPC has submitted a proposal to the Department of Energy (DOE) in response to a Funding Opportunity Announcement associated with the American Recovery and Reinvestment Act (ARRA). The EIPC is seeking to fulfill an industry planning function that will conduct analyses of transmission requirements under a broad range of futures and develop interconnection-wide transmission expansion plans.

The EIPC will not replace the regional planning that is currently done by the Planning Authorities. Rather it will roll up regional plans, coordinate with the other Interconnections, receive stakeholder input, analyze alternatives against policy objectives, and identify gaps for further study. It is expected that these efforts will begin in late 2009. While studies or analyses may not be completed in time for inclusion in

MTEP 10, the interface of the Midwest ISO's regional planning function with this initiative will be better understood and reported on.

Section 2: MTEP 09 Overview

2.1 System and Planning Region Information

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit, member-based, organization committed to being the leader in electricity markets 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 fifteen states and one Canadian province. Midwest ISO members' systems cover 920,000 square miles with 51,300 miles of transmission operated at 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, and 69kV under Midwest ISO functional control. 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 is shown in Figure 3.1-1.

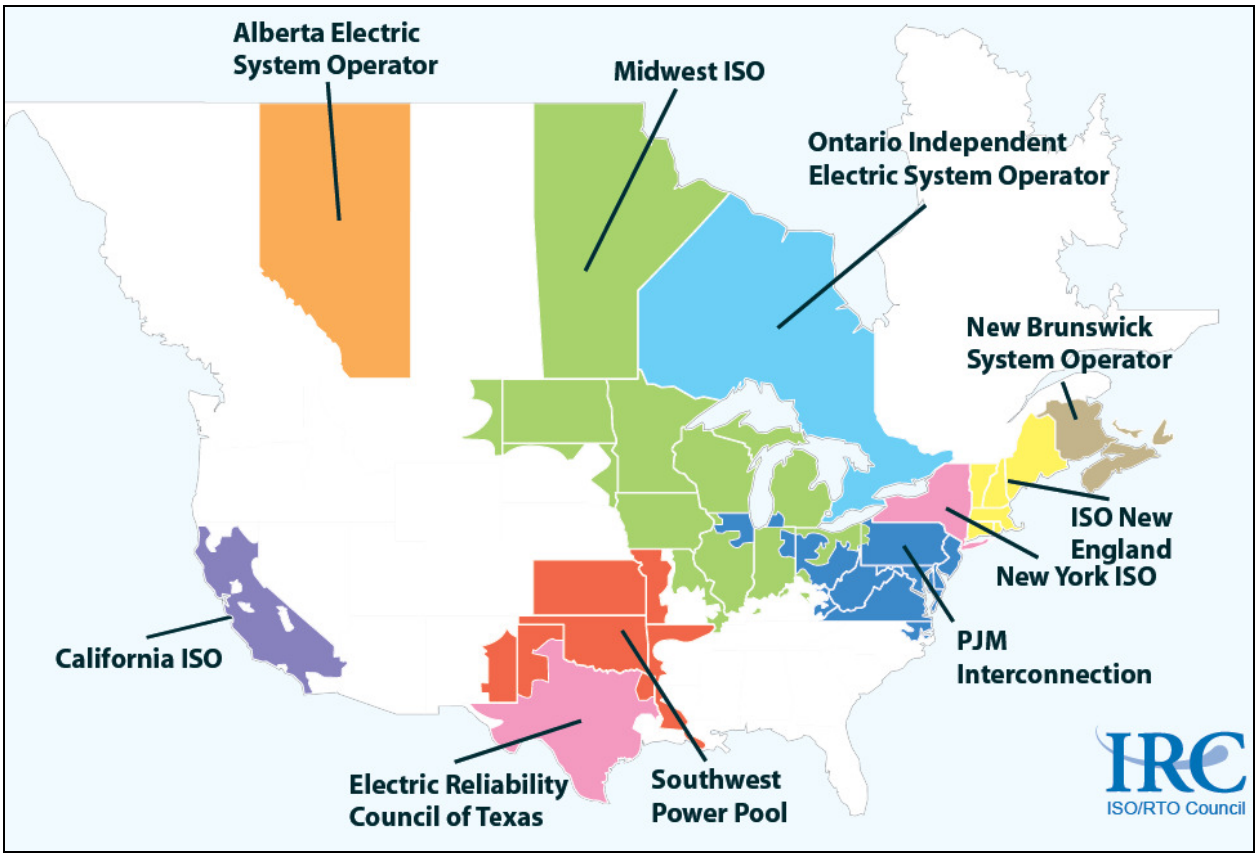


Figure 2.1-1 Midwest ISO Geographical Footprint

The following Transmission Owners are Midwest ISO members:

West Planning Region [1]

- American Transmission Company
- Central Minnesota Municipal Power Agency
- Great River Energy
- ITC Midwest
- Minnesota Power & Light Company
- Montana-Dakota Utilities
- Northwestern Wisconsin Electric
- Otter Tail Power Company
- Southern MN Municipal Power Association
- Xcel Energy – North

Central Planning Region

- Ameren MO
- Ameren IL
- 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

[1] MidAmerican Energy and Muscatine Power & Water are Midwest ISO Transmission Owners, effective September 1, 2009. They did not participate in the MTEP 09 planning cycle.

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

Figure 2.1-2 shows the Midwest ISO Planning Regions used in the MTEP study process. The planning region is also indicated for each project in Appendix A, B, and C.

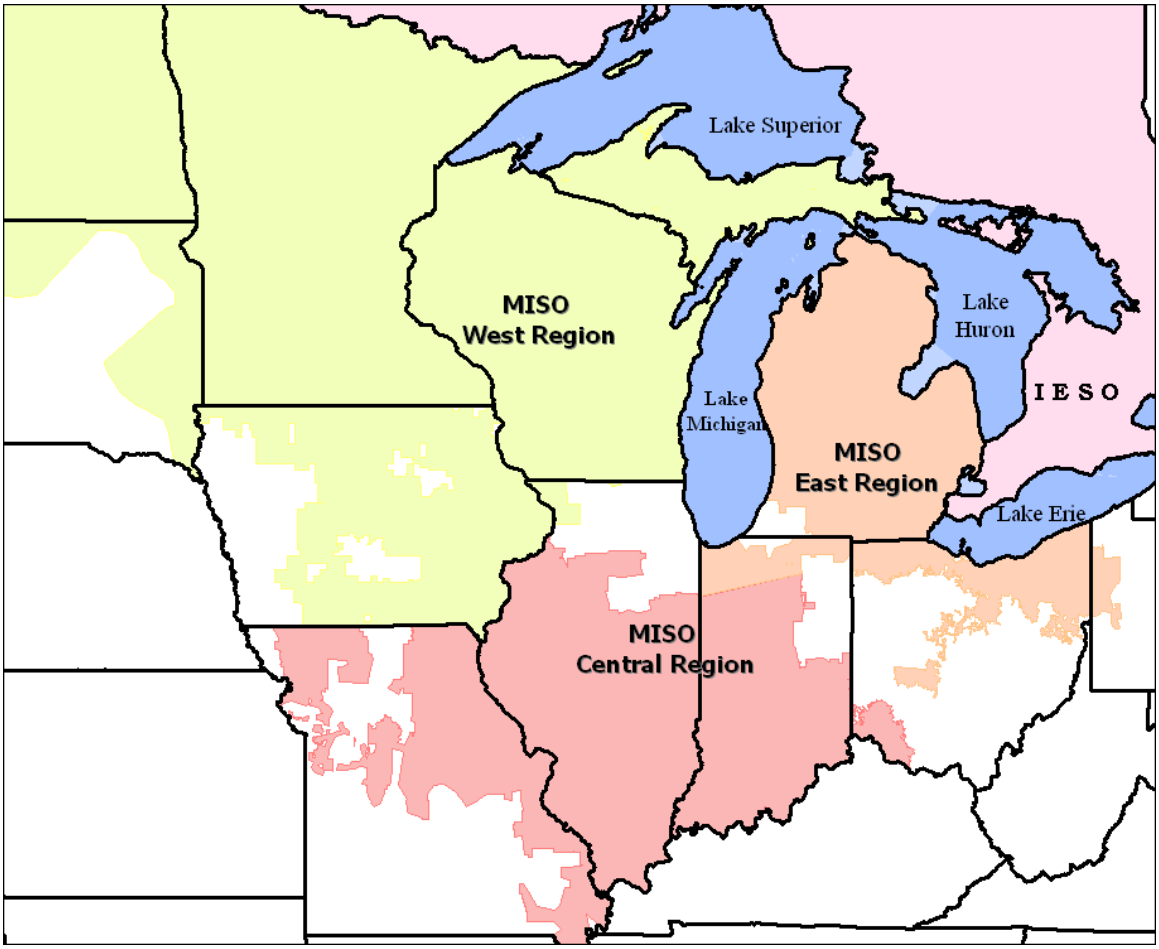


Figure 2.1-2 Midwest ISO Planning Regions

2.2 MTEP Project Types and Appendix Overview

MTEP Appendices A, B and C indicate where a project is in the MTEP planning process. The projects start in Appendix C when submitted into the MTEP process, move to Appendix B when Midwest ISO has documented their need and effectiveness, and move to Appendix A when approved by Board of Directors. While moving from C to B to A is the most common progression through the appendices, projects may also remain in Appendix C or B for a number of planning cycles or may go from C to B to A in single planning cycle.

Appendix A

Appendix A contains the transmission expansion plan projects which are recommended by Midwest ISO staff, *and approved by Midwest ISO Board of Directors,* 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 per 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 for filed TO local criteria. Yet other projects may be required to provide distribution interconnections for Load Serving Entities (LSE). 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. All projects in Appendix A have a Midwest ISO documented need.

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 done an independent need driver validation
- Midwest ISO staff has considered and reviewed alternatives with TO
- Midwest ISO staff has considered and reviewed cost estimates with TO
- Midwest ISO staff has endorsed the project
- 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 Board of Directors for approval. Projects are moved to Appendix A via a Board Presentation at any regularly scheduled Board meeting.

Appendix A is periodically updated. Although, in general, projects are 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 Board approval and inclusion in Appendix A should circumstances dictate the need for approval at a different juncture. As projects go through the process and are approved by the Midwest ISO Board of Directors, Appendix A will be updated and posted.

Appendix B

In general, MTEP Appendix B contains projects which are still in the Transmission Owners planning process or are still in the Midwest ISO review and recommendation process. 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 for which Transmission Owners have completed their analysis, but for which Midwest ISO staff has not been able to validate the reliability need or reasonableness of the solution against alternatives, at the present time. The result is that some projects which will become eligible for cost sharing are at this time not yet "ready" for Midwest ISO recommendation and are held in Appendix B until the Midwest ISO review process is completed. All projects in Appendix B have documented system needs associated with them.

Appendix C

Appendix C may contain projects which are still in the early stages of Transmission Owners planning process or are 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 they are ready to go through the MTEP process to be 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 move from B back to C if a better alternative is determined, yet the TO is not ready to withdraw the previous best alternative. Appendix C projects are not included in MTEP 09 initial powerflow models used to perform baseline reliability studies due to a high degree of uncertainty surrounding the project from Midwest ISO's perspective.

Appendix A, B, and C Lists

Transmission projects included or discussed in the Midwest ISO Transmission Expansion Plan (MTEP) are listed in one of three Appendices described as Appendix A, B or C. Appendix A lists the projects which have been approved by the Midwest ISO Board of Directors. It also lists the projects and associated facilities which are recommended to the Midwest ISO Board of Directors to be approved in this planning cycle. The new projects are indicated as "A in MTEP 09" in the Target Appendix field in the appendix listing. The Appendix is indicated as B>A for new projects and A for previously approved projects.

Projects in Appendix A are classified based on their designation in Attachment FF to the Tariff. Baseline Reliability Projects (BRP) are those transmission projects which are 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 (GIP) are the 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 (TDSP) are those transmission projects which are required to satisfy a Transmission Service Request. The costs of these projects are always direct assigned to the requestor. Regionally Beneficial Projects (RBP) are those projects which meet the Attachment FF requirements for reduction in market congestion and are shared based on cost and voltage thresholds. A project that does not meet any of these classifications is designated Other. Other incorporates a wide range of projects, from those that are designed to provide local economic or similar benefit – but do not meet the threshold requirements for qualification as a Regionally Beneficial Project – to projects that are required on the lower voltage transmission system that is outside of the Midwest ISO's functional control.

2.3 Investment Summary

This section provides investment summaries of transmission system upgrades identified in MTEP 09 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 gone into service.[2] The total estimated investment of the projects in MTEP 09 Appendix A and Appendix B for the period 2009 to 2014 is $5.20 billion. Appendix A contains $3.90 billion in investment through 2014, Appendix B contains $1.30 billion of investment through 2014, and Appendix C contains $4.6 billion in investment through 2014 and an additional $18.2 billion in investment from 2016 to 2019. Included in Appendix C is the Reference Future Extra High Voltage (EHV) conceptual transmission overlay is $14 Billion in Midwest ISO in 2018. 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. See Section 9 for Regional Generation Outlet study update on transmission development for renewable energy. See Section 10 for additional details on EHV conceptual overlay development for generation futures.

The cumulative expected project spending by year, and appendix over the 2009-2019 period, is shown in Figure 2.3-1. The investment totals by year assume 100% of project investment occurs when the project goes into service. Since a project may have facilities going into service in multiple years, these numbers, therefore, appear lumpier than actual expenditures are expected to be.

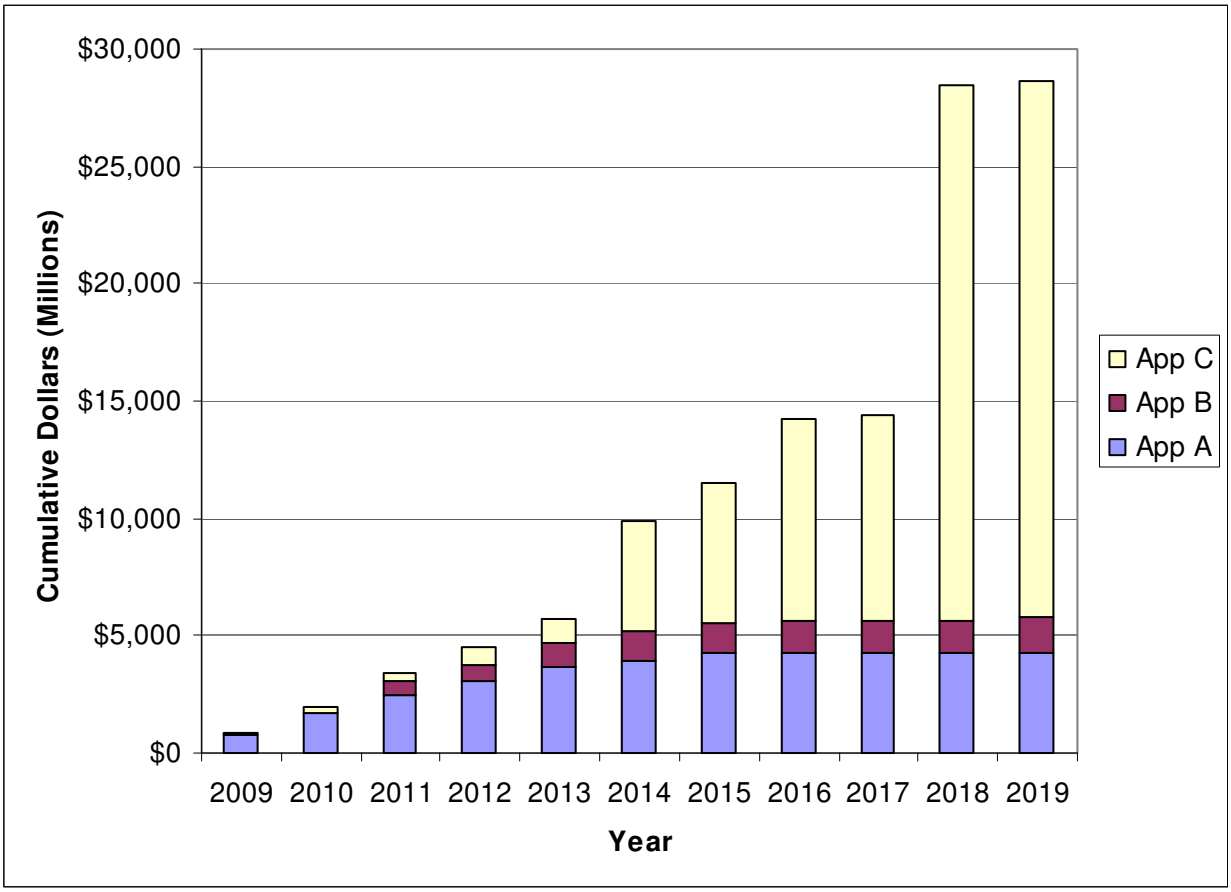


Figure 2.3-1: MTEP 09 Cumulative Projected Investment by Year and Appendix

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

The transmission investment by Planning Region through 2019 is shown in Table 2.3-1.

Table 2.3-1: Projected Transmission Investment by Planning Region through 2019

Region	Appendix A	Appendix B	Appendix C
Central	$635,655,000	$266,925,200	$7,766,675,000
East	$1,042,117,000	$62,176,000	$7,203,633,000
West	$2,624,630,000	$1,136,786,000	$7,824,045,000
Total	$4,302,402,000	$1,465,887,000	$22,793,353,000

Table 2.3-2 shows investment in New 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), and Other.[3] The numbers in Table 2.3-2 are a subset of Appendix A values shown in Table 2.3-1. These have a Target Appendix of 'A in MTEP 09' and are new to Appendix A in this planning cycle. Approximately $903 million 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 the 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 2.3-2: New Appendix A Investment by Allocation Category & Planning Region

Region	Share Status	BaseRel	GIP	TDSP	RegBen	Other
Central	Not Shared	$21,957,000				$40,474,000
	Shared	$94,385,000	$4,440,000		$5,655,000	
Central Total		$116,342,000	$4,440,000		$5,655,000	$40,474,000
East	Not Shared	$42,166,000				$262,371,000
	Shared	$88,418,000				
East Total		$130,584,000				$262,371,000
West	Not Shared	$11,778,000		$630,000		$221,463,000
	Shared	$22,500,000	$86,925,000			
West Total		$34,278,000	$86,925,000	$630,000		$221,463,000
Grand Total		$281,204,000	$91,365,000	$630,000	$5,655,000	$524,308,000

3 Other is not BRP, GIP, TDSP or Regionally Beneficial Project.

Further breakdown of the New Appendix A project data, as shown in Figure 2.3-2, reveals that new transmission build is largely concentrated in several states, namely Michigan, Minnesota, Iowa, Illinois and Indiana. 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.

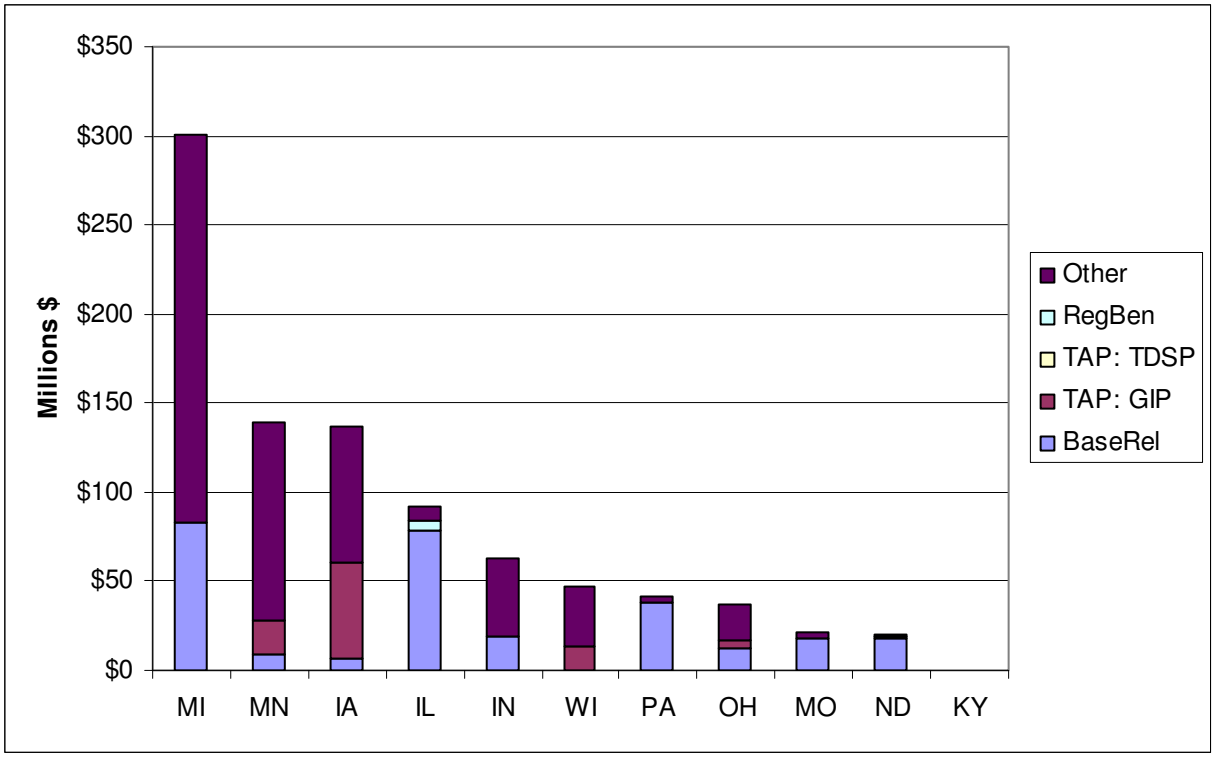


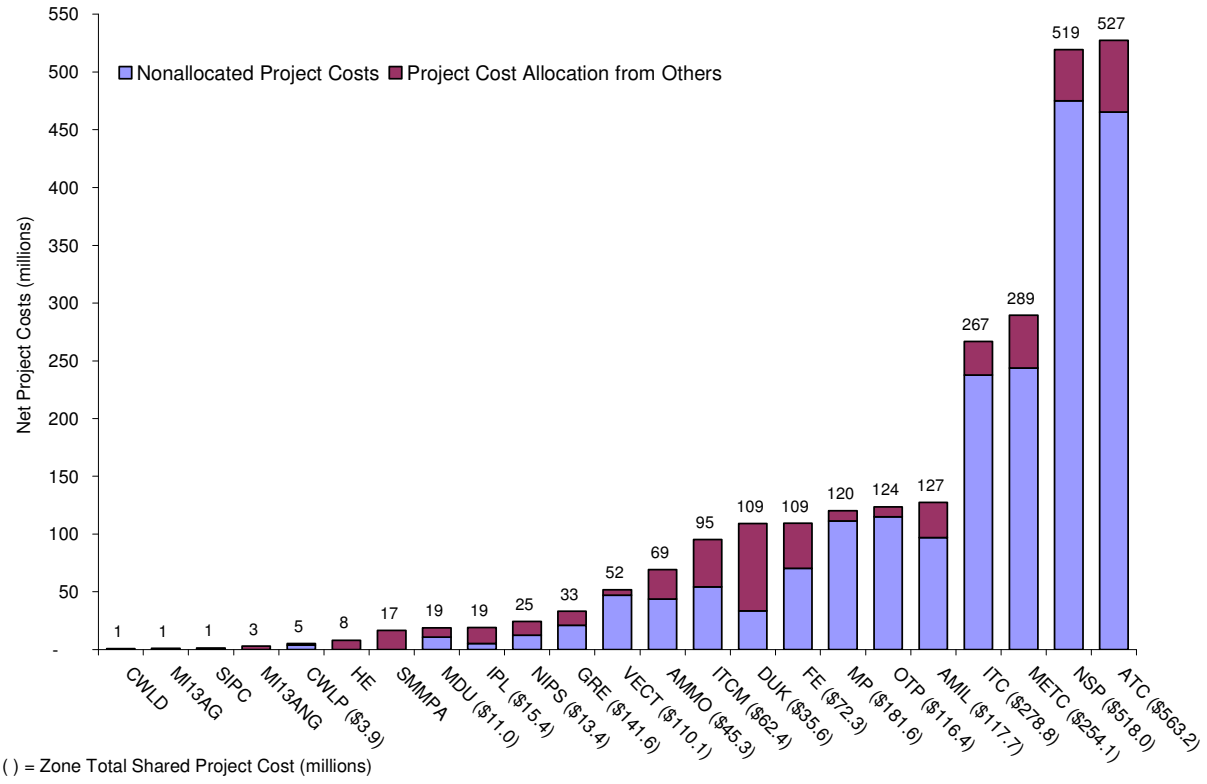
Figure 2.3-2: New Appendix A Investment by Allocation Category by State

2.4 Cost Sharing Summary

A total of $302 million of costs associated with new MTEP 09 Appendix A projects are eligible for sharing.[4] The total project cost number includes the $91 million from generator interconnection projects, where half is paid by generation developers. Additional details on new MTEP 09 cost allocations are in Appendix A-1 and A-2.

Since the Regional Expansion Criteria and Benefits (RECB) cost sharing methodology was implemented in MTEP 06 there have been 102 projects eligible for cost sharing representing $2.88 billion of transmission investment including 41 generator interconnection projects at approximately $598 million, of which 50% is paid by generation developers, 60 baseline reliability projects at $2.28 billion, and 1 Regionally Beneficial Project at $5.7 million.

Figure 2-4.1 provides the breakdown, by pricing zone, of all project costs assigned to the zone after the cost allocation per Attachment FF also referred to as RECB allocation. Costs are included for all RECB eligible projects from MTEP 06 to MTEP 09. The 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's cost and expected in-service date. The blue bar represents the non-allocated project costs for that zone, representing $2.05 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 represents the portion of zonal costs due to project cost allocation from others outside that zone, which is approximately $493 million for all pricing zones. Note that the chart excludes the portion assigned directly to generation developers. Additional details on MTEP 06 through MTEP 09 cost allocations are in Appendix A-3.



[4] Based on preliminary MTEP 09 Appendix A cost shared projects as of November 2, 2009 – subject to change as cost allocations are finalized

Figure 2-4.1: Net Project Costs by Pricing Zone from MTEP 06 through MTEP 09 Appendix A Projects

Figure 2-4.2 shows the net cost sharing impact by zone. The net impact is calculated by subtracting the costs allocated to a zone by projects outside the zone from the costs of projects within the given zone that are eligible to be shared outside the zone. Supporting detail is available in Appendix A-3.2. The distribution of the 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 important also to note that this chart represents only the cost impact and not the associated benefits which are expected to offset the allocated costs. However, as discussed in the recent RECB assessment filing at FERC , the question of how to best assess and measure benefits, what types of benefits are recognized by the participants, and whether equity will be seen over time across the pricing zones, will be the subject of continued discussion as potential modifications to the current RECB criteria are assessed by the Midwest ISO and its stakeholders.

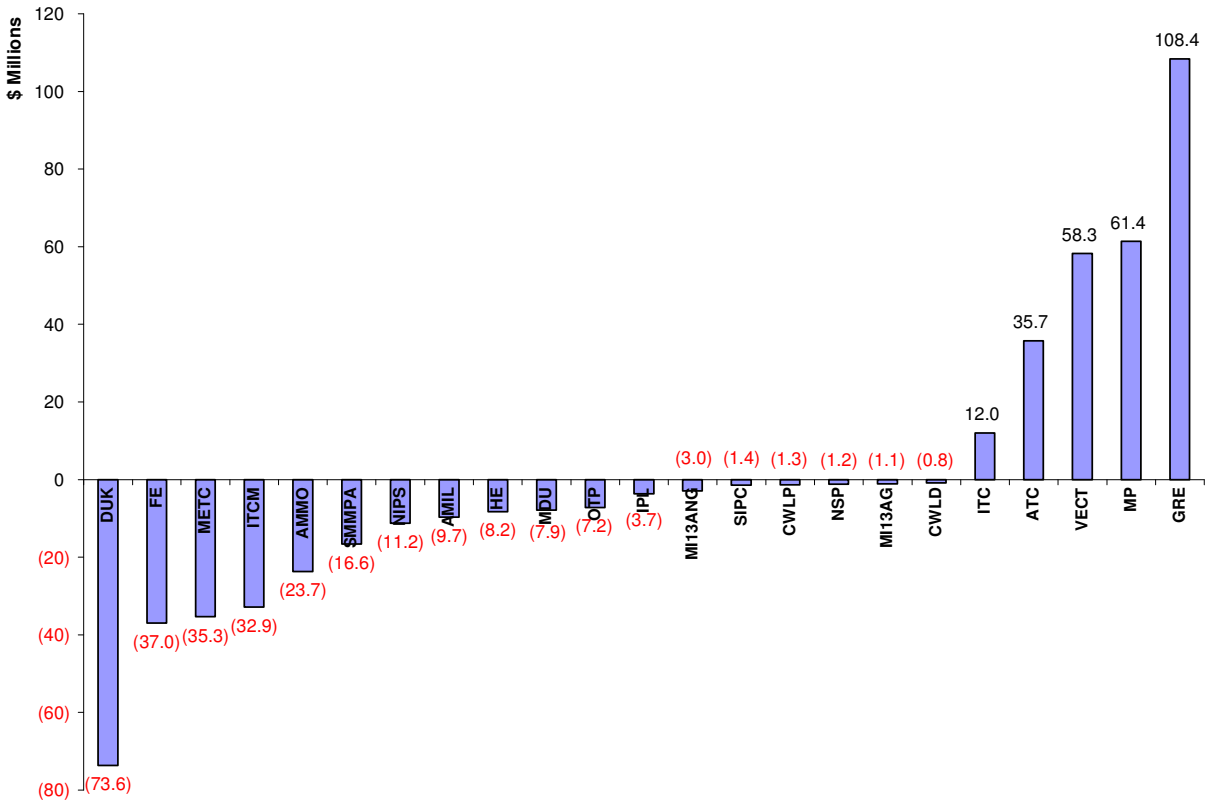


Figure 2-4.2: Net Impact on Pricing Zones of Cost Sharing for MTEP 06 through MTEP 09 Projects

Figure 2-4-3 seeks to put the project costs in greater context by representing them as a percentage of the current net plant within the pricing zone. For additional detail see Appendix A-3.2.

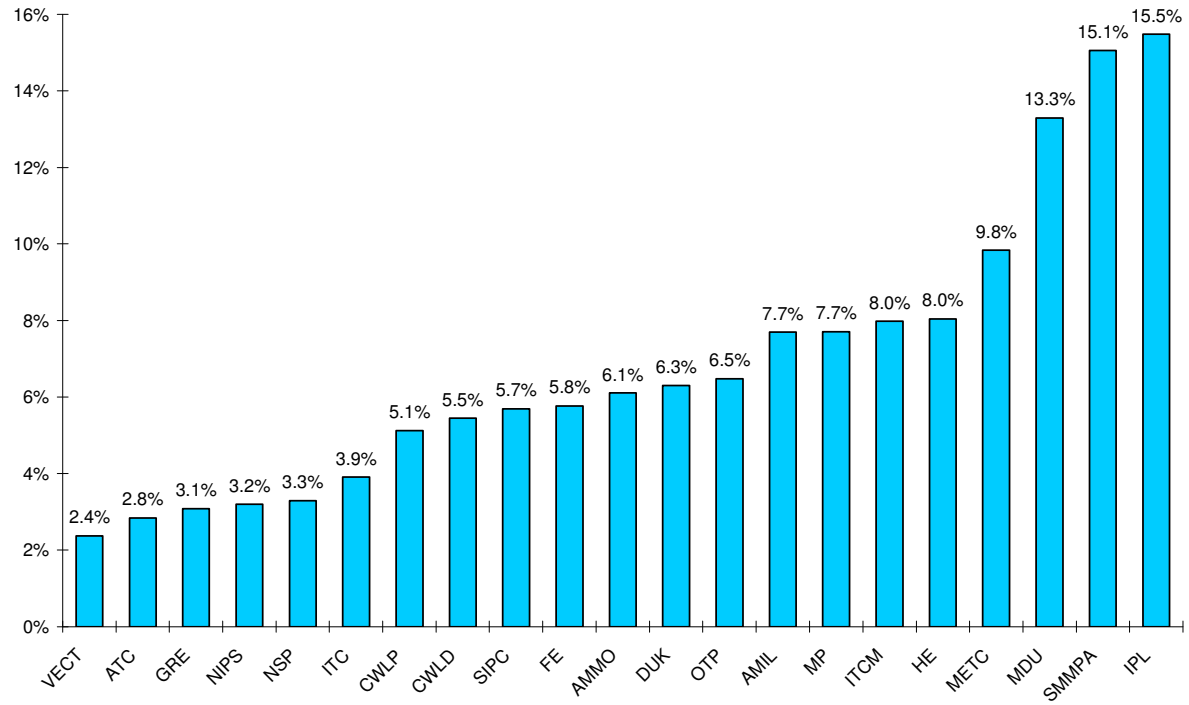


Figure 2-4.3: MTEP 06 through MTEP 09 Appendix A Project Costs Allocated from Other Pricing Zones as a Percent of Net Transmission Plant in Service (as of June 2009)

2.5 Appendix Overview

2.5.1 Appendix A and B Line Summary

There are approximately 4,530 miles of new or upgraded transmission lines in the 2009 through 2019 timeframe in Appendices A and B. About 2,350 miles of transmission line *upgrades* are projected through 2019 which is about 4.6% of the approximately 51,300 miles of line under Midwest ISO functional control. About 2150 miles of transmission involving lines on *new* transmission corridors is also projected through 2019.

The miles of transmission line by voltage class for Appendices A and B are shown in Figure 2.5-1. Line miles for projects in Appendix C are discussed in the next section.

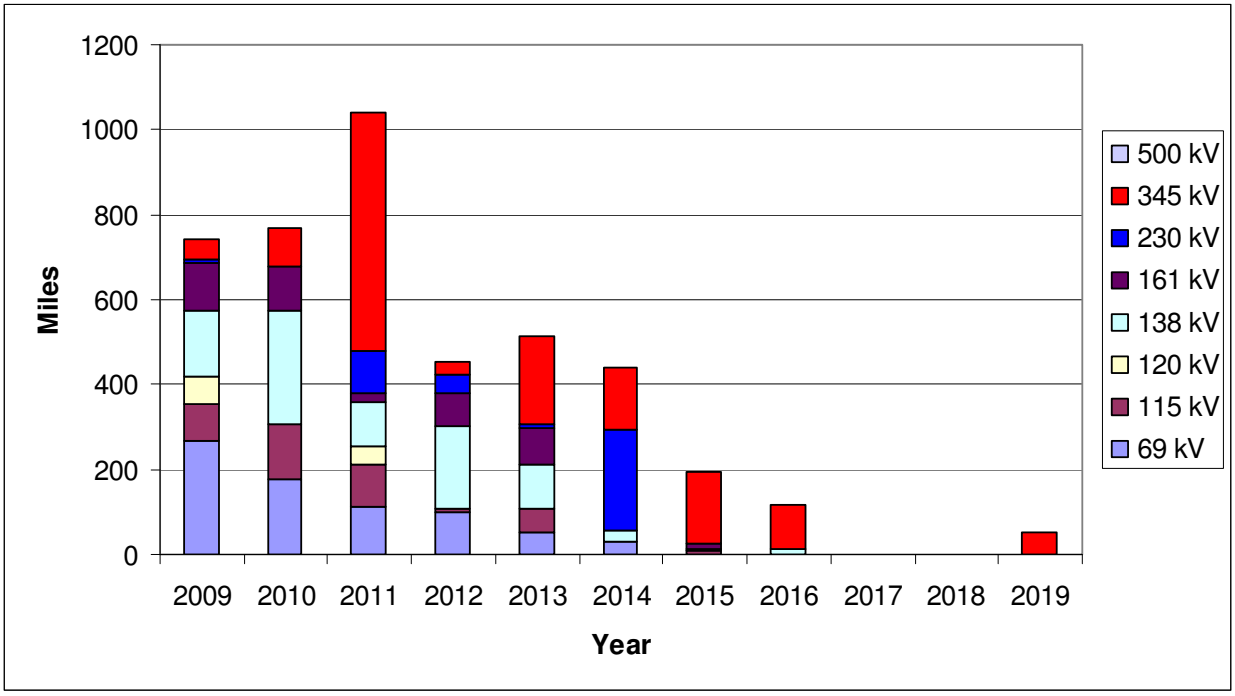


Figure 2.5-1: New or Upgraded Line Miles by Voltage Class in Appendix A & B through 2019

New transmission line mileage by state for Appendices A and B is shown in Figure 2.5-2.

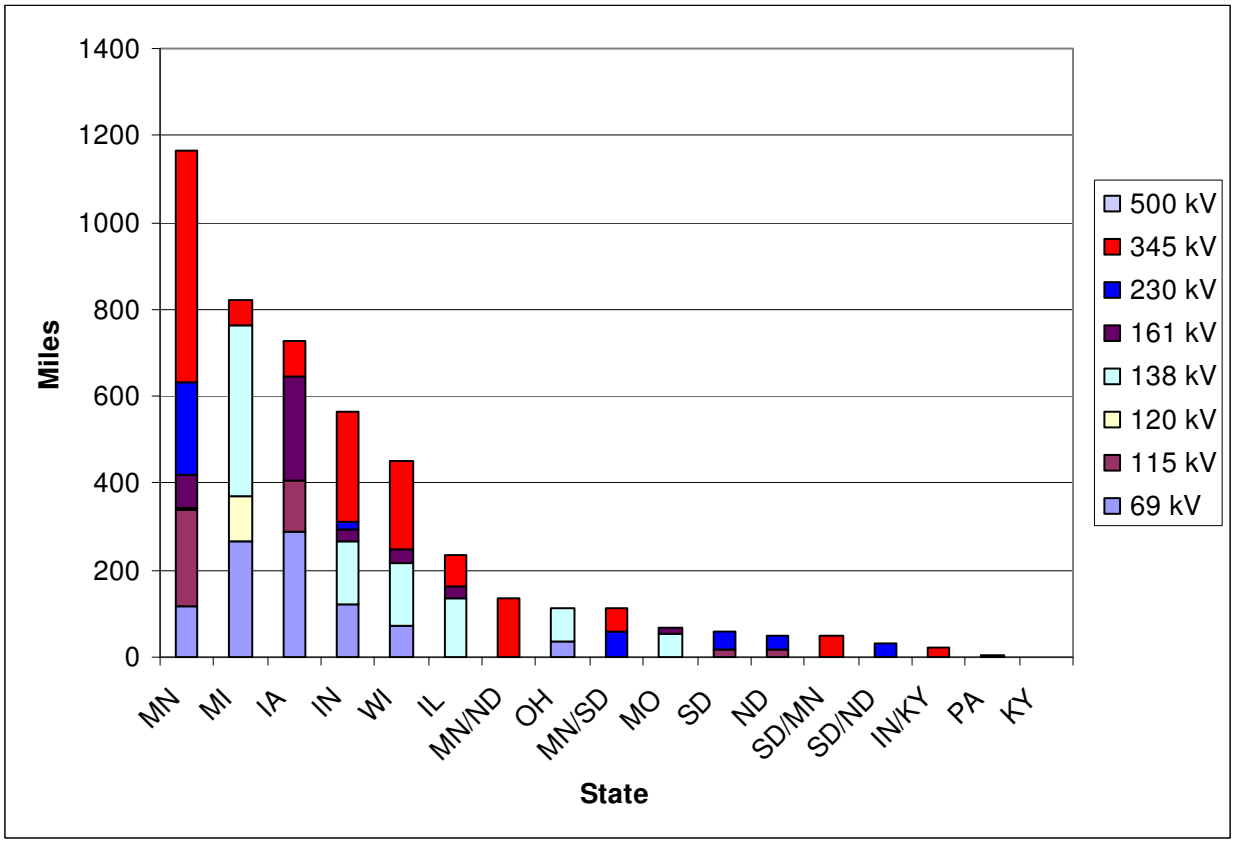


Figure 2.5-2: New or Upgraded Line Miles by State in Appendix A & B

2.5.2 Appendix C Summary

There is a $35 billion of conceptual and proposed transmission investment in Appendix C. The MTEP08 Reference Future EHV conceptual overlay is $14 billion in 2018 and is comprised of approximately 65 projects. There are multiple proposals to enable integration and delivery of large amounts of renewable energy. One 765 kV proposal is $12 billion in 2020. There are two Direct Current (DC) line proposals for renewable energy which are $1.9 billion and $1.6 billion respectively in 2014. Also included is a proposal for 765 kV backbone transmission in Michigan for $2.5 billion in 2016. Some of the proposals are competing; therefore, not all of the investment is expected. There are 390 project proposals at $3 billion to address traditional reliability needs in future years. These have just entered planning process or needs are being revisited due to changes in the system, most notably load forecast adjustments due to economic downturn.

2.6 Economic Assessment of Recommended and Proposed Expansion Plan

Midwest ISO MTEP Appendix A/B contains planned/proposed projects that are primarily premised on addressing reliability needs. However, in addition to the expected reliability benefit, these projects may provide economic benefits. The economic benefits considered include:

- Adjusted production cost saving
- Load cost saving
- CO_2 emission
- Energy loss benefit
- Capacity loss benefit

2.6.1 Study Methodology and Assumptions

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

PROMOD® Cases

The MTEP 09 2014 summer peak power flow case, which has been reviewed by MISO stakeholders and incorporates the latest PJM system update, was used as the starting point for this study. Two 2014 PROMOD® cases were developed for this study:

- 2014 PROMOD® case with Appendix A/B
- 2014 PROMOD® case without Appendix A/B

Both cases utilize the same MTEP 09 Reference Future database (containing all the generator, load, fuel, and environmental information). The detailed information associated with the Reference Future can be found in Appendix E2. The difference between these two cases is the power flow cases (i.e., the transmission topologies) that are used.

Power Flow Case

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

- One power flow case with Appendix A/B project
- One power flow case without Appendix A/B project

For both power flow cases, the transmission systems outside of the Midwest ISO are the same; they are from the Eastern Interconnection Regional Reliability Organization (ERAG) 2014 summer peak power flow case. The Midwest ISO portion, in the power flow case with Appendix A/B projects, is from MTEP 09 2014 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 2009 summer peak power flow case, which represents the current transmission topology in MISO.

Table 2.6-1 summarizes the differences of these two power flow cases.

Table 2.6-1: Power Flow Cases Difference

	Power Flow Case with Appendix A/B	Power Flow Case without Appendix A/B
MIDWEST ISO Transmission	MTEP 09 2014 Summer Peak (ERAG 2009 Summer Peak + Appendix A/B)	ERAG 2009 Summer Peak
Non-MIDWEST ISO Transmission	ERAG 2014 Summer	ERAG 2014 Summer
Generation/Load/Interchange	Not Used in PROMOD(R)	Not Used in PROMOD(R)

New Generators

The new generators identified in MTEP 09 Steps 1 and 2, under the Reference Future, are included in this study. More details on these generators can be found in Section E2

Event File

The event file is the list of flowgates (FG) which will be treated as transmission constraints in security constrained unit commitment and economic dispatch. The quality of the event file has a big impact on the quality of the study results. As PROMOD® has a limit on the total number of events, all N-1 or N-2 contingencies cannot be included in the event file. The event file for this 2014 PROMOD® case includes the flowgates from:

- Midwest ISO master flowgates file
- NERC book of flowgates
- Critical monitored line/contingencies provided by the Expansion Planning group, which are identified during the reliability study of the Appendix A/B projects.
- Appendix A/B projects that are 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.

2.6.2 Benefits Calculation

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)
  (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

The 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 decrease from the case without Appendix A/B projects to the case with Appendix A/B projects
- **Load Cost Savings:** the annual Load Cost decrease from the case without Appendix A/B projects 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 the same as that which would be used to calculate benefits for Regionally Beneficial Projects (RBP), also known as RECB II. While the projects evaluated in Appendix A and B do not necessarily meet the RECB II eligibility criteria independently, the Market Congestion is consistent with a methodology already outlined in the tariff that Midwest ISO stakeholders are familiar with, and as such provides a basis of common understanding for a discussion about benefits of a portfolio other than reliability.

Loss Benefits

- **Energy Loss Benefit (MWH):** this is the annual total loss decrease (MWH) from without Appendix A/B case to with Appendix A/B case;
- **Capacity Loss Benefit (MW):** the capacity loss benefit for MISO is the loss decrease (MW) from without Appendix A/B case to with Appendix A/B case in 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 the hourly company loss cost. This is calculated by multiplying a company's hourly loss by the company load weighted LMP at the same hour. The aggregate of these calculations is the dollar value of energy loss benefit.
- **Dollar Value of Capacity Loss Benefit:** the dollar value of the capacity loss benefit represents the value of deferring additional generation construction. It is calculated using $650/kW-$1200/kW, which the price range for the construction of different type units. Thus, the corresponding dollar value of capacity loss benefits is the Capacity Loss Benefit times these prices.
- **Maximum hourly loss decrease (MW):** this is the maximum hourly loss decrease (MW) from without Appendix A/B case to with Appendix A/B case

Other Impacts

- **Generation, Capacity Factor, and CO_2 Emission Change: c**ompare the change of generation, and capacity factor of different types of units, and change of CO_2 emission between with and without Appendix A/B projects cases.

2.6.3 Study Results

Economic Benefits

Table 2.6-2 shows the Adjusted Production Cost savings, Load Cost savings and Market Congestion benefit for the MTEP 09 Appendix A/B projects.

Table 2.6-2: Economic Benefits in 2014

	Load Cost Savings	Adjusted Production Cost Savings	Market Congestion Benefits
Midwest ISO East	$598 million	$173 million	$300 million
Midwest ISO Central	$469 million	$222 million	$296 million
Midwest ISO West	$747 million	$207 million	$369 million
Midwest ISO	$1,813 billion	$602 million	$965 million

The MTEP 09 Appendix A/B projects can save Midwest ISO $602 million in adjusted production cost, and $1.8 billion in Load Cost. Market Congestion benefits are $965 million.

As discussed above, the full portfolio of Appendix A and B projects is not modeled. Thus, the total cost of the MTE09 Appendix A/B projects in MTEP 09 2014 power flow case is $4 billion. Table 2.6-3 shows the Benefit to Cost (B/C) Ratio of the Appendix A/B projects, based on the Economic Benefits shown in 2.6-2 and $4 billion in project cost, under different fixed charge rates. The fixed charge rate varies by pricing zone, but on average is approximately 20% for the Midwest ISO footprint.

Table 2.6-3: B/C Ratio of MTEP 09 Appendix A/B projects in 2014

	Total Project Cost - $4 billion		
Fixed Charge Rate	**Annual Project Cost (million $)**	**Market Congestion Benefits (million $)**	**B/C Ratio**
14%	560	965	1.72
16%	640	965	1.51
18%	720	965	1.34
20%	800	965	1.21
22%	880	965	1.10
24%	960	965	1.01
26%	1,040	965	0.93
28%	1,120	965	0.86

The 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:

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

5) Mid-American and MPW in MISO: in base PROMOD® case, Mid-American and MPW are not in MISO; in this sensitivity test, model Mid-American and MPW are included in MISO market.

Table 2.6-4 shows the Adjusted Production Cost savings, Load Cost savings and Market Congestion benefits of the MTEP 09 Appendix A/B project for MISO in different sensitivities.

Table 2.6-4: 2014 Economic Benefits of Sensitivity Runs

	Base Case	5% Higher Load	5% Lower Load	40% Higher Gas Price	40% Lower Gas Price	MidAmerican and MPW in MISO
Adjusted Production Cost Savings (million $)	602	829	435	740	454	600
Load Cost Savings (million $)	1,813	2,523	1,461	2,354	1,201	1,882
Market Congestion Benefits (million $)	965	1,337	743	1,224	678	985

Table 2.6-5 shows the B/C Ratio of the Appendix A/B projects under different fixed charge rates in different sensitivities. Market Congestion benefits are used to determine the ratios in the table.

Table 2.6-5: B/C Ratio of MTEP 09 Appendix A/B projects in 2014

Fixed Charge Rate	Annual Project Cost (million $)	Base Case	5% Higher Load	5% Lower Load	40% Higher Gas Price	40% Lower Gas Price	MidAmerican and MPW in MISO
14%	560	1.72	2.39	1.33	2.19	1.21	1.76
16%	640	1.51	2.09	1.16	1.91	1.06	1.54
18%	720	1.34	1.86	1.03	1.70	0.94	1.37
20%	800	1.21	1.67	0.93	1.53	0.85	1.23
22%	880	1.10	1.52	0.84	1.39	0.77	1.12
24%	960	1.01	1.39	0.77	1.28	0.71	1.03
26%	1,040	0.93	1.29	0.71	1.18	0.65	0.95
28%	1,120	0.86	1.19	0.66	1.09	0.61	0.88

Loss Benefits

Loss benefits attributed to Appendix A/B projects are summarized in Table 2.6-6. The annual (2014) energy loss decrease is 579,030 MWH. Using the company's hourly load-weighted LMP to price this energy loss, the loss cost saving (i.e., the dollar value of the energy loss benefit) is approximately $65 million in 2014. . Note that Energy loss benefit is not incremental to the Market Congestion Benefits, but rather a partial driver of the Adjusted Production Cost Savings.

The capacity loss benefit is based on the loss decrease in Midwest ISO peak hour, which permits delaying the installation of additional generation capacity.. It is approximately 123 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 range savings in new unit construction is $90 - $166 million (in 2014 dollars, assuming 2% inflation rate).

Table 2.6-6: MIDWEST ISO Loss Benefits with Appendix A/B Project in 2014					
	Energy Loss Benefit	Value of Energy Loss Benefit	Capacity of Loss (Peak) Benefit	Value of Capacity Loss Benefit	Maximum Hourly Loss Decrease
Midwest ISO	579,030 MWH	$65 million	123 MW	$90~166 million	676 MW

Other Benefits

Table 2.6-7 shows the annual generation and capacity factor changes for different types of units. These are Midwest ISO units only. After adding the 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 -1.07% to +0.71%). Total Midwest ISO generation (excluding wind) decreases by about 1,479 GWH. Adding the Appendix A/B projects results in less wind energy being curtailed (174GWH), and increased import of less expensive generation.

From Table 2.6-7 also indicates that coal units generate less in the case including Appendix A/B projects. This drives annual CO_2 emission to decrease by approximately 2 million tons as shown in Table 2.6-8.

Table 2.6-7: 2014 Generation and Capacity Factor Change for Different Type Units			
		Generation (MWH)	Capacity Factor
Combined Cycle	No Appendix Projects	23,939,342	20.41%
	With Appendix Projects	24,777,190	21.13%
	Change	**837,848**	0.71%
CT Gas	No Appendix Projects	4,100,834	1.60%
	With Appendix Projects	2,917,610	1.14%
	Change	**-1,183,224**	**-0.46%**
CT Oil	No Appendix Projects	116,257	0.23%
	With Appendix Projects	55,397	0.11%
	Change	**-60,859**	**-0.12%**
Hydro (existing)	No Appendix Projects	14,131	19.48%
	With Appendix Projects	14,131	19.48%
	Change	**0**	**0.00%**
Hydro Run-of-River	No Appendix Projects	3,758,159	39.85%
	With Appendix Projects	3,758,159	39.85%
	Change	**0**	**0.00%**
Hydro Storage	No Appendix Projects	1,017,760	42.74%
	With Appendix Projects	1,017,761	42.74%
	Change	**0**	**0.00%**
IGCC	No Appendix Projects	143,073	5.99%
	With Appendix Projects	162,477	6.80%
	Change	**19,404**	**0.81%**
Nuclear	No Appendix Projects	78,120,798	87.56%
	With Appendix Projects	78,120,798	87.56%
	Change	**0**	**0.00%**

		Generation (MWH)	Capacity Factor
ST Coal	No Appendix Projects	490,400,193	74.49%
	With Appendix Projects	489,526,750	74.36%
	Change	**-873,442**	**-0.13%**
ST Gas	No Appendix Projects	265,358	1.67%
	With Appendix Projects	94,965	0.60%
	Change	**-170,393**	**-1.07%**
ST Oil	No Appendix Projects	44,562	0.25%
	With Appendix Projects	5,310	0.03%
	Change	**-39,252**	**-0.22%**

Table 2.6-8: 2014 Annual CO_2 Emission Change for Different Type Units

	CO_2 Emission (Ton)
No Appendix Projects	521,731,764
With Appendix Projects	519,619,229
Emission Decrease	2,112,535

While Table 2.6-8 shows a decrease in CO_2 emissions in 2014, a result of decreased wind curtailment and increased access to combined cycle generation, the gross annual CO_2 change may be different, and even increasing in future years or future analysis as additional transmission is added. Increased transmission capacity allows for greater access to less expensive generation. In many cases the generation with the lowest production cost has a higher CO_2 emission rate. In MTEP 08, the addition of the Appendix A/B projects relieved system constraints and allowed the system to dispatch lower cost steam turbine coal units in place of combined cycle and combustion turbines, thus increasing annual CO_2 emissions. While this increase represented a very small portion (0.23%) of the total CO_2 emissions, it demonstrates that transmission expansions can have the effect of increasing carbon production.

2.6.4 Conclusion

The PROMOD® simulations and economic analysis show that the Appendix A/B projects will bring not only reliability benefit to Midwest ISO, but also substantial economic benefit. In the study year (2014), Midwest ISO will save approximately $1.8 billion in Load Cost, and $602 million in Adjusted Production Cost. These benefits are against a total project cost of about $4 billion. Under a 20% fixed charge rate, the Benefit/Cost ratio of these projects is about 1.0. The sensitivity runs show that with higher load growth or higher gas price, these projects can provide even greater economic benefits.

The simulations and analysis also show that the Appendix A/B project also create benefits through a reduction in losses. In 2014, the annual energy loss decrease is about 579 GWH, which equates to about $65 million saving. The capacity loss benefit is 123 MW in 2014, which means the footprint can defer the installation of a 123 MW unit. This is equivalent to a range of savings in new unit construction of $90 - $166 million.

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

Section 3: MTEP Plan Status

3.1 MTEP 08 Status Report

This section gives an update on implementation of projects approved by the Board of Directors in the Midwest ISO Transmission Expansion Plan (MTEP). Any given MTEP Appendix A contains newly approved projects along with previously approved projects that were not in service when the MTEP 08 appendices were set. A new addition to the MTEP report is a historical perspective of all past MTEP approved plans in Section 3.2.

The transmission planning responsibilities of the Midwest ISO include monitoring the progress and implementation of necessary system expansions identified in the MTEP. The Midwest ISO Board of Directors approved the last MTEP (MTEP 08) in December of 2008. This section provides a review of the status of the approved project facilities contained in the MTEP and listed in MTEP 08 Appendix A. The Midwest ISO Board of Directors has been receiving quarterly updates on the status of the active MTEP plan since December of 2006. The information in this report reflects the 2nd Quarter of 2008 status report to the Board of Directors, which included status on MTEP 08 projects through June 30, 2009.

The purpose of tracking the progress of projects is to ensure that a good faith effort to actively move necessary projects forward towards completion is occurring, as prescribed in the Transmission Owner's agreement. Most projects that are planned and approved for construction move forward in a timely manner towards the desired in-service date. This is true despite the variety of reasons why a project may be delayed in this process, 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 the Midwest ISO cannot ascertain a reasonable cause for expected project delays such as the considerations 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. Over half of the projects in MTEP Appendix A are comprised of multiple facilities.

Status on MTEP 08 Planned Facilities

MTEP 08 Appendix A has 480 projects comprised of 902 facilities. The MTEP 08 Appendix A includes expansion facilities through 2018 plan year.

As a whole, $4.122 billion of the $4.171 billion in the MTEP 08 Appendix A or (98.8%) of the approved facilities included in MTEP 08 are in service, on track, or have reasonable delays.

There were 135 in-service date adjustments to projects. Little or no impact on reliability is expected because of the schedule adjustments which are primarily driven by economic slow down. Therefore, it is reasonable and prudent for Transmission Owners to adjust project schedules to match project drivers.

An examination of the withdrawn projects is prudent to ensure the planning process of Midwest ISO and its members not only addresses the needed system additions, but to ensure that when a project is withdrawn there is either good cause or that a different project covers the need of the project that was withdrawn. MTEP 08 Appendix A contains projects approved in MTEP 08 and past MTEPs which are not yet in service, so withdrawn facilities may have been approved in prior MTEPs, but withdrawn after MTEP 08 was approved.

There were 35 facilities (3% of 902) that were withdrawn for the following reasons:

- the customers 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 had good reasons for no longer implementing the plan. The majority were cancelled due to service requests being withdrawn or changes in need, due to reduction in load forecast. The transmission owners are clearly making a good faith effort to construct the approved projects.

3.2 MTEP Plan Implementation History

This section shows the implementation and plan status of all approved MTEP plans including the current MTEP plan. The historical perspective shows quite a bit of variability in transmission plan development. This is normal due to the long development time of transmission plans and the life cycle of a transmission plant.

Figure 3-1 shows the cumulative transmission investment dollars for projects, by plan status, for all past MTEPs from MTEP03 through the current MTEP09 cycle. MTEP09 data shown, subject to Board approval, is from the current MTEP study and will be added to the data set tracked by the Board of Directors. The steady increase in planned facilities is certainly a testament to the coordinated planning efforts of Midwest ISO and its Transmission Owning members. Note that these statistics do not include a number of new Midwest ISO members who did not participate in this planning cycle.

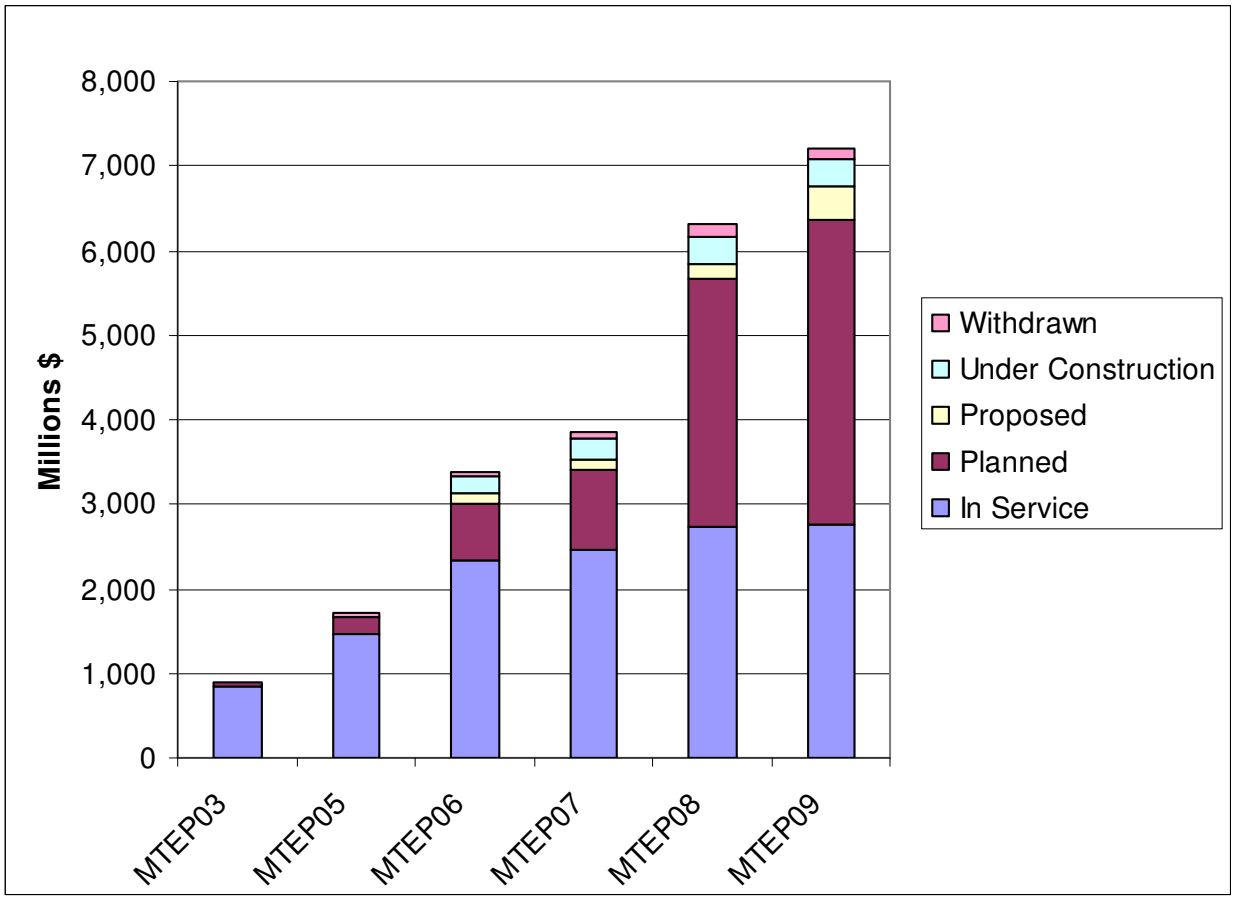


Figure 3-1: Cumulative Approved Investment by Facility Status

Figure 3-2 shows MTEP project investment by Facility Status for each MTEP. The historical perspective shows quite a bit of variability in transmission plan development. This 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 also shows the maturing of the MTEP process. MTEP 06 and MTEP 07 were approved in the same calendar year, which accounts for the small number of projects in MTEP 07. In MTEP 08 the number of planned projects increased due to developing transmission needs, including several large sized transmission upgrades. MTEP09 will be a year for analysis and determination of the best plans to serve those needs, with a large amount of the transmission needed to integrate renewables, thought to be significant, expected to show up in MTEP 10 and beyond. The Proposed category also shows up more in MTEP09 because of the maturity of plans in this most recent MTEP. Likewise, the In-Service category can be seen increasing in past MTEPs as projects get constructed. This graph is also a testament to the good faith effort of Midwest ISO's Transmission Owners to implement the approved plan.

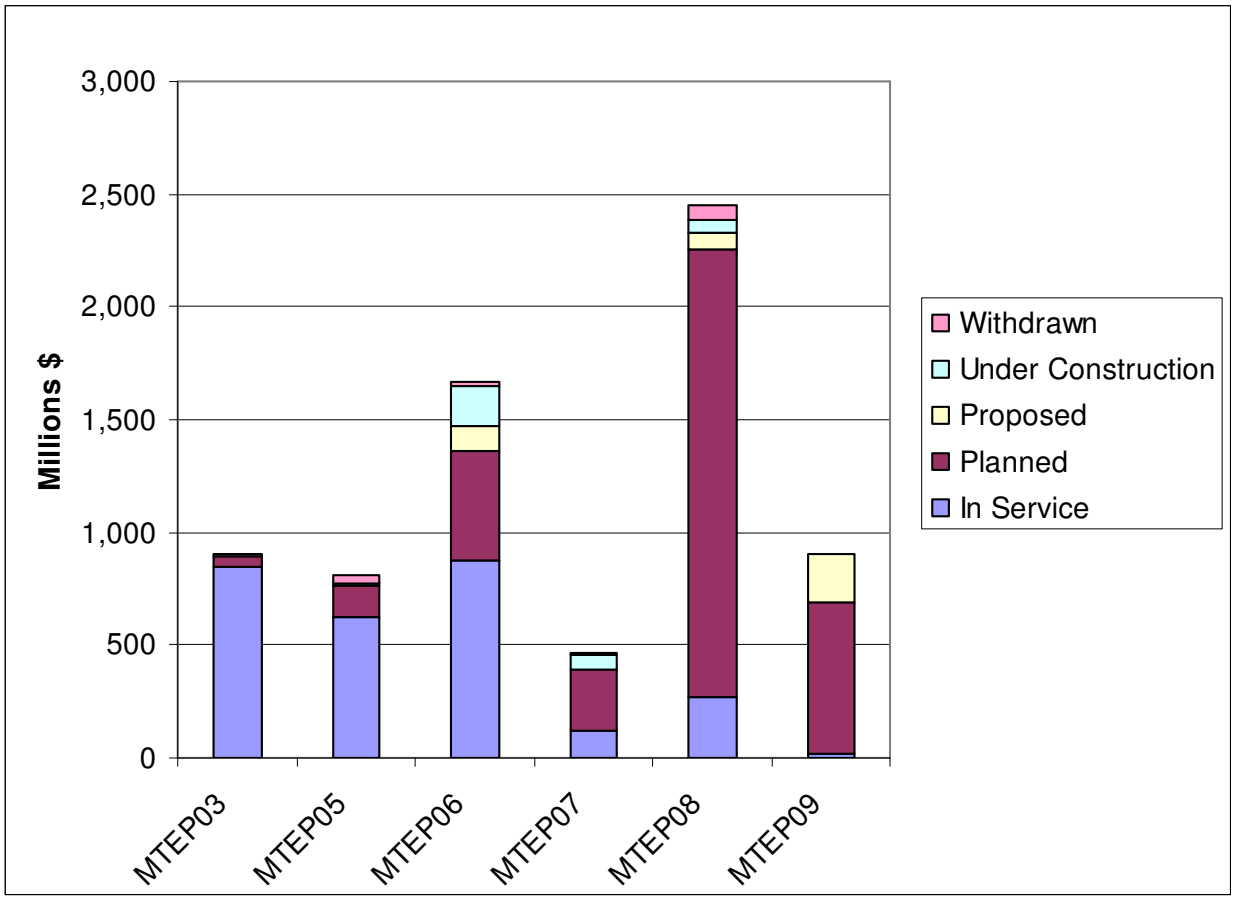


Figure 3-2: Approved MTEP Investment by Facility Status

Section 4: Midwest ISO Planning Approach

4.1 Planning Approach Evolution

In 2009, the Midwest ISO furthered its efforts to develop a comprehensive expansion planning process that meets both reliability and economic expansion planning needs. Increasingly, in the role of the Regional Planning Authority, the Midwest ISO is confronted with questions that impact large areas of the footprint over a long time horizon. This is particularly true in the current environment of shifting energy policy. Key issues and questions facing transmission planning include new renewable energy policies, reducing congestion on the grid, and incorporating new generation and demand response programs while still meeting load growth. Overlying all these concerns is the requirement to deal with an aging transmission infrastructure, changing regulatory environment, and the need to keep cost allocation fair. The numerous questions and uncertainties require a longer time horizon for study, but also a more hypothesis based approached to planning which is bounded by likely outcomes which address all the underlying issues.

Thus, a new more comprehensive planning approach seeks to reveal answers to questions such as:

- Is there a business case for increased transmission build?
- What type and location of transmission is required to effectively integrate wind from an operational perspective?
- Does the cost sharing methodology reflect all the primary value drivers?
- Is the value of benefits which may flow across borders accurately captured?

The level of uncertainty that exists around future policy decisions, in particular, creates difficulty for those involved in the planning function and causes hesitancy for those with the resources to undertake transmission expansion projects. To minimize the risk involved with planning a system under such conditions, the process must consider projects in the context of all potential outcomes. The work of the Midwest ISO and its stakeholders to identify transmission plans that result in the least regrets regardless of policy decisions will help to alleviate the impacts of those future outcomes.

The role of the Midwest ISO is not to (and the Midwest ISO 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 Owner's Agreement, under the regulation of state and federal authorities. The Transmission Owners Agreement provides for the TOs to "make a good faith effort to design, certify and build" the facilities included in the MTEP that are approved by the Midwest ISO Board of Directors.[1] 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. Thus, although the Midwest ISO may in its regional planning role identify alternative, or even incremental, plans to those identified by stakeholders, the responsibility for a transmission project to be approved and built ultimately requires the acceptance and approval of those who must build it and a sufficient business case to allow regulatory approval. To achieve this end, it is necessary to continue to evolve the level and robustness of analysis around the transmission expansion plan.

[1] Transmission Owners Agreement Section VI of Appendix B

In developing its enhanced transmission planning approach, the Midwest ISO considered its overall role in the process. These thoughts, combined with the general dissatisfaction expressed by many around the level of investment in transmission infrastructure, also underlie the guidance which the Midwest ISO Board, in 2005, provided to the Midwest ISO community and staff in an effort to improve the transmission investment in the region and guide the Midwest ISO transmission planning process. The principles, which were reconfirmed in February 2007, are:

- **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 (e.g. 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

For the Midwest ISO to support these efforts from an analytical perspective, new tools and methods have been added to the planning toolkit to evaluate total value of transmission projects, many of which meet longer term needs (i.e., 20 years). These new tools and methods are neither a replacement for short-term reliability analysis, nor for more straightforward economic and reliability analysis in the sub-20-year range.

Thus, the new planning cycles consist of a number of discrete, but interrelated elements.

- **Short term reliability analysis to meet NERC criteria:** this is typically power flow based analysis focused in the five-year range. Additional screening is done for the ten-year time frame. These studies are conducted annually and economic analysis may be used in the evaluation of alternatives.
- **Long-term value based analysis:** formerly described as economic analyses, these multi-year studies focus on long-term (10-20 year) needs, starting with the analysis of value drivers such as energy flow and ending with reliability assessment of the proposed plans. One current example of this is the Joint Coordinated System Plan (JCSP).
- **Targeted studies:** typically using a version of the long-term value based planning process; targeted studies typically focus on nearer term solutions (less than 20 years) that require a more comprehensive analysis than reliability alone, in part due to project drivers other than reliability improvement.

The execution of these related processes serve to address the first three Guiding Principles. Guiding Principle 1 is primarily addressed through the Long-term value based analysis (discussed further in Section 10) and the execution of Targeted Studies such as the Market Efficiency Study (discussed further in Section 8). Guiding Principle 2 is primarily addressed through the five and ten-year NERC reliability assessment, the results of which are reviewed in Section 7. The concept of Targeted Studies was identified in large part to ensure proper focus on Guiding Principle 3. As the concept of value based planning was introduced, it was first applied to assess long-term needs up to 20 years in the future. However, because of immediate policy drivers, such as state Renewable Portfolio Standard Requirements, studies such as the Regional Generation Outlet Study (RGOS) were introduced. The RGOS (discussed further in Section 9) and others like it are largely focused on providing specific transmission answers that do not fit neatly into a short- term reliability or value-based mold. As the value-based planning process becomes more ingrained at the Midwest ISO, and with its stakeholders, the line between value-based and reliability-based planning will continue to blur. Ultimately, the goal is execution of transmission planning which reflects a fully integrated view of the value of the project – inclusive of reliability, market efficiency, and other value drivers – across all planning horizons. Efforts such as the Regional Expansion Criteria and Benefits Task Force (RECBTF) and the work done to support the efforts of the state regulators in the Upper Midwest Transmission Development Initiative (UMTDI) and OMS Cost Allocation and Regional Planning (CARP) groups (both discussed in Section 4.4 below), are in place to address Guiding Principles 4 and 5.

As these functions - short term reliability, long-term value based and targeted studies - become fully integrated, longer-term solutions that provide greater benefits will become alternative solutions to address issues that are today solved through a series of shorter-term, and many times less valuable, mitigation steps. That is not to say, however, that the discrete analyses will disappear. Studies over each of the timeframes are still required to meet the planning needs of the region in the most expedient and efficient standpoint. In fact, with continued experience, the Midwest ISO has recognized the value of having the combination of plans. As the Midwest ISO seeks to implement nearer term reliability upgrades through the queue and the NERC reliability analyses, results from targeted studies provide insight into potentially more efficient alternative solutions based on the larger-scale transmission developed therein. Similarly, targeted studies such as the Regional Generation Outlet Study are informed by the long-term transmission roadmaps created through efforts such as the MTEP long-term value-based planning and the Joint Coordinated System Plan. By planning in the reverse order from which transmission is actually built, the nearer term transmission solutions can be developed in such a way to support future goals through more efficient plan development, including such considerations as preserving future right of way requirements.

4.2 Compliance Requirements and Activities

Compliance is one of the Midwest ISO's foundational focus areas. The 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. It is an area where Midwest ISO must excel on a daily basis. Achieving and maintaining excellence in compliance is imperative to the ongoing success of the Midwest ISO. The annual MTEP process is a key component of the Midwest ISO's compliance activities.

4.2.1 Corporate Compliance

The Corporate Compliance Oversight Committee (CCOC), formed in May 2008, provides high-level oversight for all Midwest ISO compliance activities and supports an overarching culture of compliance within the Midwest ISO. The CCOC oversees the development and implementation of the Midwest ISO's Compliance Master Plan addressing framework, processes, and tools for managing compliance activities. The CCOC directs the activities of a newly-created Corporate Compliance Management Team (CCMT).

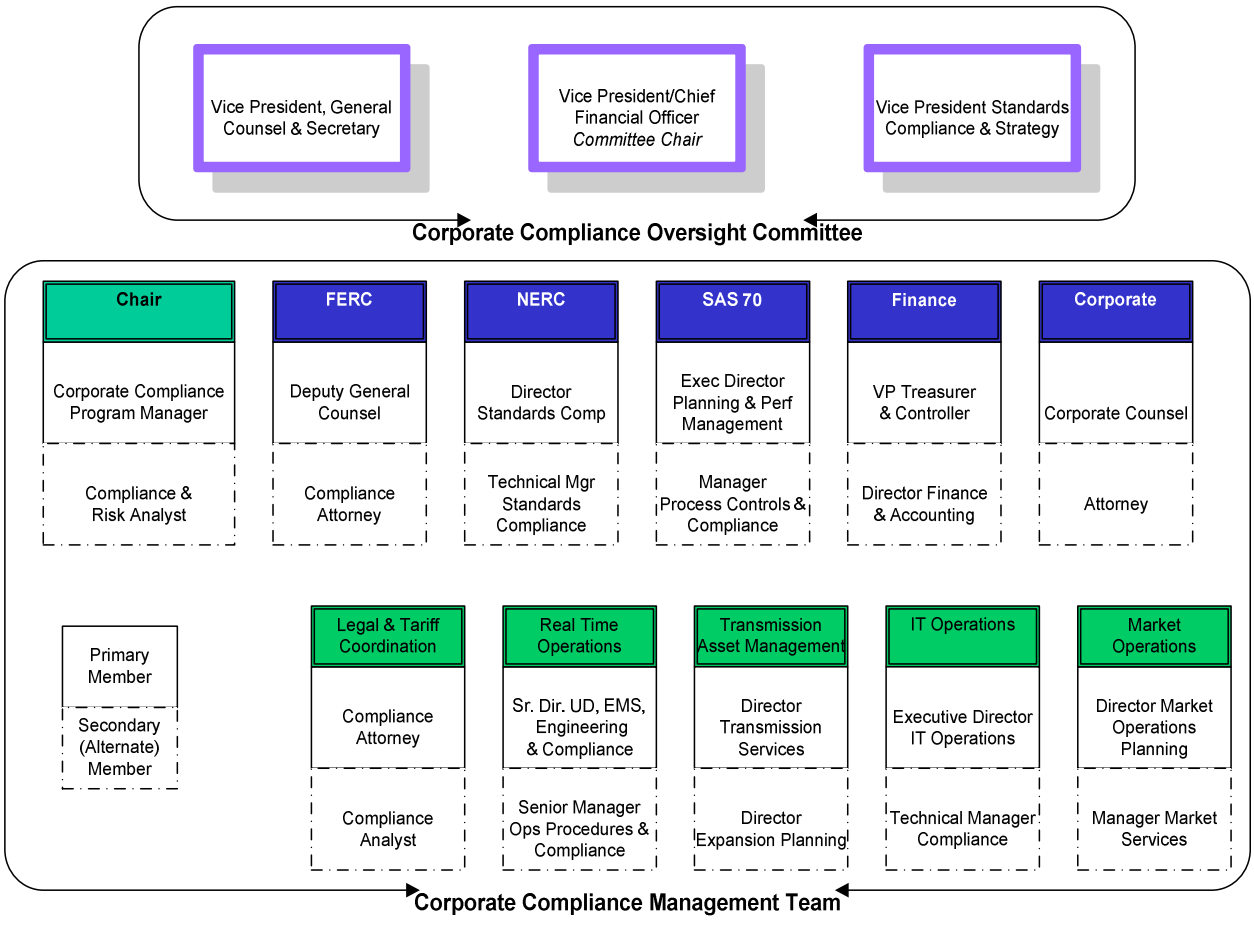


Figure 4.2-1: CCOC and CCMT Organizational Chart

The Corporate Compliance Management Team is responsible for developing and implementing the Midwest ISO's Compliance Master Plan. The CCMT's responsibilities include identifying and pursuing opportunities for continuous improvement to ensure effective compliance management for the Midwest ISO.

As part of the Corporate Compliance Management Team, Transmission Asset Management (TAM) performs a Baseline Reliability Analysis[2] through the annual MTEP studies in support of NERC compliance. The Baseline Reliability Analysis assesses the existing plan against the NERC contingency Table 1 events from the TPL-001 through TPL-004 Transmission Planning (TPL) standards. The Midwest ISO evaluates whether the system, as planned, meets the NERC TPL standards. The Midwest ISO then develops and tests for additional transmission system upgrades to address any identified issues, and then tests the performance of the corrective action plan for baseline reliability. IROL testing in the planning horizon is also done via the MTEP process in support of the NERC FAC-014 (Facility Connection Requirements) standard.

This compliance section describes the study process used to make an assessment of system reliability. The regulatory approved NERC defined standards as well as Midwest Reliability Organization (MRO) Regional Standards can be seen in Table 4.2.1 below.

Table 4.2.1: NERC and Regional Standards Applicable to MTEP Study

NERC Standards	Effective Date	NERC Website
FAC-010-2	July 1, 2008	http://www.nerc.com/
FAC-014-2	January 1, 2009	http://www.nerc.com/
TPL-001-0	April 1, 2005	http://www.nerc.com/
TPL-002-0	April 1, 2005	http://www.nerc.com/
TPL-003-0	April 1, 2005	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

Table 4.2.1: NERC and Regional Standards Applicable to MTEP Study

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

4.2.2 Areas of Compliance Addressed through MTEP

The Midwest ISO has three key areas of compliance which are addressed through the annual MTEP study process and that are discussed further in the subsections that follow:

- **FERC Order 890 -** Process steps incorporated within the MTEP cycle to demonstrate compliance are documented below.
- **NERC Standards –** A general discussion on Midwest ISO's support of NERC compliance is documented below. Specific narratives corresponding to individual NERC TPL requirements and pointers to associated evidence can be found in Section 6.1.
- **Module E -** Process steps incorporated within the MTEP cycle to demonstrate compliance to FERC Order 890 are documented below.

FERC Order 890 Planning Principals

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 a further compliance filing.

The nine planning principles each transmission provider was directed to address by Order No. 890 in its Attachment K planning process are:

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 that it adopted a principles-based reform to allow for flexibility in implementation of, and to build on 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 that 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:

http://www.midwestmarket.org/publish/Document/3b0cc0_10d1878f98a_-7d040a48324a

Added Planning Process Steps in 2008 to Address Order 890

A key element of the principals is involving transmission customers early in the planning process. At the beginning of the MTEP09 planning cycle, Subregional Planning Meetings (SPM) were held in the West, Central and East planning regions of Midwest ISO. The primary purpose of SPM was to 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 are 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, and the Midwest ISO as required to meet the Order 890 Planning Requirements, and based on discussions with stakeholders before and during the December 2008 SPMs, the following schedule and requirements for the SPMs was established:

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**	1. 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	Transmission Owner
	2. Expected cost of the project	
	3. Significant milestones in project schedule up to the projected in-service date	
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	Midwest ISO Staff
By July 15th	First Draft of current cycle MTEP report	Midwest ISO Staff

*Additional more focused technical study task forces to be formed as necessary to carry out the sub-regional planning responsibilities

** For MTEP09, the January 31st deadline had been extended by 1 week to February 6th 2009.

MTEP09 SPM Schedule		
Date	Meeting	Location
9-Dec-08	1st Central Sub Regional Planning Meeting	Carmel, IN
16-Dec-08	1st East Sub Regional Planning Meeting	Detroit, MI
18-Dec-08	1st West Sub Regional Planning Meeting	St. Paul, MN
26-Feb-09	Michigan Technical Study Task Force Meeting	MPSC Office, Lansing - MI
7-May-09	2nd Central Sub Regional Planning Meeting	Carmel, IN
14-May-09	2nd East Sub Regional Planning Meeting	Novi, MI
5-May-09	2nd West Sub Regional Planning Meeting	St. Paul, MN
16-June-09	Michigan Technical Study Task Force Meeting	Jackson, MI
17-July-09	3rd East Sub Regional Planning Meeting	Merrillville, IN
20-July-09	3rd West Sub Regional Planning Meeting	St. Paul, MN
23-July-09	3rd Central Sub Regional Planning Meeting	Carmel, IN

The above Information Requirement and Schedules is also posted at the Midwest ISO website at:

http://www.midwestmarket.org/publish/Document/20b78d_11ef44fc9c0_-7fce0a48324a?rev=4

Other Key Inputs to the Planning Process

The analytical inputs and assumptions for the baseline reliability analysis are:

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

Planning criteria, models, contingencies, and mitigation plan development are discussed in Section 6.1.

Economic Planning Requirements of Order 890

The economic planning studies principle of Order No. 890 requires transmission providers to account for economic, as well as 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 that economic considerations are adequately addressed when planning for OATT customers as well.

The Commission emphasized that 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 that evaluate 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, the provisions concerning Regionally Beneficial Projects in section II.B of Attachment FF, which have been approved by the Commission. Midwest ISO, via the Planning Advisory Committee and other Technical Study Groups formed to address Targeted Studies, conducts with stakeholders, long-range economic planning. 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. This long-term planning 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 the opportunity for stakeholders to provide input concerning more near-term congestion issues impacting customers. Through the Sub-regional Planning Meeting 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 footprint. In this way the most problematic issues, identified and prioritized collectively with all stakeholders, are addressed, rather than 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 via the SPM discussions, are examples of more near term economic studies in compliance with Order No. 890 economic planning requirements. In its Orders accepting the 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 that the Midwest ISO's approach of addressing the most significant congestion or generation integration issues, identified and prioritized collectively, with all stakeholders, is consistent with, or superior to, Order No. 890's requirement of responding to a select number of economic studies on a request-by-request basis.

NERC Standards

The Baseline Reliability Analysis performed in the annual MTEP studies demonstrates that 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, as identified in the Midwest ISO TP BPM Section 4.3.1 – Steps in the Short-Term Planning Process[3]. This ensures that the 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[4] for the Baseline Reliability Analysis are:

- The transmission system condition to be modeled and analyzed with associated load
- Generation and base interchange values
- The contingencies and system events to be analyzed
- The facilities monitored with respect to the Planning Criteria
- The current transmission expansion plans from the planning process

The Midwest ISO performs valid transmission studies up to and beyond the five-year Short-Term Planning horizon aiding in identifying critical thermal issues. All Midwest ISO Transmission Expansion Plan reports and Appendices list all contingency results, before and after impact of planned/proposed upgrades to demonstrate their effectiveness within the project evaluation process. Each MTEP report includes a list of all existing and planned facilities on an annual basis.

At the end of each valid MTEP assessment, additional analysis is performed to ensure that there are no outstanding limits that have not been mitigated. For MTEP studies, Appendix A and B lists all planned/proposed upgrades that are needed to meet system performance. Project completion is closely monitored by the Midwest ISO and reported to the Board of Directors on a quarterly basis. In service dates for MTEP projects are included in Appendix A & B and they are monitored through project tracking with 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, where revised, revisions are evaluated at the time of revision and further reviewed in subsequent MTEP analyses.

In addition to Midwest ISO's Baseline Reliability study, the Midwest ISO, in coordination with its Transmission Owners, routinely perform 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.

[3] 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

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

Typical analyses include:

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.
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, such as: prospective Independent Power Producers (IPPs), interconnections with other control areas, Generation Interconnection and/or Transmission Service Requests. In these cases, engineering judgment may be used to determine appropriate contingency scenarios that need to be studied in order to insure compliance with any applicable individual TOs transmission planning criteria and the NERC Planning Standards. Transmission Owner planning criteria is outlined in Section 6.1.

Module E Compliance

The Midwest ISO is required, per Module E of the Tariff, to perform Loss of Load Expectation (LOLE) analysis on an annual basis for the purposes of determining a minimum Planning Reserve Margin (PRM) for the upcoming Planning Year (June through May) as well as a ten-year LOLE analysis for informational purposes. The 2009 Planning Year was the first Planning Year that the Midwest ISO performed LOLE analysis for the purpose of establishing a PRM.

Also, the Midwest Reliability Organization, as well as ReliabilityFirst Corporation, has created standards for performing LOLE analysis that are at different levels of approvals. These standards will be applicable to the Midwest ISO as a registered Planning Authority with the NERC. The study process that has been created is designed to be compliant with the respective standards in the Midwest ISO footprint.

The 2009 Midwest ISO LOLE study report can be found at:

http://www.midwestmarket.org/publish/Document/62c6cd_120e7409639_-7f2a0a48324a

4.3 Influence of Evolving Policy

The Midwest ISO's approach to planning is greatly influenced by the decisions and actions of policy makers. There are currently efforts underway at all levels of government that are aimed at reducing the environmental impacts of energy generation and on enabling more effective and efficient use of energy supplies. The impacts of the electric industry are currently being scrutinized more than at any time in the recent past. Topics currently being discussed and analyzed include renewable energy, carbon reduction, energy efficiency, and a smart grid. The continued evolution in both the maturity and flexibility of the planning process is critical since the potential outcomes of any policies created around these issues may very different, making it more challenging for the industry to predict a future state and to plan for meeting the objectives associated with it.

4.3.1 State Policy

The Midwest ISO footprint includes eleven states that currently have either an RPS goal or mandate. In total, these requirements represent approximately 23,000 MW of generation[5]. That number has increased from 15,000 a year ago as additional states have enacted legislation to demonstrate their commitment to promoting renewable energy policies. The state requirements are very diverse in the amount, location, and, type of generation required, as well as in the time given to achieve the mandates, adding additional complexity to enabling the meeting of the standards.

These requirements continue to influence the mix of generation within the interconnection queue as well as the location of those generators. The interconnection queue continues to be dominated by requests from wind generators, the siting of which are concentrated in geographic areas that are rich in wind potential but distant from major load centers. These trends continue to advance the need for a transmission build out that would allow for the delivery of renewable generation to states with RPS requirements. One challenge that will have to be addressed, as increasing amounts of transmission is required, is how the cost for this transmission will be allocated across multiple states. As discussed further in Section 4.4, a number of state governors and regulators in the Midwest ISO region are currently taking an active role in developing cost allocation policies to enable the integration of large quantities of renewable generation.

4.3.2 Federal Policy

Discussions at the federal level encompass a broader set of objectives, but consistent with state efforts, include a focus on the integration of renewable generation. Increasing the utilization of renewable energy is one part of the Obama Administration's aggressive energy agenda, with specific policies for a federal renewable mandate being proposed as part of current House and Senate legislation. The federal Renewable Energy Standard (RES) provisions in the House and Senate bill differ on specifics, but both would require a significant investment in future renewable generation. The current standards being proposed would have a much greater impact on the Midwest ISO planning efforts as it would be expected that a large volume of renewable generation to supply the nation's needs would originate in the Midwest ISO footprint. This scenario would require incremental build out of the transmission system beyond that already needed under the current state standards.

[5] As of July 1st, 2009

Another focus of the President's plan is reducing the impact to the environment of carbon emitting generation. A carbon cap-and-trade program is once again being discussed as a solution to reduce greenhouse gas emissions. Although bills containing similar legislation were defeated in 2008, support exists for such policy change, with the House passing the Waxman-Markey bill at the end of June, which included a carbon cap-and-trade program. The passage of any cap-and-trade legislation would greatly change the economics for coal generation, resulting in a reduced utilization of this comparatively inexpensive source of energy. Such a program would not only significantly affect the generation mix in the Midwest ISO, but would create the need for transmission expansions that would enable the integration of a larger volume of clean energy resources.

The concerns around carbon's impact to the environment will not only affect the existing coal-fired fleet, but also plans for future expansions to generation capacity. These concerns are resulting in a dramatic reduction in the amount of coal generation being approved, and is reflected in the level of coal capacity in the generation interconnection queue. Currently there are 4,100 MW of coal capacity in the queue compared to 9,100 MW in June 2006. The continued lack of approvals for future coal-fired generation will significantly impact the way the country meets future increases in energy demand.

Another component of President Obama's energy agenda is a focus on a smart grid. This includes demand response programs, energy storage, and plug-in hybrid cars. The Administration has proposed action plans that seek to provide guidance on standards for the coordination of the bulk power systems with new and emerging technologies and to help address the challenges associated with incorporating these technologies. A fourth focus of potential legislation is energy efficiency, which seeks to drive more efficient products, materials, and behaviors. Included in this initiative are the developments of a broad range of more stringent building and appliance standards, including such things as efficiency standards for lighting products or grants to increase funding for weatherization of a large number of homes annually. All of these developments require changed assumptions about levels, and perhaps even the profile, of load which in turn could result in a different transmission plan than what might be considered under an alternate paradigm

Each of these programs on their own would have impacts to both generation utilization and transmission planning. The potential for many or all of them being incorporated into future legislation would introduce a good deal of complexity into the planning of the system. In addition, transmission siting and cost allocation hurdles must be overcome in order for the Extra High Voltage (EHV) grid overlay that both bodies are considering, and that would enable the types of advances described above, to become a reality.

The planning process is also influenced by federal support for interconnection-wide planning. The Department of Energy has released a Funding Opportunity Announcement (FOA) that will award financial assistance, to chosen entities, that will develop 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 Responding to Policy to Advance Infrastructure Investment

With climate change and national security issues gaining momentum in recent years, the utility industry has found itself at the center of an increasing number of policy discussions. It is widely believed that these discussions, which are taking place across a very broad set of political and regulatory bodies, will ultimately culminate in decisions and policies that will require regional transmission solutions to be designed and built. In its role as the Regional Planning Authority for its footprint, the Midwest ISO is currently leading, or engaged with, several efforts that are working towards the development of such regional planning solutions and eliminating barriers to construction, most notably cost allocation. The allocation of transmission project costs has long been a contentious issue throughout the industry. The lack of a widely accepted methodology for identifying the beneficiaries of transmission expansion projects, driven largely by renewable integration, and subsequently allocating the costs to those beneficiaries, has the potential to reduce the amount of transmission being built, introducing risk into satisfying the mandates. The efforts underway represent a positive step towards development of workable solutions to support implementation of regional plans.

The Regional Generation Outlet Study (RGOS) was initiated in response to the growing focus on the use of renewable sources of energy. As more and more states created Renewable Portfolio Standards (RPS) it became clear that areas rich in renewable sources of generation would need to be identified, and plans for connecting those resources to load centers would need to be developed. Phase I of RGOS (discussed further in Section 9) began with the identification of Renewable Energy Zones in the states of Illinois, Iowa, Minnesota, and Wisconsin. The Midwest ISO, using wind data provided by the National Renewable Energy Lab (NREL), was able to identify the locations with the greatest wind energy output potential. Those locations were then combined into zones, which it was assumed, would be representative of future generation siting. The focus then turned to enabling delivery of energy from those zones to load centers to meet the RPS mandates for those states in RGOS Phase I.

As these efforts were underway, the governors and regulators of North and South Dakota, Iowa, Minnesota, and Wisconsin came together and formed a group called the Upper Midwest Transmission Development Initiative (UMTDI). The group identified two goals for 2009 – the development of regional transmission plans that would enable the RPS in their states to be met, and a methodology for allocating the costs of those plans. The RGOS work effort was already working towards the transmission development goal, at least for a subset of these states, creating an intersection of the efforts and an opportunity for the Midwest ISO to support the UMTDI. Indicative transmission plans, connecting renewable energy zones identified under RGOS with load centers, were developed. The design of such plans enabled the determination of ranges for key parameters, including line miles, costs, different voltage classes, and net present value, that could then be considered across scenarios. The Midwest ISO provided this output to the UMTDI for use in selecting scenarios to guide the RGOS. Phase I of RGOS is now focused on the detailed transmission analysis and design associated with the scenarios chosen by the UMTDI. The second objective of the UMTDI is centered on the issue of determining who will pay for the transmission expansions necessary to integrate the volume of renewable generation needed to meet current RPS requirements. The UMTDI plans to utilize the transmission plans and analyses produced by RGOS Phase I to develop cost allocation recommendations for the UMTDI states.

Phase II of RGOS, which focuses on the states of Illinois, Missouri, Ohio, Indiana, Michigan, Pennsylvania, and any increase in RGOS I states, was kicked-off in May. This study will utilize a similar process, as that employed in RGOS I, to arrive at detailed transmission plans needed to meet RPS goals and mandates in the states involved in the study.

The full Organization of Midwest ISO States (OMS) has a parallel effort evaluating regional planning and cost allocation. The Cost Allocation Regional Planning (CARP) Initiative is focused on developing recommendations for improvements to cost allocation that will enable the meeting of existing and potential future environmental policy. The CARP effort is considering both a broader scope – evaluating carbon, efficiency and renewable impacts to the transmission plan – and a broader scale – the entire Midwest ISO footprint. The OMS is developing a set of scenarios, or regional plans, that will cover a wide range of potential future outcomes and provide a basis for assessing the impacts of various cost allocation methodologies that will be tested, which could then be applied more broadly within the Midwest ISO. Consistent with Guiding Principle 5, the Midwest ISO is supporting this effort by providing the necessary models, and analytical and design support, to produce output which can inform the CARP as they craft their recommendations.

Concurrent with the formation of the UMTDI and OMS CARP, the Midwest ISO was determining how best to address cost allocation issues that were identified in feedback provided by stakeholders in August of 2008. Late in 2008, the Midwest ISO agreed to collaborate with its stakeholders to develop improvements to its RECB I and II methodologies, which pertain to baseline reliability, generator interconnection, and economically beneficial projects, respectively. To accomplish this, the Midwest ISO re-instituted the RECB Task Force which began meeting in early 2009.

As this group began to develop its work plan, cost allocation issues driven by the RECB I methodology for allocation of Generator Interconnection Projects (GIP) became a top priority. Although not previously identified as an unintended output of the current cost sharing methodologies, it became apparent that the GIP methodology resulted in a disproportionate share of costs relative to load being allocated to select Transmission Owning members in the western part of the Midwest ISO footprint. The disproportionate share of costs being allocated to a few zones is due to a combination of the amount of generation wishing to locate in those zones relative to load and the Line Outage Distribution Factor (LODF) methodology used by the Midwest ISO to allocate those costs, which keeps a significant portion of the costs in the zone where the generator is located, regardless if the output is intended for that zone. These issues were creating scenarios where it was not going to be economically feasible for those TOs to remain members of the Midwest ISO. Given the need to address this in an expedited manner, the RECB Task Force determined that it would organize its efforts in three phases, the first of which would focus on modifying the way costs associated with Generator Interconnection projects are allocated. After much discussion and consideration of multiple proposals with the stakeholder community, the Midwest ISO is preparing to file a proposed solution with FERC in July.

Phase II for this group will focus on cost allocation for transmission projects that are identified as enabling integration of large quantities of renewable generation or other locationally constrained resources. An expected result of this effort is the movement of costs currently considered as Generator Interconnection Projects to the new category of cost allocation. This shift is expected due to the current absence of a final transmission plan, and associated cost sharing methodology, to address large-scale renewable integration (such as that being developed through the RGOS), This results in significant amounts of transmission build out to integrate renewables occurring in the queue. Efforts to both develop a methodology and criteria for identification of such projects will be undertaken in this phase. As part of the Phase II cost allocation development process, the recommendations provided by the CARP and UMTDI will be taken into consideration as the new cost allocation methodology is formulated. Phase III of the RECB Task Force's efforts will be for addressing any remaining concerns and issues with RECB I and II methodology that have not been mitigated through the work of prior phases.

4.5 Estimated Impacts of Future Scenarios

As discussed in Sections 4.3.1 and 4.3.2, the electricity industry is facing a number of impending policy changes from both the state and federal level that produce a great deal of uncertainty to the industry including potential rate increases to retail customers. At the state level, as shown in Figure 4.3-1 all but two of the thirteen 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 location of future renewable generation, required transmission to enable renewable integration, and future cost allocation methodologies for transmission investment. In addition to state policies, the Federal government, at the time of this writing, was considering legislation for a 20% Federal RPS and implementation of a cap-and-trade program to reduce $C0_2$ emissions. All of this uncertainty around future energy policy complicates the already challenging task of developing a long-term plan. To address this high-level of uncertainty the Midwest ISO examines multiple future scenarios through its long-term planning process to capture the wide spectrum of potential policy outcomes.

4.5.1 Future Policy Scenarios

In MTEP 09 the Midwest ISO examined a number of policy-driven future generation expansion scenarios (Futures) to develop "best plans" for a range of assumptions on what could happen in the future under various policy structures. The futures developed were based on policy discussions taking place at the time, which can and will differ from current and future legislation as those discussions evolve. The following future policy scenarios have been examined to estimate potential impacts to retail rate payers in the Midwest ISO footprint.[6]

- **Reference Future** – represents the status quo where future economic and political conditions are expected to remain consistent with the recent past. Also, includes the state renewable mandates as of January 1, 2008. (see Figure E1-2)
- **Renewable Future –** assumes that 20% of the energy consumed in the Midwest ISO by 2024 will be supplied by Wind
- **Environmental Future –** assumes that starting in 2010 a $25 per ton cost will be added to CO_2 emissions. Also, assumes that the annual energy growth rate will be 25% lower than for the three other Futures.
- **Gas Future** – assumes that future capacity additions will be limited to only Combined Cycle and Combustion Turbines located close to load. Also, includes the necessary wind additions to meet the same state renewable mandates as in the Reference Future.

All of the Futures included in this rate impact analysis require significant investment in both generation and transmission expansion over the 15-year study horizon to meet the various policy objectives. This increased investment is expected to have an impact on the retail 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, approximately 60% of the generating capacity in the Midwest ISO footprint is more than 30 years old. As is shown in this rate impact analysis all of the scenarios examined show consumer retail rates increasing at a faster rate than inflation (assuming a 3% inflation rate).

[6] For additional description of the MTEP09 Futures refer to Section 10.2 and Appendix E.1.

4.5.2 Current Retail Electricity Rates

Before discussing the potential impact of the Future scenarios, consider the current cost of electricity to the retail customer. The current Midwest ISO load, weighted by state average retail electricity rate for the residential, commercial, and industrial sector, is approximately 8.4 ¢/kWh, which is about 13% lower than the national average of 9.7 ¢/kWh.[7] Figure 4.5-1 provides the average retail rate in cents/kWh for each state in the Midwest ISO footprint, and shows that across the Midwest ISO footprint the retail rate paid by consumers varies greatly. Based on information provided by the Energy Information Administration (EIA) in the Annual Energy Outlook 2009 the generation, transmission, and distribution cost components of the retail electricity rate in 2009 are estimated to be on average 68.0%, 6.9%, and 25.1%, respectively.[8] This equates to approximately 5.7 ¢/kWh for generation, 0.6 ¢/kWh for transmission, and 2.1 ¢/kWh for distribution.[9] For this rate impact analysis it is assumed that the average Midwest ISO residential customer uses approximately one MWh of electricity each month, which is equal to an annual electricity bill of approximately $1,009, based on an 8.41¢/kWh retail rate.

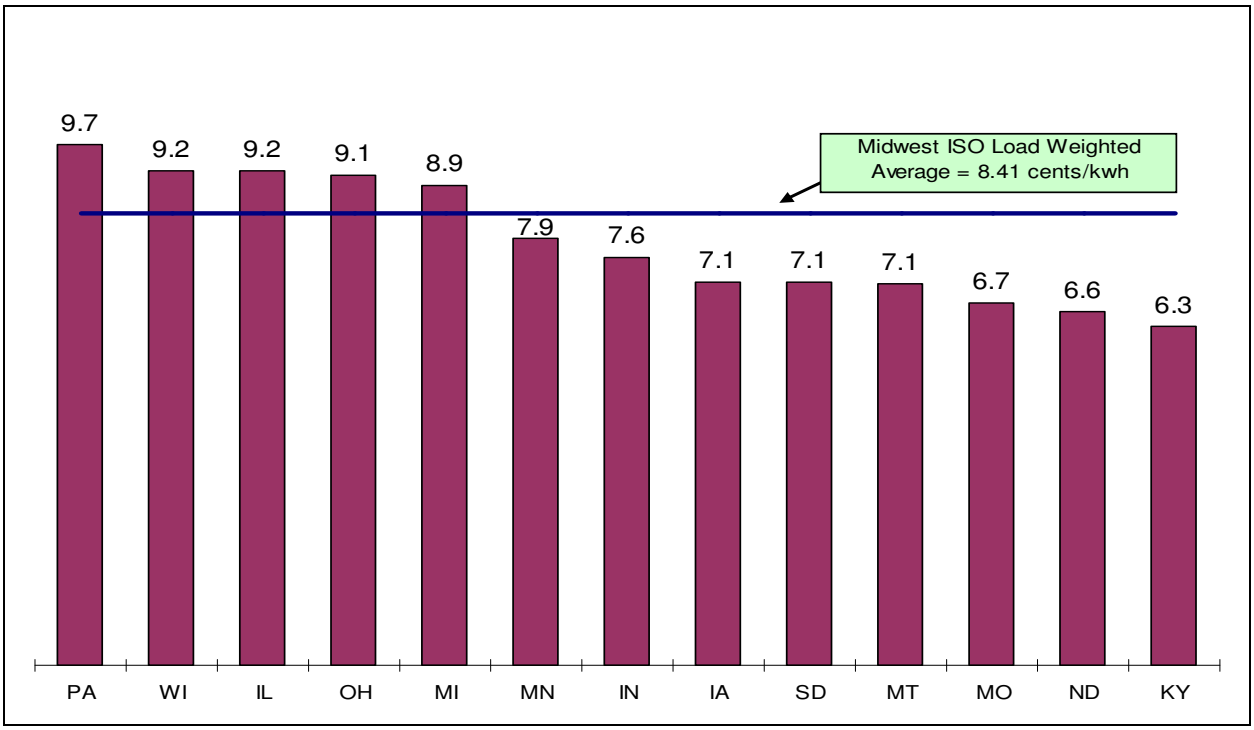


Figure 4.5-1: Midwest ISO Retail Rate for all Sectors in ¢/kWh (2009 Dollars)

[7] Data courtesy of the Energy Information Administration (EIA) Electric Power Monthly in July 2009. The Midwest ISO rate was calculated by taking the load weighted average of the thirteen states that compromises the Midwest ISO footprint.

[8] The Midwest ISO average generation, transmission, and distribution components were calculated based on rate component data provided in the EIA Annual Energy Outlook in 2009 by the following reliability 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 reliability regions including only those local balancing authorities in the Midwest ISO footprint.

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

4.5.3 Overview of Rate Impact Methodology and Results

To measure the potential impact to rate payers under each of the Future scenarios, the Midwest ISO projected a potential 2024 retail rate by estimating the revenue requirements for the following generation, transmission, distribution rate components:[10]

Transmission Component

- Transmission overlay investment required to support the generation capacity expansion for each Future through 2024[11]
- Additional required reliability transmission investment through 2024 (constant across all Futures)
- Non-depreciated current transmission that would still be recoverable in 2024 (constant across all Futures)

Generation Component

- Production Costs for the Midwest ISO generation fleet associated with each Future in 2024 - includes fuel, emissions, variable and fixed O&M costs
- Generation capital investment associated with the capacity expansion for each Future through 2024[12]
- Non-depreciated current generation that would still be recoverable in 2024 (constant across all Futures)

Distribution Component

- Assumes that the distribution component of the current Midwest ISO retail rate at 2.1 ¢/kWh will grow at the assumed rate of inflation through 2024

To calculate the 2024 retail rate, the revenue requirements for the generation, transmission, and distribution components described above were distributed across the forecasted 2024 energy usage levels. The 2024 rate was then discounted by the rate of inflation to 2009 dollars for comparison to the current Midwest ISO retail rate.[13] The results of that calculation are shown in Figure 4.5-2 for each of the Future scenarios. All Futures show that, based on the various economic and policy assumptions made, rates for retail customers can be expected to grow at a rate faster than would be experienced if rates simply increased at the rate of inflation. However, the magnitude of this impact varies greatly across the four Futures from 3.1% for the Reference Future to 23.2% for the Environmental Future. Also, the rate component driving the increase varies across the Futures, from increased capital expenditures in the Renewable Future to meet the 20% Federal renewable mandate or increased production costs in the Environmental Future due to the $25 per ton carbon cost on emissions. Major rate increase drivers for each Future are discussed in more detail in the next section.

[10] Additional detail on the rate calculation methodology is provided in Appendix E4

[11] Based on the conceptual EHV transmission overlay identified in the MTEP 08 Futures analysis, except for the Gas Future, which assumes that non-wind generation will be sited close to load-centers. Mileage and assumed per mile costs by voltage class for each Future's conceptual EHV transmission overlay is provided in Appendix E2

[12] Refer to Figure 10.2-2 for details on the capacity expansion, by fuel type, for each Future. Generation Siting maps for each Future are provided in Section 10.2.4.

[13] 2024 energy usage levels are from the Powerbase database utilized in the capacity expansion, assumes an annual 1.5% energy growth rate through 2024 for all Futures, except the Environmental Future which assumes a 25% reduction in the annual energy growth rate

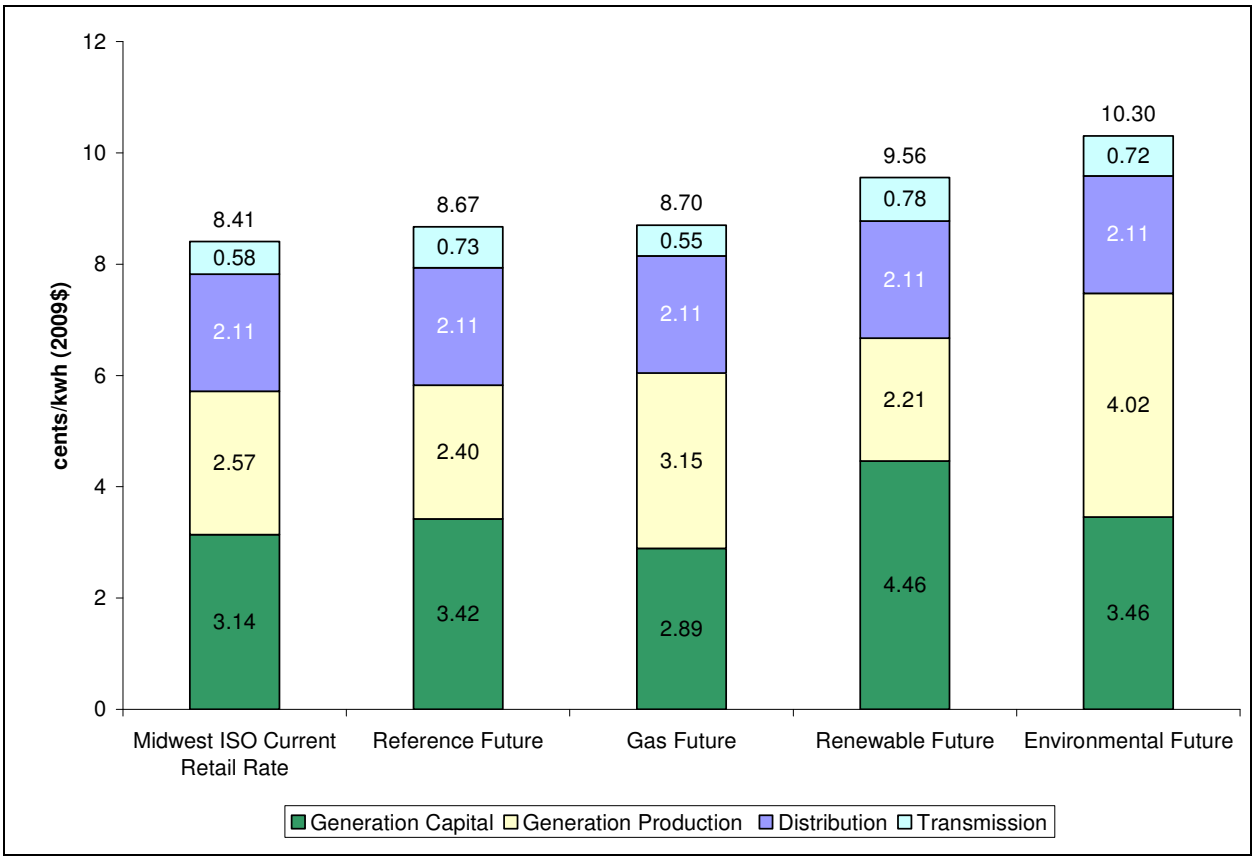


Figure 4.5-2: Comparison of Estimated Retail Rate for each Scenario

(cents per KWh in 2009 $)

4.5.4 Rate Impact Drivers under Future Policy Scenarios

Table 4.5-3 compares the Reference Future retail rate to the Midwest ISO current retail rate by rate component to illustrate which component is driving the overall estimated increase of $31 to the average residential ratepayer's annual electricity bill.[14] The increase in generation capital and transmission investment in the Reference Future is in part being driven by the need to meet the state renewable mandates included in the study. Offsetting this increased capital investment, to some degree, is an estimated reduction in production costs attributable to increasing amounts of lower production cost wind meeting higher percents of total energy served by 2024. One item to note is that the current state renewable mandates in the Midwest ISO footprint have increased since this study was performed - from approximately 15,000 MW to 22,000 MW - which would require additional generation and transmission investment to meet those mandates.

[14] Based on an average monthly usage of 1 MWh

Table 4.5-3: Comparison of Reference Future Retail Rate to Current					
	Rate Component				
Retail Rate	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh 2009$)	3.14	2.57	0.58	2.11	8.41
Reference Future Retail Rate (cents per kWh 2009$)	3.42	2.40	0.73	2.11	8.67
% Increase/Decrease over Current Retail Rate	8.9%	-6.6%	26.0%	0.0%	3.1%
Increase/Decrease to Avg. Retail Rate Payer's Annual Electricity Bill	$ 33.56	$ (20.32)	$ 18.21	$ -	$ 31.45

Table 4.5-4 compares the Gas Future retail rate to the Midwest ISO current retail rate by rate component. The overall estimated rate increase under the Gas Future Scenario is only marginally higher than the Reference Future at $35; however, the rate components driving the increase are materially different. Due to the restriction on the type and location of future generation capacity to only Combined Cycle or Combustion turbines, which have a lower capital cost than the coal capacity added in the Reference Future, the Gas Future's generation capital component is reduced.

Restricting the location of the gas generators near load centers also reduces the required transmission investment; however, the wind generation sited to meet the renewable mandates was not restricted to locations near load and the associated regional transmission for this wind generation is reflected in the transmission component of the Gas Future. Under a purely "local" scenario with all generation sited near load the required transmission investment is reduced even further, but generation capital investment increases as more installed wind capacity is required due to siting in lower capacity areas close to load.

Offsetting the reductions in generation and capital investment is the significant increase in production costs associated with the increased total fuel costs of natural gas generators as the share of energy met by gas generation more than doubles by 2024. The Gas Future assumed a natural gas price of $8 per M/btu with a 4% annual escalation applied. The overall rate impact of the Gas Future is highly dependent on the assumed price of natural gas, which has varied greatly over the past year from a high of $14/Mbtu in 2008 to a low of approximately $4/Mbtu in 2009.

Table 4.5-4: Comparison of Gas Future Retail Rate to Current					
	Rate Component				
Retail Rate	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh 2009$)	3.14	2.57	0.58	2.11	8.41
Reference Future Retail Rate (cents per kWh 2009$)	2.89	3.15	0.55	2.11	8.70
% Increase/Decrease over Current Retail Rate	-7.9%	22.3%	-5.3%	0.0%	3.5%
Increase/Decrease to Avg. Retail Rate Payer's Annual Electricity Bill	$ (29.95)	$ 68.89	$ (3.68)	$ -	$ 35.26

Figure 4.5-5 shows that the estimated rate under the Renewable Future to meet a 20% Federal mandate by 2024 is almost 14% higher than the current rate, representing nearly a $138 increase to the average retail bill. The generation and transmission capital components rate show a similar trend, as seen in the Reference Future, although at a much higher magnitude due to the increased wind capacity additions and associated transmission build-out required to meet the 20% Federal mandate. Also, as in the Reference Future, the Renewable Future shows a potential reduction in production cost partly offsetting the increase in generation and transmission capital investment as the share of energy met by wind is increased from approximately 2% currently to 20% in 2024.

Table 4.5-5: Comparison of Renewable Future Retail Rate to Current					
	Rate Component				
Retail Rate	Generation Capital	Generation Production	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh 2009$)	3.14	2.57	0.58	2.11	8.41
Reference Future Retail Rate (cents per kWh 2009$)	4.46	2.21	0.78	2.11	9.56
% Increase/Decrease over Current Retail Rate	42.0%	-14.3%	33.7%	0.0%	13.7%
Increase/Decrease to Avg. Retail Rate Payer's Annual Electricity Bill	$158.42	$ (44.01)	$ 23.55	$ -	$ 137.97

Figure 4.5-6 shows that the Environmental Future, which imposes a $25 cost per ton on CO_2 emissions, results in the largest potential impact to residential ratepayers with an estimated 22.5% increase. The main driver of the rate increase is the $25 cost per ton of CO_2 emissions representing approximately 87% of the total $227 annual rate increase, and 16.7% of the total retail rate. This impact assumes that 100% of the associated CO_2 costs are passed on to the retail rate payer. Part of the increased generation capital expenditures in the Environmental Future can be attributed to a switch from carbon-intensive generation types, like coal or gas, to increased nuclear capacity. Of the four Futures, the Environmental is the only one to see an increase in the share of energy met by nuclear, increasing by approximately 50%, due to the increased costs associated with carbon-intensive fuel types.

Table 4.5-6: Comparison of Environmental Future Retail Rate to Current						
	Rate Component					
Retail Rate	Generation Capital	Generation Production	CO_2 Emmissions Costs	Transmission	Distribution	Total
Midwest ISO Current Retail Rate (cents per kWh 2009$)	3.14	2.57	-	0.58	2.11	8.41
Reference Future Retail Rate (cents per kWh 2009$)	3.46	2.37	1.65	0.72	2.11	10.30
% Increase/Decrease over Current Retail Rate	10.0%	-7.9%	100.0%	22.8%	0.0%.	23.1%
Increase/Decrease to Avg. Retail Rate Payer's Annual Electricity Bill	$ 37.66	$ (24.26)	$ 198.00	$ 15.95	$ -	$ 227.35

The potential rate impacts from the four Future scenarios show that higher electricity rates are likely; however, the magnitude of the rate increase will vary greatly depending on the actual economic and policy situations that occur. The range of outcomes illustrates the importance of performing long-term scenario analysis to provide decision-makers with the necessary information to minimize the potential impacts to end-users in the form of higher rates.

4.6 Conditions Precedent to Transmission Investment

When compared to the generation costs, it is clear that transmission is but a small portion of the expected future cost for energy. However, despite the increased efficiency which well-planned transmission can bring, there are a number of barriers to increasing transmission build. The difficulty with procuring the necessary right of way, combined with the potential for transmission built in one state to provide as much benefit beyond state, or even Regional Transmission Organization (RTO), borders as it does within the states building the line, has caused widespread concern about the ability to build the infrastructure suggested by the preliminary value based transmission plans. The Midwest ISO recognizes that in order to build the enabling transmission to support future generation growth, and new energy policy, a number of conditions must first be met:

1. **A robust business case for the plan –** First and foremost, it must be demonstrated that the hypothesized benefits of any plan, including a fully developed transmission overlay, exists. This includes a thorough understanding of value drivers, underlying assumptions, and a complete evaluation of alternatives, including an alternative in which significant transmission infrastructure build out is not able to occur. Without appropriate benefits justification, it is not expected that a stakeholder such as a Transmission Owner would sponsor the plan. Nor would the state

regulators, who are the ultimate judge of whether a project justification is sufficient, be willing to approve.

2. **Increased consensus around regional energy policies –** Across the Midwest ISO, different states have different views around which benefits may 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. One example of this is the introduction of RPS across the Midwest ISO. There is a mismatch in the view of the needs for transmission to integrate renewable resources, with the divide largely along the dividing line between the states with RPS in place, or those without. The difference in public policy leads to different goals and requirements for the transmission level required; even a sub-regional consensus will go a long way to break the logjam around the build out of large transmission projects. In part, that is true because a sub-regional consensus makes it more likely that the third condition precedent can be achieved.
3. **A regional tariff that matches who benefits with who pays over time –** Over time, those paying for the increased transmission must derive proportional benefits to feel satisfied with the investment; this is particularly true in an RTO, where participation is voluntary. The question of determining beneficiaries becomes increasingly complex as the Midwest ISO seeks to incorporate a more complete set of value drivers, such as reflecting public policy drivers, into the transmission assessment process. The question of wind generation once again provides a straightforward example of the difficulties here. States with a high proportion of wind-rich sites may see significant benefit from the economic development that corresponds with the construction and operation of numerous new wind farms. States with RPS see benefit in sourcing greater proportions of energy from wind generators. States with a higher local generation cost may see benefits of sourcing lower cost wind generation from outside the local region. Other states may see no benefit, from a policy or economic perspective, of having access to increased levels of wind generation. Given all those viewpoints, the question of who pays for the required transmission infrastructure to integrate wind generation is a thorny problem. This is particularly true since wind generation is likely to require transmission build out in a location a number of states, or even an RTO, away from the expected beneficiaries.
4. **Cost recovery mechanisms that reduce financial risk –** Ultimately, the investors in the transmission projects must be assured of appropriate returns, commensurate with the risks faced and, in the case of regulated utilities, that the shareholders will not subsidize the rate payers.

It may be possible to proceed with some level of increased transmission build out after meeting a subset of these conditions. However, construction of an overlay system equivalent to the current interstate highway system will require all conditions to be met across the Eastern Interconnection.

Section 5: Midwest ISO System Information

5.1 Midwest ISO System Overview

Prior MTEP reports have provided statistics on new transmission plans. This report includes the same information in Section 2. In order to provide context to the new facility statistics associated with Appendices A, B, and C, MTEP 09 includes statistics on the existing transmission system which is under Midwest ISO functional control. Transmission Owners' facility lists are posted on the Midwest ISO website at http://www.midwestmarket.org/page/Transmission+Facilities. The transmission line, substation, and transformer statistics below are based on these function control listings.

5.1.1 Existing Transmission System Assets

Transmission Lines

Midwest ISO Transmission Owners[1] have transmission lines with operating voltages from 500 kV to 35 kV. Few Transmission Owners have 69 kV transmission under Midwest ISO functional control. Most utilities have significantly more line miles at the lower voltages (100 kV class) than higher voltages (345 kV). There are only 16 miles at the 35 kV class so it is not shown in the chart below. Total line mileages in all voltage classes are 51,300 miles. The figure below shows Midwest ISO Transmission Owners transmission line miles by voltage class which are under Midwest ISO functional control.

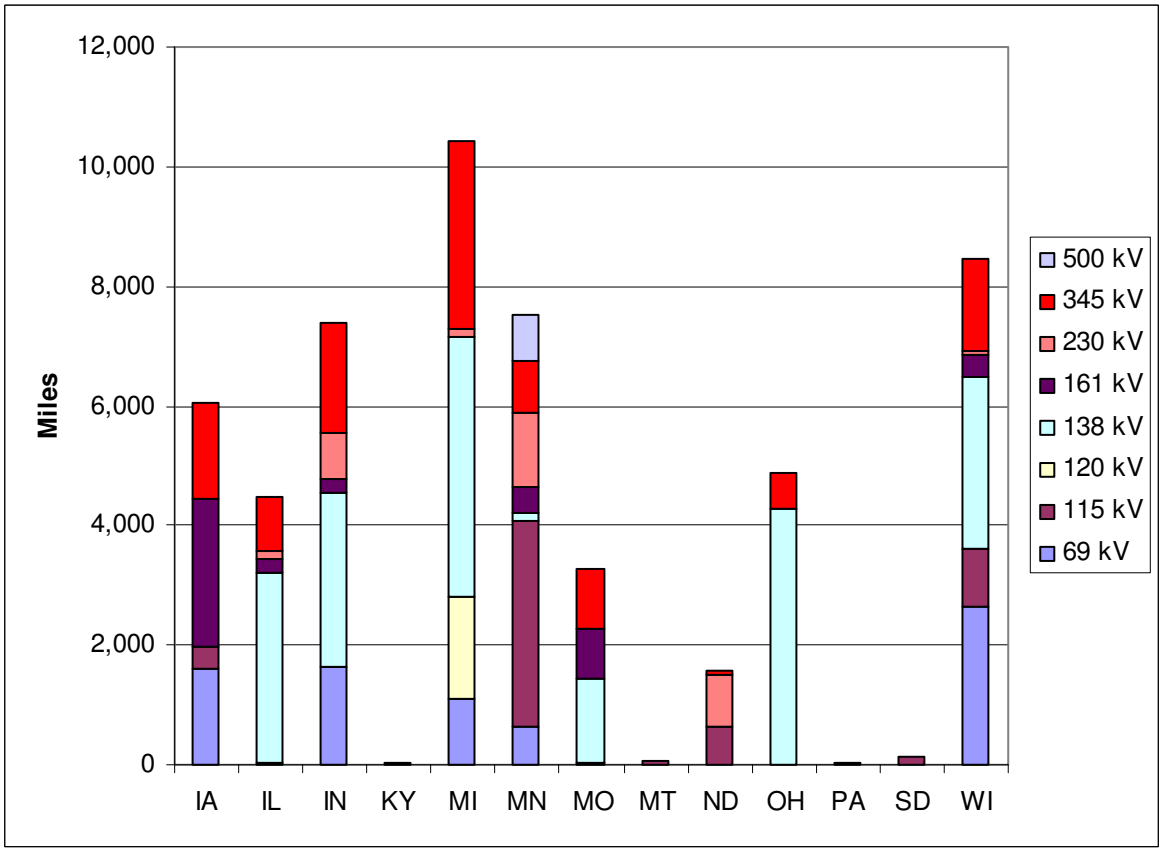


Figure 5.1-1: Transmission under Midwest ISO Functional Control by Voltage Class

[1] MidAmerican Energy, Muscatine Power & Water and Cedar Falls Utilities are Midwest ISO Transmission Owners, effective September 1, 2009. They did not participate in the MTEP09 planning cycle and their facilities are not included in these statistics.

The Midwest ISO is divided into three planning regions for MTEP purposes. Figure 5.1-2 shows that there are significantly more line miles in the West planning region, which is geographically larger.

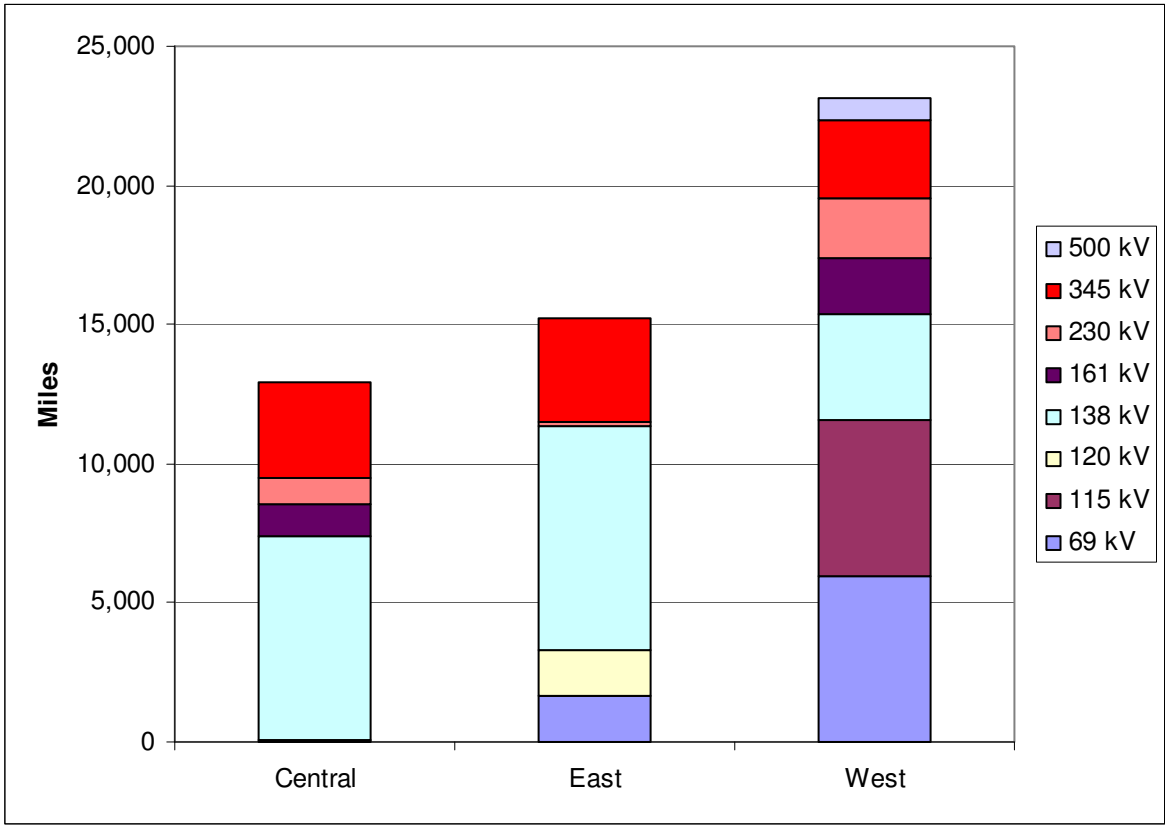


Figure 5.1-2: Transmission Under Midwest ISO Functional Control by Planning Region and Voltage Class

Transmission Substations

Transmission substations transform voltage from one level to another. As power moves closer to end users, the voltage is stepped down. Switching stations are substations without transformers which have multiple transmission line terminations. There are approximately 1,900 transmission substations and switching stations under Midwest ISO functional control. Figure 5.1-3 shows the number of substations and switching stations by state. Note that most utilities in Wisconsin have 69 kV transmission under Midwest ISO functional control, therefore, there are a lot of substations and switching stations at the 69 kV voltage level.

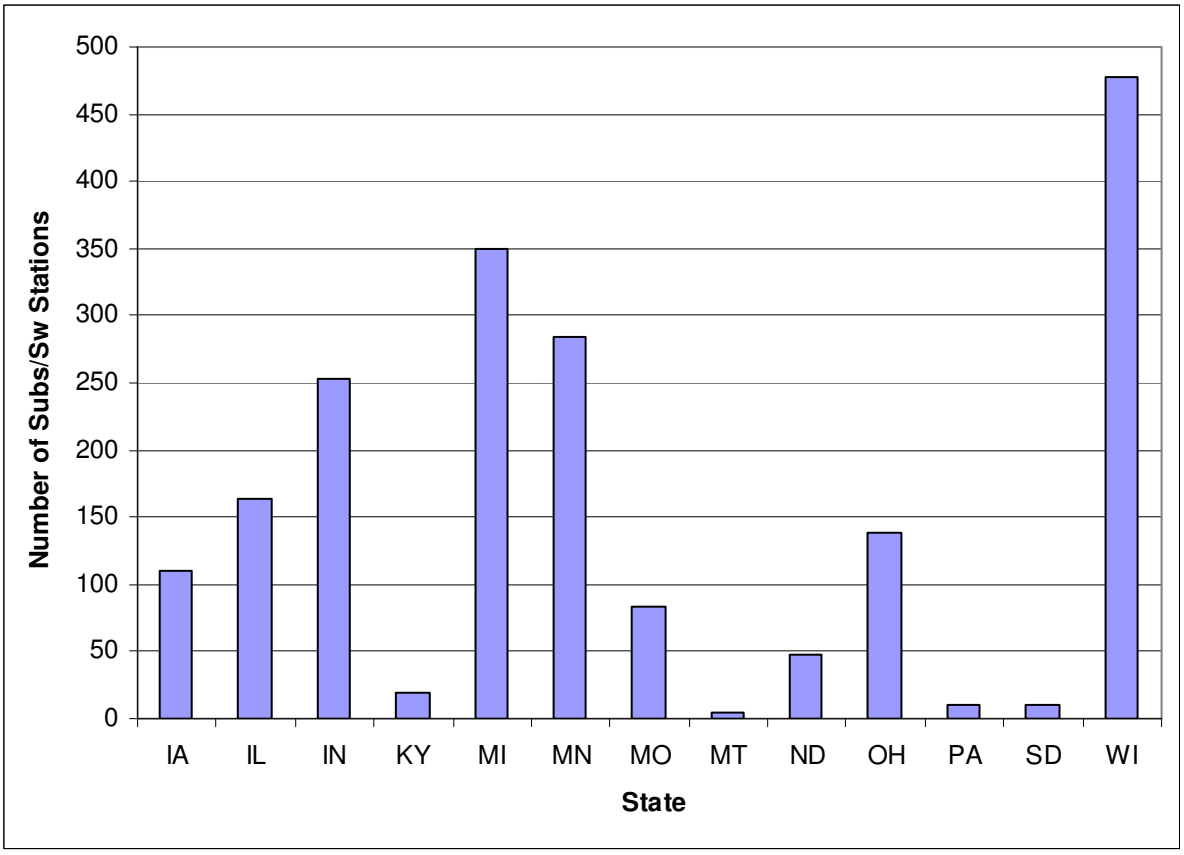


Figure 5.1-3: Substations & Switching Stations Under Midwest ISO Functional Control

Typical transmission substations have a high side voltage of 345 kV and a low side voltage of 115, 120, 138 or 161 kV. There are also 500/345 kV substations, 138/69 kV substations, and many other combinations. The table below shows the range of transmission transformers in Midwest ISO and the number of transformers at those voltage levels.

Table 5.1-1: Transmission Transformers Under Midwest ISO Functional Control

High Side kV	Low Side kV	Count	MVA
765	138	2	2,073
500	345	2	2,406
500	230	5	2,090
345	230	31	15,620
345	161	20	7,430
345	138	201	86,965
345	120	26	11,830
345	115	37	15,788
345	69	2	772
230	230	1	800
230	161	2	589
230	138	19	4,418
230	120	13	7,335
230	115	33	7,412
230	69	8	432
161	138	19	3,959
161	115	17	2,825
161	69	82	7,794
138	120	3	748
138	115	7	1,127
138	69	246	22,828
120	120	2	1,120
115	69	5	246
Transformer	**Totals**	**783**	**206,607**

Generating Plants

There are 432 generating plants in the Midwest ISO system with approximately 1,200 generating units at those plants. Figure 5.1-4 shows the distribution of those plants and units across the states within the Midwest ISO. Commercial Pricing Node information was used to produce the statistics, so exact number of units will vary. Wind plants are counted as a single unit per plant although they may have many individual turbines. Note that the large number of plants and units in Iowa and Minnesota is attributed, in part, to wind plants. The type and capability of the generation fleet is described in Section 5.1.2.

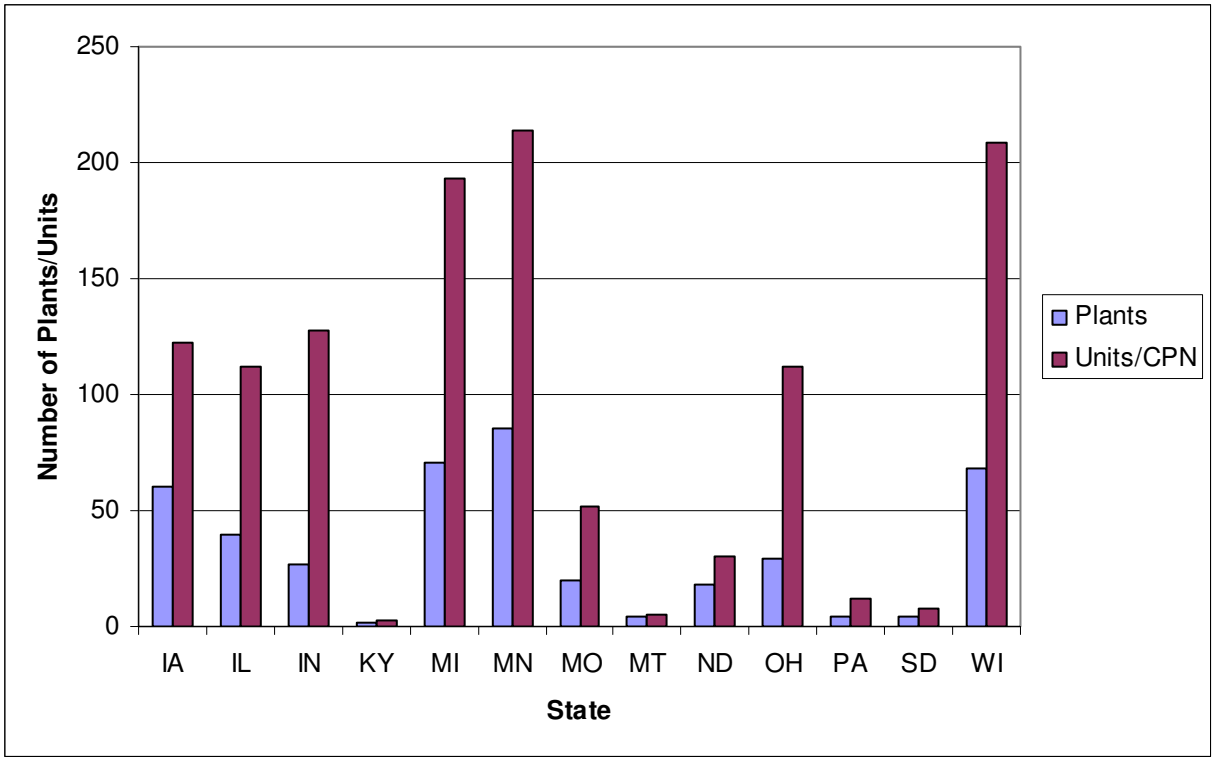


Figure 5.1-4: Generating Plants and Units

Reactive Resources

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

Table 5.1-2: Switched Shunts

kV	Cap (Mvar)	Reactor (Mvar)
500	600	
345	1157	-850
230	1227	-45
161	1019	-210
138	7506	-15
120	640	
118	32	
115	5528	-155
72	99	
69	6157	-36
60	7	
46	2713	
41.6	22	-5
36	525	
34.5	699	-257
27.6	537	
26.4	29	
26.2	313	
24.9	31	-125
23	142	
15	20	
14.4	77	
13.8	343	-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	12	
0.6	372	
0.575	49	
0.48	51	
Total	**30204**	**-2157**

5.1.2 Current System Demand and Capacity

Section 5.2 includes a detailed discussion on forecasted load and generation in the Midwest ISO market. However, the following subsections provide a snapshot of current supply and demand levels as part of the overview of the existing system.

Demand

The Midwest ISO Market's adjusted all-time peak demand of 109,157 MW occurred on 7/31/2006. Demand has declined each year since then and the current economic recession has resulted in a forecasted 2009 demand of 95,890 MW for the Midwest ISO, well below the peak demand that was forecasted for 2009 when this analysis was performed in 2008. Figure 5.1-5 shows the actual peak load levels from 2005 through 2008 and the forecasted probable peak load levels from 2009 to 2018. The 90/10 and 10/90 bands are industry standards for high and low (respectively) load conditions. These high and low levels create a larger bandwidth of possible load conditions that account for volatility in load forecasts. The decreased demand forecast is primarily reflective of the Midwest ISO members' expectation of a slow recovery of demand based on current economic conditions and the associated decreased load level.

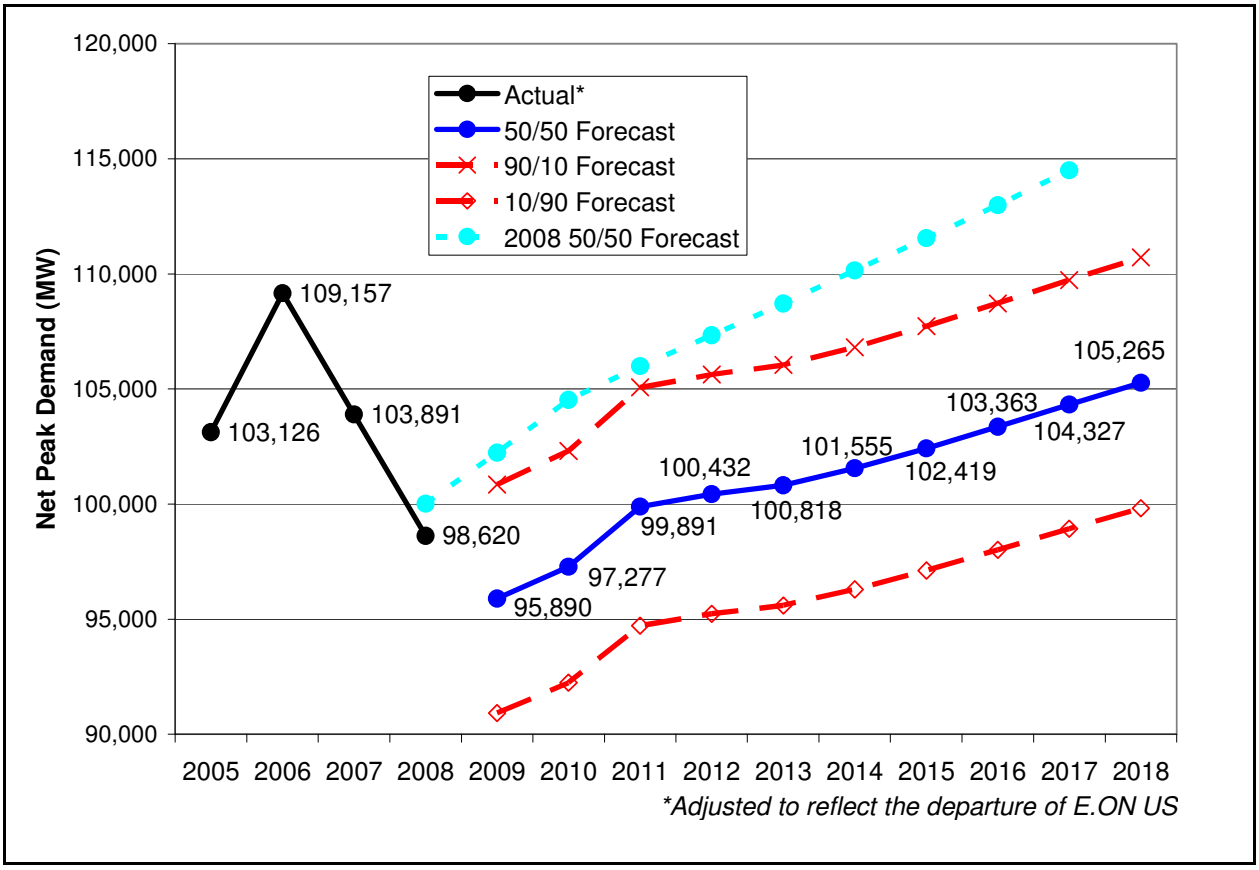


Figure 5.1-5: Historical and Forecasted Peak Demands

Capacity Resources

Nameplate capacity in the Midwest ISO of 131,308 MW is expected to be available in 2009. Coal-fired facilities represent over 50% of the capacity resources within the Midwest ISO Market. Gas fueled units account for another 25% of the fleet. In recent years, the number of wind farms, and run-of-river hydro facilities, has increased to meet renewable mandates. The Midwest ISO experienced a 1,941 MW, or 68% growth, in the amount of nameplate wind capacity during 2008. A breakdown of the 2009 nameplate rated capacity can be seen in Figure 5.1-6. The waste units are composed of four refuse-derived fuel plants, two wood waste burners, and one turkey waste plant.

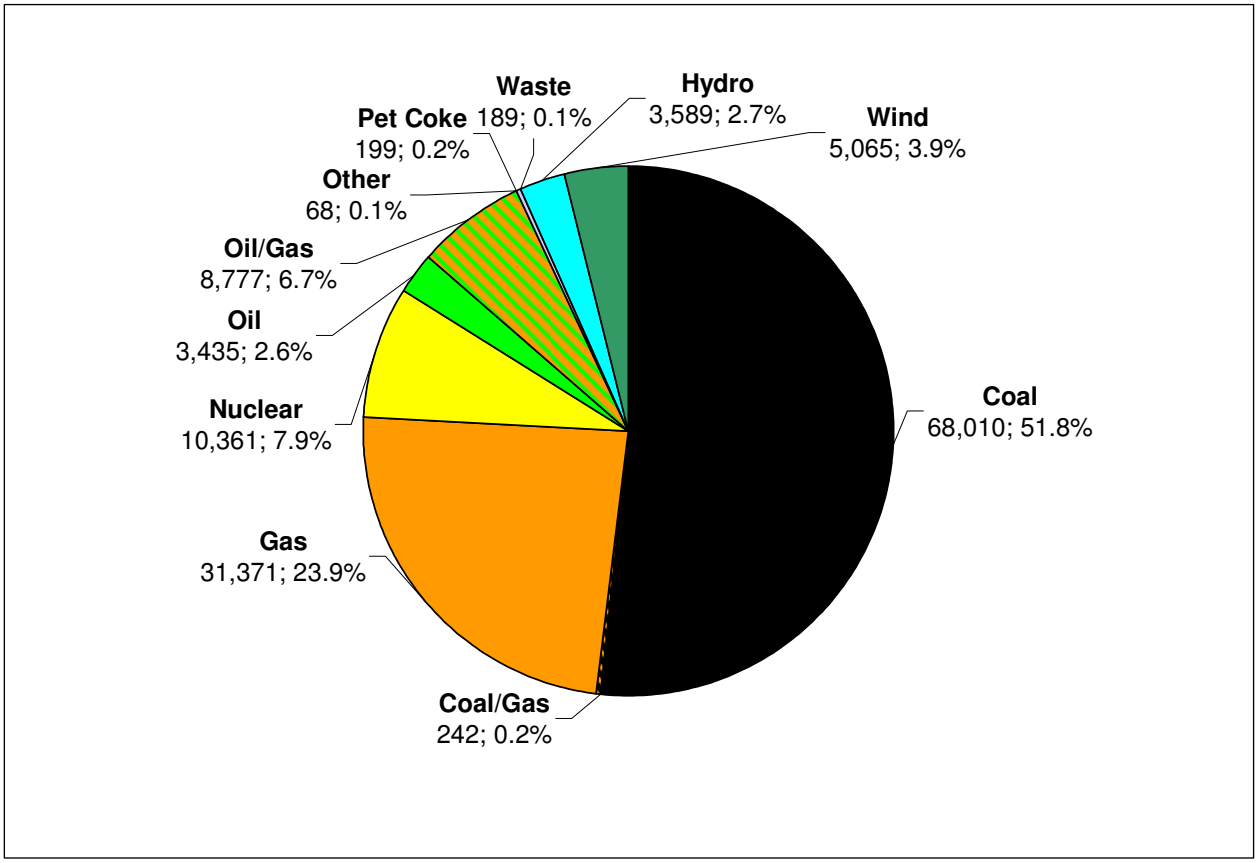


Figure 5.1-6: 2009 Nameplate Capacity by Fuel Type

The age of the generation fleet is becoming an issue of greater importance. Currently, the majority of baseload units within the Midwest ISO are 30 to 40 years old. By the year 2018, approximately 60% of the generation fleet will be at least 40 years old. Coal units, which make up over 50% of the fleet, and much of the baseload capacity, will have an average age of 47 years in 2018. As this capacity continues to age, without appropriate upgrades, maintenance, or replacements, the probability of retirement and higher forced outage rates increases. Figure 5.1-7 outlines the age of units within the generation fleet by fuel type.

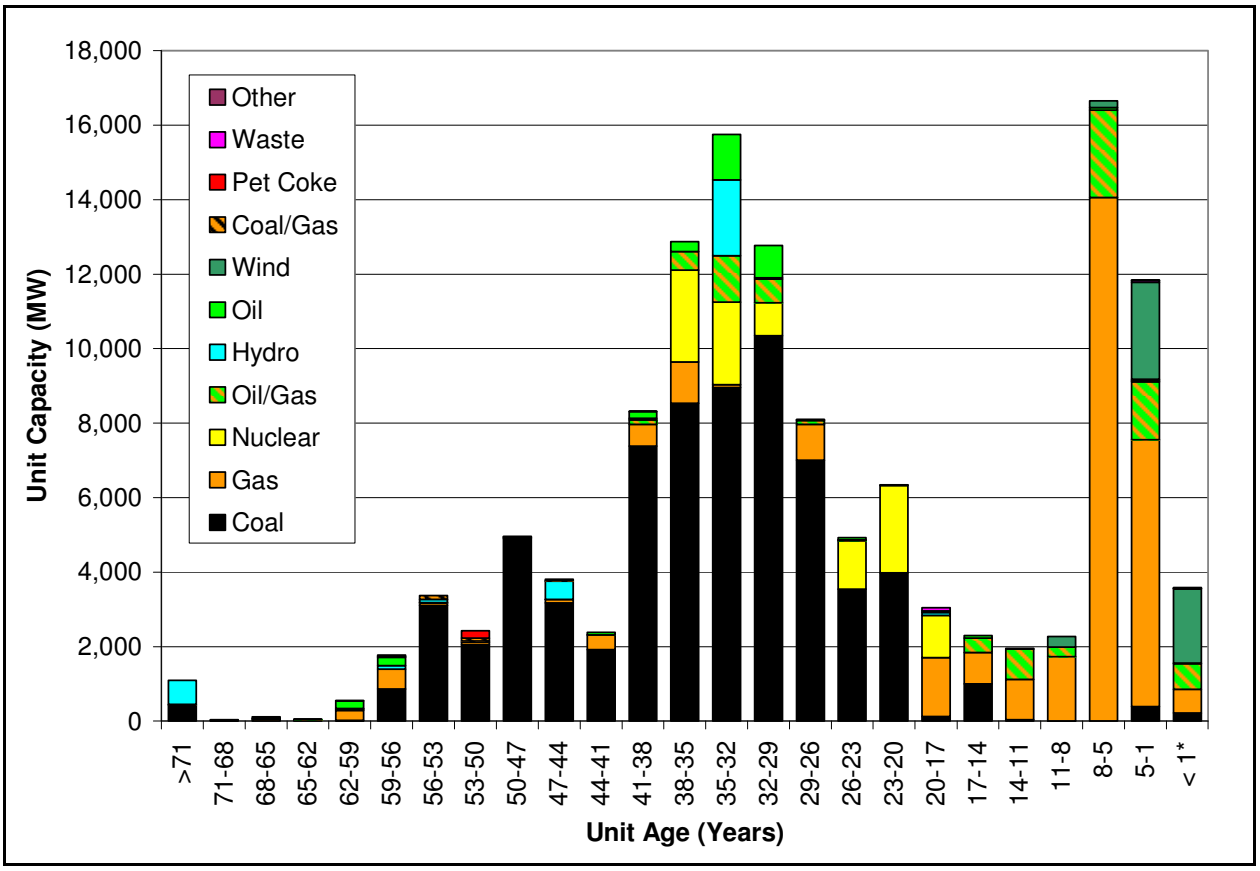


Figure 5.1-7: Age of Generation Fleet by Fuel Type
* - indicates data includes units with in service dates beyond 2008

5.2 Load and Generation Forecast

The following section contains the ten-year load and generation forecast for the Midwest ISO Market Footprint referenced from the Midwest ISO Long-Term Reliability Assessment. A complete version of the Midwest ISO Long-Term Reliability Assessment can be found at:

http://www.midwestmarket.org/page/Regulatory+and+Economic+Standards

5.2.1 Demand

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

Gross Demand Forecast

The demands as reported by Network Customers are weather normalized, or 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, seasonal peak load forecast is created on a regional basis by summing the coincident seasonal forecasts for the individual Load Serving Entities (LSE) in the larger regional area of interest. Table 5.2-1 compares the non-coincident peak gross demand forecasts collected in the 2009 data request to the forecast collected through the 2008 data request. The 2009 data collection non-coincident peak forecast is organized by Midwest ISO Planning Regions.

Table 5.2-1: Non-Coincident Peak Demand Forecasts

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	31,536	31,946	33,344	33,863	34,316	34,702	35,134	35,561	36,010	36,413
East	38,112	38,400	39,355	39,346	39,342	39,369	39,468	39,628	39,818	40,018
Central	37,501	38,252	38,633	38,688	38,642	39,002	39,374	39,773	40,142	40,520
Midwest ISO	107,149	108,599	111,332	111,897	112,301	113,072	113,976	114,962	115,970	116,951
2008 Forecast	**114,831**	**117,167**	**118,774**	**120,191**	**121,626**	**123,131**	**124,658**	**126,174**	**127,780**	

Historically, the Midwest ISO has experienced between a 1.5% and 2.0% load growth rate; however, the current recession has had a significant effect on the load forecast for 2009. Since 2008, the downturn in the economy has resulted in the closing, or reduction in production, of many major commercial load customers. There was a 4.93% reduction in the gross demand forecast for the 2008 summer season (not displayed in Table 5.2-1). While compiling this forecast, the current economic conditions were often cited as a major uncertainty in determining growth rates. Currently, the consensus of the group seems to be a load growth rate indicative of a recovery within the next two years followed by roughly a 1% growth for the next eight years.

Using four years of historic market data, a load diversity factor was calculated by observing the individual peaks of each load zone and comparing against the system peak for the load zone. When aggregated, there is a 0.96 diversity factor applied to the peak. The same diversity factor was applied to all ten years. As shown in Table 5.2-2, the gross coincident demand forecast ranges from 102,477 MW in 2009 to 111,852 MW in 2018, which ranges from 5% to 8% lower than 2008 forecasts with the out years having a larger difference due to a lower growth rate in the 2009 forecasts.

Table 5.2-2: Coincident Peak Demand Forecasts

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Midwest ISO	102,477	103,864	106,478	107,019	107,405	108,142	109,006	109,950	110,914	111,852
2008 Forecast	**108,255**	**110,293**	**112,537**	**114,080**	**115,441**	**116,839**	**118,265**	**119,732**	**121,188**	

Demand Response Programs

With the update to the Module E process of load and resource reporting there has been a decline in reported demand response programs. Programs may already be reflected in a gross load forecast resulting in a more significant drop in gross load forecast versus net load forecasts.

The Midwest ISO currently separates demand response into two separate categories: Direct Controlled Load Management and Interruptible Load.

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, air conditioner interruption programs account for the vast majority of DCLM during the summer months. Table 5.2-3 details the reported 2009 data request DCLM forecast by Planning Region and compares it to the total 2008 data request forecast.

Table 5.2-3: Direct Controlled Load Management Forecasts

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	218	218	218	218	218	218	218	218	218	218
East	242	242	242	242	242	242	242	242	242	242
Central	150	150	150	150	150	150	150	150	150	150
Midwest ISO	610	610	610	610	610	610	610	610	610	610
2008 Forecast	**1,775**	**1,811**	**1,834**	**1,849**	**1,862**	**1,869**	**1,877**	**1,885**	**1,887**	

Interruptible Load (IL) is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator.

As shown in Table 5.2-4, there has been over a 1,000 MW decrease in the amount of reported interruptible load from the 2008 data request. The majority of this decease can be attributed to the change in reporting procedures utilized this year as compared to last. It should be noted that with the economic downturn a decrease in interruptible programs may be experienced due to industrial plant shut downs.

Table 5.2-4: Interruptible Load Forecasts

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	810	810	810	810	810	810	810	810	810	810
East	535	535	535	535	535	535	535	535	535	535
Central	417	417	417	417	417	417	417	417	417	417
Midwest ISO	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762	1,762
2008 Forecast	**2,899**	**2,814**	**2,861**	**2,858**	**2,875**	**2,854**	**2,908**	**2,925**	**2,941**	

Behind-the-Meter Generation

In the Midwest ISO, there is approximately four GW of generation capacity that Market Participants designate as a capacity resource, which does not participate in the Market. This capacity is referred to as Behind-the-Meter (BTM) Generation. BTM Generation has been historically considered a load reduction, however, due to a recent FERC order it is now accounted for as a capacity addition. Table 5.2-5 details the amount of BTM Generation designated on summer peak from 2009 to 2018.

Table 5.2-5: Behind-the-Meter Generation

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
East	1,918	1,918	1,918	1,918	1,918	1,918	1,918	1,918	1,918	1,918
Central	1,298	1,298	1,298	1,298	1,298	1,298	1,298	1,298	1,298	1,298
Midwest ISO	4,216	4,216	4,216	4,216	4,216	4,216	4,216	4,216	4,216	4,216
2008 Forecast	**3,381**	**3,385**	**3,396**	**3,399**	**3,391**	**3,395**	**3,394**	**3,401**	**3,405**	

Net Internal Demand

Net Internal Demand is the coincident gross demand forecast less demand response programs as seen in the Figure 5.2-1 formula. During peak conditions, Behind the Meter Generation 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 BTM generation 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 response programs are reducing demand at the reported levels during the system peak. If during the system peak there is adequate capacity, it is not expected that all demand side management programs will be executed, causing the actual load to be in excess of the demand forecasts. During the all-time peak on July 31, 2006 the Midwest ISO experienced 3,047 MW of Demand Side Management executions and BTM Generation caused load to reduce by an additional 2,705 MW. Market Participants reported approximately 3,500 MW of Demand Side Management and 2,700 MW of BTM Generation in the 2006 Data Request.

Coincident Net Demand = Coincident Gross Demand - DCLM - IL

Figure 5.2-1: Coincident Net Internal Demand Formula

Probable Peak Load = Coincident Gross Demand - DCLM – IL – BTM Generation

Figure 5.2-2: Probable Peak Load

The projected Net Internal Demand for the Midwest ISO Market ranges from 100,106 MW for the summer of 2009 to 109,481 MW in 2018. A much lower gross demand forecast has resulted in a significant decrease in net load levels from last year's forecasts. Table 5.2-6 details the 2009 and 2008 data request coincident Net Internal Demand forecasts. The average coincident ten-year Net Internal Demand growth rate from Midwest ISO Market Participant supplied forecasts is 1.0%.

Table 5.2-6: Coincident Net Internal Demand Forecasts

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Midwest ISO	100,106	101,493	104,107	104,648	105,034	105,771	106,635	107,579	108,543	109,481
		1.4%	2.6%	0.5%	0.4%	0.7%	0.8%	0.9%	0.9%	0.9%
2008 Forecast	**105,619**	**107,912**	**109,385**	**110,726**	**112,102**	**113,542**	**114,947**	**116,378**	**117,902**	

The Midwest ISO Market's adjusted all-time peak demand of 109,157 MW occurred on 7/31/2006. The current economic recession has resulted in the Midwest ISO forecast not reaching those same levels within the next ten years. Figure 5.2-3 shows the actual peak load levels from 2005 through 2008 and the forecasted probable peak load levels from 2009 to 2018. The 90/10 and 10/90 bands are industry standards for high and low (respectively) load conditions. These high and low levels create a larger bandwidth of possible load conditions that account for volatility in load forecasts.

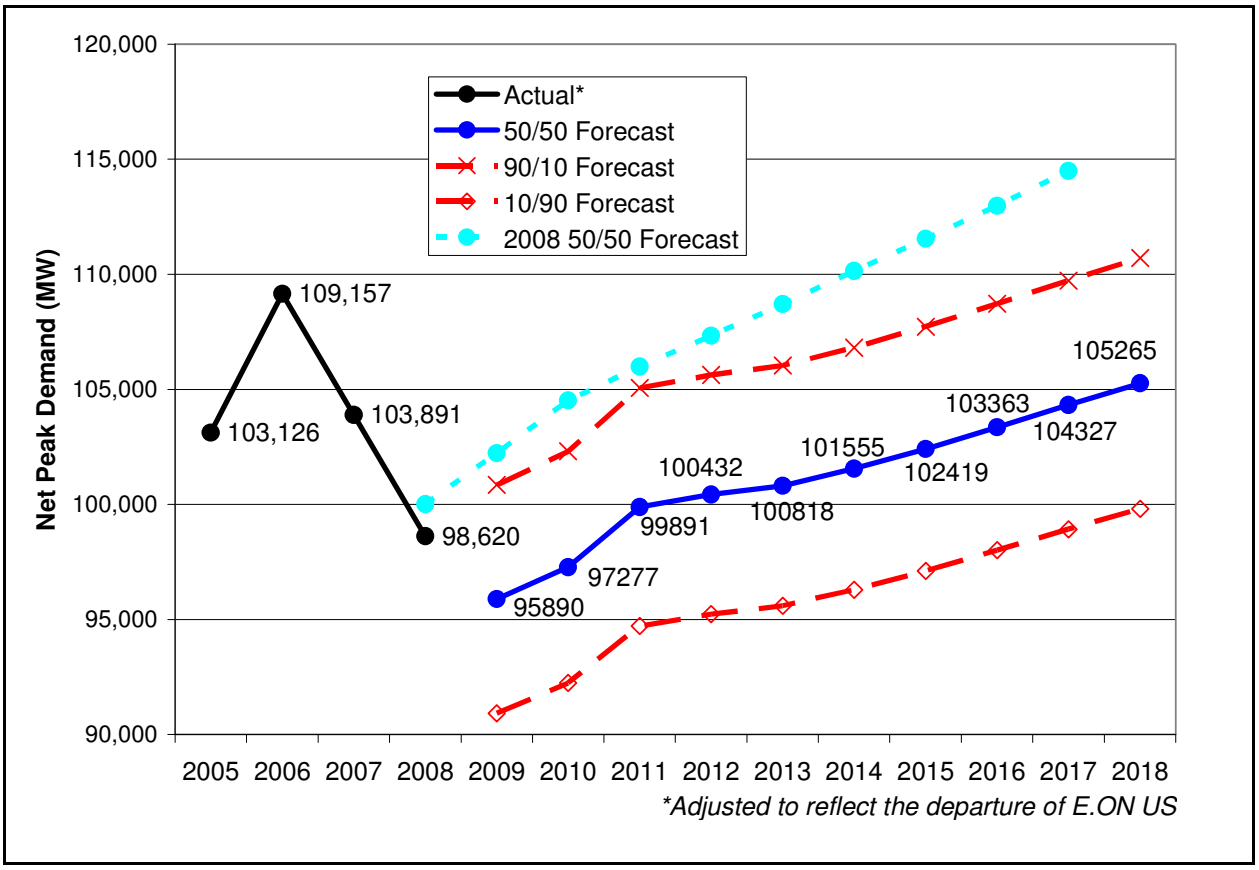


Figure 5.2-3: Historical and Forecasted Peak Demands

5.2.2 Capacity Resources

This section utilizes capacity values derived from various sources in order to produce a detailed analysis of the resource adequacy for the next ten years. Member reported data, nameplate capacities and historical analysis provide for a varied look at the 2009 baseline capacity levels. The Midwest ISO Generator Interconnection Queue is used to identify future unit expansions.

2008 Baseline Capacity Levels

To create an accurate capacity projection, a reliable first year baseline capacity must be established. The following sections detail derates, outages, and import capability expected during the 2009 peak.

Midwest ISO Generation

Nameplate capacity of 131,308 MW is expected to be available in 2009 in the Midwest ISO. Coal-fired facilities represent over 50% of the capacity resources within the Midwest ISO Market. Gas fueled units account for another 25% of the fleet. In recent years, the number of wind farms and run-of-river hydro facilities has increased to meet renewable mandates. The Midwest ISO experienced a 1,941 MW or 68% growth in the amount of nameplate wind capacity from 2008. A breakdown of the 2009 nameplate rated capacity can be seen in Figure 5.2-5. The waste units are composed of four refuse derived fuel plants, two wood waste burners, and one turkey waste plant.

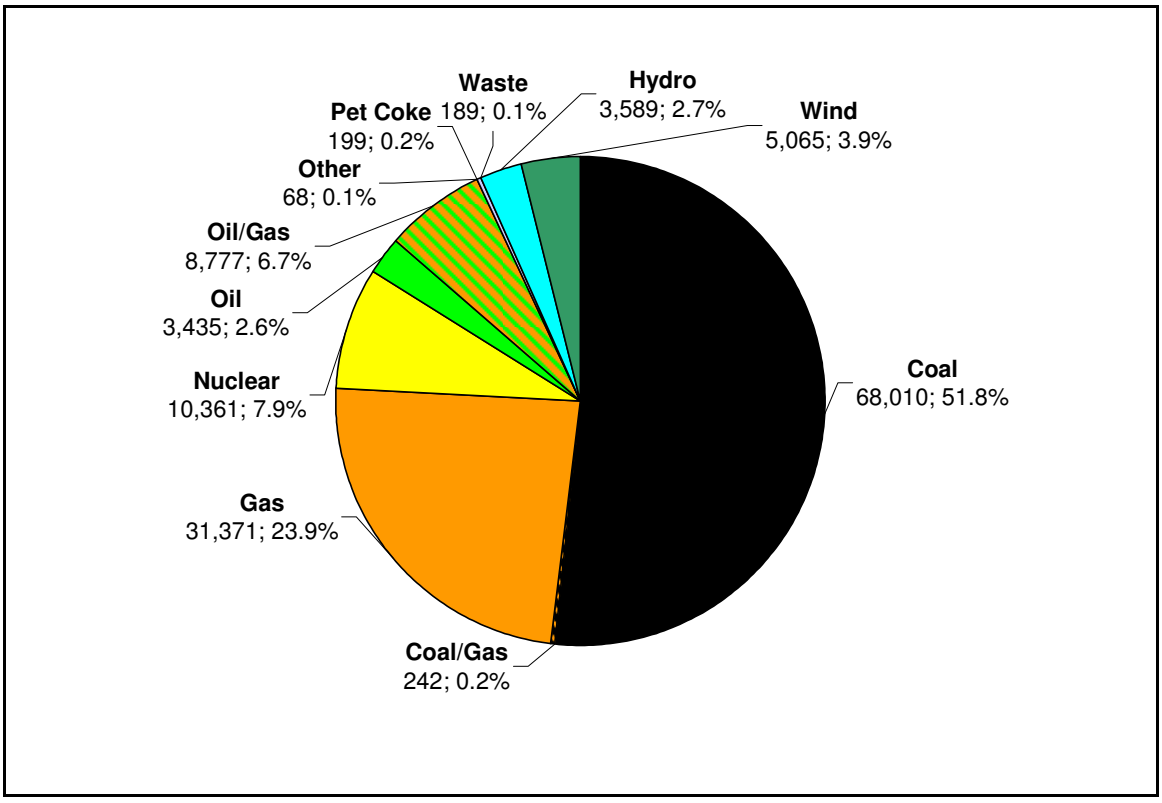


Figure 5.2-4: 2009 Nameplate Capacity by Fuel Type

Out-Year Proposed Generation

Currently, there are 283 projects within the Midwest ISO Generator Interconnection Queue which are being considered for additions throughout the Long Term Reliability Assessment (LTRA). These additions total 65.2 GW. Of the 283 projects, 244 of them are proposed wind plants which total 50.1 GW (nameplate capacity).

Because of the intermittent nature of proposed wind and run-of-river hydro units, a summer capacity credit was applied. Proposed wind units were given a 20% peak capacity credit factor and a 50% peak capacity credit was applied to proposed run-of-river hydro plants. Empirical data indicates that the variability of wind output makes it unlikely that 20% of its nameplate rated capacity will actually be available at peak in spite of that number representing an "average" value. Statistical analysis will be undertaken to further explore the risk profile of wind capacity, and adjustments will be proposed if necessary to accurately reflect its contribution to resource adequacy.

Even though 283 projects are currently being analyzed for inclusion within the LTRA, there is only a certain percentage of each type of project that results in the addition of actual capacity to the Midwest ISO footprint. Confidence factors are used to describe the probability that capacity with a specific queue status will be built. Because each fuel type has different necessities for interconnection, confidence factors were calculated for each fuel type using historic data. Table 5.2-8 provides the confidence factors by fuel type for units with and without interconnection agreement status distinction. When all fuels are weighted and totaled, units with a signed Generator Interconnection Agreement (GIA) have a total confidence factor of 80% and all queued units (signed GIA plus non-signed GIA) have an equivalent 20% confidence factor.

Table 5.2-8: Confidence Factors by Fuel Type

Fuel Type	Signed IA	All Queued
Coal	79.6%	15.6%
Gas	91.7%	23.9%
Hydro	46.0%	4.1%
Nuclear	46.0%	43.2%
Oil	100.0%	74.5%
Wind	66.2%	18.9%
Other	100.0%	9.0%
TOTALS	**80%**	**20%**

Figure 5.2-5 provides a timeline of cumulative active queued capacity additions for the Midwest ISO. This included all units within the queue process.

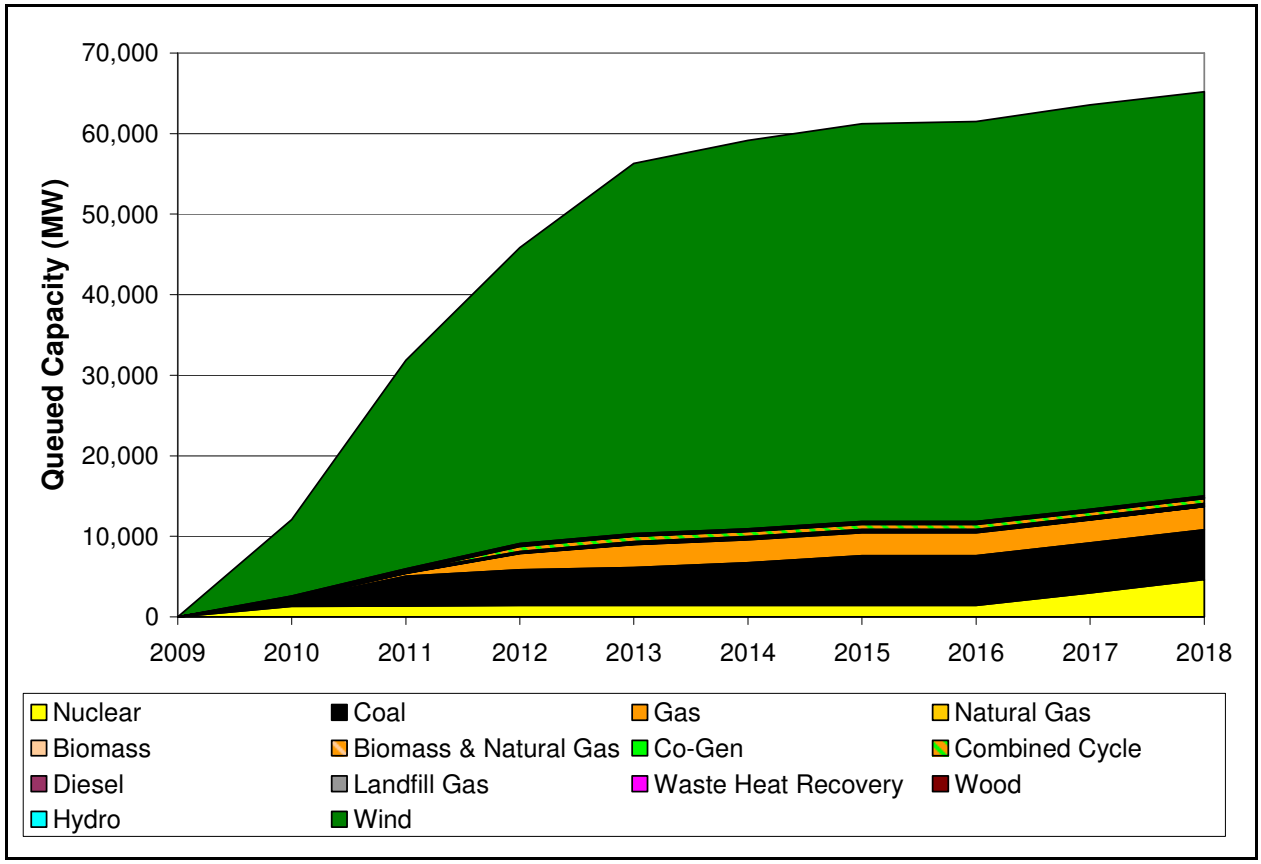


Figure 5.2-5: Midwest ISO Total Cumulative Queued Capacity

By applying the confidence intervals previously discussed to the entirety of the Queue represented in Figure 5.2-5 the timeline in Figure 5.2-6 is obtained.

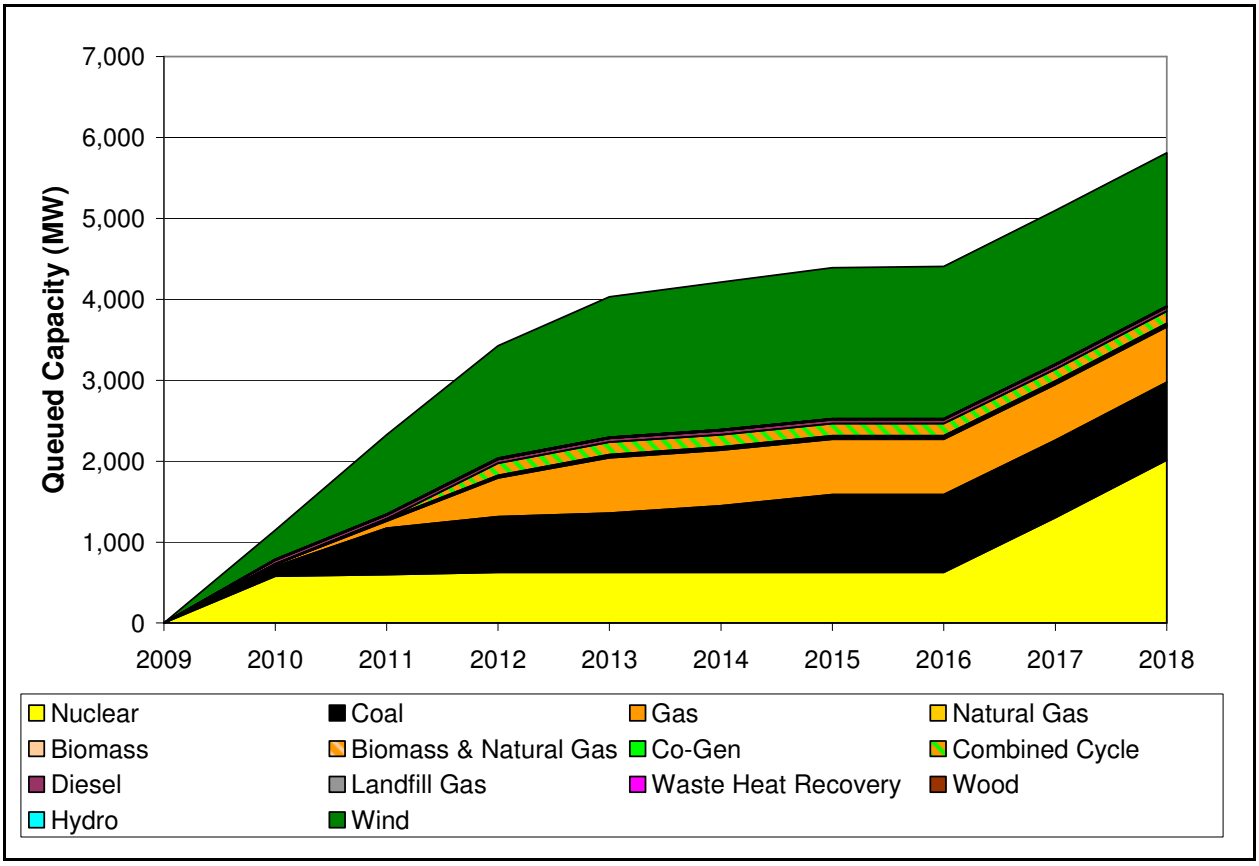


Figure 5.2-6: Midwest ISO Cumulative Queued Capacity with Confidence Interval

Of the 283 active queued capacity projects, there are 19 projects with a signed Generator Interconnection Agreement (GIA) and an expected in-service date prior to 2018. These projects are expected to add 3,256 MW of additional capacity to the Midwest Market footprint. The expected capacity additions are primarily composed of coal projects totaling 1,575 MW. Gas fueled combined cycle projects amount to 830 MW and proposed signed GIA wind units total 847 MW.

Figure 5.2-7 provides a timeline of cumulative active queued capacity additions with a signed GIA for the Midwest ISO.

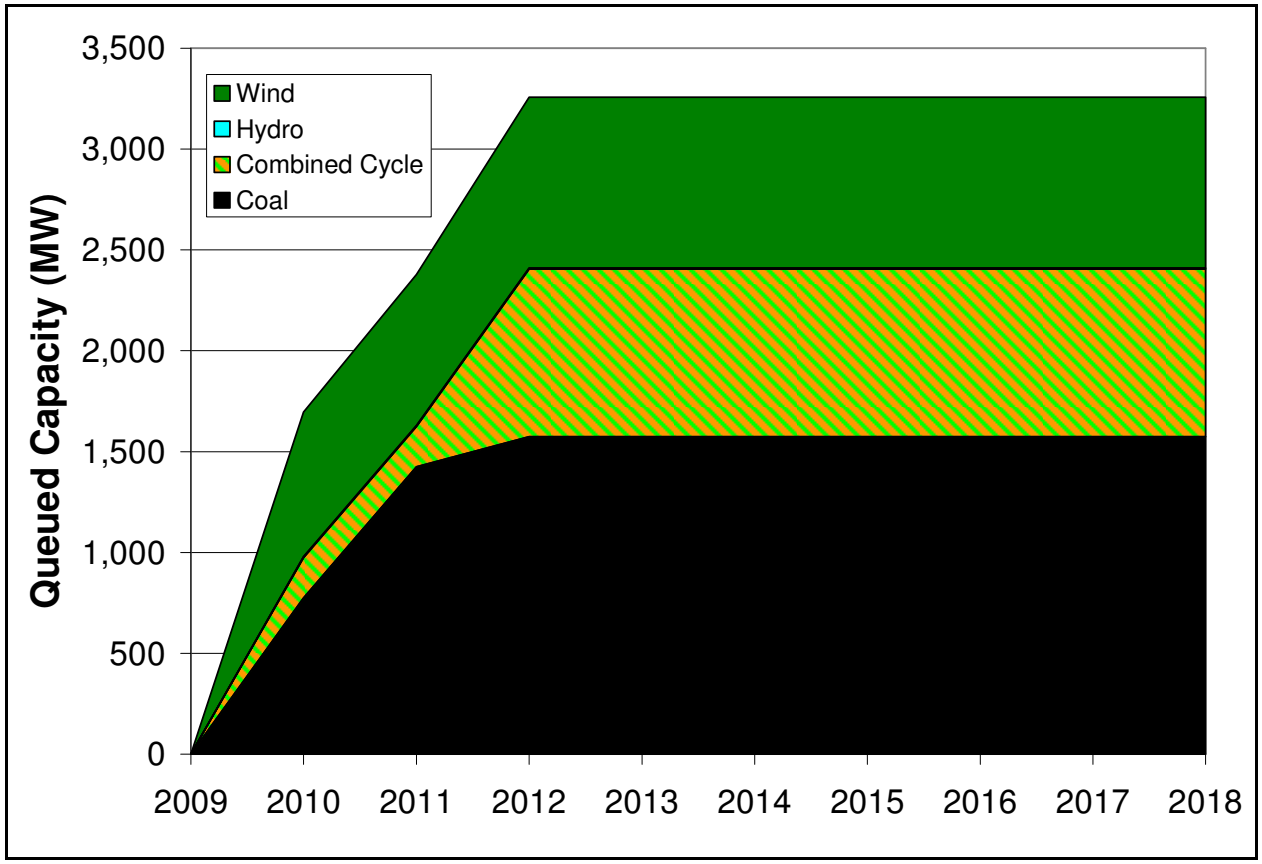


Figure 5.2-7: Midwest ISO Signed IA Cumulative Queued Capacity

Projected Capacity

Currently, there is 131,308 MW of capacity that is expected to provide energy to the Midwest ISO during summer peak conditions. In order to establish a projected out year capacity fuel breakdown, the confidence factors are utilized.

The forecasted capacity is attained by adding generation in the queued generation with a confidence factor applied and removing units with a retirement date prior to 2018. Applying confidence factors to the appropriate queued statuses and fuel types yields generation expansions totaling 2,491 MW, using the confidence factors on signed GIA queued capacity, and 5,811 MW, using the confidence factors on all queued capacity over the ten-year horizon.

Since the 2008 summer period, 235 MW of capacity was retired or reclassified; however, projecting retirements for the next ten years is very difficult to determine, because most Market Participants do not wish to disclose such market sensitive information. For the purposes of this assessment, no units were assumed to retire.

Figures 5.2-8 and 5.2-9 break-down the forecasted 2018 capacity by fuel type. Figure 5.2-8 includes signed GIA queued units, with the appropriate confidence factors applied, and totals 133,798 MW. Figure 5.2-9 utilizes all queued capacity units, with corresponding confidence factors applied, and totals 137,119 MW. In both cases the predominant fuel type is coal, accounting for approximately 50% of the total capacity. The largest change during the ten year span is in the amount of wind generated capacity.

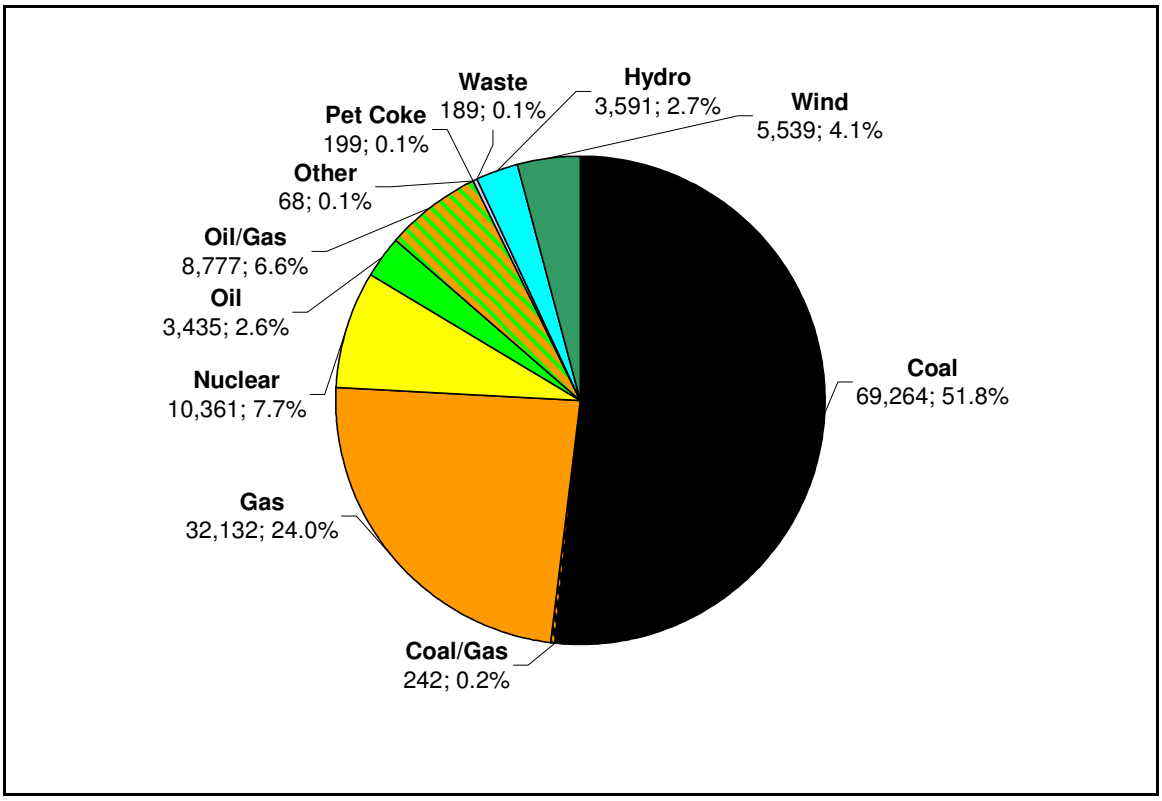


Figure 5.2-8: 2017 Projected Capacity by Fuel Type – Signed GIA

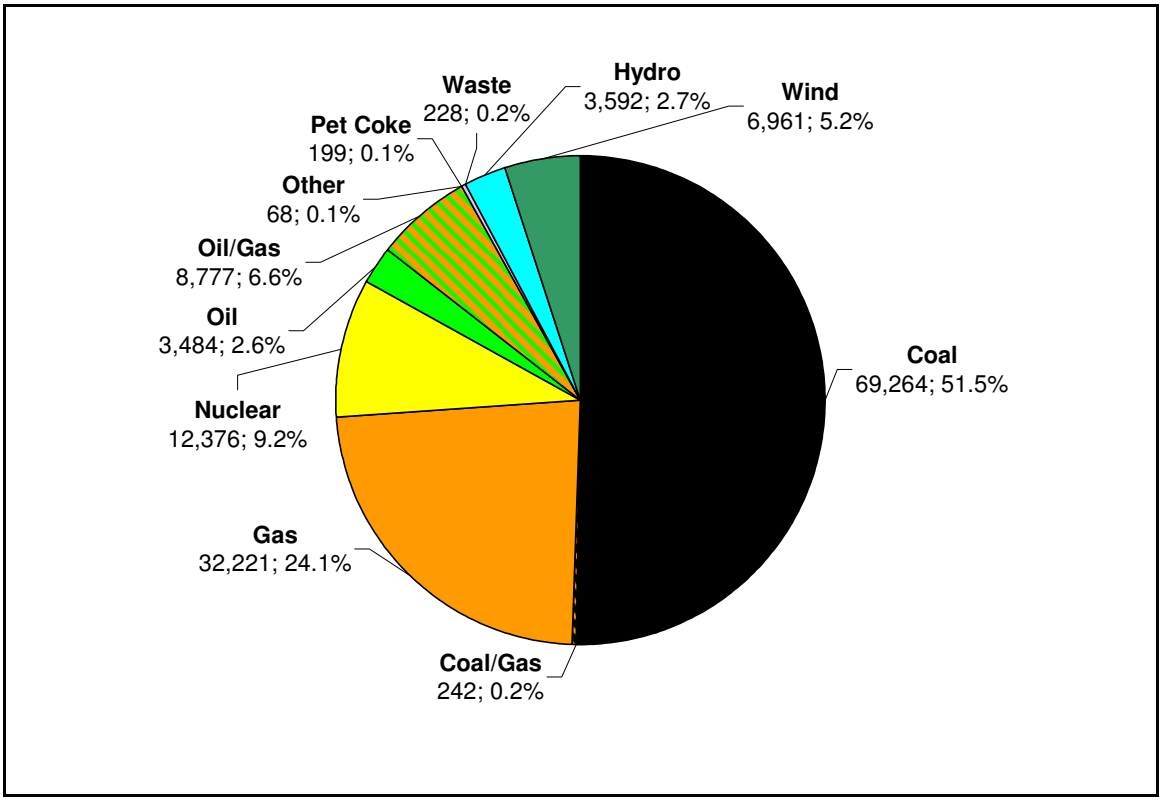


Figure 5.2-9: 2017 Projected Capacity by Fuel Type – All Queue Entries

Age of Generation Fleet

Currently, the majority of baseload units within the Midwest ISO are 30 to 40 years old. By the year 2018, approximately 60% of the generation fleet will be at least 40 years old. Coal units which make up over 50% of the fleet and much of the baseload capacity will have an average age of 47 years in 2018. As this capacity continues to age, without appropriate upgrades or maintenance the probability of retirement and higher forced outage rates increases. Figure 5.2-10 outlines the age of units within the generation fleet by fuel type.

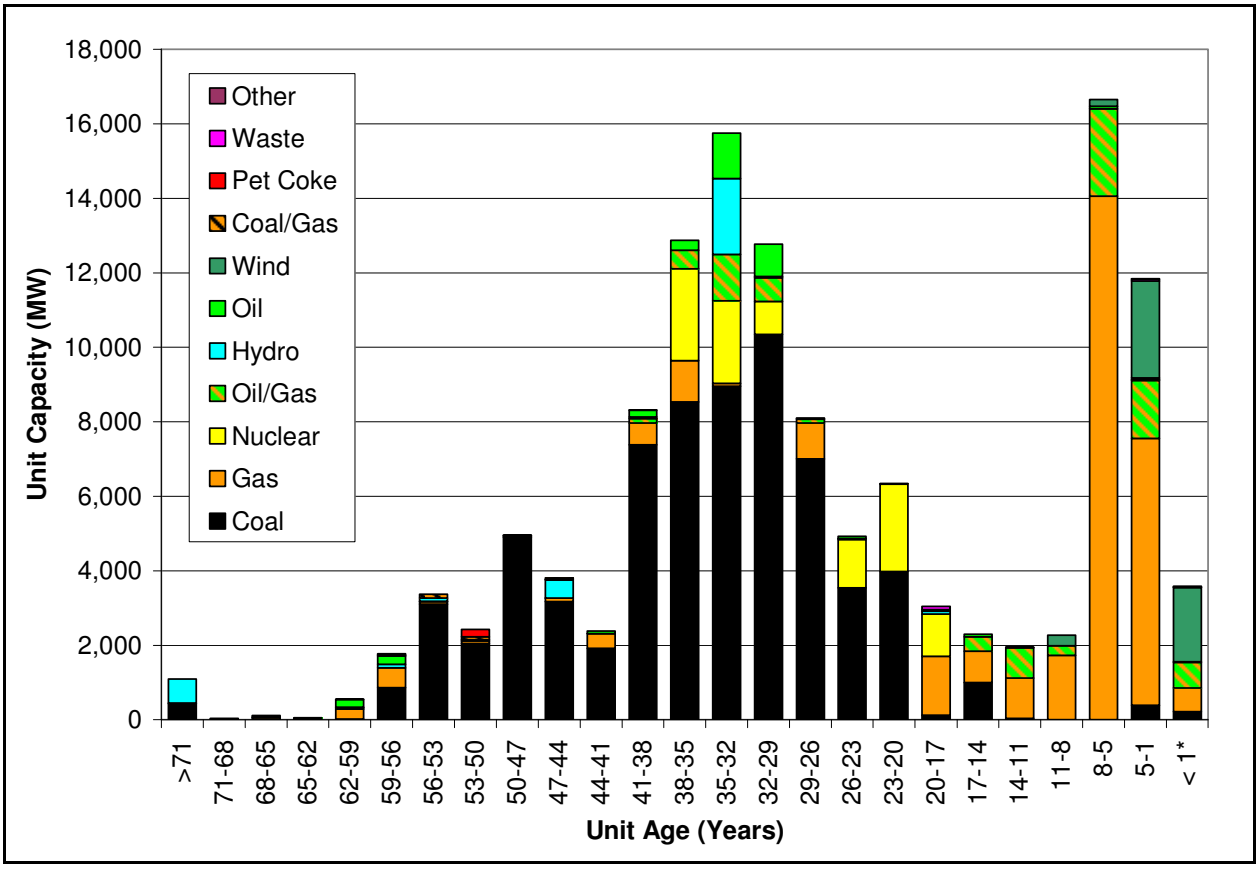


Figure 5.2-10: Age of Generation Fleet by Fuel Type

* - indicates data includes units with in service dates beyond 2008

5.3 Reserve Margin Requirements

A study conducted by the Midwest ISO has determined a planning reserve margin equal to 12.69% of the non-coincident net load forecasts submitted by Load Serving Entities. This study was conducted by the same engineering staff which conducted the Midwest Planning Reserve Sharing Group (PRSG) study for the 2008-2009 planning year and was supported by much of the same membership.

This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD® was used to perform a security constrained economic dispatch which provided the congestion driven zonal definitions used within MARS.

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves that would result in the system experiencing one loss of load event every ten 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 every year. As modeled within the GE MARS software, the system would achieve this reliability level when the amount of capacity available is 1.1269 times that of the non-coincident load forecasts.

Within Module E, individual Load Serving Entities (LSEs) maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 2.35 % diversity factor. This was the lowest diversity experienced on the system since Midwest ISO market start and resulted in an individual LSE reserve level of 12.69%. This value is comparable to previous reserve margins averaging 14.5% and is made possible by the large size of the Midwest ISO footprint and the inherent diversity.

A complete report on the Midwest ISO Loss of Load Expectation study can be found on the Regulatory and Economic Standards page of the Midwest ISO website under Module E heading at the following link.

http://www.midwestiso.org/page/Regulatory+and+Economic+Standards

5.3.1 Module E Verification Process

The Midwest ISO performs an evaluation each month to determine if all load serving entities within the Midwest ISO Balancing Authority have sufficient qualified capacity to meet their planning reserve requirement. The Midwest ISO determines a load service entity's planning reserve requirement by applying the planning reserve margin that was determined through the annual Loss of Load Expectation study. Midwest ISO determines whether a generation resource or demand response qualifies as capacity under Module E: Resource Adequacy of the Midwest ISO Tariff. Capacity that meets the Tariff terms and conditions to qualify as capacity is referred to as either accredited capacity or a Planning Resource Credit (PRC). Midwest ISO Market Participants use Planning Resource Credits as their commodity for commercial capacity transactions.

Midwest ISO uses the Module E Capacity Tracking Tool (MECT) to allow Midwest ISO Market Participants to confirm the transfer of Planning Resource Credits, and provide instantaneous status for load serving entities whether they have sufficient planning reserve listed in their resource plan. The MECT contains a resource plan for each Market Participant that lists the type of planning resource and quantity of capacity that has been assigned to its resource plan. The MECT also insures that accredited capacity or Planning Resource Credits are only utilized by one Midwest ISO load serving entity.

The Midwest ISO is required to file at FERC annually, by August 1st, the Cost of New Entry (CONE). In the Initial Planning Year (June 1, 2009 - May 31, 2010), CONE was $80,000 /MW-Month. A load serving entity must pay the financial settlement if they are deficient in planning reserves for any given planning month. The financial settlement is determined by calculating the capacity that the load serving entity is deficient and then multiplying it by the CONE value. Since implementing the CONE penalty, no LSEs have missed their reserve target.

MECT provides the necessary information to the Market Participant regarding their must offer requirement in the day-ahead market and reliability assessment and commitment process. The load serving entities are required to also enter their demand forecast parameters so Midwest ISO can evaluate whether a load serving entity under-forecasted by more than one standard deviation. The Midwest ISO informs the applicable state regulatory entity if the load serving entity is jurisdictional to the state and did under-forecast.

5.4 Long Term Risk Assessment

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 of the out-looking ten-year planning period. This study quantifies the effects altering the load forecast, external commitments, wind capacity credit, forced outage rates and differing unit expansions have on LOLE. While LOLE values can be determined for various scenarios, the likelihood of each scenario is not derived. The purpose of this analysis is not to determine reserve requirements necessary to meet projected load levels, but to point out the effects of changes in system conditions on LOLE so that future risk can be managed.

5.4.1 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 each changing variable has on LOLE. However, to establish a baseline for comparison, a base case was analyzed. In this analysis the out year cases utilized for the Midwest ISO Module E study, which established a planning reserve margin, were used after ensuring that only capacity currently available was included within the model. These cases, built for years 2013 and 2018, utilized the same zonal establishment methodology outlined in the LOLE Report available here:

http://www.midwestiso.org/publish/Document/62c6cd_120e7409639_-7f2a0a48324a

The base case provides the "best guess" of risk levels in planning years five and ten; however, because 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. When analyzing variables along a normal distribution, it is industry standard practice to use 10/90 and 90/10 levels as outlying cases that represent the extreme values of load. These load values represent the load at which there is 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.

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

Figures 5.4-1 and 5.4-2 provide a projected reserve margin timeline for the base case and high and low demand cases utilizing a nameplate capacity level with and without unit expansion. The minimum reserve requirement is represented on the graphs in the form of a red line. The requirement starts at 15.4% for the current planning year and increases to 17% by the end of the ten year period. The increase is a result of the increased congestion that could be experienced without the addition of transmission expansions that would alleviate congestion and enhance energy flows on the system.

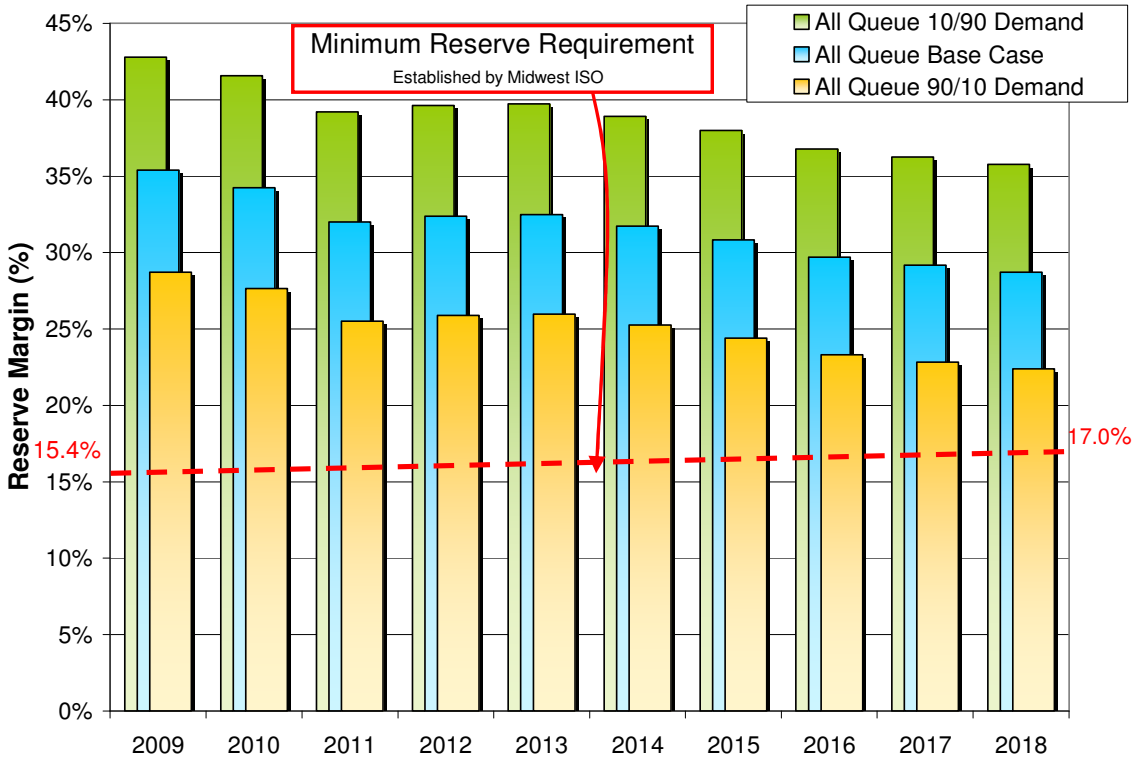


Figure 5.4-1: 2009 – 2018 Reserve Margin Forecast without Capacity Additions

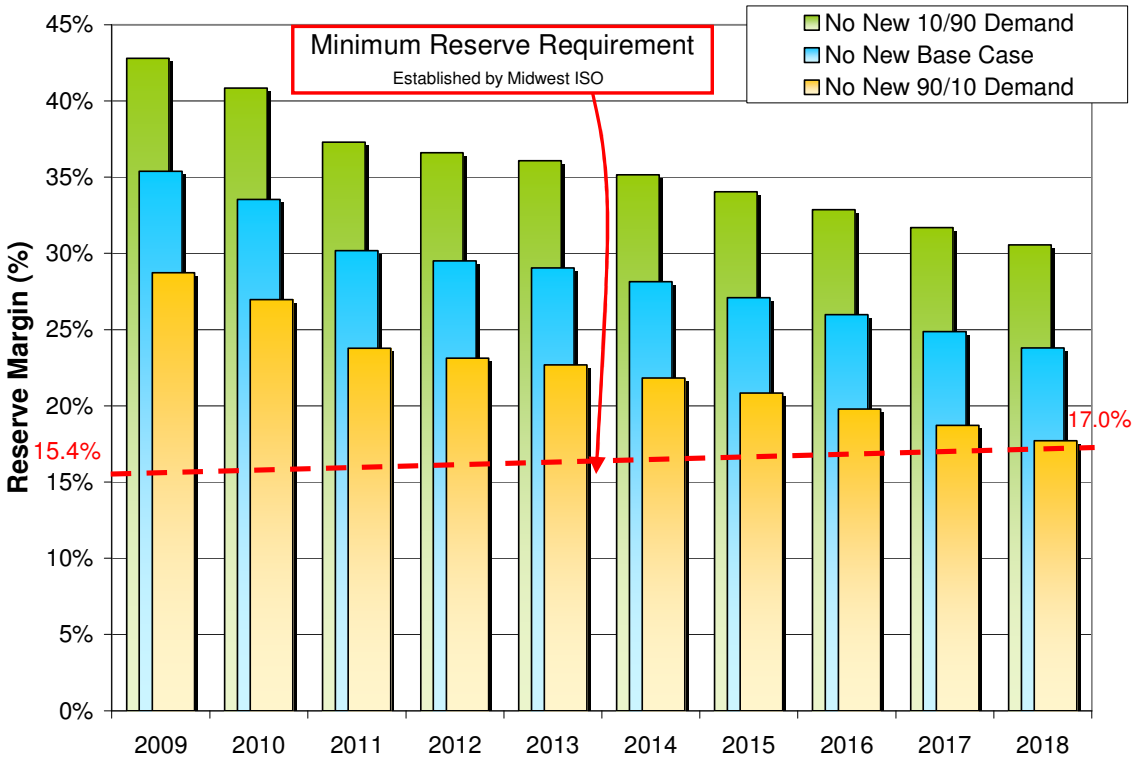


Figure 5.4-2: 2009 – 2018 Reserve Margin Forecast with Capacity Additions

Tables 5.4-1 and 5.4-2 show the values for nameplate reserve margins out through the next ten year period with and without capacity expansion.

Table 5.4-1: 2009-2018 Reserve Margin Forecast without Capacity Additions

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reserve Margin (MW)	35,418	34,031	31,417	30,876	30,490	29,752	28,888	27,944	26,981	26,043
Reserve Margin (%)	35.4%	33.5%	30.2%	29.5%	29.0%	28.1%	27.1%	26.0%	24.9%	23.8%
Reserve Margin (MW)	30,241	28,782	26,033		25,058	24,282	23,373	22,381	21,367	20,381
Reserve Margin (%)	28.7%		23.8%	23.1%	22.7%	21.8%	20.8%	19.8%	18.7%	17.7%
Reserve Margin (MW)	40,607	39,292	36,813	36,300	35,934	35,235	34,415	33,521	32,607	31,718
Reserve Margin (%)	42.8%	40.8%	37.3%	36.6%	36.1%	35.1%	34.0%	32.9%	31.7%	30.6%

Table 5.4-2: 2009-2018 Reserve Margin Forecast with Capacity Additions

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Base Load (50/50) Case									
Reserve Margin (MW)	35,418	34,743	33,307	33,893	34,114	33,557	32,874	31,942	31,670	31,445
Reserve Margin (%)	35.4%	34.2%	32.0%	32.4%	32.5%	31.7%	30.8%	29.7%	29.2%	28.7%
	High Load (90/10) Case									
Reserve Margin (MW)	30,241	29,494	27,923	28,481	28,682	28,087	27,359	26,378	26,057	25,783
Reserve Margin (%)	28.7%	27.6%	25.5%	25.9%	26.0%	25.2%	24.4%	23.3%	22.8%	22.4%
	Low Load (10/90) Case									
Reserve Margin (MW)	40,607	40,003	38,703	39,318	39,558	39,039	38,401	37,518	37,296	37,120
Reserve Margin (%)	42.8%	41.6%	39.2%	39.6%	39.7%	38.9%	38.0%	36.8%	36.2%	35.8%

An LOLE of one-day-in-ten 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 year it can be said that the system is less reliable than generally accepted.

LOLE results from the base case are displayed in Figure 5.4-3. The 90/10 and 10/90 load levels are industry standards for high and low load levels. The previous year results are at the standard load level without adjustment. Figure 5.4-3 illustrates the rapid drop in risk from a significant load reduction in that last year's base case results indicate far great risk than the current year simulation, and are more comparable to current year 90/10 results. There is a non-linear relation between LOLE and reserve margin; as reserve margins decrease LOLE increases exponentially.

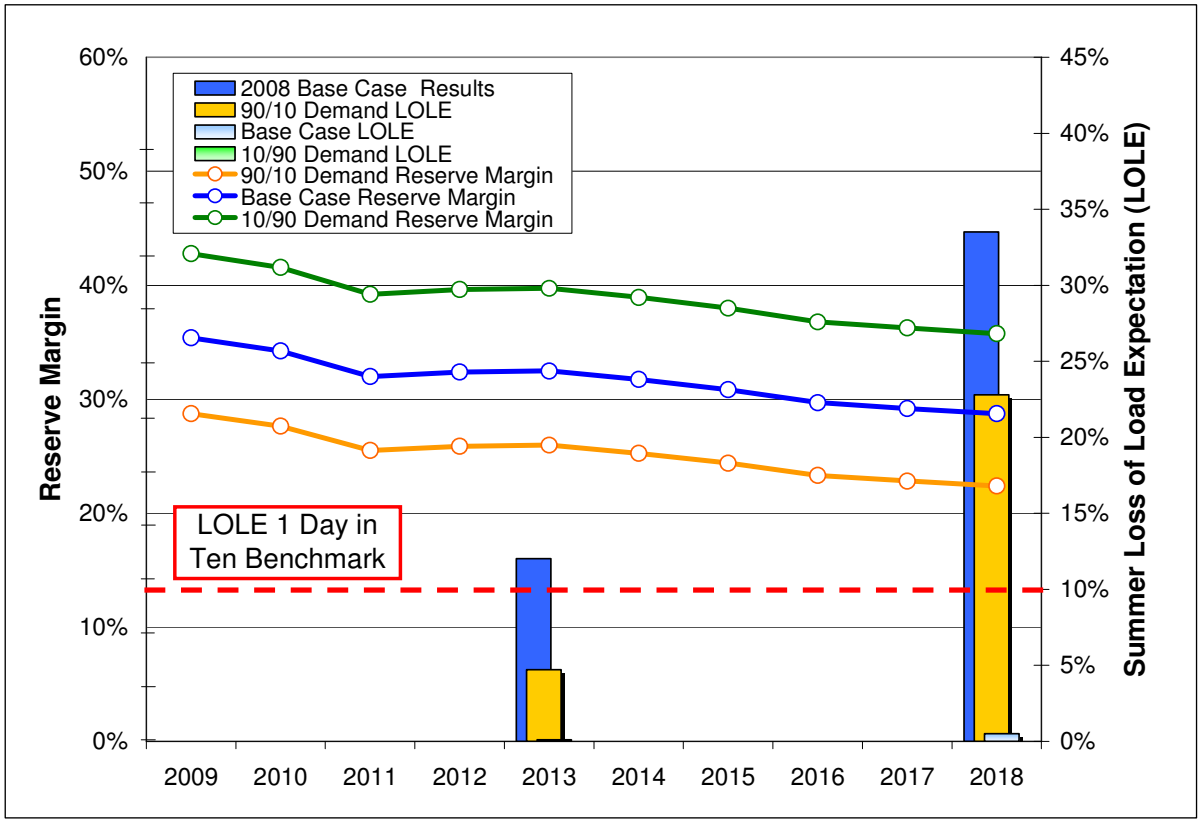


Figure 5.4-3: 2009 – 2018 Loss of Load Expectation Forecast

As can be seen in Figure 5.4-3 the Loss of Load Expectation only exceeds the industry standard of one-day-in-ten years during the 2018 time frame, and even then only when there is no unit expansion and a higher load level experienced.

5.4.2 Future Uncertainties – Sensitivity Analysis

Section 5.4.1 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 "best guess" conditions; however, there are a high number of uncertainties that have the potential to radically 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 is at its lowest level during peak conditions
- External reserve margins are falling and therefore future imports may be limited

To quantify the affects 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 of the out years. In each case only a single variable was changed to observe the effects that particular variable had on LOLE.

As determined in the base case analysis in Section 5.4.1, LOLE exceeded the 1 day in 10 years benchmark only in the year 2018 in the high load case. When conducting sensitivity analysis only high load cases resulted in a LOLE result exceeding the one-day-in-ten benchmark for either year and then only with a lack of unit expansion was that benchmark consistently exceeded.

During the year 2013 analysis it was determined that the one-day-in-ten benchmark would only be exceeded during high load conditions and then only with a complete lack of external support. As can be seen in Table 5.4-3 the only cases exceeded 0.1 LOLE occurred for both expansions during the high load and no external support cases.

Table 5.4-3: 2013 Sensitivity Results

	2013 – No New Units			2013 – 20% of Queued Units		
SCENARIO	High Load	Base Load	Low Load	High Load	Base Load	Low Load
Base Case	0.047	0.001	0.000	0.017	0.000	0.000
Increased Forced Outage Rate	0.099	0.003	0.000	0.040	0.001	0.000
No External Support	0.284	0.014	0.000	0.131	0.004	0.000
No Wind Availability	0.074	0.001	0.000	0.025	0.000	0.000

Similar to the 2013 results, it was only during high load conditions that any of the 2018 cases exceeded one-day-in-ten. As seen in Table 5.4-4 it should be noted that without unit expansion, even with the present load growth values, the system exceeds the industry standard LOLE benchmark for all sensitivities in this analysis.

Table 5.4-4: 2018 Sensitivity Results

	2018 – No New Units			2018 – 20% of Queued Units		
SCENARIO	High Load	Base Load	Low Load	High Load	Base Load	Low Load
Base Case	0.228	0.005	0.000	0.012	0.000	0.000
Increased Forced Outage Rate	0.467	0.021	0.000	0.038	0.000	0.000
No External Support	1.177	0.087	0.001	0.137	0.002	0.000
No Wind Availability	0.325	0.009	0.000	0.020	0.000	0.000

Using the base case as a benchmark, it was possible to derive the impact that each variable has on LOLE. A range of LOLE was derived for each uncertainty by adjusting the variable under scrutiny. In this manner it was determined that a change in external support has the largest potential to negatively affect out-year LOLE values. Assuming that no new units were put into service in the intervening four years, the risk assessment for 2013 would appear as in Figure 5.4-4. If, in the next ten years the

installation of new units followed historic trends, the 2018 sensitivities would be outlined by Figure 5.4-5. It should be noted that these sensitivity results rely on updated load forecasts that take into account the current recession. Since it is impossible to know what load will return after the recession, and how deeply it will impact future load growth, these results are subject to variation in future years should the load forecasts return to previous levels.

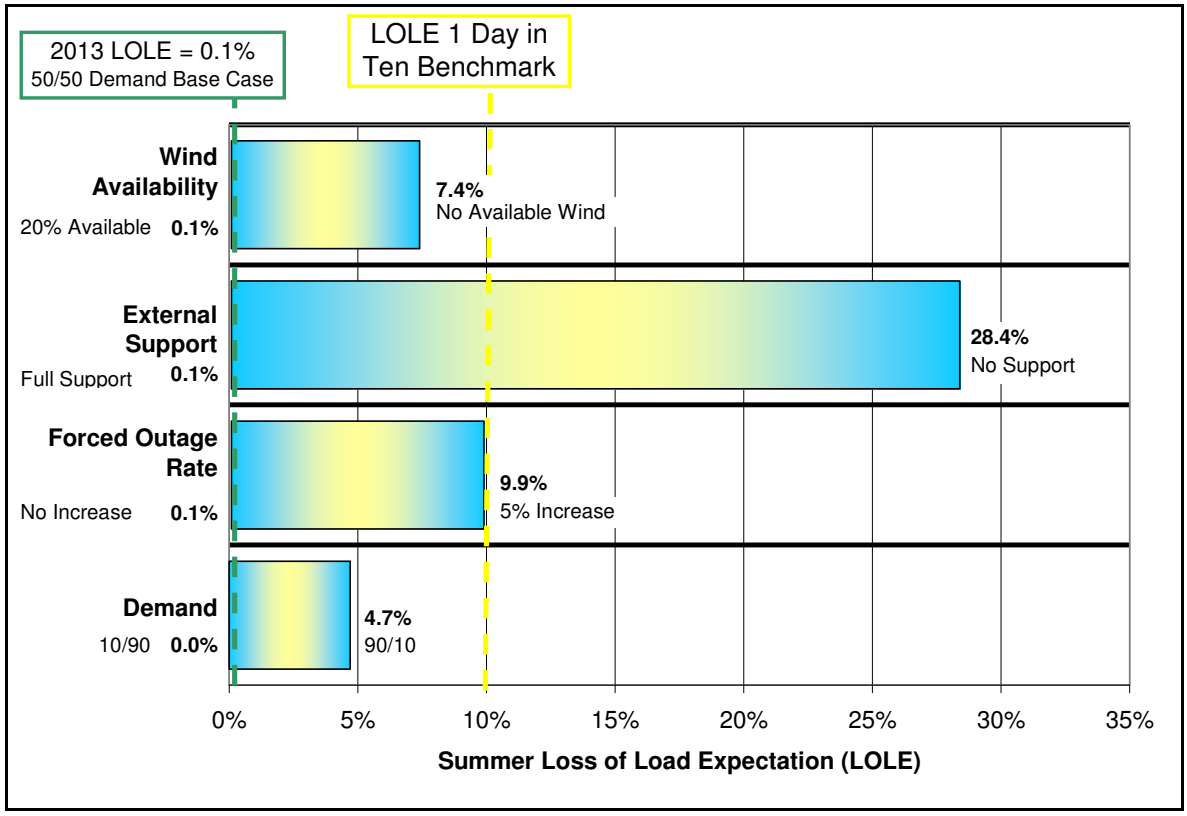


Figure 5.4-4: Year 2013 LOLE Sensitivity to Variable Adjustment - No New Capacity

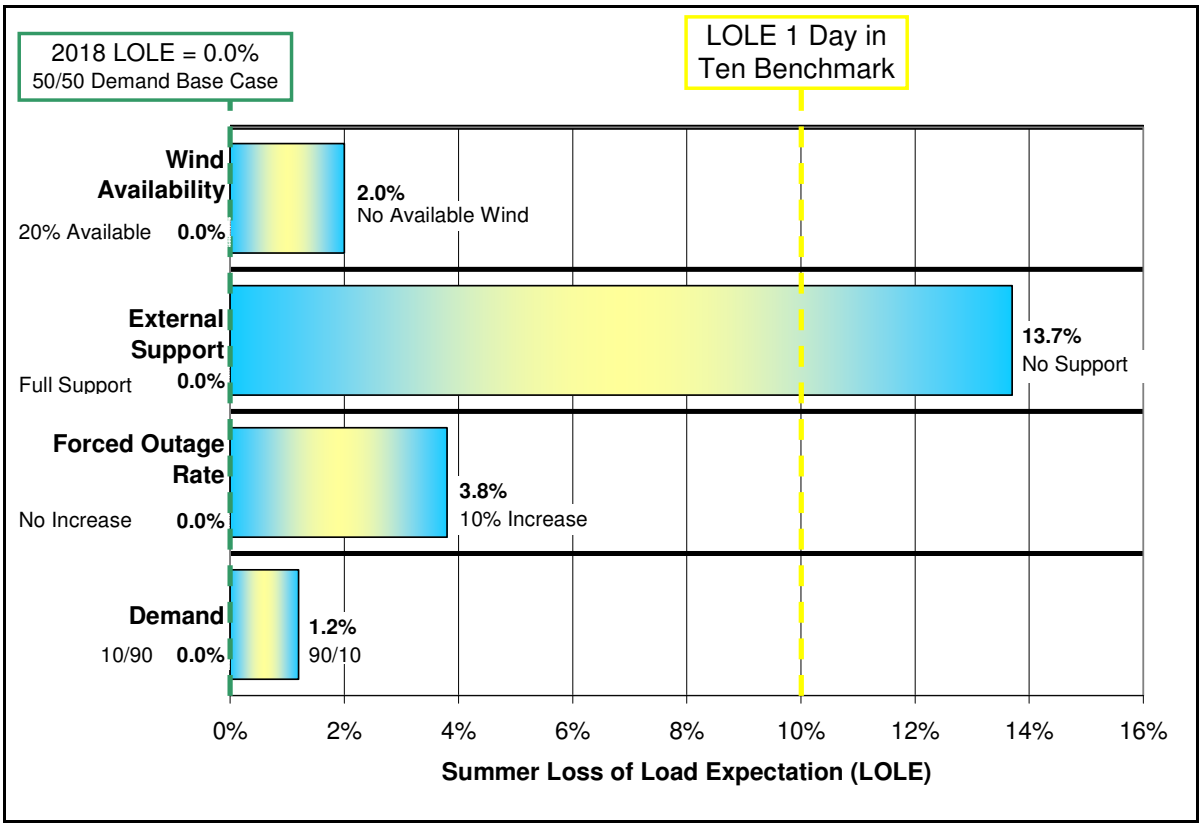


Figure 5.4-5: Year 2018 LOLE Sensitivity to Variable Adjustment - 20% All Queue

5.4.3 Sensitivity Descriptions

The following sections provide descriptions for each uncertainty – changing variable – used in the sensitivity analysis.

Forced Outage Rate

As the generation fleet ages there is an increased probability that forced outage rates will rise. Much of this effect is negated by continued maintenance and unit upgrades, but there is still a possibility for up to a 10% increase in forced outage rates in the out year analysis. The average age of units within the generation fleet can be seen in Figure 5.4-6. Examining previous studies on the outage rates during peak conditions, as seen in Figure 5.4-7, it was seen that 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 the bounds normally experienced during a system peak.

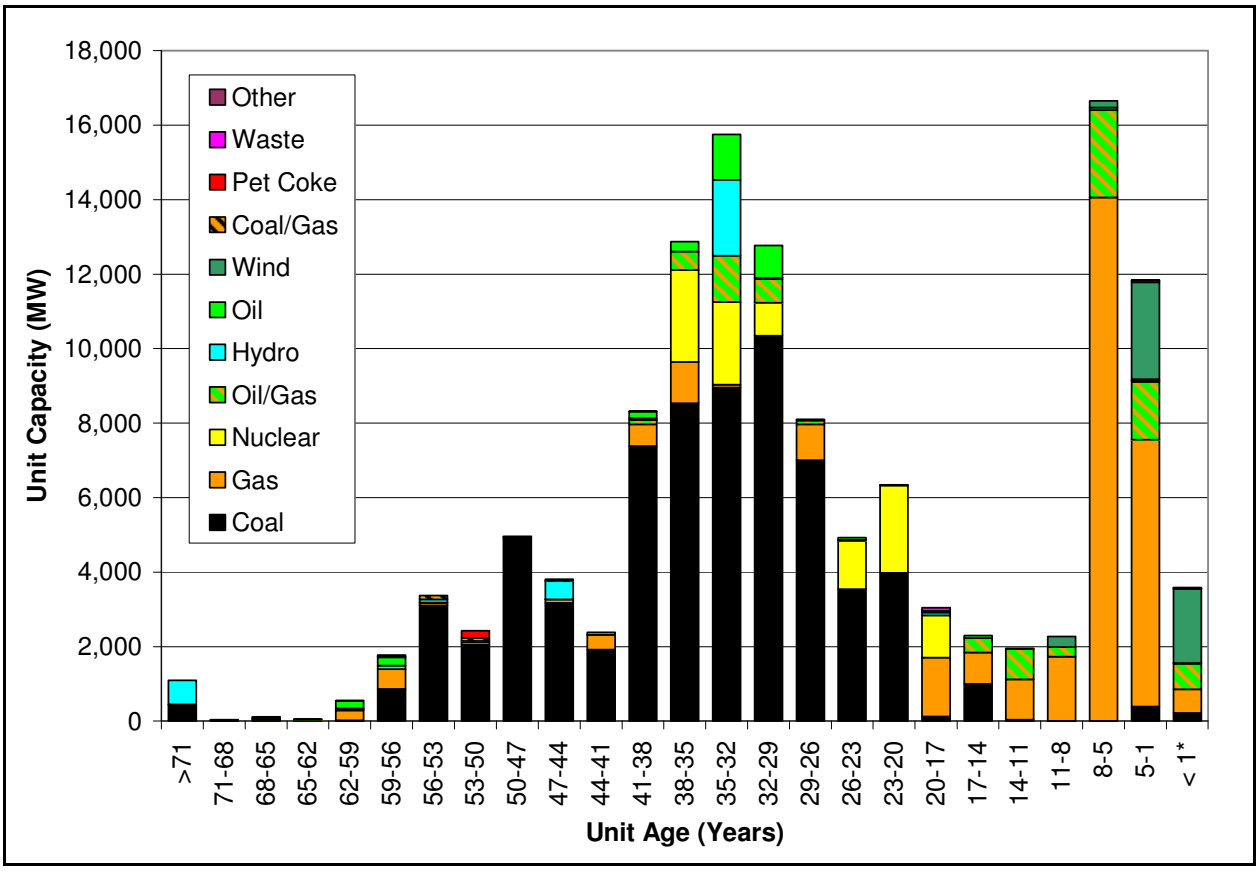


Figure 5.4-6: Age of Generation Fleet by Fuel Type

* - indicates data includes units with in service dates beyond 2008

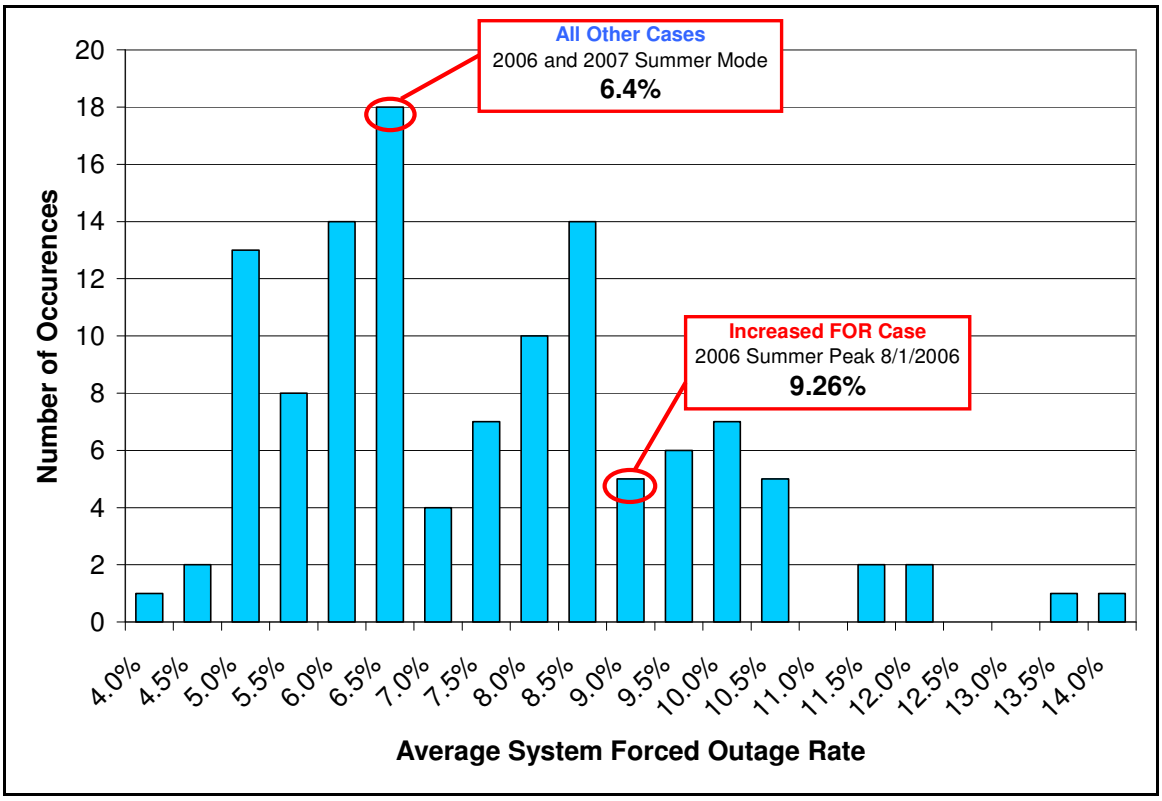


Figure 5.4-7: Case Summary of Average System Forced Outage Rates

Wind Availability

The intermittent nature of wind capacity allows for no guarantee in the amount available on peak, as detailed in Section 3.1.1. As wind begins to comprise a greater portion of footprint capacity, this variability becomes 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 a 20% peak capacity credit, as consistent with previous studies; however, during the annual peaks for three of the four past years wind production has been much lower than 20%.

To examine the effects of wind production being at its lowest level during peak conditions, and to establish a risk bandwidth, wind was given a 0% capacity credit in the Wind Availability case.

External Support

Currently there is 5,202 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.

To simulate the most extreme circumstance where no external commitments are available, the import capability was modified to 0 MW.

Demand Forecast Uncertainty

As outlined in Section 5.1, three 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.

Risk Management

Risk analysis was performed on cases that represent a diverse combination of variables. While a risk level was determined for each case, the probability of each case's occurrence is not stated. It is likely that the base case will most appropriately model the system as it occurs throughout the ten year period, but the increasing probability of various uncertainties occurring makes planning exclusively for base case conditions overly optimistic. In the event that system conditions should 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 which estimates the percent probability that there will be insufficient resources for that case. It is difficult to determine a probability for each case occurring as the amount of correlation between variables is unknown. Although various factors played a part in the risk analysis, a lack of external support proved to play the most integral part in increasing the risk experienced by the system. As reserve levels declined, associated risk levels rose exponentially.

With the inclusion of new capacity throughout the ten year time frame it was rare that LOLE values exceeded the one-day-in-ten years benchmark. It should be noted that to experience these lower levels of risk, load forecasts must not increase over the next ten years and unit expansion must continue as has been seen historically. Those two conditions are unlikely to be met exactly, so in order to manage risk in the following ten years the following steps can be taken:

1. **Capacity Expansion:** Historically, 20% of the queued capacity within the Midwest ISO (signed GIA plus non-signed GIA) has gone into service. If this trend is realized for the next ten year period, with current load projections risk can be effectively managed for all sensitivities, save for a lack of external support.
2. **Load Forecast:** It is difficult to project the effects of the current recession, but should load forecasts begin to climb again, following an economic recovery, the reliability of the system must be reassessed.
3. **Increased Forced Outage Rate:** When the average system Forced Outage Rate (FOR) is increased by 5% and 10% in the years 5 and 10 respectively, increased risk to the system is experienced. Continued maintenance and the installation of new units should serve to mitigate this risk.
4. **Wind Availability:** Currently, there is 5,065 MW of nameplate rated capacity which accounts for 3.9% of the fleet. This small amount of capacity had the least effect on LOLE when producing below historical averages. However, in the Midwest ISO Generator Interconnection Queue over 75% of the nameplate capacity consists of wind units. As wind begins to comprise a larger portion of the footprint, a lower than average production greatly affects system reliability.
5. **No External Support Case:** When external support is eliminated, both the 2013 and 2018 cases exceed the reliability benchmark of one-day-in-ten years. External support acts just as internal generation does and any significant drop in external support should be counteracted by an appropriate increase in internal capacity availability.

For a more detailed outline of the next ten year forecasts and risk assessment, please see the 2009 LTRA posted at the following link:

http://www.midwestiso.org/page/Regulatory+and+Economic+Standards

Section 6: Reliability and Value-Based Planning Methodologies

6.1 Reliability Planning Methodology Overview

The Midwest ISO performs many types of reliability analyses in its MTEP studies. The reliability assessment tests the existing plan using appropriate North American Electric Reliability Corp.(NERC) Table 1 events, determines if the system, as planned, meets Transmission Planning (TPL) standards, develops and tests additional transmission system upgrades to address any identified issues, and then tests the performance of the mitigation plan. This section describes the study process used to make an assessment of system reliability. The North American Reliability Corp. (NERC) TPL Standards can be found on the NERC website at:

http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html

6.1.1 Baseline Reliability Assessment Methodology

This section describes how the analyses and assessment performed by Midwest ISO meets the requirements of NERC TPL standards. The section is organized by TPL-002-0 (Category B) requirements, which are also representative of Category A, B, C and Category D requirements, although TPL-001 and TPL-004 requirements are not numbered identically. Additional elements of the study process are also described.

R1 The Planning Authority, and Transmission Planner, shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category A, B, C and D of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

The Midwest ISO demonstrates a valid assessment performed annually through its Midwest ISO Transmission Expansion Plan (MTEP) Report. It is part of Midwest ISO planning practices to create Planning models used in the simulations modeling all projected customer demands and firm transmission transactions. The valid assessments through the ten-year planning horizon are made and demonstrated in each MTEP report by utilizing results from simulations performed both in the current MTEP cycle and from recently performed simulations in prior MTEP cycles. Mitigation options, including transmission expansion Projects, planned and controlled system adjustments are available for all identified constraints for all Category A, B, C and D contingencies studied in MTEP 09. Therefore, Midwest ISO assesses in years 1 through 10 that the transmission network can be operated to supply projected customer demands and firm transmission services over the range of forecast system demands under the Category A, B, C and D contingency conditions defined in TPL table 1. See sub-requirements for details on models, contingencies and system conditions tested.

The MTEP performs a series of evaluations of the system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that the transmission system upgrades are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state powerflow and dynamic stability simulations at multiple demand levels, and load and generator deliverability, voltage-stability analysis of the transmission system performed by Midwest ISO staff and reviewed in an open Stakeholder process. Small-signal stability analysis is also performed periodically. Additional details on how the assessment is accomplished are described in the following requirements.

R1.1 Be made annually.
As noted earlier, the Midwest ISO performs an annual assessment and that assessment is documented in each year's MTEP report. MTEP reports such as this MTEP 09 have been published since 2005 (or MTEP05).

R1.2 Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

Section 4.3 of Midwest ISO Transmission Planning Business Practices Manual (TP-BPM) states that "Short-term planning addresses identification of needs and solutions in the time frame of 1 to 10 years, with particular focus on the next 5 years. Screening reliability analyses are performed in the 6-10 year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards."

In MTEP 09, assessment was conducted for the period 2010 through 2019. This valid assessment has been based on powerflow simulations representative of various system conditions in years 2011, 2013, 2014, 2016, 2018 and 2019. The MTEP 09 simulations were conducted for the years 2011, 2014 and 2019. Simulations for the other years in the planning horizons have been performed in the recent prior MTEP cycles.

R1.3 Be supported by a current or past study, and/or system simulation testing, that addresses each of the following categories, showing system performance following Category A, B, C and D of Table 1. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

In MTEP 09, assessment was conducted for the period 2010 through 2019. This valid assessment has been based on powerflow simulations representative of various system conditions in years 2011, 2013, 2014, 2016, 2018 and 2019. The MTEP 09 simulations were conducted for the years 2011, 2014 and 2019. Simulations for the other years in the planning horizons have been performed in the recent prior MTEP cycles. Category A, Category B, Category C and Category D events per Table 1 were analyzed. Section 6.1.4 below provides additional details on contingencies analyzed. Thermal and voltage issues were flagged using Transmission Owner's design criteria limits per Section 6.1.2.

R1.3.1 Be performed and evaluated only for those Category B, C and D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

Section 4.3.6 of Midwest ISO TP-BPM states that "The Midwest ISO applies the following principles in contingency selection:

- Where possible, evaluate all contingencies system wide within each Category
- Consider the input and expertise of Midwest ISO member Transmission Planners by incorporating their explicit contingency lists
- Supplement the explicit lists provided by Midwest ISO members with automated contingency generation to increase coverage
- For contingencies involving loss of more than one contingency, evaluate an extensive list of contingency combinations focusing on combinations of facilities that have a greater chance of impacting each other producing more severe results"

See Section 6.1.4 for more details on contingencies analyzed.

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

Critical system conditions deemed appropriate by Midwest ISO transmission planning engineers are developed in each MTEP cycle. In addition to Steady State and Transient Stability Studies investigating critical contingencies at load levels besides Summer Peak, voltage stability analysis is also performed across select interfaces within the Midwest ISO footprint.

Section 4.3.5 of the Midwest ISO TP-BPM states that, "…sensitivity models incorporating other variations in generation dispatch are also created. These sensitivity models represent different snapshots of critical system conditions pertaining to the Midwest ISO market operations."

In MTEP 09 steady state analyses were performed using 2011, 2014 and 2019 Summer Peak, 2014 Shoulder Peak (70% of Peak Load) and 2014 Light Load (40% of Peak Load) powerflow models. All steady state contingencies evaluated in Summer Peak models were also evaluated in the Shoulder Peak and Light Load models in Steady State Analyses. All models were dispatched to represent Midwest ISO market conditions with generators dispatched per market wide regional merit order. See Section 6.1.3 for details on modeling methodology applied to MTEP 09 base cases.

Transient Stability analyses were performed using the 2014 Shoulder Peak (70% of Peak Load) and 2014 Light Load (40% of Peak Load) powerflow models. Both Shoulder Peak and Light Load cases modeled Wind Generation at 90% of Name Plate. With Wind generation at higher output and other Baseload units dispatched on market wide economics, these two models represent different instances of actual market operation when higher West (larger concentration of Wind Generation) to East (Larger concentration of Load) transfers within the Midwest ISO footprint are seen. When select disturbances are tested on these system conditions, it is believed to show pronounced system oscillatory behavior. These models also represent a system that is more stressed from a reactive power standpoint thus representing a more severe condition to test excitation system response to critical faults tested. See Section 6.1.4 under Dynamic Stability for details on disturbances tested.

In addition to Steady State Contingency Analysis and Dynamic Stability Analysis, Voltage Stability Analysis was also performed in MTEP 09. This study is performed by applying a host of transfers representing various market conditions to the base case. Transfers selected (shown below) are based on past analysis or input from real-time operations believed to represent conditions that may result in marginal reactive system performance.

- West Region Transfers
  - West to East
    - Minnesota, North Dakota, South Dakota to Wisconsin
    - Minnesota, North Dakota, South Dakota, Montana and Iowa to Wisconsin
    - Minnesota to Illinois
    - Nebraska to Illinois and Missouri
  - East to West
    - Pennsylvania, Ohio, Michigan, Southern Indiana and Kentucky to Wisconsin and Michigan's Upper Peninsula
    - Illinois and Missouri to Nebraska
    - Illinois to Minnesota
  - South to North
    - Ohio and Chicago area to Wisconsin
- Central Region Transfers
  - South to North
    - Kentucky and Tennessee to Ohio, Michigan and Chicago area
  - West to East
    - Illinois to PJM
    - Illinois to Ohio
  - South to North
    - Tennessee to Chicago area
- East Region Transfers
  - South to North
    - Ohio to Michigan
    - Ohio and Chicago Area to Michigan
    - Tennessee and Southern Ohio to Northern Ohio
    - Tennessee and Southern Ohio to Michigan, New York and Northern Ohio
  - West to East
    - Illinois and Ohio to PJM

R1.3.3 Be conducted annually, unless changes to system conditions do not warrant such analyses. As described in Section 1.3 above, MTEP 09 assessment was based on powerflow simulations conducted in the current planning cycle, as well as simulations conducted in prior recent MTEP cycles. While there are specific simulations for three years within the 10 year planning horizon in this annual cycle, system conditions in particular load growth has not significantly changed between these annual assessments to warrant repeating simulations for each year in the 10 year planning horizon. Details of actual aggregate loads modeled in the Midwest ISO member footprint are documented in Section 6.1.3 below.

R1.3.4 Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

As noted above, Section 4.3 of TP-BPM states that "Short-term planning addresses identification of needs and solutions in the time frame of 1 to 10 years, with particular focus on the next 5 years. Screening reliability analyses are performed in the 6-10 year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards."

The recent MTEP 09 analysis focused on system performance in near-term planning horizon (1-5 years). All steady state contingencies evaluated in the 2014 (5-year out) Summer Peak model were also evaluated using the 2019 (10-year out) Summer Peak model. The process is to:

Review 5th year analyses for violations >90%
Review potential near and longer term solutions
Evaluate violation levels in 10 year out model (2019)
If constraints are seen in the 10 year out model, interpolate to overload year
Document assumed or proposed mitigation, assumed lead time, and start year of construction (i.e. determine year BOD approval needed)

Additional analysis is performed as needed using the 2019, 10-year out model to study impact and benefits of planned projects that do not otherwise demonstrate adequate benefits in the 5-year out analysis.

No issues were seen in the six through ten year assessment period that require planning solutions with lead times longer than the 5-year planning horizon and therefore need not be addressed within this MTEP cycle.

R1.3.5 Have all projected firm transfers modeled.
The models used in MTEP analysis have all projected Firm transfers modeled. Model transaction documentation is in Appendix D. See Section 6.1.3 for detailed discussion on model assumptions.

R1.3.6 The sub-requirement that analyses are performed at selected demand levels over the range of forecast demands.

Reliability analyses were performed at selected demand levels. Section 3.3.2 of TP-BPM states that "Load Demand will generally be modeled as the most probable (50/50) coincident load projection for each Transmission Owner service territory, for the study horizon under study…". While it is Midwest ISO practice to generally include a 50/50 coincident load, Midwest ISO planning evaluates the need to study a 90/10 coincident load level on an as needed basis. In some specific instances where significant system changes may occur between 50/50 and 90/10 forecast load levels such as voltage collapse, these are studied within the MTEP Voltage Stability Analysis.

In MTEP 09 steady analyses were performed using 2011, 2014 and 2019 Summer Peak, 2014 Shoulder Peak (70% of Peak Load) and 2014 Light Load (40% of Peak Load) powerflow models. See Section 6.1.3 for additional details. Sensitivity models representing other demand levels and system conditions may be used as part of the transmission project review process. An example of this is to capture any and all transmission system issues for different levels of the Ludington Pumped Storage Power Plant in Michigan; additional cases were developed to evaluate critical contingencies:

2014 Peak Load with 6 Units at Ludington operating in Generating Mode

2014 85% Load with 5 Units at Ludington operating in Generating Mode

2014 85% Load with 1 Unit at Ludington operating in Pumping Mode

2014 70% Load with 5 Units at Ludington operating in Pumping Mode

MTEP 09 Voltage Stability Analysis included evaluation of voltage stability issues arising from load in Cleveland increasing beyond the 50/50 to 90/10 level. No voltage stability issues were found.

R1.3.7 Demonstrate that system performance meets Category A, B, C and D contingencies.

Section 7 of this report describes projects moving to Appendix A (moving from proposed to planned) in MTEP 09. Appendix D1 of this report documents effectiveness of the projects.

MTEP 09 Reliability analysis was conducted with models containing all planned and proposed projects.

Some thermal and voltage criteria violations were seen for all Category A, B, C and D contingencies and are documented in Appendix D3-6. The table also documents associated mitigations for all violations involving system adjustments such as generation redispatch.

R1.3.8 Include existing and planned facilities.

Models used in MTEP Reliability Analysis contain existing and planned transmission facilities. The topological starting point of MTEP 09 analysis is projects with documented system needs in Appendix A and Appendix B from prior MTEP's as well as future facilities expected to be approved in MTEP 09. In the event that project effectiveness cannot be demonstrated within the current MTEP cycle, these are removed from the final model.

R1.3.9 Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

The models used in MTEP analyses include generator reactive capabilities, fixed shunt capacitors, switched shunt capacitors, synchronous condensers, static var compensators, and other var sources. Note that only on-line generators will provide reactive support according to powerflow solution controls.

R1.3.10 Include the effects of existing and planned protection systems, including any backup or redundant systems.

The MTEP models, contingency files and disturbance files used in this analysis include effects of existing and planning protection systems.

R1.3.11 Include the effects of existing and planned control devices.

The powerflow models used in MTEP analysis contain existing and planned control devices, such as, Load Tap Changing (LTC) transformers, phase angle regulating transformer controls, generator voltage controls, Direct Current line controls, and switched shunts controls. These controls are enabled during solutions. Base cases are solved with area interchange also.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The powerflow models used in MTEP analysis generally assume that planned outages are not scheduled during peak load periods. However, areas within the system may include outages to the extent that actual operating experience indicates that these areas experience difficulty in scheduling outages. Additionally, in MTEP reliability analysis, contingent events include combination of planned and forced outages and are generally studied using off-peak MTEP models such as at 70% shoulder peak load model as outages are expected to be performed at these levels and system performance for single forced outage is expected to meet performance requirements of Table 1. Some planned upgrades have been developed in part based upon this criterion.

In MTEP 09, in addition to the 70% shoulder peak load model, various 85% shoulder peak models representing different system conditions were developed (See R1.3.6). Contingent events, including planned and forced outages, were analyzed using these models.

R1.4 Address any planned upgrades needed to meet the performance requirements of Category A, B, C and D of Table I.

Section 7 of this report describes projects moving to Appendix A (moving from proposed to planned) in MTEP 09. Appendix D1 of this report documents effectiveness of the projects. MTEP 09 Reliability analysis was conducted with models containing all planned and proposed projects.

Some thermal and voltage criteria violations were seen for all Category A, B, C and D contingencies and are documented in Appendix D3-6. The table also documents associated mitigations for all violations involving system adjustments such as generation redispatch.

With all mitigation plans applied as necessary, no outstanding reliability issues were seen in MTEP 09. Some plans such as planned / controlled loss of load or redispatch of network resources applied as mitigation measures for Category C violations in this cycle may be reviewed in the next cycle to determine cost effectiveness compared with transmission projects.

R1.5 Consider all contingencies applicable to Category B, C and D.

The MTEP 09 study analyzed these events. See Section 6.1.4 for additional details on contingencies analyzed. Thermal and voltages issues were flagged using Transmission Owner's design criteria limits.

R2 When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

In the MTEP planning cycle, the Midwest ISO works collaboratively with Transmission Owners and stakeholders to develop mitigation plans for identified issues. These plans are tested by Midwest ISO staff for effectiveness. The mitigation plans are developed to meet the requirements 2.1 and 2.2 below.

R2.1 Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

The MTEP report summarizes the mitigation plans required to maintain adequate system performance in Appendix A and B of this study. Documentation of such plans is included in Appendix D1. Projects in Appendix C may address identified issues, but Midwest ISO staff has yet to document their effectiveness.

R2.1.1 Including a schedule for implementation.

MTEP Appendix A and B has for each project facility an expected in service date which forms a schedule for implementation. Proposed In-Service dates are finalized as part of project review process. Some in-service dates may be pushed out or advanced based on when constraint is expected to appear.

R2.1.2 Including a discussion of expected required in-service dates of facilities.
MTEP Appendix A, B, and C have expected in-service dates for each project facility.

R2.1.3 Consider lead times necessary to implement plans.
At the start of the MTEP planning cycle, Midwest ISO staff reviews project in service dates and estimated lead times for construction. Any concerns on timely implementation of plans are discussed with Transmission Owners and in-service dates revised in-order to put the project, or alternate near term op-guides, in place before transmission constraint is expected to arise.

R2.2 Review, in subsequent annual assessments (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

Midwest ISO collaborates with Transmission Owners to determine the continuing need for approved system facilities on as need basis. In some instances, system changes such as large generator interconnections may warrant replacing smaller projects, such as line re-conductor and terminal upgrades, in preference over entire line rebuilds. Load Forecast changes may also demonstrate that project in-service dates may need revisions.

In the MTEP process, projects moving from Appendix B to Appendix A are reviewed by Midwest ISO staff. During this project review process, staff may not determine the need for the project. This in some instances is an outcome of other planned projects in the area. Likewise, during the process if other past approved projects in the area may be deferred, Midwest ISO staff coordinates with Transmission Owners to help revise in-service dates of those facilities. If time permits, proposed projects in Appendix B are not included in initial MTEP models, enabling the continuing need for the project to be documented.

R3 The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

Midwest ISO documents the results of the Reliability Assessment in the MTEP report such as this MTEP 09 report. The final step of an annual planning cycle is to provide this MTEP report to the respective Regional Reliability Organizations per their requirements. For FERC Order 890 compliance, Midwest ISO has adopted numerous other measures to make the local planning process more inclusive, open and transparent to all stakeholders. One such measure was institution of MTEP Sub Regional Planning Meetings. A document listing various milestones and schedules involved in the MTEP Sub Regional Planning Process is posted on the Midwest ISO website at: http://www.midwestmarket.org/publish/Folder/2c41ee_1200f54a695_-7fd80a48324a. The Midwest ISO Transmission Plan and Draft Report are additionally reviewed in open forums at various stages

during the planning cycle by the Midwest ISO Planning Subcommittee and Planning Advisory Committee. A document listing MTEP report deliverables to open stakeholder forums is posted on the Midwest ISO website at the below link:

http://www.midwestmarket.org/publish/Document/6ef35b_121e89707ed_-7cda0a48324a?rev=1.

The final report is also made available on Midwest ISO public website.

6.1.2 Planning Criteria and Monitored Elements

In accordance with the Midwest ISO Transmission Owners Agreement, the Midwest ISO Transmission System is to be planned to meet local, regional and NERC planning standards. The baseline reliability analysis, performed by the Midwest ISO staff, tested the performance of the system against the NERC Standards, leaving the compliance to local requirements to the Transmission Owners where those standards may exceed NERC standards. The specific branch loading and bus voltage thresholds of each member's criteria (local flagging criteria) were applied to accurately reflect the different system design standards of the Midwest ISO members in this assessment.

All system elements, 100 kV and above, within the Midwest ISO Planning regions, as well as tie lines to neighboring systems, were monitored. Some non-Midwest ISO member systems were monitored if they were within the Midwest ISO Reliability Coordination Area. See Appendix D3 for Monitored element files.

6.1.3 Baseline Modeling Methodology

In MTEP 09 powerflow models were developed to represent various system conditions in 2, 5 and 10 year out planning horizon. 2011 Summer Peak, 2014 Summer Peak, 2019 Summer Peak, 2014 Shoulder Peak (70% of Peak Load) and 2014 Light Load (40% of Peak Load) powerflow models were developed. Midwest ISO coordinated with external seam regions: TVA, SPP, MAPP and PJM to reflect corresponding regions latest topology in the MTEP models. For all other areas, modeling data of corresponding year or closer match from Eastern Interconnection Regional Reliablity Organization (ERAG) 2008 series model were applied. This section describes model assumptions used in MTEP analysis.

Model Assumptions

Transactions

All models were dispatched by Midwest ISO wide regional tiered merit order. In order to determine interchanges for these models, the following approach is used:

1. Total Load is determined based on input from all Midwest ISO Transmission Owners via the Model on Demand (MOD) tool
2. Losses for each Midwest ISO area are estimated based on corresponding year ERAG models.
3. All firm drive-in and drive-out transactions between Midwest ISO member control areas with external control areas are added up from the 2008 series Multi-Area Modeling Working Group (MMWG) Interchange data. This determines Midwest ISO net interchange with external system (In all models, this number was negative implying a net import).
4. Total Generation needed to serve Midwest ISO load is then determined:

   Load + Losses – Import
5. Using regional merit order dispatch methodology described in further detail under the Generation dispatch section, Midwest ISO units are dispatched. Depending on how much generation is picked up in individual control areas, individual control area interchanges all adding up to the net Midwest ISO import are determined:

   Generation – (Load + Losses)

A Security Constrained Economic Dispatch (SCED) within Midwest ISO is then applied to all models for reliability analyses. These cases do not include any explicit Midwest ISO internal transactions (drive-within) modeled but will retain the Firm transactions to external parties modeled in the contractual dispatch case. This modeling philosophy enables Midwest ISO to plan the system based on how the market operates, still ensuring that the system is planned such that obligation of all Network Resources to serve all Network loads are met.

Losses

- Individual control area losses are calculated after the model is solved. If losses initially assumed (Step 2) are higher, such that the area swing machines over generate, these are corrected by dispatching other units, such that the total Generation dispatched in the Midwest ISO footprint covers all load and losses, after accounting for any imports.

Load

As noted earlier, 2011 Summer Peak, 2014 Summer Peak, 2019 Summer Peak, 2014 Shoulder Peak (70% of Peak Load) and 2014 Light Load (40% of Peak Load) powerflow models were developed. All load data is based on 50/50 coincident load forecast by control area submitted to the Midwest ISO Model on Demand (MOD) tool by Transmission Owners. Load forecasts in the models include existing demand side management and conservation programs.

Table 6.1-1: Aggregate Load

MTEP Cycle	Aggregate Load (MW) in Planning Models						Estimated Annual Load Growth (Based on 2 yrs. Documented load data)
	Year 2011	Year 2013	Year 2014	Year 2016	Year 2018	Year 2019	
MTEP09	116,636		120,600			126,800	1.03%
MTEP08		123,624			130,988		1.16%
MTEP07		123,624			130,988		1.16%
MTEP06	125,935			134,404			1.31%

Generation

All models were dispatched to represent Midwest ISO market conditions with generators dispatched per market wide regional merit order. Block order of units based on PROMOD® cost curves were then separated into seven tiers, with Level 0 units the first, and Level 6 the last, to be dispatched.

Level_0: Must Run, Self-Scheduled, Wind (modeled at 20% nameplate in peak cases and 90% nameplate in shoulder peak and light load cases), Hydro, Loads, SVC's, Non-MISO which are on-line

Level_1: Network Resources

Level_2: Energy Resources

Level_3: Future Gens without IA

Level_5: Fake or Retired (things not used or changed)

Level_6: Non-MISO Off-line. MISO units missing data

Assumptions

Level_0, Sort units by Fuel type, then Pmax decreasing

Level_1 has $0 cost blocks. For all $0 cost units sort by Pmax decreasing and have Coal before Gas

Based on Load, Losses and Net Interchange, the following amount of total generation was dispatched in each model:

2011 Summer Peak:	113,471 MW
2014 Summer Peak:	117,214 MW
2014 Shoulder Peak:	84,218 MW
2014 Light Load:	48,095 MW
2019 Summer Peak:	123,821 MW

In 2019 Summer Peak model with the highest generation requirement, Level 0 and Level 1 units were sufficient. In other words in the MTEP 09 cycle, in no models were any Level 2 and higher Tier units dispatched online.

Reactive Resources

Powerflow models used in the analysis contain existing and planned reactive resources, specifically: generator reactive capabilities, fixed shunt capacitors, switched shunt capacitors, synchronous condensers, static var compensators, and other var sources. Note that only on-line generators will provide reactive support according to controls.

Control Devices

Powerflow models contain existing and planned control devices, such as, Load-Tap Changing (LTC) transformers, phase angle regulating transformer controls, generator voltage controls, area interchange controls, Direct Current line controls, and switched shunts controls. Note that area interchange is not used during contingency analysis.

Model Topologies

The different model phases reflect different topologies dependent on which future projects were included in the models. The transmission system topology contains existing and planned transmission facilities. Future facilities with expected in service dates after summer 2011, 2014 or 2019 were not modeled in the respective models. The final model containing the list of all MTEP 09 Appendix A and B projects was posted at the MTEP ftp site (ftp://mtep.midwestiso.org/MTEP 09/models/) for review on April 17th. See Appendix D4 for modeled future facility documentation of the models.

6.1.4 Contingencies Examined

Regional contingency files were developed by Midwest ISO Staff collaboratively with Transmission Owner and Regional Study Group input. NERC Category A, B, C and D contingency events on the transmission system under Midwest ISO functional control were analyzed. In general, contingencies on the Midwest ISO members' transmission system at 100 kV and above were analyzed in MTEP 09, although some 69 kV transmission was also analyzed.

Steady State Analysis – Contingencies Studied

Category B Events {Total Tested: 9,611}

- All NERC Category B (single line, single transformer, or single generator outage) contingency events were analyzed in AC contingency analysis.

Category C Events {Total Tested: 1,749,544}

- All critical NERC Category C1, C2, C4 and C5 events were analyzed. Rationale for defining these as more severe than others not selected have been documented in Appendix D8 by regional planners.
  {Total Tested: 16,062}
- All explicit category C3 contingent events generally considered more severe that were received from Midwest ISO member Transmission Owners were analyzed.
  {Total: 415,376}
- In addition to the above explicitly defined Category C events, the following automatically generated events that Midwest ISO deems more severe than other C3's not considered were also analyzed
  - C3: Automatic Bus Double branch contingent events above 100 kV. Bus Double branch contingencies are a combination of two branch outages from the same powerflow bus.
  - C3: Automatic Double Generator, Generator + Branch and Double Branch in two separate adjacent control areas with the following thresholds: Generators above 100 MW, Lines above 200 kV and transformers with low side above 200 kV. {Total Tested: 132,244}
  - C3: Automatic Double Generator, Generator + Branch and Double Branch within the same control area with the following thresholds: Generators above 100 MW, Lines above 100 kV and transformers with low side above 100 kV. {Total Tested: 1,185,862}

Category D Events {Total Tested: 2,001}

- All Explicit category D contingent events generally considered more severe that were received from Midwest ISO member Transmission Owners were analyzed
- D8 and D9: Global automated bus outages of all Midwest ISO member buses in each case
- D10: Loss of all generation at a plant was considered for large generating stations.

In total, approximately 1,761,156 contingencies were analyzed in steady state analysis.

- Where Midwest ISO and non-Midwest ISO systems were highly integrated, contingencies on non-Midwest ISO systems were also analyzed for impacts on the Midwest ISO members' systems.

A NERC Category C3 event is defined as a Category B event, followed by manual system adjustment, followed by another Category B event. In the MTEP process, two Category B events are analyzed (automated doubles) without the allowed manual system adjustment between the two events. NERC Planning Standards allow Category C analysis to focus on the most severe events. Midwest ISO requested that its members draw on their past studies and system knowledge to provide the severe Category C events. Those events were analyzed in this study. Midwest ISO expects that the selection of contingencies to be studied in any one MTEP will vary, so that over several MTEP studies, all areas of the system will be thoroughly tested. Midwest ISO also expects to add additional contingencies going forward based on Midwest ISO operating and planning experience. In addition, Midwest ISO staff performed independent screening analyses of multiple element outage events to help identify areas potentially vulnerable to voltage instability. See MTEP 09 Appendices D3-D5 for a list of issues identified in reliability analysis and associated mitigation plans, which may be a project in Appendix A or B or other applicable actions. MTEP 09 Appendix D1 also demonstrates project mitigation plan effectiveness.

Dynamics Stability Analysis – Disturbances Studied

Midwest ISO simulated the following disturbances on members' systems for studying different Dynamic/Transient Stability issues.

1. **First swing transient stability**

   First swing transient stability is the A-periodic drift due to large disturbances. The recommended events include:

   - B1 generator 3-phase faults with normal clearing for units >100 MW
   - B2 trip of long, heavily loaded interface lines with large phase angle difference across the interface
   - C6, C7, C8, C9 Faults with delayed clearing near large units (>200 MW). Most severe event near the unit. If C8 is the most severe, provide C8. If C9 is the most severe, provide C9.
   - Historically severe events

2. **Oscillation stability**

   This category of disturbances is to evaluate the eastern interconnection-wide oscillation disturbances by branch outages. Disturbances will trip branches related to inter-area modes with lower damping. MTEP07 small signal analysis results were used to identify the lower damped modes and branches influencing these modes. Midwest ISO staff built the disturbances for the identified lower damped modes. Recommended events include Category C3 or N-3. Additional disturbances were received from TO's based on their experience and historically severe events.

3. **Voltage/reactive power related issues**

   Midwest ISO staff will build this category of disturbances based on the MTEP 09 AC analysis results. Non-converged steady state contingencies were also tested in Dynamic Stability.

4. **Others: DC lines, SPS failures**

   Additional disturbances modeling B4 DC single pole, C4 DC bipole and D12 SPS failure were simulated. 6.1.5 Load Deliverability Analysis

In 2009 the Midwest ISO completed its first Loss of Load Expectation (LOLE) study under accepted tariff provisions, designed to meet emerging Reliability Entity (RE) requirements. The process laid the ground work for future LOLE Studies to be conducted in compliance with the tariff filing. Previously, in 2008, the Midwest ISO participated in the LOLE Study performed and PRMs were determined for members of the Midwest Planning Reserve Sharing Group (MPRSG).

6.1.5 Load Deliverability Analysis

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Midwest ISO LOLE Study

On December 28, 2007, the Midwest ISO submitted major revisions to its EMT to the Federal Energy Regulatory Commission (FERC) that involve Module E regarding Resource Adequacy Requirements (RAR); these revisions were conditionally accepted by FERC on March 26, 2008. The filing along with subsequent clarifications and drafting of the Business Practice Manual (BPM) have laid the ground work for establishing a process by which LOLE study zones are determined. Zones of interest are based on identifying congestion in the transmission system. These congestion driven zones are utilized in modeling the calculation of planning reserve margins, and allow quantitative evaluation of load deliverability and aggregate generation deliverability.

The new process of defining zones enhances the load deliverability study by identifying potential areas where load deliverability could be at higher risk due to constraints and also identifies where generation may have limits to being deliverable outside of specific zones. The congestion based zones and the associated transmission system limitations are the key inputs to probabilistic application use for the LOLE study. The generator outage data needed for the LOLE study, and the requirements to report such data, are also part of the revised Module E filing. The LOLE calculation will verify if the load in the study zones is at risk of exceeding the one day in ten years criteria. Stakeholder participation or awareness about the Midwest ISO LOLE studies is possible through participation or tracking of the activities of the Loss of Load Expectation Working Group (LOLEWG) that was established in May 2008 to conduct the LOLE studies in accordance with the Tariff and related business practices. The study is done annually to set the PRM each year, and means that the PRM is primarily a function of four drivers:

- The reliability performance of the generators in the Midwest ISO
- The probability of the load varying form the base 50/50 forecast
- The transmission network and the relative location of load and generation throughout the network.
- The amount of assistance that can be reliably obtained on from outside the Midwest ISO.

The results of the 2009-2010 LOLE Study Report are discussed in Section 7.3 of this report.

6.1.6 Generator Deliverability Analysis

The Generator Deliverability analysis determines the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints, that is, without being bottled-up. This test is performed as part of the generators interconnection study process on new generators before granting Network Resource (NR) status. The generator is required to fix any transmission constraints limiting deliverability, in order to be treated as a Network Resource. A generator that is certified deliverable (not bottled-up) could be designated by any Load Serving Entity (LSE) within the Midwest Market Footprint to satisfy its Resource Adequacy requirement as specified in Module E of the Midwest ISO Energy Market Tariff.

The deliverability levels of already granted Network Resources may deteriorate over time as a result of load growth and other changes to the transmission system. A Baseline Generator Deliverability Study is performed in order to identify and address any new transmission constraints to ensure ongoing deliverability of Network Resources. Also, baseline generator deliverability upgrades represent a reliability need to ensure the continued ability to count on Network Resources nominated to meet reserves.

The Baseline Generator Deliverability analysis was performed using the MTEP 09 2014 Summer Peak model and by applying single transmission contingencies to deliverability dispatch patterns. The general generator deliverability study assumptions, as described under Section 5.1.2 of the Business Practices Manual for Generation Interconnection, were used for the analysis. The deliverability was tested only up to the granted Network Resource levels of the Network Resource units modeled in MTEP 09 2014 Summer Peak case. Results of the generator deliverability test have been documented in Section 7.

6.1.7 Mitigation Plan Development

The Midwest ISO staff works collaboratively with Transmission Owners and stakeholders to review and develop mitigation plans. Midwest ISO staff presented the MTEP 09 projects to stakeholders at the first round of Subregional Planning Meetings in December. Proposed plans were then reviewed again in additional detail at the 2nd round of Subregional Planning Meetings (SPM) in May, after Midwest ISO staff had reviewed and performed preliminary analysis of the project proposals, submitted earlier, at the beginning of the planning cycle. Feedback from stakeholders was incorporated into the project review process. The 3rd and final round of SPMs were then held for each of the three Planning regions, presenting the final list and details of projects moving forward for Midwest ISO Board of Directors (BOD) approval in 2009. Cost allocation of all RECB eligible projects was also presented at this meeting. Details on information requirements and timelines are documented in Section 6.1.1.

The Midwest ISO transmission system is divided into three Planning regions – West, Central, and East - to facilitate the MTEP study and Subregional Planning Meetings. Midwest ISO Staff members are assigned Transmission Owners in each planning region. Midwest ISO Transmission Owning members and other interested stakeholders participated in the MTEP study and development of mitigation plans.

During the MTEP planning cycle, the Planning Subcommittee (PS) stakeholder group reviews MTEP analysis, project recommendations, and the MTEP report. Review of cost allocation of projects recommended for the Midwest ISO Board of Director approval, via the MTEP study, is done by the Planning Subcommittee and a specific stakeholder meeting for the purpose of reviewing the projects eligible for regional cost allocation. The last step in development of the mitigation plan is presentation of the final plan to the Midwest ISO Board of Directors for their review and approval.

6.1.8 Planning for Long-Term Transmission Rights

Long Term Transmission Rights (LTTR's) are Auction Revenue Rights (ARR's) allocated during Stage 1A & Restoration of the annual allocation.

- As long as they are requested, the allocation of last year's LTTRs is guaranteed, even if deemed infeasible.
- The cost of funding infeasible LTTRs is uplifted across all LTTR holders.

FERC requires each transmission organization with an organized electricity market to implement a transmission planning process that accommodates the LTTRs that are awarded by ensuring that they remain feasible. The Midwest ISO has developed, through stakeholder discussions with the Long Term Transmission Rights Planning Working Group and the Planning Advisory Committee, a series of analytical steps to evaluate the reasons for LTTR infeasibility, and to determine the best approach to addressing these infeasibilities. These analyses link LTTR binding constraints to upgrades to be developed through the planning process.

Present planning practices ensure that all base load generation can be delivered to loads reliably. It is recognized that there are some differences in the Infeasible LTTR Study and planning models that can lead to infeasibility where no planned upgrade is identified

- Differences in the modeling of planned outages (included in seasonal Infeasible LTTR Study)
- Modeling detail - Loop flow modeling
- Variation in the nomination patterns.
    - A Market Participant may choose not to re-nominate existing LTTRs, which may cause infeasibility of other LTTRs. New Stage 1A requests that did not exist in the previous allocation may cause the curtailment of LTTRs.
- Expiration of an existing right that provided counterflow to other rights
- Nomination of rights that do not correspond to a physical source in the planning models

Stakeholders agreed that upgrades should not be built to accommodate feasibility of LTTR where no reliability or congestion issue can be identified in real-time or planning studies.

Midwest ISO Planning approach:

- Identify infeasibility and near-infeasibility that has a corresponding planned upgrade that will increase feasibility
- Identify planned upgrades that could benefit LTTR feasibility when implemented or if advanced
- Factor increased feasibility cost benefits (reduced uplift) into the consideration of planning alternatives to an economic or reliability constraint identified in the planning process
- Identify uplifted revenue associated with each binding constraint

In order to include LTTR feasibility considerations in the MISO transmission expansion planning process, an information exchange has been established between the FTR & Pricing Administration (FPA) group performing the ARR Allocation and the Expansion Planning (EP) group responsible for long term transmission planning. The following information is to be provided to the MTEP group by the FPA each year after annual auction:

- A list of curtailed LTTRs in each of the eight allocation cases
- A list of binding constraints causing LTTR curtailment
- A list of the "near-infeasible," most heavily loaded, branches in the Infeasible LTTR Study
- A list of planned outages included in the ARR allocation studies
- Uplift cost associated with the funding of infeasible LTTRs

Results from MTEP 09 Planning Cycle

Section 7 provides the results of the following analyses:

- Upgrades (Planned and Proposed Reliability Projects or economic proposed projects) that are associated with infeasible LTTRs in 2009 allocation
- Constraints with uplifted LTTR revenue that are non-MISO constraints that may be addressed in Joint Planning Processes with other entities
- Constraints with uplifted LTTR revenue that do not correlate to real-time or projected reliability or congestion issues

6.2 Long-Term Plan: 10-20 Year Horizon

To meet FERC Order 890 requirements for the execution of a multi-region planning process that evaluates both economic and reliability projects, several complex and time-intensive processes must be incorporated into the overall planning approach. In order to perform a credible economic assessment, a period of analysis spanning at least 15 years is required. The following broad steps outline the processes necessary to perform an economic assessment and develop high voltage overlays to meet the requirements for each of the Futures evaluated in MTEP 09.

- **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
- **Step 3:** Design preliminary transmission plans for each Future
- **Step 4:** Test for robustness
- **Step 5:** Perform reliability assessment and integration
- **Step 6**: Final design of integrated plans
- **Step 7**: Cost allocation

The flow of the process is outlined in Figure 6.2-1 and subsequently described in greater detail:

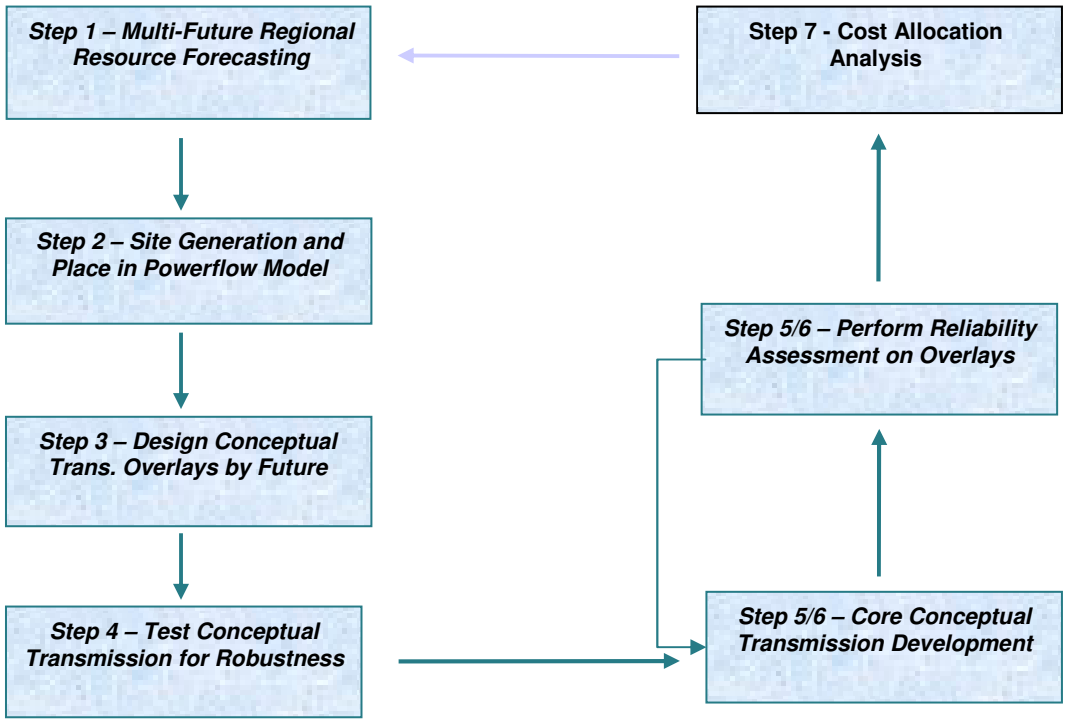

Figure 6.2-1: MTEP'09 Process – Economic Transmission Planning

For the MTEP 09 report, Steps 1 and 2 were refreshed to incorporate updated assumptions. Step 3 was performed for two Futures in coordination with JCSP08 work. The primary focus of MTEP 09 was the development of process that will test robustness and analyze portfolios of transmission consistent with Steps 4 and 5. However, all seven steps of the entire process are described on the following pages.

6.2.1 Step 1: Create a generation portfolio forecast and assessment process

To effectively design and evaluate the impact of new transmission within MTEP 09 regions, a multi-dimensional analysis of future generation implications is necessary. The existing Generation Interconnection Queue provides initial insight into the new generation being proposed within the footprint, but do not provide the extended time horizon required.

A resource forecasting model is required to determine the total resource needs to supplement the Generation Interconnection Queue capacity. The regional resource forecast model determines, on a consistent least-cost basis, the type and timing of new generation and energy efficiency resources that need to be incorporated into the planning models in order to maintain adequate reserves. For this purpose, the Electric Generation Expansion Analysis System (EGEAS) model from the Electric Power Research Institute is used for the three regions in the Midwest ISO footprint. Regional resource forecasts are developed for each of the three planning areas within Midwest ISO. For PROMOD® modeling, forecasts are developed using the same assumption set for regions external to the Midwest ISO. These areas include MAPP, SPP, TVA, PJM, SERC, New York, and New England. Resource expansions are needed for all of these areas so as not to produce generation biases from one region to another which would in turn skew transmission flows. A target reserve margin of 15% was used for all areas, with the exception of PJM where 15.5% was used.

Each area is generation sufficient.

6.2.2 Step 2: Incorporate Generation from Futures into Models

Once the future generation from the regional resource forecast process is developed it must be sited. The 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 questions at the heart of the matter are "do you first site transmission and then build generation, or site likely generation and then build the transmission system to support the generation assumptions?" The indicative siting of generation is likely to be controversial; however, the tariff driven queuing system hasn't provided the time horizons required and, absent the generation assumption, transmission line benefit analyses have no economic under-pinning. Using the fixed in place generation as a starting point, the development of the transmission plan around this fixed generation can proceed to provide integrated reliability and economic enhancements. The future generation is needed for the development of the long-term transmission models and this process must be developed and completed as an input into those models.

Development of 16-year out MTEP 09 transmission models requires that adjustments to the model building process be undertaken. The ten-year out North American Electrical Reliability Corp. (NERC) planning model developed by the Multi-area Modeling Working Group (MMWG) serves as the starting point. Transmission Owners supply known system upgrades, along with load growth forecasts, while the generation additions are incorporated from the Generation Interconnection Queue, wind siting, and the regional resource forecasting process.

With the development of the long-term power flow models, the corresponding PROMOD® security constrained economic dispatch models can then be developed. PROMOD® requires an underlying power flow model for each year that is being studied. The economic evaluation process is structured to analyze future impacts and incorporate sensitivity and risk assessment in the process.

6.2.3 Step 3: Design Preliminary Transmission Plans for Each Future

For MTEP 09 the methodology described below is applied to both the Reference and 20% Wind Energy Futures.

First, Midwest ISO staff uses the power flow and PROMOD® models developed in Step 2 and runs PROMOD® using the same assumptions used in the development of the regional resource forecasts. PROMOD® models corresponding to each of the two Futures are developed, with all of the uncertainty variables (e.g. emissions levels and rates, fuel prices and limitation, resource retirements, etc.) for that particular Future being incorporated. Transmission expansion concepts for the year 2024 were developed for each Future:

- Hourly economic simulations were run to determine the properties of the "Constrained" base system.
- Hourly economic simulations were run to determine the properties of an unconstrained base system or "Copper Sheet".
- "Constrained" system and the "Copper Sheet" differences provides:
    - The total benefit by geographic area that potentially could be "captured" by a conceptual transmission expansion.
    - The areas of economic sources and sinks as shown graphically in Figure 6.2-2. Interface Area boundary identification for monitoring is indicated by the color changes in Figure 6.2-2.
    - A "Monitored" case, based on the unconstrained case, provides the hourly flow information into each Interface Area and the benefit of the change of flow from the "Constrained" case. The benefit provides a rough budget estimate for transmission construction. The flows can be used to estimate the voltage and type of construction of the lines and transformers to transfer energy from the sources to the sinks.
    - Transmission concepts are formed and tested by economic simulation to determine the benefit capture percentage by area, individual hourly line and transformer hourly flow, the Interface flows, and flow not achieved in the "Monitored" case. Transmission constraints that are sorted by the summation of the hourly shadow prices for a year are also produced. Maps of the generation are used to locate transmission through areas requiring future interconnections. The transmission configurations are modified using the information provided. This process is repeated until there are few issues to resolve. Four steps are required to converge on an adequate solution.
    - Line ratings are then placed on the conceptual lines using a rating system as a multiple of the Surge Impedance Loading based on the line length for AC lines. High Voltage Direct Current (HVDC) lines are rated by the HVDC terminal capacity which usually matches the line power transfer capability. HVDC ratings do not change with distance with the exception of provision for losses.

Information on the mitigation of carbon dioxide, and other pollutants, are available from the computer simulations, as are the affects on capacity factors and fuel usage by other generation. These processes are all collaboratively performed with stakeholders in an open planning process.

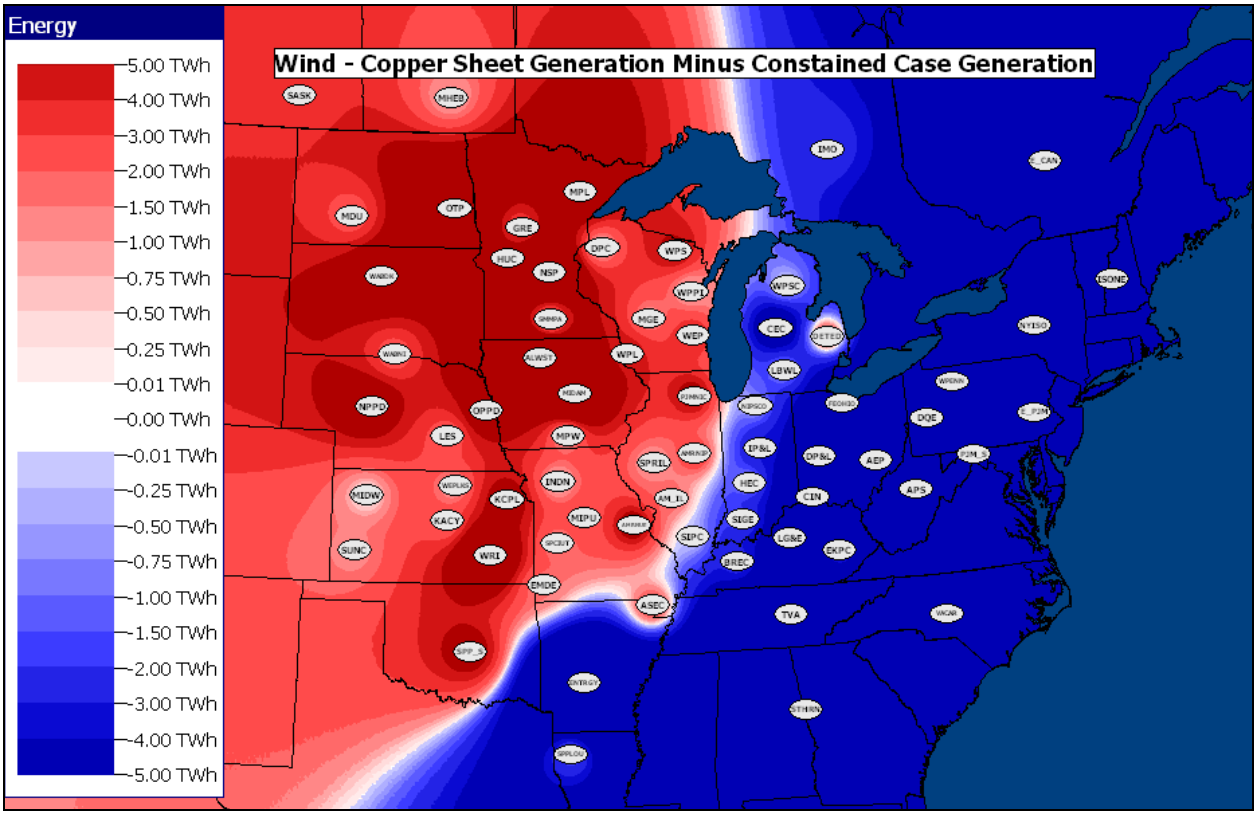

Figure 6.2-2: Location of Economic Sources and Sinks

6.2.4 Step 4: Test Transmission for Robustness

The outcome of the process in Step 3 is the development of transmission plans for each Future being studied. Up to this point the preliminary plans are developed in isolation of each of the other Futures. The ultimate goal is to develop one transmission plan that performs the best under all Futures. The planning process is fraught with uncertainty; the objective is to manage the uncertainty as much as possible. Therefore, each preliminary transmission plan must be analyzed under the uncertainty conditions associated with the development of each of the other plans. For example, if a transmission plan developed under a high Environmental Future performs well under a high Fuel Future and Renewable Energy Future it is considered to be robust; however if the plan developed under one set of Future conditions does not perform well under other Futures then potential adjustments to the transmission plan will need to be evaluated.

To perform the robustness tests, each preliminary plan is tested under the uncertainties used to develop each of the other Futures and their associated transmission plans. A set of output attributes for making the value comparisons are used for the comparison process. Such output attributes could consist of the following:

- LOLE/Reserve margin effects
- Short and long-term cost metrics
- Investor impacts
- Economic development impacts
- Degree of difficulty in implementing
- Environmental
- National security implications

6.2.5 Step 5: Consolidate Overlays

Each conceptual transmission overlay is comprised of multiple lines and line segments. It is not feasible to test all combinations of line segments and lines, as performed in a dynamic program such as EGEAS, for capacity expansion. Instead, the value of each line segment, in combination with all other segments, is best obtained from a PROMOD® analysis. However, the PROMOD® model for the Eastern Interconnection contains extensive data and is an hourly chronological model that requires 3-5 days, on average, to complete a single year 2024 simulation. Running all combinations of line segments in the development of portfolios is clearly not a feasible option. Alternate approaches are required. The use of a screening level model to test line segments for a subset of the 8,760 hours per year, possibly 100-200 hours is under evaluation for use.

One advantage of evaluating multiple Futures is to gain insight into what configurations produce value. If the same line appears in multiple Futures, it is a good indication that it is robust and would result in a less future regrets than a line that does not. Using engineering judgment in combination with screening tools allows for the development of meaningful portfolios of projects which can then be tested in detail in PROMOD®. Once a set of portfolios are developed, based on the conceptual overlays, detailed power flow studies are needed to identify reliability issues and modify the portfolios as needed.

Section 10.5 introduces a process that the Midwest ISO has been developing and will continue to develop through future stakeholder interaction. This process will look at both robustness testing and portfolio development.

Portfolios identify discreet sets of lines that can be pursued for development if all of the conditions are met. In order to build the enabling transmission to support future generation growth and new energy policy, a number of conditions must first be met. These conditions precedent to infrastructure investment are described in Section 4.6. It may be possible to proceed with some level of increased transmission build-out after meeting a subset of these conditions; however, construction of an overlay system equivalent to the current interstate highway system will require all conditions to be met across the Eastern Interconnection.

6.2.6 Step 6: Evaluation of Conceptual Transmission for Reliability

The reliability of the MTEP 09 region is tested for 2018 in the parallel reliability study that is the focus of Section 7 of this report. The 2018 reliability assessment is a stand alone study, and is only indirectly tied to the economic assessment and development of a conceptual overlay through the common power flow model. The conceptual overlays developed through the economic assessment portion of MTEP 09, which is the subject of Section 10 of this report, need to be tested for their reliability benefits to identify issues that can be addressed.

TVA has taken on the task of developing the updated 2018 reliability model with the economic overlay components for both the Reference and 20% wind energy overlays. The objective is to determine the reliability based value the overlays can contribute. As value driven regional expansions are justified, traditionally developed peak-hour based reliability plans will be affected and the combined impact has to be understood to produce a lower cost system. The economic overlays have reliability value and this step is to determine the extent of that value. This evaluation is currently on-going and adjustments to the conceptual overlays will be required based upon the reliability assessment.

6.2.7 Step 7: Cost Allocation

Cost allocation of the overlays is not addressed in MTEP 09. Cost allocation is mentioned in this section solely to recognize that it is the single most important issue impacting the development of regional and multi-regional high voltage transmission.

Cost allocation mechanisms vary across the Eastern Interconnection. There is not a single concept for effectively aligning the amount that an entity pays with the amount that the same entity benefits from a project. The whole concept of who benefits, and by how much, is one of the most contentious issues that the Midwest ISO faces. Any project will have more or less value to one area relative to another. The value of the project rests in what output attributes are considered in the determination of value. Minimization of existing costs may be attractive to one area while the minimization of long-term cost is to another. Access to renewable resources may be the primary driver for one constituency while local jobs may be a priority and focus in another.

Section 7: Near and Long Term Reliability Analysis

7.1 New Planning Projects

This section lists the projects which are moving to Appendix A as part of MTEP 09. These projects provide mitigations for reliability issues or for improved market efficiency.

Note that Appendix A is a rolling list which includes all previously approved projects plus those approved in MTEP 09. 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 is one that was approved in a prior MTEP. One with the B>A designation was either in Appendix B in prior MTEP cycle or was in Appendix C in the beginning of MTEP 09 cycle and as needs were identified, designation changed from C>B and is now being recommended for Appendix A. The projects in Table 7-1 are recommended by the Midwest ISO staff for approval by the Board of Directors in this MTEP 09. The table 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)
  - Regionally Beneficial Projects (RBP)
  - Other
- Share Status
- Expected In Service Date
- Estimated Cost
- Facility under Midwest ISO functional control or with agency agreement

Appendix D1 file contains the complete project justifications for those interested in additional project information. The project's region is indicated in first column in Table 7-1.

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
Central	AmerenIL	2269	South Bloomington 138 kV Capacitor Bank	Install an 80 MVAR, 138 kV Capacitor Bank at the South Bloomington Substation	IL	BaseRel	Not Shared	$1,224,100	6/1/2009	Planned	B>A	Y
Central	AmerenIL	2271	Hennepin-Oglesby Line 1556 Term. Equipment	Upgrade terminal equipment at Hennepin to match line conductor capability (1360 A summer emergency)	IL	BaseRel	Not Shared	$902,000	6/1/2009	Planned	B>A	Y
Central	AmerenIL	2277	Steelville Sub. 138 kV Bus-Tie	Rconnect 2-CT's to 1000 A	IL	BaseRel	Not Shared	$50,000	6/1/2009	Planned	B>A	Y
Central	AmerenIL	2278	Mt. Vernon, West Bus-Tie	Upgrade bus conductor to 1200 A summer normal capability	IL	BaseRel	Not Shared	$30,000	6/1/2009	Planned	B>A	Y
Central	AmerenIL	2276	Clinton Route 54 Sub. Bus-Tie	Reconnect 600 A CT to 1200 A	IL	BaseRel	Not Shared	$50,000	12/1/2009	Planned	B>A	Y
Central	AmerenIL	2059	Centerville Breaker Addition	Install a 138 kV PCB at Centerville Substation to replace normally-open 138 kV Switch #1497. Minimum capability 2000 A. New breaker is to be operated normally closed.	IL	BaseRel	Not Shared	$1,139,000	6/1/2010	Proposed	B>A	Y
Central	AmerenIL	2063	North Coulterville-230/138 kV Transformer Upgrade	Replace existing 140 MVA, 230/138 kV transformer with a 225 MVA unit. Install new 230 kV circuit switcher and disconnect switch. Install new potential transformers for station power and upgrade the wave trap on the Coulterville-Tilden 138 kV line	IL	BaseRel	Not Shared	$1,251,000	6/1/2010	Proposed	B>A	Y
Central	AmerenIL	2274	Oglesby Substation 138 kV Breaker Replacements	Replace 5-138 kV circuit breakers and CT's, and a wave trap on 138 kV Line 1516 with new equipment having a minimum continuous current capability of 1,200 A	IL	BaseRel	Not Shared	$1,05 7,000	6/1/2010	Planned	B>A	Y
Central	AmerenIL	2281	Mt. Vernon-Ashley 138 kV	Replace 2-600 A, 138 kV disconnect switches at Ashley terminal with 1200 A switches	IL	BaseRel	Not Shared	$64,000	6/1/2010	Planned	B>A	Y
Central	AmerenIL	2284	Turkey Hill-S. Belleville 138 kV Line 1532	Replace terminal equipment at both ends to 1600 A continuous capability	IL	BaseRel	Not Shared	$471,000	6/1/2010	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
Central	AmerenIL	2270	Hennepin-Oglesby Line 1516 Term. Equipment	Replace three 138 kV breakers and wave trap in the Hennepin Substation Increase clearances to ground on 14.46 miles of 795 kcmil ACSR from Hennepin to the Ottawa tap Upgrade Hennepin to Oglesby 138 kV terminal equipment to 1,200 A	IL	BaseRel	Not Shared	$2,525,000	6/1/2011	Planned	B>A	Y
Central	AmerenIL	2279	Grand Tower-Steeleville 138 kV Reconductor	Reconductor 6.19 miles of 477 kcmil ACSR to carry 1200 A under summer emergency conditions	IL	BaseRel	Not Shared	$1,866,000	6/1/2011	Planned	B>A	Y
Central	AmerenIL	2287	Stallings-E. Collinsville 138 kV Line Upgrades (Line 1426)	Upgrade terminal equipment at Stallings and East Collinsville to a minimum 1,600A capability Increase ground clearance on 8.59 miles of 138 kV line from Stallings to East Collinsville.	IL	BaseRel	Not Shared	$1,395,000	6/1/2011	Proposed	B>A	Y
Central	AmerenIL	2472	New 345 kV Supply at Fargo Substation	Tap existing 345 kV line from Duck Creek to Tazewell and create new Maple Ridge Substation ($6.5M) Build a new supply line to the Fargo Substation by extending 20 miles of 345 kV from the new Maple Ridge Substation ($50.1M) Create Fargo Station and install 560 MVA 345/138 kV Transformer ($9.4M)	IL	BaseRel	Shared	$66,019,000	12/1/2016	Planned	B>A	Y
Central	AmerenIL	2272	Hennepin-E. Kewanee 138 kV-Term. Equipment	Replace 600 A CT at Hennepin with 1200 A unit	IL	Other	Not Shared	$71,000	12/1/2009	Planned	B>A	Y
Central	AmerenIL	2273	Supply to LaFarge Customer Substation	Provide 161 kV supply to customer substation	IL	Other	Not Shared	$570,000	12/1/2009	Planned	B>A	Y
Central	AmerenIL	2764	Pana North Transformer Upgrade	Replace existing 400 MVA unit with an existing spare transformer with 560 MVA capacity	IL	Other	Not Shared	$5,300,000	12/31/2010	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
Central	AmerenIL	2285	South Belleville 138-34.5 kV Substation	Upgrade terminal equipment for South Belleville-17th Street circuit position to 1,600A continuous capability. Reconductor 2.57 miles of 138 kV conductor between South Belleville and the Belleville 17th Street tap	IL	Other	Not Shared	$2,642,000	6/1/2011	Planned	B>A	Y
Central	AmerenIL	2829	Coffeen-Coffeen North 345 kV	Install a second 345 kV bus tie between Coffeen and Coffeen N ring busses; add a ring bus position at each station. Replace Coffeen N. wave trap and Ramsey E. switch to increase line rating from 956 MVA to 1195 MVA.	IL	RegBen	Shared	$5,591,000	12/31/2010	Planned	B>A	Y
Central	AmerenMO	2282	Selma-St. Francois 138 kV Line Reconductor	Reconductor 15.5 miles of paralleled 4/0 Cu conductor to 1200 A summer emergency capability	MO	BaseRel	Not Shared	$4,650,000	12/1/2010	Planned	B>A	Y
Central	AmerenMO	1240	Reconductor Sioux-Huster-1 and-3 138 kV	Reconductor 9.1 miles of 138 kV line on Sioux-Huster 1 and 3 lines	MO	BaseRel	Shared	$12,966,000	6/1/2012	Proposed	B>A	Y
Central	AmerenMO	2787	North Park 138-12.47 kV Substation	Construct a new 138/12 kV substation with two 33MVA transformers, sourced from 138 kV Page-Berkeley Lines 1 and 2	MO	Other	Not Shared	$2,650,000	6/1/2009	Planned	B>A	Y
Central	AmerenMO	2275	AECI Spalding Substation Connection	Tap Peno Creek-Palmyra 161 kV for Spalding connection	MO	Other	Not Shared	$749,100	12/1/2009	Planned	B>A	Y
Central	DEM	2376	Pierce 345/138 kV TB B & A Replacement	Replacement of failed Pierce 125 MVA TB "B" plus 125 MVA TB "A" with 400 MVA system spare & reconductor 138 kV cir 1889	OH	BaseRel	Not Shared	$1,541,334	5/1/2009	In Service	B>A	Y
Central	DEM	1567	Rockies Express-Install 138 kv Ring Bus	Rockies Express-Inst Ring Bus-Install Four Breaker 138 kV ring bus & associated equipment and 2-138/13.1 distribution Xfmrs; on the 5689 ckt	OH	BaseRel	Not Shared	$500,000	6/1/2009	In Service	B>A	Y
Central	DEM	2374	Evendale Replace 138kv CB 952	Replace CB 952 and disconnect sws at Evendale Sub with 2000 Amp rated eq, upgrade F4685 metering @ both Sta. (Metering was 1255A limmited-New rating will be 1600A-382 mva)	OH	BaseRel	Not Shared	$500,000	6/1/2009	In Service	B>A	Y
Central	DEM	2373	Lafayette Concord Jct to Laf Industry S.-138 kV uprate	Lafayette Concord Jct to Laf Industry S.-13808 ckt-uprate 397acsr conductor to 100C-one h-frame structure to replace	IN	BaseRel	Not Shared	$11,400	12/31/2009	Planned	B>A	Y

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Central	DEM	2149	West End 138kv bus tie and 1389 line bkrs	West End substation-Install a 138 kV circuit breaker to tie the east and west 138 kV busses together and a line breaker in the 1389 ckt	OH	BaseRel	Not Shared	$1,040,000	6/1/2010	Planned	B>A	Y
Central	DEM	2151	Wilder 138 kV-5985 reactors & wavetrap	Wilder Sub-Install 138 kV, 3.8 Ohm reactors in ckt 5985; replace 138kv-5985 1200A wavetrap with 1600A	OH	BaseRel	Not Shared	$690,000	6/1/2010	Planned	B>A	Y
Central	DEM	2375	G941 Yankee-69 kV New Sub for SunCoke (Middletown Coke Co. Inc) generator.	Install 69kv substation and 5 brkr ring bus on Yankee Rd. for SunCoke (Middletown Coke Co. Inc) generator, loop F5661 & F5666 through station	OH	GIP	Shared	$4,440,000	12/31/2010	Planned	B>A	NT
Central	DEM	2152	WVPA Anson North new 69kv dist sub	WVPA Anson N. Jct-DEM to Install two single 1200 amp 69kv line switches with provisions for tap line-in the 69186 line between Whitestown and Brownsburg N. Jct to serve new WVPA sub	IN	Other	Not Shared	$86,000	3/1/2009	In Service	B>A	NT
Central	DEM	1572	Wards Corner new 138-13.1 KV substation	Loop the F9482 ckt through a new substation with a 138-13.1 KV-22.4 mva xfmr	OH	Other	Not Shared	$656,000	6/1/2009	In Service	B>A	Y
Central	DEM	1888	Liberty-new 69/13 kV distribution sub	new Liberty 22.4MVA 69-13.09 kV sub and approx. 5.5 mile-69kv line-954 kcmil 45/7 ACSR-from Allen sub	OH	Other	Not Shared	$3,100,000	6/1/2009	Under Construction	B>A	NT
Central	DEM	2336	HE Martinsville Park Ave 69 kV Switches	HE Martinsville Park Ave (new sub)-Install two one-way 1200amp 69 kV line swiches at tap for new HE sub in 6903 line	IN	Other	Not Shared	$150,000	6/1/2009	In Service	B>A	NT
Central	DEM	2338	HE Solar Sources Portal #1-69 kV Switches	HE Solar Sources Portal #1-install 69 kV-1200A line Switches in the 6963 ckt to serve new HE mine load	IN	Other	Not Shared	$62,363	6/1/2009	In Service	B>A	NT
Central	DEM	1562	Bloomington Rockport Rd	Build 22.4MVA 138/12 kV sub w/ 2 12 kV exits in Bloomington, IN near intersection of SR37 & Rockport Road. Tap 13837 line.	IN	Other	Not Shared	$513,000	8/1/2009	Under Construction	B>A	Y
Central	DEM	2335	HE Gateway Ind Pk 69 kV Switches	HE Gateway Industrial Park (new sub)-Install two one-way 1200amp 69 kV line swiches at tap for new HE sub in 6918 line	IN	Other	Not Shared	$103,000	8/1/2009	Under Construction	B>A	NT
Central	DEM	1882	Carmel 69 kV to Towne Rd Jct ckt 6989 rebuild	Reconductor 69 kV-6989 line from Carmel 69 kV to Towne Rd N. Jct with 954 ACSR @ 100C, Shell Jct. Switch to be upgraded from 600 amp to 1200 amp	IN	Other	Not Shared	$834,141	12/1/2009	Planned	B>A	NT
Central	DEM	1885	Todhunter to Carlisle 69 kV-F5661 line uprate	Todhunter to Carlisle 69 kV-Feeder 5661 Uprate to 100C	OH	Other	Not Shared	$561,600	12/1/2009	Planned	B>A	NT

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Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
Central	DEM	2138	Greenwood HE Gilmore 69 kV Switches	Greenwood HE Gilmore-Upgrade (2) 69 kV line switches for 1200 amp capacity (or replace if required) in the 69102 line	IN	Other	Not Shared	$183,000	12/1/2009	Planned	B>A	NT
Central	DEM	1883	Brown to S. Bethel 69 kV-F5863 line uprate	Brown to S. Bethel 69 kV line uprate-Modify spans in F5863 as required to provide clearance for 100C operation-477 kcmil ACSR conductor	OH	Other	Not Shared	$97,057	12/31/2009	Planned	B>A	NT
Central	DEM	1884	Wilder to Kenton 69 kV-F965 line uprate	Wilder to Kenton 69 kV line uprate-Modify spans in 69 kV Feeder 965 as required to provide clearance for 100 C operation-477 kcmil ACSR conductor	KY	Other	Not Shared	$128,975	12/31/2009	Planned	B>A	NT
Central	DEM	2126	Martinsville SE Jct replace line switches	600A switches 1&2 to be replaced with 1200A switches in the 6903 line	IN	Other	Not Shared	$146,000	12/31/2009	Planned	B>A	NT
Central	DEM	2141	Terminal Sub Phase 2 Rehab	Terminal Substation-replace 138kv bank breaker and moving from line terminal 1782 over to main 138kv bus #1; replacing: 345kv(4514) wave trap, 138kv(1782 and 7481) wave traps	OH	Other	Not Shared	$1,269,000	12/31/2009	Under Construction	B>A	Y
Central	DEM	1879	KY University 138 kV Bus and Dist Bk addition	Reconfigure 138 kV bus for and add on a 22.4 MVA (2nd) distribution xfmr	KY	Other	Not Shared	$90,513	6/1/2010	Planned	B>A	Y
Central	DEM	2150	Plainfield West 69-12kv Distribution Sub	Plainfield West new dist sub; 22.4MVA w/4 12 kV exits; loop 69125 ckt through sub	IN	Other	Not Shared	$161,000	6/1/2010	Planned	B>A	NT
Central	DEM	2131	Whiteland Jct to Madison Ave Jct Uprate 69	Whiteland Jct to Madison Ave Jct uprate 1.29 miles 69 kV line section for 100C operation	IN	Other	Not Shared	$28,000	6/30/2010	Planned	B>A	NT
Central	DEM	1647	Carmel SE 69/12 KV new distribution substation	Construct Carmel SE Bank 1 22.4MVA bank with 2 exits-extend a new radial 69kv from Carmel 146th St (no new bkr-share dist bk terminal)	IN	Other	Not Shared	$2,000,000	6/1/2011	Planned	B>A	NT
Central	DEM	2128	Martinsville to Martinsville SE 69 kV Jct Uprate	Martinsville to Martinsville SE 69 kV Jct Uprate 6903 line's 336acsr to 100C operation	IN	Other	Not Shared	$439,000	6/1/2011	Planned	B>A	NT
Central	DEM	2334	Fishers 106th St 69/12kv New Sub	New Fishers 106th St 69/12 kv sub: Construct 69 kV line in and out of sub and 69kv bus including 69kv breaker	IN	Other	Not Shared	$174,000	6/2/2011	Planned	B>A	NT
Central	DEM	1880	Columbia 138 kV-22.4MVA Sub	Columbia 138 kV-22.4MVA Sub-New site or purchase and rebuild existing Siemens Sub #537-in F5484 between Warren and Maineville	OH	Other	Not Shared	$215,000	12/31/2011	Planned	B>A	Y

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Central	DEM	2148	Cadiz to Milner's Corner Jct 69kv reconductor	Cadiz to Markleville to Milner's Corner J-Reconductor 69kv-69131 ckt-9.24 mile section with 477ACSR@100C; Replace 69kv three way switch at Milner's Corner Jct with three one way 1200A switches; Upgrade the Markleville 600A switches #1 and #2 to 1200A	IN	Other	Not Shared	$3,860,000	5/1/2012	Planned	B>A	NT
Central	DEM	2133	Franklin to Forsythe new 69 kV line	Franklin 230 sub to Forsythe 69 sub-Build new 3.5 mile 69 kV line; new line terminal at Forsythe end only	IN	Other	Not Shared	$1,030,000	6/1/2012	Planned	B>A	NT
Central	DEM	2154	Carmel Rohrer Rd 69/12kv New Sub	Carmel Rohrer Rd 69/12-22.4MVA sub to looped through the 6989 ckt. at or near the existing Carmel Shell Oil tap	IN	Other	Not Shared	$591,143	6/1/2012	Planned	B>A	NT
Central	DEM	2331	Shelbyville NE to Knauf 69kv-6946 ckt. Reconductor	Shelbyville NE to Knauf Reconductor 1.75 miles of 397ACSR on 6946 ckt. with 954acsr@100C	IN	Other	Not Shared	$777,000	6/1/2012	Planned	B>A	NT
Central	DEM	2332	Zionsville Turkeyfoot to Zionsville 96th St Jct 69 kV-69155 ckt. Reconductor	Zionsville Turkeyfoot to Zionsville 96th St Jct Reconductor 1.59 mile 69 kV-69155 ckt with 954ACSR@100C	IN	Other	Not Shared	$704,000	6/1/2012	Planned	B>A	NT
Central	DEM	2132	Frances Creek 69 kV capacitor	Frances Creek Install 36MVAR 69 kV capacitor bank	IN	Other	Not Shared	$615,500	6/30/2012	Planned	B>A	NT
Central	DEM	2153	Mohawk to Lee Hanna 69 kV reconductor	Mohawk to Lee Hanna 69 kV reconductor 69130 ckt (5.27 mi) with 954acsr@100C	IN	Other	Not Shared	$2,317,000	6/1/2013	Planned	B>A	NT
Central	DEM	2327	Speed to HE Bethany 69 kV-6955 Reconductor Ph1	Speed to HE Bethany 69 kV-6955 Reconductor Ph1-Replace 5.2 miles of 3/0 ACSR with 477 ACSR (new limiter 4/0acsr)	IN	Other	Not Shared	$1,560,000	6/1/2013	Planned	B>A	NT
Central	DEM	2127	Martinsville 69163-1 switch replacement	69163-1 switch replacement near tap to HE Cope with 1200A switch	IN	Other	Not Shared	$40,000	6/1/2019	Planned	B>A	NT
Central	IPL	2053	Petersburg 345/138 kV East and West Autotransformers	Replace and upgrade existing East and West 345/138 kV autotransformer at Petersburg Substation	IN	BaseRel	Shared	$15,400,000	6/1/2012	Planned	B>A	Y
Central	Vectren (SIGE)	2461	Dubois Sub Z84 terminals	Add 1 new 138 kV terminal to existing sub to avoid 3 term line, breaking up Duff-Dubois-Culley 138 kV line	IN	BaseRel	Not Shared	$1,000,000	6/1/2010	Planned	B>A	Y
Central	Vectren (SIGE)	2465	Leibert Rd 138/12 kV Substation	New 138/12 kV Substation for load growth	IN	Other	Not Shared	$3,000,000	6/1/2011	Planned	B>A	NT
Central	Vectren (SIGE)	2466	Roesner Rd 138/12 kV Substation	New 138/12 kV Substation for load growth	IN	Other	Not Shared	$3,000,000	6/1/2013	Planned	B>A	NT
East	FE	2263	Brookside-Cloverdale 138 kV Line-Reconductor	Reconductor 20.38 miles of 336,4 ACSR with 336.4 ACSS/TW.	OH	BaseRel	Not Shared	$1,169,400	6/1/2010	Planned	B>A	Y

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Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	FE	2753	BP Oil-138 kV Service	138 kV service to BP Oil. Loop two existing 138 kV lines into new BP Substation	OH	BaseRel	Not Shared	$800,000	11/1/2011	Planned	B>A	Y
East	FE	1612	Cranberry Substation	Construct a 500/138 kV Sub with four exits in the Cranberry/Adams Township area.	PA	BaseRel	Shared	$37,738,043	6/1/2012	Planned	B>A	Y
East	FE	2814	Midway-Richland-Wauseon 138 kV line-Reconductor	Reconductor the Naomi Jct-Wauseon 138 kV line section (4.98 miles) from 336.4 ACSR to 795 ACSR. Modify setting or replace thermal relay at Wauseon	OH	BaseRel	Not Shared	$650,000	6/1/2013	Planned	B>A	Y
East	FE	2769	ZincOx-New Customer Tap	New 20 MW to 30 MW customer being tapped to the Vulcan-Wauseon between York and Delta		Other	Not Shared	$200,000	11/30/2009	Planned	B>A	Y
East	FE	2249	Inland Substation-Cleveland Public Power 4th Interconnect	Install a 138 kV exit with breaker and add a breaker to the Q-14-IN-IV at Inland Substation. Replace an overdutied Q-18 breaker at Ivy Substation.	OH	Other	Not Shared	$895,500	9/1/2010	Planned	B>A	Y
East	FE	2788	Hitchcock Reconfigure			Other	Not Shared	$982,000	10/1/2010	Planned	B>A	Y
East	FE	1920	Shinrock/Johnson area 138-69 kV Substation	Build a 138/69 kV substation with a high side ring bus on the Beaver-Brookside 138 kV Line. Install 3-69 kV exits and necessary reconductoring on the Johnson 69 kV Line.	OH	Other	Not Shared	$6,091,601	6/1/2011	Planned	B>A	Y
East	FE	2791	Toledo 69 kV Line Reconfigurations Associated with BP Oil 138 kV Service Project	Reconfigure the existing 69 kV lines: BP Oil (6896) to Locust (6815) line, BP VRDS (6885) to Ironville (6965) line, BP ISO2 (6899) to Ironville (6967) line tpo create the following 69 kV lines: A new Ironville (6967) to Locust (6815) line and a new Ironville (6965) radial 69 kV line (to CSX-Toledo, Union Oil and N. O. switch 6647). The reconfiguration is necesary due to the project to rpovide 138 kV servie to BP Oil. (RPA WOH-09-080721-152149)		Other	Not Shared	$198,900	6/1/2011	Proposed	B>A	Y

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East	FE	2790	69 kV line to connect 69 kV radials at Hillcrest (Y-194) and Grant St (Y-196)	Build 69 kV line section (approx 1.6 mi) from Grant St 69 kV Substation to Hillcrest Substation. Replace Y-196 line exit relays at Cedar Street Substation with SEL 321 and SEL 311B relays to replace basic overcurrent relays presently installed for radial circuit. Install SCADA controlled MOAB switches at Grant Street and Hillcrest for line sectionalizing. The switch at Grant Street towards Hillcrest will be equipped with a vacuum interruptor.	OH	Other	Not Shared	$610,635	6/1/2011	Planned	B>A	Y
East	FE	2264	Greenford Substation-Install 69 kV, 14.4 MX Cap Bank	Install a 14.4MVAR, 69 kV cap bank at Canfield.	OH	Other	Not Shared	$200,000	6/1/2012	Planned	B>A	Y
East	FE	2789	Masury-Salt Springs Cap Bank Addition	Install 21.6 MVAR capacitor bank at Vienna 69 kV substation. Bank installation will include free standing disconnect switch, cap switcher, CT's, cap bank, plus all associated foundations and pads.		Other	Not Shared	$580,000	6/1/2012	Proposed	B>A	Y
East	FE	1607	Hanna Sub-Loop the Cham-Mansfield 345 kV Line in	Loop the Chamberlin-Mansfield 345 kV Line in and out of Hanna Substation creating a Chamberlin-Hanna and a Hanna-Mansfield 345 kV Line.	OH	Other	Not Shared	$5,597,657	6/1/2013	Proposed	B>A	Y
East	FE	2120	Keystone Substation, New 138-36 kV Substation	Construct 2 138 kV loops to a new Keystone 138-36 kV distribution substation for additional support of the area	OH	Other	Not Shared	$4,000,000	12/31/2013	Planned	B>A	Y
East	FE	2266	Pine Substation-Add (1) 100/134 MVA 138/69 kV transformer unit	Add one new 100/134 MVA unit with the ability to be switched to either East or West bus at Pine Substation.	PA	Other	Not Shared	$4,244,800	6/1/2015	Proposed	B>A	Y
East	ITC	2518	Bloomfield-Wheeler 120 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$20,000	6/1/2010	Planned	B>A	Y
East	ITC	2538	NERC Relay Loadability Compliance 2010	Upgrade relays throughout system	MI	BaseRel	Not Shared	$2,250,000	12/31/2010	Planned	B>A	Y
East	ITC	2539	NERC Relay Loadability Compliance 2011	Upgrade relays throughout system	MI	BaseRel	Not Shared	$2,250,000	12/31/2011	Planned	B>A	Y
East	ITC	2544	Oakwood	New distribution interconnection served from River Rouge-Navarre 120 kV circuit	MI	Other	Not Shared	$200,000	7/1/2009	Planned	B>A	Y
East	ITC	2543	MacSteel GOAB	Install 3-way GOAB switch at North Star Tap point on Custer-Monroe 120 kV circuit	MI	Other	Not Shared	$200,000	7/31/2009	Planned	B>A	Y
East	ITC	1860	Breaker Replacement Program 2009	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2009	Planned	B>A	Y

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East	ITC	1862	Cable Termination Replacement 2009	Replace high pressure gas filled underground cable terminations throughout system.	MI	Other	Not Shared	$3,000,000	12/31/2009	Planned	B>A	Y
East	ITC	1864	Relay Betterment Program 2009	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2009	Planned	B>A	Y
East	ITC	2523	Capacitor Replacement 2009	Replace capacitor banks	MI	Other	Not Shared	$565,000	12/31/2009	Planned	B>A	Y
East	ITC	2526	Potential Device Replacement 2009	Replace aging potential devices	MI	Other	Not Shared	$300,000	12/31/2009	Planned	B>A	Y
East	ITC	2529	Power Plant Control Relocation 2009	Relocate substation controls currently located in power plant control rooms	MI	Other	Not Shared	$1,200,000	12/31/2009	Planned	B>A	Y
East	ITC	2532	Wood Pole Replacement 2009	Replace deteriorating wood pole	MI	Other	Not Shared	$1,200,000	12/31/2009	Planned	B>A	Y
East	ITC	2535	Synchronizing Sites 2009	New 120 kV synchronizing sites	MI	Other	Not Shared	$565,000	12/31/2009	Planned	B>A	Y
East	ITC	2540	Genoa-Latson	Replace all line structures and insulators.	MI	Other	Not Shared	$1,500,000	6/1/2010	Planned	B>A	Y
East	ITC	2545	Marathon/Navarre	New distribution interconnection served from Navarre substation	MI	Other	Not Shared	$640,000	9/1/2010	Planned	B>A	Y
East	ITC	1861	Breaker Replacement Program 2010	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2010	Planned	B>A	Y
East	ITC	1863	Cable Termination Replacement 2010	Replace high pressure gas filled underground cable terminations throughout system.	MI	Other	Not Shared	$3,000,000	12/31/2010	Planned	B>A	Y
East	ITC	1865	Relay Betterment Program 2010	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2010	Planned	B>A	Y
East	ITC	1872	Scio	Distribution Interconnection to add new 120/41 kV transformer. Loops the Lark-Spruce 120 kV circuit into the station.	MI	Other	Not Shared	$3,000,000	12/31/2010	Planned	B>A	Y
East	ITC	2524	Capacitor Replacement 2010	Replace capacitor banks	MI	Other	Not Shared	$565,000	12/31/2010	Planned	B>A	Y
East	ITC	2527	Potential Device Replacement 2010	Replace aging potential devices	MI	Other	Not Shared	$300,000	12/31/2010	Planned	B>A	Y
East	ITC	2530	Power Plant Control Relocation 2010	Relocate substation controls currently located in power plant control rooms	MI	Other	Not Shared	$1,200,000	12/31/2010	Planned	B>A	Y
East	ITC	2533	Wood Pole Replacement 2010	Replace deteriorating wood pole	MI	Other	Not Shared	$1,200,000	12/31/2010	Planned	B>A	Y
East	ITC	2536	Synchronizing Sites 2010	New 120 kV synchronizing sites	MI	Other	Not Shared	$565,000	12/31/2010	Planned	B>A	Y
East	ITC	2541	Hunters Creek-Robin-Wabash	Install double groundwire peaks and second shield wire.	MI	Other	Not Shared	$2,400,000	12/31/2010	Planned	B>A	Y
East	ITC	2542	Hunters Creek-Stratford-Pointiac	Install double groundwire peaks and second shield wire.	MI	Other	Not Shared	$1,100,000	12/31/2010	Planned	B>A	Y
East	ITC	2546	East Ann Arbor	New distribution interconnection served from Coventry-Superior 120 kV circuit	MI	Other	Not Shared	$5,650,000	5/1/2011	Planned	B>A	Y

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Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	ITC	2519	Breaker Replacement Program 2011	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2011	Planned	B>A	Y
East	ITC	2520	Cable Termination Replacement 2011	Replace high pressure gas filled underground cable terminations throughout system.	MI	Other	Not Shared	$3,000,000	12/31/2011	Planned	B>A	Y
East	ITC	2521	Relay Betterment Program 2011	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2011	Planned	B>A	Y
East	ITC	2525	Capacitor Replacement 2011	Replace capacitor banks	MI	Other	Not Shared	$565,000	12/31/2011	Planned	B>A	Y
East	ITC	2528	Potential Device Replacement 2011	Replace aging potential devices	MI	Other	Not Shared	$300,000	12/31/2011	Planned	B>A	Y
East	ITC	2531	Power Plant Control Relocation 2011	Relocate substation controls currently located in power plant control rooms	MI	Other	Not Shared	$1,200,000	12/31/2011	Planned	B>A	Y
East	ITC	2534	Wood Pole Replacement 2011	Replace deteriorating wood pole	MI	Other	Not Shared	$1,200,000	12/31/2011	Planned	B>A	Y
East	ITC	2537	Synchronizing Sites 2011	New 120 kV synchronizing sites	MI	Other	Not Shared	$565,000	12/31/2011	Planned	B>A	Y
East	METC	2491	Tallmadge-Wealthy 138 kV ckt. #1	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$60,000	7/1/2009	Planned	B>A	Y
East	METC	1828	Argenta-Palisades 345 kV ckt. 1 & 2	Remove the SAG limit on Argenta-Palisades 345 kV ckt 1& 2. Upgrade terminal equipment at both substations.	MI	BaseRel	Shared	$10,880,000	6/1/2010	Planned	B>A	Y
East	METC	2493	Bullock-Summerton 138 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$100,000	6/1/2010	Planned	B>A	Y
East	METC	2495	Bullock-Warren 138 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$200,000	6/1/2010	Planned	B>A	Y
East	METC	2496	Bullock-Tittabawassee 138 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$420,000	6/1/2010	Planned	B>A	Y
East	METC	2516	NERC Relay Loadability Compliance 2010	Upgrade relays throughout system	MI	BaseRel	Not Shared	$2,250,000	12/31/2010	Planned	B>A	Y
East	METC	2501	Northern Reactive	Install 3 capacitors in the northern part of Michigan	MI	BaseRel	Not Shared	$2,700,001	4/1/2011	Planned	B>A	Y
East	METC	2489	Terminal Equipment upgrade at Tippy	Terminal Equipment upgrade at Tippy	MI	BaseRel	Not Shared	$60,000	6/1/2011	Planned	B>A	Y
East	METC	2500	Murphy Second 345/138 kV Transformer	Install a second 345/138 kV transformer at Murphy substation	MI	BaseRel	Not Shared	$18,446,000	6/1/2011	Planned	B>A	Y
East	METC	2517	NERC Relay Loadability Compliance 2011	Upgrade relay throughout system	MI	BaseRel	Not Shared	$2,250,000	12/31/2011	Planned	B>A	Y
East	METC	662	Weeds Lake	Loop the 345 kV Argenta-Robinson Park 345 kV circuit into a new 345/138 kV EHV substation called Weeds Lake. Build 4 new (approximately 6 miles) 138 kV circuits to loop the two Argenta-Milham 138 kV lines into the substation.	MI	BaseRel	Shared	$39,800,002	6/1/2013	Proposed	B>A	Y
East	METC	2488	Stronach-Tippy 138 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$240,000	6/1/2013	In Service	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	METC	2492	Battle Creek-Verona 138 kV ckt. #2	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$200,000	6/1/2013	Planned	B>A	Y
East	METC	2494	Bullock-Dow Corning 138 kV	Upgrade terminal equipment.	MI	BaseRel	Not Shared	$400,000	6/1/2013	Planned	B>A	Y
East	METC	2474	Harvard Lake	New distribution interconnection served from Four Mile-North Belding 138 kV.	MI	Other	Not Shared	$200,000	6/1/2009	Planned	B>A	Y
East	METC	240	Garfield-Hemphill 138 kV	Terminal equipment upgrade	MI	Other	Excluded	$60,000	8/1/2009	Proposed	B>A	Y
East	METC	2476	Hubbardston Road	New distribution interconnection served from Marquette-Bingham 138 kV.	MI	Other	Not Shared	$170,000	8/1/2009	Planned	B>A	Y
East	METC	2477	Cochran Junction	Install a switch pole and line switch at Cochran junction towards Island Road.	MI	Other	Not Shared	$175,000	10/15/2009	Planned	B>A	Y
East	METC	1839	Acme	New 138/46 kV Bulk Power station served from Keystone-Stover 138 kV circuit. Requires a new 138 kV ring bus at Plum station located at the Clearwater Junction point.	MI	Other	Not Shared	$4,060,000	11/15/2009	Planned	B>A	Y
East	METC	2473	LaBarge	New distribution interconnection served from Gaines-Thompson Rd. 138 kV.	MI	Other	Not Shared	$12,000	12/1/2009	Planned	B>A	Y
East	METC	2479	Chase	CE 138/46 kV transformer upgrade at Chase substation	MI	Other	Not Shared	$12,000	12/1/2009	Planned	B>A	Y
East	METC	2480	Hazelwood	CE to install circuit switcher as high-side protective device for 138/46 kV transformer	MI	Other	Not Shared	$12,000	12/1/2009	Planned	B>A	Y
East	METC	1821	Breaker Replacement Program 2009	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2009	Proposed	B>A	Y
East	METC	1823	Relay Betterment Program 2009	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2009	Proposed	B>A	Y
East	METC	1826	Sag clearance 2009	Identify and remediate inherent sag limitations on heavily loaded METC transmission lines throughout the system.	MI	Other	Not Shared	$3,400,000	12/31/2009	Proposed	B>A	Y
East	METC	2508	Wood Pole Replacement 2009	Replace deteriorating wood pole	MI	Other	Not Shared	$4,500,000	12/31/2009	Planned	B>A	Y
East	METC	2511	Power Plant Control Relocation 2009	Relocate substation controls currently located in power plant control rooms	MI	Other	Not Shared	$1,200,000	12/31/2009	Planned	B>A	Y
East	METC	2512	Battery Replacement 2009	Replace batteries and chargers	MI	Other	Not Shared	$300,000	12/31/2009	Planned	B>A	Y
East	METC	2513	Potential Device Replacement 2009	Replace aging potential devices	MI	Other	Not Shared	$300,000	12/31/2009	Planned	B>A	Y
East	METC	2514	Transformer Monitoring 2009	Install temperature and bushing monitors on EHV transformers	MI	Other	Not Shared	$1,200,000	12/31/2009	Planned	B>A	Y
East	METC	2475	Titus Lake	Distribution interconnection to add a second transformer at Titus Lake.	MI	Other	Not Shared	$4,200,000	6/1/2010	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	METC	2478	Capital Ave	New distribution interconnection served from Battle Creek-Verona #2 138 kV (Line connection change to Battle Creek to Island Road)	MI	Other	Not Shared	$170,000	6/1/2010	Planned	B>A	Y
East	METC	2481	Forrest Grove	New distribution interconnection served from Campbell-Ransom 138 kV circuit.	MI	Other	Not Shared	$170,000	6/1/2010	Planned	B>A	Y
East	METC	2483	Maines Road	New distribution interconnection served from Marshall-Blackstone 138 kV circuit	MI	Other	Not Shared	$170,000	6/1/2010	Planned	B>A	Y
East	METC	2484	Scenic Lake	New distribution interconnection served from Cornell-Tihart 138 kV circuit	MI	Other	Not Shared	$170,000	6/1/2010	Planned	B>A	Y
East	METC	2497	RTU / SCADA Re-direction Program	Install and/or upgrade RTU's and SCADA points throughout system	MI	Other	Not Shared	$12,500,000	6/1/2010	Planned	B>A	Y
East	METC	1822	Breaker Replacement Program 2010	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2010	Proposed	B>A	Y
East	METC	1824	Relay Betterment Program 2010	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2010	Proposed	B>A	Y
East	METC	1827	Sag clearance 2010	Identify and remediate inherent sag limitations on heavily loaded METC transmission lines throughout the system.	MI	Other	Not Shared	$3,400,000	12/31/2010	Proposed	B>A	Y
East	METC	2503	Battery Replacement 2010	Replace batteries and chargers	MI	Other	Not Shared	$300,000	12/31/2010	Planned	B>A	Y
East	METC	2504	Potential Device Replacement 2010	Replace aging potential devices	MI	Other	Not Shared	$300,000	12/31/2010	Planned	B>A	Y
East	METC	2505	Power Plant Control Relocation 2010	Relocate substation controls currently located in power plant control rooms	MI	Other	Not Shared	$1,200,000	12/31/2010	Planned	B>A	Y
East	METC	2506	Transformer Monitoring 2010	Install temperature and bushing monitors on EHV transformers	MI	Other	Not Shared	$1,200,000	12/31/2010	Planned	B>A	Y
East	METC	2509	Wood Pole Replacement 2010	Replace deteriorating wood pole	MI	Other	Not Shared	$3,400,000	12/31/2010	Planned	B>A	Y
East	METC	1806	Canal Jct-Island Rd 138 kV	Rebuild 11 miles of 138 kV line to 954 ACSR	MI	Other	Not Shared	$9,000,000	6/1/2011	Planned	B>A	Y
East	METC	2485	Ironwood	New distribution interconnection served from CE's 138 kV spur on the Ransom-Buck Creek 138 kV.	MI	Other	Not Shared	$12,000	6/1/2011	Planned	B>A	Y
East	METC	2515	Tihart-Oakland (Genoa) 138 kV	Replace all line structures and insulators.	MI	Other	Not Shared	$23,500,000	6/1/2011	Planned	B>A	Y
East	METC	1833	Sag clearance 2011	Identify and remediate inherent sag limitations on heavily loaded METC transmission lines throughout the system.	MI	Other	Not Shared	$3,400,000	12/31/2011	Proposed	B>A	Y
East	METC	2498	Breaker Replacement Program 2011	Replace defective, damaged, or over dutied breakers throughout system.	MI	Other	Not Shared	$5,650,000	12/31/2011	Proposed	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	METC	2499	Relay Betterment Program 2011	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI	Other	Not Shared	$1,200,000	12/31/2011	Proposed	B>A	Y
East	METC	2510	Wood Pole Replacement 2011	Replace deteriorating wood pole	MI	Other	Not Shared	$3,400,000	12/31/2011	Planned	B>A	Y
East	METC	2522	'Power Plant Control Relocation 2011	Relocate substation controls currently located in power plants control rooms	MI	Other	Not Shared	$1,200,000	12/31/2011	Proposed	B>A	Y
East	METC	2486	Haakwood	New distribution interconnection served from Riggsville-Livingston 138 kV (on the Rondo-Vanderbilt section)	MI	Other	Not Shared	$170,000	1/1/2012	Planned	B>A	Y
East	METC	1810	Iosco-East Tawas 138 kV	Rebuild 12 miles of 138 kV to 954 ACSR.	MI	Other	Not Shared	$10,000,000	6/1/2012	Planned	B>A	Y
East	METC	2482	Hawthorne	New distribution interconnection served from Four Mile-Blendon 138 kV circuit.	MI	Other	Not Shared	$170,000	6/1/2012	Planned	B>A	Y
East	METC	2487	Birchwood	New distribution interconnection served from Spaulding-Plaster Creek 138 kV (on the Spaulding-Kraft section)	MI	Other	Not Shared	$170,000	6/30/2012	Planned	B>A	Y
East	METC	646	Edenville Jct.-Warren 138 kV	Replace poles on the Edenville-Warren 138 kV line	MI	Other	Not Shared	$12,500,000	12/1/2012	Planned	B>A	Y
East	METC	2507	Alcona-Mio 138 kV	Rebuild the line to 954 ACSR future-double-circuit (pre-built to 230 kV)	MI	Other	Not Shared	$24,500,000	6/1/2013	Planned	B>A	Y
East	Midwest ISO-NIPS	2797	Dune Acres-Michigan City CT upgrade	Replace a circuit breaker at Michigan City and upgrade the CT's to 1000/5 amps to increase the SE rating up to the conductor capacity limit which is 222 MVA	IN	Other	Not Shared	$345,000	10/1/2009	Proposed	B>A	Y
East	Midwest ISO-NIPS	2798	State Line-Wolf Lake-Sheffield 138 kV line reconductoring with ACSS conductor	Replace the existing bundled '300 kcm CU-397.5 kcm ACSR' with bundled (2) 336.4 kcm ACSS (1089 A @ 200 C each side) and the 900 kcm ACSR with 954 kcm ACSS (2131 A @ 200 C). Total length is 4.2 miles (State Line-Wolf Lake 1.2 miles and Wolf Lake-Sheffield 3 miles).	IN	Other	Not Shared	$2,700,000	4/1/2010	Proposed	B>A	Y
East	NIPS	2313	Aetna Sub-Replace Circuit 138-102S Breaker	Aetna Sub-Replace Circuit 138-102S Breaker	IN	BaseRel	Not Shared	$108,491	6/1/2009	Proposed	B>A	Y
East	NIPS	2314	RMSGS-Add 345kv N. Bus Tie Breaker	RMSGS-Add 345 kV N. Bus Tie Breaker	IN	BaseRel	Not Shared	$720,814	6/1/2009	Proposed	B>A	Y
East	NIPS	2317	Circuit 13823-Hartsdale to Munster-Capacity Upgrade	Rebuild section of Hartsdale to Munster 138 kV line.	IN	BaseRel	Not Shared	$90,000	12/1/2009	Planned	B>A	Y
East	NIPS	2325	Liberty Park bus Upgrades	Replace 500KCM Copper and 397.5 KCM acsr with 1272 KCM Al.	IN	BaseRel	Not Shared	$234,000	12/1/2009	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
East	NIPS	2775	Hartsdale Capacitors	Add (3) steps of 10.8MVAR capacitors to the Hartsdale 69 kV bus	IN	BaseRel	Not Shared	$950,000	12/1/2009	Planned	B>A	Y
East	NIPS	2326	Gary Airport Expansion	Relocate Chicago Ave 345 kV to new Gary Avenue substation including Chicago Ave 345/138 kV 336 MVA transformer and rebuild section underground of circuit 13825 Roxana to Mitchell	IN	Other	Not Shared	$15,000,000	12/1/2008	In Service	B>A	Y
East	NIPS	2310	New Praxair 138 kV substation @ Whiting	Customer Expansion	IN	Other	Not Shared	$2,780,453	12/1/2009	Proposed	B>A	Y
East	NIPS	2316	Highland Sub-69 kV Switched Capacitors	Replace Existing capacitors with 2-9.6 mVAR steps. Upgrade Controllers. Work in 2007 for engineering only.	IN	Other	Not Shared	$729,007	12/1/2009	Proposed	B>A	Y
East	WPSC	2770	Gilmore	New distribution interconnection served from Hersey to Vestaburg circuit.	MI	Other	Not Shared	$200,000	6/1/2010	Planned	B>A	Y
East	WPSC	2771	Monterey	New distribution interconnection served from Hersey to Vestaburg circuit.	MI	Other	Not Shared	$200,000	7/2/2010	Planned	B>A	Y
East	WPSC	2735	Alba-Westwood Line Rebuild	Alba-Mancelona-Westwood 69 kV line rebuild (11 miles) to 143 MVA	MI	Other	Not Shared	$5,605,000	12/31/2013	Proposed	B>A	Y
East	WPSC	2736	East Bay-South Boardman Line Rebuild	East Bay-South Boardman Dist-South Boardman 69 kV line rebuild (16 miles) to 143 MVA	MI	Other	Not Shared	$8,015,000	12/31/2013	Proposed	B>A	Y
East	WPSC	2737	South Boardman-Kalkaska Generation Line rebuild	South Boardman-Kalkaska gen 69 kV line rebuild (3.4 miles) to 143 MVA	MI	Other	Not Shared	$1,710,000	12/31/2013	Proposed	B>A	Y
West	ATC LLC	2452	G706 Randolph Energy Center Wind Farm	G706 Randolph Energy Center Wind Farm; taps Friesland-Hamilton 138 kV line	WI	GIP	Shared	$3,867,377	10/1/2010	Planned	B>A	Y
West	ATC LLC	2455	G611 Ecomet Wind	G-T Interconnection Taps Forest Jct-Elkhart Lk 138 kV	WI	GIP	Shared	$4,464,956	12/31/2010	Planned	B>A	Y
West	ATC LLC	2796	Ledge Wind G773	G-T Interconnection Taps Forest Jct-Lost Dauphin 138 kV	WI	GIP	Shared	$4,950,990	3/1/2011	Proposed	B>A	Y
West	ATC LLC	2161	Uprate Glenview-Shoto 138 kV	Increase line clearance to 200 deg F SN/SE	WI	Other	Not Shared	$1,412,755	6/1/2009	Proposed	B>A	Y
West	ATC LLC	2458	Stoughton Terminal uprates	Uprate Stoughton Terminal Equipment	WI	Other	Not Shared	$697,998	6/1/2009	Planned	B>A	Y
West	ATC LLC	2776	Spring Green Mobile Cap	Mobile cap bank placed at Spring Green	WI	Other	Not Shared	$670,116	7/15/2009	Planned	B>A	Y
West	ATC LLC	2022	Uprate Delta-Mead-NorthBluff 69 kV	Increase line clearance to 167 deg F SN/SE	MI	Other	Not Shared	$156,000	9/1/2009	Planned	B>A	Y
West	ATC LLC	2023	Uprate Masonville-Gladstone 69 kV	Increase line clearance to 167 deg F SN/SE	MI	Other	Not Shared	$190,418	9/1/2009	Planned	B>A	Y
West	ATC LLC	2024	Uprate North Bluff-Gladstone 69 kV	Increase line clearance to 167 deg F SN/SE	MI	Other	Not Shared	$178,059	10/1/2009	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	ATC LLC	2459	Sun Valley T-D	Tap Sun Valley Tap into Oregon-Verona 69-kV & Construct a 3.3 mile Sun Valley Tap-Sun Valley 69-kV line	WI	Other	Not Shared	$3,046,857	10/17/2009	Planned	B>A	Y
West	ATC LLC	2021	Uprate Chandler-LakeheadTap-Masonville 69 kV	Increase line clearance to 167 deg F SN/SE	MI	Other	Not Shared	$535,000	10/30/2009	Planned	B>A	Y
West	ATC LLC	2453	Rebuild Arpin-Rocky Run 345 kV	Rebuild Arpin-Rocky Run 345 kV	WI	Other	Not Shared	$23,544,820	6/1/2010	Planned	B>A	Y
West	GRE	2554	Tamarac Two 115 kV line breakers	Tamarac Two 115 kV line breakers, 115 kV capacitor	MN	BaseRel	Not Shared	$668,000	6/1/2009	Planned	B>A	Y
West	GRE	2562	G362-Pleasant Valley 345/161 KV transformer	G362 Network Upgrades: Pleasant Valley 345/161 kV transformer (GRE part of G362)	MN	GIP	Shared	$8,100,000	2/1/2010	Planned	B>A	Y
West	GRE	2557	Lake Mina (REA) 115 kV	Lake Mina (REA) 115 kV	MN	Other	Not Shared	$387,000	6/1/2009	Planned	B>A	Y
West	GRE	2560	Alexandria-Parkers Prairie Tap Retemp (26.75miles)	Alexandria-Parkers Prairie Tap Retemp (26.75miles)	MN	Other	Not Shared	$255,000	6/1/2009	Planned	B>A	NT
West	GRE	2561	Le Sauk 115 kV conversion with Sartell	115 kV conversion	MN	Other	Not Shared	$375,000	6/1/2009	Planned	B>A	Y
West	GRE	2575	Mary Lake-Buffalo 69 kV transmission	Mary Lake-Buffalo 69 kV transmission	MN	Other	Not Shared	$718,000	6/1/2009	Under Construction	B>A	NT
West	GRE	2619	Remmele Tap-Big Lake-Waco-Elk River West Temperature Upgrade	Remmele Tap-Big Lake-Waco-Elk River West Temperature Upgrade	MN	Other	Not Shared	$268,000	6/1/2009	Planned	B>A	NT
West	GRE	2556	Ritter Park (DEA) 115 kV Substation	Ritter Park (DEA) 115 kV Substation	MN	Other	Not Shared	$1,335,000	11/1/2009	Planned	B>A	Y
West	GRE	2612	Soderville Bus Replacement	Upgrade Bus capacity	MN	Other	Not Shared	$340,000	12/1/2009	Proposed	B>A	NT
West	GRE	2613	Pilot Knob--Yankee Doodle Projects	Conversion to 115 kV	MN	Other	Not Shared	$1,870,000	12/1/2009	Planned	B>A	Y
West	GRE	2559	Orr (LCP) 13 mile, 69 kV line	Orr (LCP) 13 mile, 69 kV line	MN	Other	Not Shared	$5,275,000	12/31/2009	Planned	B>A	NT
West	GRE	2563	Athens to Martin Lake 69 kV System Upgrades and Permitting	Athens to Martin Lake 69 kV System Upgrades and Permitting	MN	Other	Not Shared	$6,000,000	12/1/2010	Planned	B>A	NT
West	GRE	2553	Milroy-Sheridan 69 kV line addition	Milroy-Sheridan 69 kV line addition	MN	TDSP	Not Shared	$630,000	6/1/2009	Under Construction	B>A	Y
West	ITCM	2349	Savanna 161 kV Terminal Upgrades	Upgrade terminal equipment at the Savanna 161 kV substation (CTs, jumpers, switches, etc.) so that the Galena-Savanna-York 161 kV line is conductor limited.	IL	BaseRel	Not Shared	$205,000	6/1/2009	Planned	B>A	Y
West	ITCM	2351	Powesheik 161 kV Breaker Upgrades	Upgrade the 3 existing 161 kV Powesheik breakers to 2000 amp and add a 4th breaker to separate the Powesheik-Beacon 161 kV line and the Powesheik 161/69 kV TRF.	IA	BaseRel	Not Shared	$965,000	6/1/2009	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	ITCM	2365	Lansing-Genoa 161 kV upgrades & relay	Upgrade the terminal limits & relaying on the Lansing-Genoa 161 kV.	IA	BaseRel	Not Shared	$100,000	12/31/2010	Planned	B>A	Y
West	ITCM	2366	Adams-Harmony 161 kV upgrades & relay	Upgrade the terminal limits & relaying on the Adams-Harmony 161 kV.	MN	BaseRel	Not Shared	$100,000	12/31/2010	Planned	B>A	Y
West	ITCM	2358	Hazleton-Blackhawk 161 kV Rebuild	Rebuild 12 miles of the Hazleton-Blackhawk 161 kV line (ITC owned portion)	IA	BaseRel	Shared	$5,400,000	12/31/2012	Proposed	B>A	Y
West	ITCM	2372	G573,574,575 Nuthatch	G573,574,575 Nuthatch	IA	GIP	Shared	$4,360,113	9/15/2009	Planned	B>A	Y
West	ITCM	1775	Triboji-CBPC Milford 69 kV	Rebuild the Triboji-Milford 69 kV line.	IA	GIP	Shared	$2,023,508	12/31/2009	Planned	B>A	NT
West	ITCM	2786	G595 Network upgrades	G595 Network upgrades	IA	GIP	Shared	$25,531,831	12/31/2010	Planned	B>A	Y
West	ITCM	2339	G612-Marshalltown-Boone 115 kV to 161 kV	Construct a new Story Co 161 kV switching station and rebuild the Marshalltown-Boone 115 kV to 161 kV.	IA	GIP	Shared	$22,100,799	12/31/2013	Planned	B>A	Y
West	ITCM	2450	New Woodburn Jct. 69 kV Switching Station	Construct a new 3-terminal 69 kV switching station at the existing Woodburn Jct 69/34 kV sub.	IA	Other	Not Shared	$1,000,000	3/31/2009	Planned	B>A	NT
West	ITCM	2340	Grand Junction-Paton REC tap 34 kV Rebuild	Rebuild the 34 kV line from Grand Jct-Paton REC tap to 69 kV. Retire Dana 34 kV/dist sub and construct in & out taps for new Grand Jct North 69 kV/dist. Sub. (still operate at 34 kV)	IA	Other	Not Shared	$3,260,000	12/31/2009	Planned	B>A	NT
West	ITCM	2342	Boone-Jewell 34 kV Rebuild	Rebuild 25.3 miles of 34 kV line from Jewell to approximately 6 miles south of the Ridgeport dist. substation to 69 kV standards. This line will continue to be operated at 34 kV.	IA	Other	Not Shared	$6,685,000	12/31/2009	Planned	B>A	NT
West	ITCM	2346	Welton 3.6 mile 34 kV line Retire	Retire 3.6 miles of 34 kV near Welton.	IA	Other	Not Shared	$90,000	12/31/2009	Planned	B>A	NT
West	ITCM	2347	Bonaparte-Farmington Retirements	Retire the Bonaparte 69 kV sub and the Bonaparte-Farmington (7.4 mile) 34 kV line	IA	Other	Not Shared	$225,000	12/31/2009	Planned	B>A	NT
West	ITCM	2352	Old Settlers 115 kV Substation	Construct 115 kV taps, 115 kV bus, and breakers for new 2 TRF 115 kV/dist. Substation.	IA	Other	Not Shared	$2,815,000	12/31/2009	Planned	B>A	Y
West	ITCM	2354	Saints Run 115 kV Substation	Construct 115 kV taps, 115 kV bus, and breakers for new 2 TRF 115 kV/dist. Substation.	IA	Other	Not Shared	$1,495,000	12/31/2009	Planned	B>A	Y
West	ITCM	2355	Barilla 69 kV/dist. Sub & 69 kV Caps	Construct 2 new 69 kV 4.8 MVAR Cap banks, associated Bkrs, bus, switches, reactors, and line taps at a new Consumers Energy sub near Barilla.	IA	Other	Not Shared	$750,000	12/31/2009	Planned	B>A	NT

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	ITCM	2359	Bridgeport 161 kV Area Upgrades	Upgrade the Bridgeport 161 kV sub & the EIC sub. These upgrades combined with the Tri-County upgrades will allow for the Bridgeport 69 kV sub to be retired. The Bridgeport 69 kV sub needs to be retired to allow for the plant to expand.	IA	Other	Not Shared	$6,900,000	12/31/2009	Planned	B>A	Y
West	ITCM	2360	Burlington 69 kV/13 kV Sub Rebuild	Replace the existing Burlington distribution sub with a new substation on land adjacent to existing sub. (Line taps, Breakers, bus, etc.)	IA	Other	Not Shared	$588,000	12/31/2009	Planned	B>A	NT
West	ITCM	2343	West Branch-West Liberty 34 kV Rebuild	Rebuild 15.1 miles of 34 kV line from West Branch-West Liberty to 69 kV standards. This line will continue to be operated at 34 kV.	IA	Other	Not Shared	$4,146,850	3/31/2010	Planned	B>A	NT
West	ITCM	2348	Beaver Rock 69 kV Switching Station	Construct a new 3-terminal 69 kV switching station along the Beaver Channel-Rock Creek 69 kV line.	IA	Other	Not Shared	$1,390,000	3/31/2010	Planned	B>A	NT
West	ITCM	2353	Big River 69 kV 3-terminal Switching Station	Construct a new 3-terminal 69 kV switching station where the Big River REC line taps the Agency-Sawyer 69 kV line.	IA	Other	Not Shared	$1,200,000	3/31/2010	Planned	B>A	NT
West	ITCM	2341	Monticello-Amber Conversion & Lovell REC Rebuild	Rebuild 8.5 miles Monticello-Amber 34 kV to 69 kV, add 69 kV bkr at Sand Springs, Monticello Industrial, & Amber. Operate Sand Springs-Amber at 69 kV. Also rebuild 2.21 miles of 34 kV to 69 kV east of Lovell REC but continue operation of this portion at 34 kV in 2009.	IA	Other	Not Shared	$3,775,000	6/1/2010	Planned	B>A	NT
West	ITCM	2356	Oran-Oelwein 69 kV Rebuild	Rebuild 8 miles of 69 kV line Oran-Oelwein.	IA	Other	Not Shared	$2,000,000	6/1/2010	Planned	B>A	NT
West	ITCM	2345	Eldora Area Rebuild & Breaker Station	Rebuild approx 20 miles of 34 kV to 69 kV from the Hubbard Rural sub to a new 4-terminal Eldora North 69 kV switching station and operate at 69 kV. The new switching station will tap the CBPC Pleaseant-CBPC Eldora 69 kV line. The 4th terminal will be needed in the near future to feed the Eldora North-Union-Conrad 69 kV line after substations are ready for conversion. This line will be rebuilt to 69 kV standard in 2009.	IA	Other	Not Shared	$14,560,000	6/30/2010	Planned	B>A	NT

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	ITCM	2344	Wyoming-Massillon 34 kV Rebuild	Rebuild 12 miles of 34 kV line from Wyoming-Massilon to 69 kV standards. This line will continue to be operated at 34 kV.	IA	Other	Not Shared	$3,000,000	12/31/2010	Planned	B>A	NT
West	ITCM	2361	Dyersville West Rebuild	Rebuild the Liberty-Dyersville 69 kV west line.	IA	Other	Not Shared	$920,000	12/31/2010	Planned	B>A	NT
West	ITCM	2362	Dover 69 kV Switching Station	Construct a new 3-terminal 69 kV switching station.	MN	Other	Not Shared	$1,275,000	12/31/2010	Planned	B>A	NT
West	ITCM	2363	Glenville 161/69 kV	Construct a new 161/69 kV 75 MVA substation	MN	Other	Not Shared	$2,970,000	12/31/2010	Planned	B>A	Y
West	ITCM	2364	Thompson 2 mile 69 kV dbl ckt	Rebuild 69 kV double circuit line near Thompson, IA	IA	Other	Not Shared	$460,000	12/31/2010	Planned	B>A	NT
West	ITCM	2368	Montgomery-LE Center 69 kV Rd Move	Retire & rebuild 3.4 mile Montgomery-LE Center 69 kV line.	IA	Other	Not Shared	$765,000	12/31/2010	Planned	B>A	NT
West	ITCM	2369	Fairfax-Williamsburg 34 kV to 69 kV Rebuilds	Rebuild 26.6 miles of 34 kV line from the Fairfax sub to the Williamsburg115 kV sub to 69 kV. These lines will continue to operate at 34 kV.	IA	Other	Not Shared	$6,903,000	12/31/2010	Planned	B>A	NT
West	ITCM	2370	Andrew Tap & Monmouth Rebuilds	Rebuild the 5.75 mile Andrew Tap & 2 miles of line in the Monmouth area. These lines will continue to operate at 34 kV.	IA	Other	Not Shared	$1,869,250	12/31/2010	Planned	B>A	NT
West	ITCM	2371	New Marengo 69 kV Switching Station	Construct a new 3-terminal 69 kV switching station at the existing Marengo 34 kV sub.	IA	Other	Not Shared	$1,000,000	12/31/2010	Planned	B>A	NT
West	ITCM	2357	Hazleton-Fairbank REC 69 kV line & breaker station	Construct a 69 kV Hazleton-Fairbank line and a new 3-terminal 69 kV switching station.	IA	Other	Not Shared	$2,150,000	6/1/2011	Planned	B>A	NT
West	ITCM	2367	Anita Area 34 kV to 69 kV Rebuilds	Rebuild 5 miles from the Anita-Exira REC to 69 kV. Also rebuild 4.7 miles of the Anita to the Anita-Wiota Joint sub. Rebuild 21.9 miles from Thompson-Redfield. These lines will continue to operate at 34 kV.	IA	Other	Not Shared	$7,895,000	6/30/2011	Planned	B>A	NT
West	MDU	2471	Tioga area upgrades	Project upgrades to accommodate load growth in the area	ND	BaseRel	Not Shared	$2,200,000	12/1/2009	Planned	B>A	Y
West	MDU	1355	Heskett-Additional 230/115 kV Switchyard and 115 kV Capacitor	Heskett-Additional 230/115 kV Switchyard 230 115 Switchyard in parallel w/ existing Heskett switchyard and Cap Bank	ND	BaseRel	Shared	$11,000,000	11/1/2012	Planned	B>A	Y
West	MP	2552	Skibo	Skibo-Hoyt Lakes 138 ckt 1, Sum rate 202	MN	BaseRel	Not Shared	$2,540,000	12/30/2010	Proposed	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	MP	2763	LSPI 34.5	Add 115/34.5 kV Transformer and line exit to LSPI 115/14 kV Sub	MN	Other	Not Shared	$500,000	9/1/2009	Planned	B>A	Y
West	MP	2758	Taft	New 115/34.5 Substation	MN	Other	Not Shared	$992,500	10/1/2009	Planned	B>A	Y
West	MP	2757	Grand Rapids	Add new 115/23 kV Lind-Greenway Substation off MP Line #29	MN	Other	Not Shared	$2,741,100	12/1/2009	Planned	B>A	Y
West	MP	2760	Virginia	Add 115/46 kV 39 MVA LTC transformer	MN	Other	Not Shared	$1,284,100	12/1/2009	Planned	B>A	Y
West	MP	2756	Essar Phase 1	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	6/30/2010	Planned	B>A	Y
West	MP	2759	Laskin	Move Virginia 115/46 kV Transformer to Laskin	MN	Other	Not Shared	$500,000	6/1/2011	Planned	B>A	Y
West	OTP	2750	Spiritwood 115 kV Substation Expansion	Build New 115 kV Bus Expansion & Add Two New 115/12.5 kV Transformers	ND	Other	Not Shared	$1,100,000	7/1/2009	Planned	B>A	Y
West	OTP	2749	Fertile-Fertile Jct. 41.6 kV Line	Build New 1.5 Mile 41.6 kV Line to Eliminate Critical Contingency	MN	Other	Not Shared	$165,000	6/1/2010	Planned	B>A	NT
West	OTP	2751	New Perham 115/12.5 kV Substation	Build New 115/12.5 kV Substation at Perham to Serve as a Back-up Source for Outage of Primary Source	MN	Other	Not Shared	$400,000	12/31/2012	Proposed	B>A	Y
West	OTP, GRE, MPC	2738	Ramsey 230/115 kV Transformer Upgrade	Increase Transformer Capacity & Improve Category C Contingency Performance to Devils Lake Area	ND	BaseRel	Not Shared	$5,000,000	11/1/2010	Planned	B>A	Y
West	XEL	2307	St. Cloud Loop	(1) New 4 mile 115 kV line from St. Cloud tap tap to Mayhew Lake substation.(2) Convert Benton Co-St. Cloud double circuit to bifurcated line and reterminarte into Mayhew Lake substation (3) Convert St. Cloud tap to Granite City into bifurcated line (this results in single 115 kV circuit from St. Cloud to Granite City).	MN	BaseRel	Shared	$6,100,000	6/1/2012	Proposed	B>A	Y
West	XEL	2765	Uilk Wind farm (G185)	This is a new 4.5 MW interconnection at Chanarambie	MN	GIP	Shared	$118,100	12/1/2008	Planned	B>A	Y
West	XEL	2178	G362 Pleasant Valley XEL	G362 Network upgrades: New 161 kV line from Pleasant Valley-Byron 161 kV line	MN	GIP	Shared	$10,007,181	6/1/2012	Planned	B>A	Y
West	XEL	2159	Nelson Cap Bank	Add 18 MVAR cap at Nelson substation	WI	Other	Not Shared	$721,000	6/1/2010	Planned	B>A	NT
West	XEL	2772	South Minneapolis	1 new 115 kV distribution substation with four terminations tapping the Elliot Park-Southtown line, 1.25 new miles of double circuit 795 SAC to a new 115 kV distribution substation	MN	Other	Not Shared	$28,390,000	10/1/2010	Planned	B>A	Y

Table 7.1-1: MTEP 09 New Appendix A Projects

Region	Geographic Location by TO Member System	ID	Project Name	Project Description	State	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	App ABC	Midwest ISO Facility
West	XEL	2156	North Mankato 115 kV project	1) New 345/115 kV TR at the proposed Helena 345 kV switching station. 2) New 115 kV line from Helena-St. Thomas. 3) New 115/69 kV substation near St. Thomas. 4) New 69 kV switching station at Lesueur Tap.	MN	Other	Not Shared	$17,450,000	6/1/2011	Planned	B>A	Y
West	XEL	2157	Douglas Co 2nd TR	2nd Douglas Co 115/69 kV transformer	MN	Other	Not Shared	$4,435,000	6/1/2011	Planned	B>A	NT
West	XEL	2158	Upgrade Sauk Center-Osakis 69 kV line	Upgrade Sauk Center-Osakis 69 kV line to a lower impedance.	MN	Other	Not Shared	$4,514,000	6/1/2011	Planned	B>A	NT
West	XEL	2308	Grove Lake-Glenwood line rebuild	This project is to rebuild 13 miles of 69 kV line from Grove Lake switching station to Glenwood to 477 ACSR	MN	Other	Not Shared	$16,350,812	6/1/2011	Proposed	B>A	NT
West	XEL	1952	Plato capacitor bank	This project is to add a 10 MVAR cap bank at Plato. This project is required to convert the existing 69 kv line from Young America-Glencoe to 115 kV (part of Glencoe-West Waconia 115 kV line project).	MN	Other	Not Shared	$700,000	12/1/2011	Planned	B>A	NT
West	XEL	2160	Park Falls TR upgrade	Upgrade the Park Falls 115/34.5 kV TR to 47 MVA	WI	Other	Not Shared	$3,355,800	6/1/2012	Planned	B>A	NT
West	XEL	2176	Cannon Falls transmission improvements	(1) Change breaker configuration at Colville Substation (2) Add 115 kV Ring bus at Cannon Falls (3) Install new 115/69 kV transformer at Colville substation (4) New 2 mile 69 kV line from Cannon Falls to Byllesby.	MN	Other	Not Shared	$6,235,000	6/1/2012	Proposed	B>A	Y
West	XEL	2309	Maple Lake-Watkins line rebuild	This project is to rebuild 20 miles of 69 kV line from Maple Lake to Watkins in west Central Minnesota	MN	Other	Not Shared	$2,487,000	6/1/2012	Proposed	B>A	NT

7.2 Reliability Analysis Results

Results of MTEP 09 Steady State Analyses results are included in Appendix D3 of this report. This is posted at the Midwest ISO ftp site: ftp://mtep.midwestiso.org/MTEP 09/. Midwest ISO Planning region is separated into West, Central and East planning regions. The following table 7-2 shows the generation, load, losses and interchange modeled in each of the five planning models used in MTEP 09 Reliability Analysis.

Table 7.2-1: Balancing Area Summary for MTEP 09 Models

Planning Region	BA Name	2011 Summer Peak				2014 Summer Peak				2014 Shoulder Peak				2014 Light Load				2019 Summer Peak			
		Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change
West	ALTW	4,738	4,412	112	214	4,043	4,705	106	-768	4,096	3,341	130	625	2,387	1,965	122	301	4,805	5,062	112	-368
	ALTE	3,470	2,749	88	632	3,177	3,015	101	59	3,434	2,198	63	1,172	2,051	1,345	41	664	4,193	3,444	122	627
	WEC	8,150	7,318	153	674	8,186	7,670	145	366	6,066	5,560	144	357	3,319	3,397	78	-162	8,687	8,258	163	261
	WPS	2,698	2,583	63	52	2,627	2,722	63	-158	2,824	2,080	52	691	1,317	1,317	37	-37	2,783	2,897	70	-185
	MGE	396	807	15	-428	366	854	14	-503	322	604	14	-297	221	353	3	-137	413	915	15	-518
	UPPC	78	220	6	-149	78	221	6	-150	51	159	4	-112	51	94	3	-47	105	224	13	-133
	XEL	9,019	9,818	267	-1,066	8,827	10,227	304	-1,705	7,878	7,229	226	422	6,333	4,263	198	1,871	10,864	10,734	296	-167
	MP	2,448	1,677	120	650	2,578	1,986	108	484	1,782	1,727	77	-22	1,266	1,137	60	69	2,792	2,111	112	569
	SMMPA	177	576	1	-401	156	603	1	-447	142	483	1	-342	37	305	1	-269	193	649	1	-456
	GRE	3,050	3,375	95	-423	3,293	3,739	102	-551	1,718	2,692	78	-1,055	641	1,615	41	-1,018	3,382	4,316	107	-1,044
	OTP	1,316	1,614	85	-384	1,539	1,833	77	-372	1,261	1,234	67	-40	1,359	960	61	337	1,857	2,053	124	-321
	MDU (in WAPA)	190	503	11	-324	206	463	10	-267	192	311	7	-126	52	113	9	-70	281	481	14	-213

Table 7.2-1 continues on the next page with the Central and East regions

Table 7.2-1: Balancing Area Summary for MTEP 09 Models

Planning Region	BA Name	2011 Summer Peak				2014 Summer Peak				2014 Shoulder Peak				2014 Light Load				2019 Summer Peak			
		Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change	Generation	Load	Loss	Inter-change
Central	HE	1,148	843	35	270	1,426	898	45	483	1,150	610	23	517	359	349	8	2	1,398	976	51	372
	DEM	12,119	13,773	473	-2,138	13,060	14,381	480	-1,812	7,980	10,500	327	-2,858	2,719	6,320	132	-3,744	13,237	15,501	507	-2,782
	Vectren	1,554	1,978	32	-456	1,550	1,968	31	-450	1,533	1,560	20	-47	128	1,109	37	-1,017	1,547	2,054	31	-538
	IP&L	3,180	3,297	77	-198	3,307	3,415	75	-186	2,242	2,386	61	-209	897	950	17	-74	3,422	3,600	78	-260
	CWLD	149	327	3	-181	148	339	3	-194	148	167	1	-20	0	136	1	-136	167	382	2	-217
	AmerenMO	9,241	9,185	144	-88	9,660	9,435	208	17	7,975	6,612	111	1,252	3,472	3,901	52	-481	9,524	10,058	181	-715
	AmerenIL	11,570	10,272	212	1,086	13,069	10,628	317	2,124	5,525	7,661	96	-2,232	5,704	4,600	77	1,027	12,384	11,042	241	1,101
	CWLP	571	472	3	96	698	485	3	210	336	342	1	-8	197	199	1	-3	697	508	3	186
	SIPC	311	400	10	-100	310	420	9	-119	269	293	4	-28	0	293	4	-297	269	439	10	-181
East	First Energy	12,929	15,201	385	-2,656	13,363	15,634	389	-2,660	10,509	11,625	251	-1,367	4,616	7,431	106	-2,920	13,765	16,202	406	-2,842
	NIPSCO	3,155	3,730	67	-641	3,147	3,825	62	-740	2,578	2,637	63	-122	1,719	1,602	34	83	3,287	3,951	58	-722
	METC	11,359	10,366	356	637	11,921	10,400	339	1,182	6,111	7,396	268	-1,553	4,286	4,385	96	-195	13,196	10,278	355	2,564
	ITC	10,901	11,142	229	-470	11,165	10,830	203	132	8,442	7,617	152	673	5,350	4,354	100	897	11,035	10,695	193	147

Of the 274 projects being recommended by the Midwest ISO staff for approval by the Board of Directors in MTEP 09, 64 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 the reliability while accommodating the ongoing needs of the existing Market Participants and Transmission Customers.

7.3 Dynamic Stability Analysis Results

Section 6.1.4 of MTEP 09 report lists types of disturbances tested in Dynamic Stability Analysis. Disturbances were simulated in MTEP 09 2014 Light Load (40% load) and Shoulder Peak (70% load) models. A total of 779 disturbances were simulated of which 410 were Category B, 271 were Category C and 98 were Category D contingencies. System was stable for all faults simulated. Results tables listing all simulated disturbances are tabulated in Appendix D5 of MTEP 09 report.

7.4 Voltage Stability Analysis Results

Section 6.1.1 of MTEP 09 report 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 MTEP 09 2014 Summer Peak model. Summary report with associated p-v plots are documented in Appendix D4 of MTEP 09 report.

7.5 Load Deliverability Analysis Results

To determine the ability of an area to sufficiently supply its load with generation from inside the area or with imports generated externally, a load deliverability analysis is conducted. This process is done 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 year 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 every year. Section 6.1.5 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 2009-2010 LOLE Study set the required Planning Reserve Requirement (PRM) for the 2009/2010 Planning Year which covers the period starting in June 2009 and extending through May 2010. The study concluded that a minimum system wide planning reserve of 15.4% is required to maintain a Loss of Load Expectation of 1 day in 10 years. By adjusting for the 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 12.69% was applied to the individual 2009 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 was included the following:

- A load deliverability analysis was conducted to determine the ability of all areas of the system to achieve an LOLE of at least 1 day in 10 years from 2009 through 2018.
- 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.
- Zones exist where the transfer capability out of the zone limits the delivery of internal generation resources to external zones

Although this analysis found that all zones would be able to meet the 1 day in 10 year benchmark, it is the case that aggregate generation is not fully deliverable in the 2009 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 0.61% for 2009. Section 8.2.2 discusses the impact of congestion on the PRM through 2018.

7.6 Generator Deliverability Analysis Results

Table 7.6-1 below shows the list of constraints that limit deliverability of about 3,282 MW of Network Resources. See Appendix D6 for the detailed results with a list of impacted Network Resources.

The description of table 7.6-1 column headings is below.

- **Overload Branch:** An overload caused by "bottling-up" of aggregate deliverable generation. Deliverability was tested only up to the granted NR (Network Resource) levels of the existing and future NR units modeled in MTE09 2014 case.
- **Map ID:** Use Map ID to find an approximate location of the overloaded element on Fig. 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 7.6-1: MTEP09 (2014 SUPK) Baseline Generator Deliverability Constraints Summary

Overloaded Branch	Area	Map ID	Contingency	Rating (MVA)	Delta Increase
Fernald 115/161 kV transformer	ALTW	1	System Intact (Cat. A)	75	29.8%
Palmyra 345/161 kV transformer	AMMO	3	Louisa--Sub T--Hills 345 kV	370	20.3%
Henry Co.--New Castle 138 kV line	DEM	5	Cadiz--Henry Co. 138 kV	151	20.3%
Tri County--Beacon 161 kV line	MEC	1	Ottumwa 161/345 kV transformer	310	12.4%
Todhunter--Woodsdale 345 kV line	DEM	7	Todhunter--Woodsdale 345 kV ckt 2	1195	9.1%
Todhunter--Woodsdale 345 kV line ckt. 2	DEM	7	Todhunter--Woodsdale 345 kV ckt 1	1195	9.1%
Coulterville 230/138 kV transformer	AMIL	3	Cahokia--Coulterville 230 kV	140	9.1%
Pittsboro--Brownsburg 138 kV line	DEM	6	Qualitech--Whitestown 345 kV and Amo 345/69 kV transformer	287	8.8%
Qualitech--Pittsboro Junction 138 kV line	DEM	6	Qualitech--Whitestown 345 kV and Amo 345/69 kV transformer	287	8.8%
Mesaba--Blackberry 230 kV line	MP	17	Mesaba--Blackberry 230 kV ckt. 2	600	8.6%
Mesaba--Blackberry 230 kV line ckt 2	MP	17	Mesaba--Blackberry 230 kV ckt. 1	600	8.6%
Qualitech 345/138 kV transformer	DEM	6	Qualitech--Whitestown 345 kV and Amo 345/69 kV transformer	345.5	7.3%
Livingston--Livepark 138 kV line	METC	15	System Intact (Cat. A)	136	4.7%
Powerton--Powerton Jct. 138 kV line	AMIL	4	System Intact (Cat. A)	166	4.5%
Amber--Pere Marquette 138 kV line	METC	14	Pere Marquette--Stronach 138 kV	196	3.8%
Fredericktown 161 kV line	AMMO	3	Callaway unit 1	56	3.7%
Prairie State--Stallings 345 kV line	AMIL	3	Cahokia--Baldwin 345 kV	1195	3.6%
Riggsville--Rondo 138 kV line	METC	15	Emmet--Livingston 138 kV and Oden 69/138 kV transformer	144	2.4%
Goose Creek--Rising 345 kV line	AMIL	4	Goose Creek--Maroa East Junction 345 kV	448	2.4%
Rising 345/138 kV transformer	AMIL	4	Goose Creek--Maroa East Junction 345 kV	448	2.4%
Pere Marquette--Stronach 138 kV line	METC	14	Keystone--Ludington 345 kV	233	2.2%
Corwith--Vanderbilt 138 kV line	METC	15	Emmet--Livingston 138 kV and Oden 69/138 kV transformer	180	1.9%
Corwith--Hackwood 138 kV	METC	15	Emmet--Livingston 138 kV and Oden 69/138 kV transformer	180	1.9%

Table 7.6-1: MTEP09 (2014 SUPK) Baseline Generator Deliverability Constraints Summary					
Overloaded Branch	**Area**	**Map ID**	**Contingency**	**Rating (MVA)**	**Delta Increase**
Livingston--Vanderbilt 138 kV line	METC	15	Emmet--Livingston 138 kV and Oden 69/138 kV transformer	180	1.9%
Turkey Hill 345/138 kV transformer	AMIL	3	Cahokia 345/138 kV transformer and Cahokia--Baldwin 345 kV line	672	1.8%
Cahokia 345/138 kV transformer	AMIL	3	Cahokia 345/138 kV transformer and Cahokia--Campbell 345 kV line	700	1.7%
Bloomington 230 kV line	DEM	8	Bloomington 345/230 kV transformer	478	1.4%
Stallings 345/138 kV transformer	AMIL	3	Roxford--Stalling 345 kV line and Roxford 345/138 kV transformer	560	1.2%
Attica--Lafayette 230 kV line	DEM	9	Cayuga--Frankfort 230 kV	349	1.1%
Stout 138 kV line	IPL	13	16SW--Stout 138 kV	325	0.9%
River Rouge--Waterman 120 kV line	ITCT	13	River Rouge 120 kV line	276	0.4%
South Grove 345/138 kV transformer	DEM	7	Red Bank 345 kV line	478	0.1%
Elk River 230/69 kV transformer 2	GRE	12	Elk River 230/69 kV transformer 1	181	0.1%
Ottumwa--Bridgeport 161 kV line	ALTW	1	Ottumwa--Tri County 161 kV	335	0.1%
East Calamus--Grand Mound 161 kV line	ALTW	1	Salem--Rock Creek 345 kV	176	0.03%

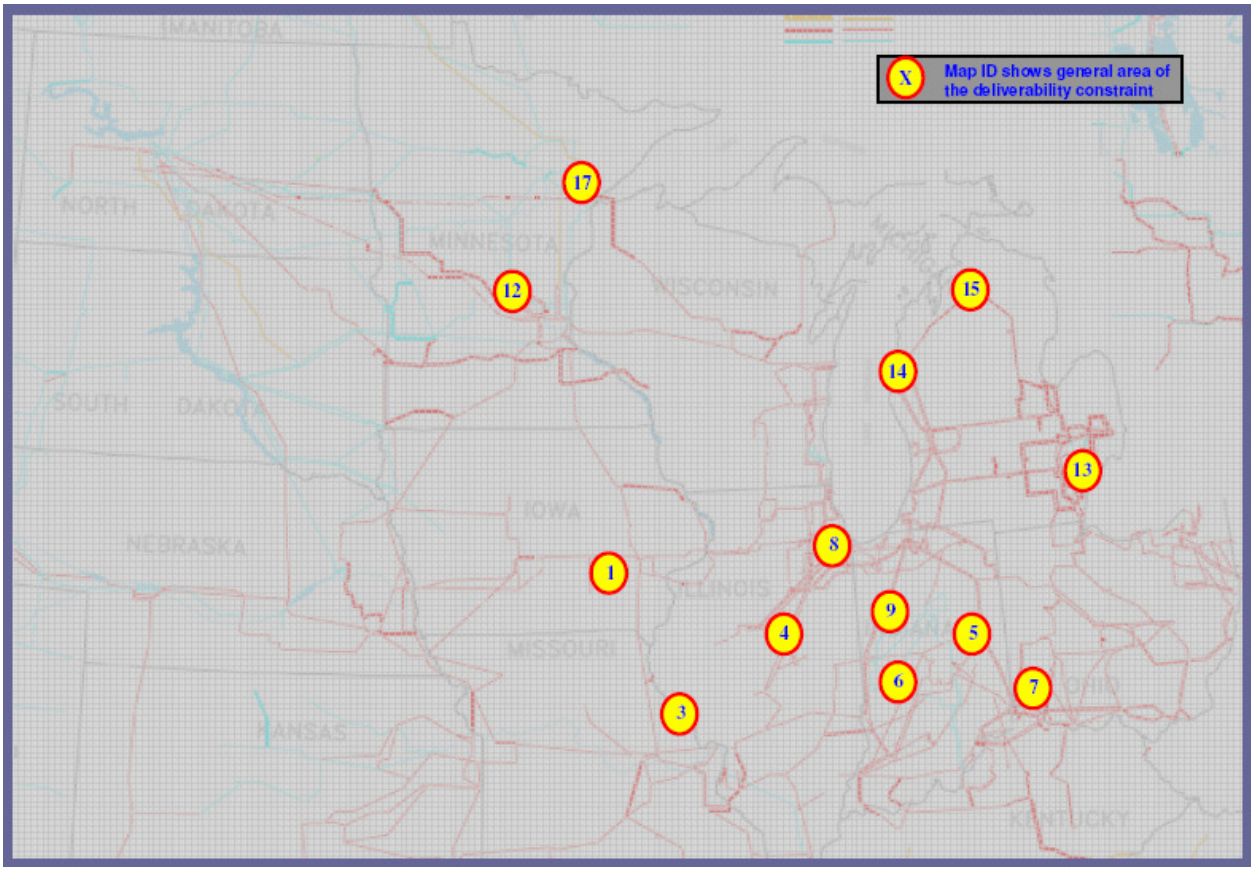

Figure 7-1:
General location of 2014 SUPK Baseline Generator Deliverability Constraints

The Midwest ISO will create a Technical Review Group (TRG) comprising of Midwest ISO stakeholders to identify planning solutions to address above documented generator deliverability issues where applicable in MTEP10 planning cycle.

7.7 Infeasible Long Term Transmission Rights (LTTR) Analysis Results

Table 7.7-1 below shows the uplift costs associated with the infeasible LTTRs in the 2009 Annual Allocation. The LTTRs represent approximately 390.9 GW for the allocation period (8 cases). The ratio of total infeasible LTTR uplift costs over the total LTTR payments from Stage 1A of the allocation is approximately 8.3% across all seasons.

Table 7.7-1: Uplift Costs Associated with Infeasible LTTR in the 2009 Annual Allocation

	Total Stage1A (GW)	Total LTTR Payment ($M)	Total Infeasible Uplift ($M)	Uplift Ratio
2009 Allocation	390.9	165.9	13.7	8.3%

The uplift was covered by approximately 96% of Market Participants that were eligible for LTTRs. Of the MWs eligible to be covered by LTTRs, approximately 92% became LTTRs.

Table 7.7-2 below further breaks down the infeasible uplift to binding constraints from the annual auction. The binding constraints are filtered for greater than $100,000.

Table 7.7-2: Infeasible Uplift to Binding Constraints from the Annual Auction						
Device	**Plans**	**Summer 2009**	**Fall 2009**	**Winter 2009**	**Spring 2010**	**Grand Total**
Pana 345/138 xfmr (flo) Coffeen-Coffeen North 345 + Coffeen UN2 SPS	Congestion on Pana 345/138 kV transformer for loss of Coffeen-Coffeen North 345 kV line was identified within top 30 most congested flowgates in Midwest ISO in 2008 Alternatives under consideration: 1. Upgrade the Pana transformer with a larger unit 2. A new 345 kV connection between the Coffeen and Coffeen North substations 3. Additional line rating upgrades via terminal equipment upgrades. Alternatives are being evaluated for eligibility for RBP (RECB II) treatment. Expect resolution by September 8th stakeholder RECB meeting	$80,530	$1,548,911	$308,293	$987,681	$2,925,416
Dune Acres-Michigan City 138 1&2 (flo) Wilton Center-Dumont 765	Midwest ISO is currently working with Transmission Owner and Merchant to formalize mitigation plans to include an upgrade of CTs at Dune Acres and upgrade of breaker at Michigan City (MTEP09 Project 2797). Upgrade planned to be in service by October 31, 2009	$1,499,112	$101,373	-	-	$1,600,486
State Line-Wolf Lake 138 (flo) Burnham-Sheffield 345	Midwest ISO is currently working with Transmission Owner and Merchant to formalize mitigation plans to include reconductoring State Line-Wolf Lake-Sheffield 138 kV line (MTEP Project 2798). Upgrade planned to be in service by March 31, 2010	$81,425	$686,957	$27,802	$495,856	$1,292,040
Burroak-Schaffer 345 (flo) Wilton Center-Dumont 765	Midwest ISO is currently working with Transmission Owner to develop preliminary mitigation plans to address reliability issues in the region. Solution expected to resolve market congestion issues as well.	-	$360,530	$690,044	-	$1,050,575
Zion-Pleasant Prairie 345 (flo) Cherry Valley-Silver Lake 345	Identified as one of Midwest ISO top congested flowgates. Study of upgrades to resolve issue revealed no positive economic benefit to Midwest ISO market	$335,452	$29,296	$799,567	$89,606	$1,253,921
Blackoak-Bedington 500 (flo) Pruntytown-Mt. Storm 500	Identified as one of Midwest ISO top congested flowgates. Study of upgrades to resolve issue revealed no positive economic benefit to Midwest ISO market	-	$686,831	-	-	$686,831
09Stuart-08Hillcrest 345	Transmission solutions to address constraint will be investigated in MTEP10	$203,032	$79,997	$10,310	$116,137	$409,478

Table 7.7-2: Infeasible Uplift to Binding Constraints from the Annual Auction						
Device	**Plans**	**Summer 2009**	**Fall 2009**	**Winter 2009**	**Spring 2010**	**Grand Total**
Sammis-Wylie Ridge 345 flo Tidd-Wylie Ridge 345	Identified as one of Midwest ISO top congested flowgates. Study of upgrades to resolve issue revealed no positive economic benefit to Midwest ISO market	-	$409,463	-	-	$409,463
ATC LLC Flow South Interface	Stiles-Plains 138 kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park-Highway 22 345 kV line projects) and P345 [Under Construction] (Morgan-Werner West 345 kV line) connect Morgan-Plains 345 kV line to the pre-existing 345 kV system, hence increase voltage stability. P352 [Under Construction] (Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV) will also help increase the FG limit	$111,217	$307	$28,337	$260,156	$400,016
Sammis-Wylie Ridge 345	Identified as one of Midwest ISO top congested flowgates. Study of upgrades to resolve issue revealed no positive economic benefit to Midwest ISO market	$107,591	$159,683	$151,518	$40,564	$459,356
Pulliam-Stiles (64441) 138 (flo) Pulliam-Stiles (64451) 138	This overload should be relieved by P345 Werner West-Highway 22-Morgan 345-kV line	$337,752	-	-	-	$337,752
Paddock-Blackhawk 138 (flo) Paddock-Townline 138	Transmission solutions to address constraint will be investigated in MTEP10	$6,216	$51,860	$263,499	$15,185	$336,760
Pruntytown-Mt. Storm 500 (flo) Blackoak-Bedington 500	Identified as one of Midwest ISO top congested flowgates. Study of upgrades to resolve issue revealed no positive economic benefit to Midwest ISO market	$158,469	-	-	$67,693	$226,162
Zimmer-Silver Grove 345 (flo) Zimmer-Port Union 345	Transmission solutions to address constraint will be investigated in MTEP10	$85,422	$52,709	$6,825	$3,805	$148,761
IP Rising 345/138 XFMR 1 (flo) Clinton-Brokaw 345 (IP4535)	Transmission solutions to address constraint will be investigated in MTEP10	$38,354	$36,307	$26,721	$40,276	$141,658
Fox Lake-Rutland 161 kV flo Lakefield-Fieldon-Wilmarth 345 kV line + SPS	Transmission solutions to address constraint will be investigated in MTEP10	$13,386	$117,480	$9,184	-	$140,050

Table 7.7-2: Infeasible Uplift to Binding Constraints from the Annual Auction						
Device	**Plans**	**Summer 2009**	**Fall 2009**	**Winter 2009**	**Spring 2010**	**Grand Total**
State Line-Wolf Lake 138 (flo) State Line-Washington Park 138	Midwest ISO is currently working with Transmission Owner and Merchant to formalize mitigation plans to include reconductoring State Line-Wolf Lake-Sheffield 138 kV line (MTEP Project 2798). Upgrade planned to be in service by March 31, 2010	-	$31,430	-	$76,335	$107,765
Scott1 B06-Buncere 220	MTEP Project: 1308. Returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the Phase Angle Regulator with 2 new phase angle regulating transformers in series. Expected to be in service by end of 2009. Solution expected to resolve issue.	$3,835	$19,452	$2,671	$77,429	$103,387
Total		**$3,061,794**	**$4,372,589**	**$2,324,772**	**$2,270,723**	**$12,029,878**

Section 8: Market Efficiency Analysis

8.1 Congestion Analysis Evolution

Congestion Analysis at the Midwest ISO continues to evolve. The review of congestion has changed substantially since MTEP 03, where for example Transmission Line Loading Relief (TLR) was the tool used in operations, and correlation to Available Flowgate Capacity (AFC) was found to be of little value. MTEP 06 was the first year where the TLR and binding of constraints in the Market were combined into a single congestion metric. MTEP 07 was the first year where congestion was compared to planned reliability projects for possible mitigation of future congestion upon the historically impacted flowgates (as in Section 8.2.1 Table 8.2-2). Each change or addition in metrics is driven by the desire to find those analyses which are most effective in driving transmission planning to address congestion in the footptint. Table 8.1-1 shows the evolution of the 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 MKT FG-Hr	AFC	Historical Shadow Price	Real Time Bound Hours	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
MTEP 03	x	x	x	x							
MTEP 05	x	x		x							
MTEP 06	x	x	x	x	x	x					
MTEP 07	x	x	x		x		x	x			
MTEP 08	x	x	x		x		x	x	x		
MTEP 09	x	x	x		x		x	x	x	x	x

MTEP 09 contains the following additional attributes that are also noted in table 8.1-1:

- Captures four years of the Midwest ISO Market operations.
- Itemizes the FG-Hr (Flowgate-Hour) that occurred in each post-market year directly in more tables.
- Presents an alternative sorting of the flowgates by computing each flowgate's median ranking across all four market years. The flowgate congested the most hours in a period has the #1 rank assigned; and, by taking the different rankings a flowgate has realized over a period of years, 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. This allows understanding of which flowgates are chronically congested.
- Reflects the sum of shadow price, the cost of incremental redispatch to relieve a constraint, in more of the tables, and chart legends directly in the text of the MTEP 09 report. Additional detail on shadow price is available in the Congestion Summary spreadsheet contained in Appendix F2.
- Estimates future congestion based on the 2009 Loss of Load Expectation (LOLE) report for the ten year look-ahead period of 2009 through 2018 (See Section 8.2.2.)

- Includes results from the Top Congested Flowgate Study (TCFS) (Section 8.3). The study reviews the top historically congested flowgates since market start and evaluates future candidate projects and portfolios that can alleviate those flowgates. This five year out study window allows us to determine whether the Appendix A or B projects have mitigated historical congestion and, if not, what additional projects are would be cost effective in reducing or removing the congestion.

While the sum of the shadow price for flowgates has been included more extensively in MTEP 09, further study is needed to estimate the cost of the re-dispatch that occurred to manage historical congestion. It is important to note that the actual dispatch cost that would have occurred in the absence of congestion cannot be derived from the direct tracking of market metrics. However an annual level benchmark correlation may be possible by performing PROMOD® simulations of the system.

Evolutionary work is continuing to isolate the cost of re-dispatch of the system as a congestion management tool. The Midwest ISO presently tracks a term called congestion rent that equals the shadow price on a flowgate multiplied by the megawatt flow on that flowgate. While congestion rent can be tracked, it greatly overstates the cost for re-dispatching the system to manage the prevailing congestion. An ongoing study is underway to review the degree to which congestion rent can be correlated to the change in dispatch costs.

Column D in Table 8.1-2, titled 'Congested FG-Hours in Period', shows that congestion has shown an increasing trend in the Midwest RA footprint since the year 2001. After peaking during the 1st Market year in 2005, congestion reduced in year two, and grew slowly in years three and four. The 4th year realized 23,137 Flowgate (FG)-Hours, continuing at a level reduced somewhat from the maximum of 27,842 FG-Hours experienced during the 1st Market year. Congestion analyzed here reflects the combined quantification from Real-Time operations and North American Electric Reliability Corp. (NERC) Transmission Loading Relief (TLR).

Congestion is an ongoing dynamic experience from year to year - or even month to month. The historical analysis of congestion is just one of several inputs used to determine whether or not a system expansion to reduce congestion is warranted. Table 8.1-2 illustrates both increased utilization of congested flowgates and also shows the number of flowgates that were congested annually. Column G, in Table 8.1-2, reflects the current snapshot of evolving new flowgates versus repeated use of earlier congested flowgates. Some flowgates that were used in the past are not utilized going forward because they have become inactive for a period of time, or replaced altogether. This transient aspect of flowgates can be attributed to changing transmission and generation infrastructure, and unique maintenance or weather driven effects within a given period of time. The number of flowgates utilized in each year is slowly decreasing, and in the post-market period, since 2005, the overall average hours that flowgates are congested remains in the range of 25 to 35 hours per flowgate as shown by Column E in Table 8.1-2.

While the overview summary in Table 8.1-2 utilizes averages to reveal the general trends, more detailed discussion follows in this section and in Appendix F2. Specifically the Appendix_F2_Congestion_Summary spreadsheet contains the itemized hours on each of the 2,604 flowgates for pre-market and each post-market year.

Table 8.1-2: 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 4th Mkt Yr
Time Period	Utilized In the Period	Cumulative Utilized Since January 2001	Congestion FG Hours In Period	Average Hours/FG In Period		Number of FG Sustained Uniquely In Each of Five Time Periods
April 2008-April 2009	653	2,604	23,137	35		391
April 2007-April 2008	798	2,213	20,748	26		448
April 2006-April 2007	829	1,672	20,392	25		462
April 2005-April 2006	841	1,105	27,842	33		527
April 2004-April 2005	200	358	11,050	55		229
April 2003-April 2004	174	316	11,094	64		^
April 2002-April 2003	89	116	10,172	114		^
April 2001-April 2002	64	64	6,432	101		^
Note: The 5th Time Period is a Composite of all four Pre-Market Periods						
Subtotal: Occurred in 1 of 5 Time Periods						2,057
Occurred in 2Time Periods						341
Occurred in 3 Time Periods						115
Occurred in 4 Time Periods						60
Occurred in 5 Time Periods						31
Total: Cumulative Utilized Since January 2001						**2,604**

Column D in Table 8.1-2 shows that, in the pre-Midwest ISO market time frame, the annual (April to April) congestion was fairly constant at 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 indicates that the Locational Marginal Pricing (LMP) market better utilizes, and effectively exploits, use of the available transmission system up to reliability limits.

There are 31 unique flowgates that have occurred in five time periods shown in Table 8.1-2. These time periods represent each of the four years since the start of the real time market in 2005, plus one additional period, that sums up the preceding four years into one post-market start category. Figure 8.1-1 illustrates the distribution of the 31 flowgates on the basis of their post-market FG-Hr. For example in Figure 8.1-1, accounting for the first 12 FG on the Y-axis, correlates to arriving at the 44th Post Market ranked position on the X-axis.

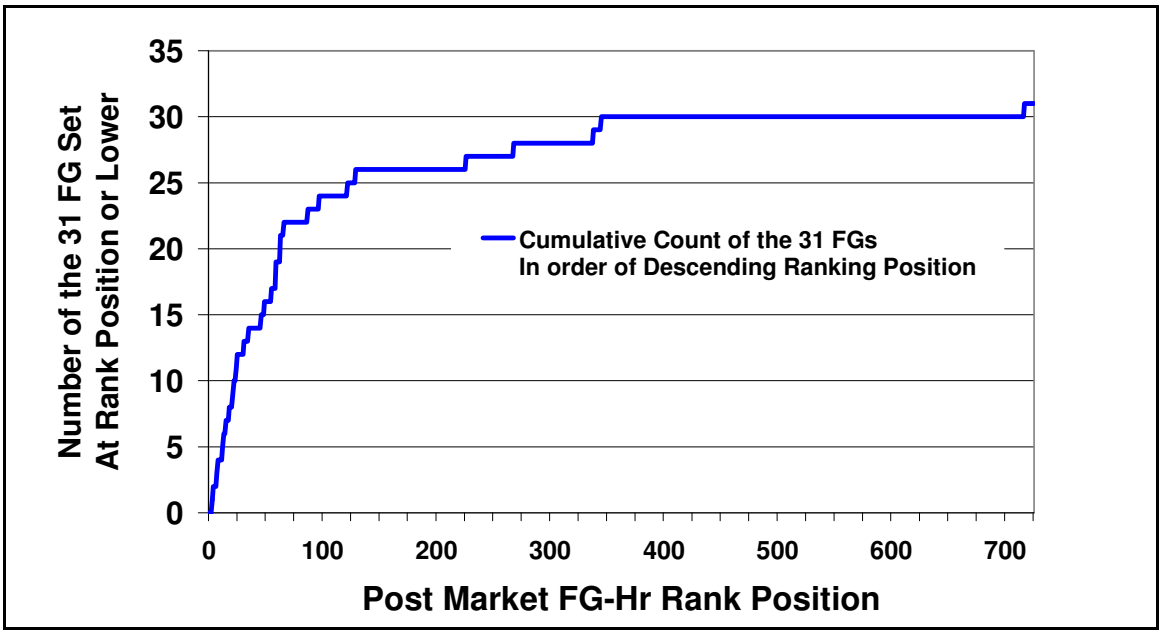

Figure 8.1-1 Post Market Rank Distribution of 31 Flowgates Congested in Pre-market and all four Post-Market Periods

For additional information, a detailed listing of the 31 flowgates represented in Figure 8.1-1 is available in Table 8.1-3. Not quite half of the unique 31 flowgates are among the top 25 most constrained flowgates since market start. Additional analysis on the top 25 flowgates is discussed in detail in Section 8.2.

Table 8.1-3 The 31 Flowgates that realized congestion In the pre-market period and all four post-market periods

(see Figure 8.1-1 for the distribution of post-market ranks relative to all 2,375 post-market FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	3rd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	4th Year Market Congestion FG-Hr/YR Apr 08 to Apr 09	BA	MTEP Map Grid
3, 3006	EAU CLAIRE-ARPIN 345 kV	630	1529	245	794	362	ALTE,NSP,WEC,WPS	J6
4, 3270	State Line-Wolf Lake 138 flo Burnham-Sheffield 345	89	151	481	847	425	PJM, NIPS	L8
7, 3012	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	697	405	420	477	261	ALTE	K7
8, 6007	GENTLMN3 345 REDWILO3 345 1	95	271	186	312	623	NPPD	D9
12, 3167	St. Francois - Lutesville 345 kV	27	39	18	217	936	AMMO	K11
13, 6009	COOPER_S	66	696	234	76	172	NPPD,MPS,AECI, OPPD	G9
15, 2980	Dune Acres-Michigan City 138 1&2 (flo) Wilton Center-Dumont 765	1130	241	107	59	742	NIPS	L8
18, 3567	Flow South	5325	646	172	25	117	WEC	K5
21, 9159	IMO_DECO	34	79	251	475	60	ONT,DECO	O7
22, 3706	Arnold - Hazleton	113	112	480	156	46	ALTW	I7
24, 111	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	7	58	92	172	364	PJM,FE	P9
25, 2086	10NEWTVL 161 10NEWTVL 138 1	3	28	8	502	103	SIGE	
31, 3724	Arnold-Vinton 161 for D.Arnold-Hazelton 345	781	105	216	135	72	ALTW	I7
35, 2131	Wylie Ridge-Sammis 345 kV line	14	40	41	15	369	FE,PJM	P9
46, 2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	38	220	6	95	7	SIGE,BREC	L11
49, 3529	N. Appleton-Rocky Run 345 kV	62	8	225	49	25	WEC,WPS	K6
55, 6002	MHEX_S	120	39	84	126	30	MHEB,WAUE,NSP	
59, 3631	Highway V - Preble 138 (flo) Lost Dauphin - Red Maple 138	698	131	1	123	10	WPS	K6

Table 8.1-3 The 31 Flowgates that realized congestion In the pre-market period and all four post-market periods

(see Figure 8.1-1 for the distribution of post-market ranks relative to all 2,375 post-market FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	3rd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	4th Year Market Congestion FG-Hr/YR Apr 08 to Apr 09	BA	MTEP Map Grid
59, 3725	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345	220	45	81	121	18	ALTW	J8
63, 6012	PRI-BYN	19	91	78	56	32	NSP,SMP	I6
63, 2337	Cook-Palisades345/BentnHrbr-Palisades345	16	96	117	41	3	PJM,CONS	L8
66, 3538	STILES4-PULLIAM 138+STILES5-PULLIAM 138	78	24	16	157	51	WEC,WPS	K6
87, 2936	Seneca-Krendale 138 flo Wylie Ridge-Cabot 500	11	123	10	20	38	FE, PJM	Q9
97, 2961	Worthington-Owen 138 (flo) Worhtington-Bloomington 345	2	68	43	29	11	CIN, HE	L10
122, 3135	ALBION-CROSSVL + XENIA-MT VERNON	6	95	21	3	2	AMIL	L11
129, 3752	Salem 345/161 XFMR (flo) Tiffin-Arnold 345	1	3	51	59	3	ALTW	J8
226, 3719	Salem 345/161 (flo) Quad Cities-Sub 91	164	6	46	8	6	ALTW	J8
268, 2336	BentnHrbr-Palisades345/Cook-Palisades345	46	16	9	23	4	PJM,CONS	
338, 2053	Galagher-Paddys West 138 flo Jefferson-Rockport 765	5	2	9	1	28	LGEE,CIN	N11
345, 6072	L20D 230 kV	10	9	9	12	9	MHEB	
717, 2485	Gallagher-Paddys W 138 (flo) Trimble Co.-Clifty Creek 345	5	4	2	1	7	LGEE,CIN	

As one moves forward in planning the transmission system, careful consideration is necessary to identify transmission investments that are required to address chronic congestion as opposed to reacting to acute but short-lived congestion. Most of the historical congestion observed in the Midwest ISO has associated reliability based projects that will mitigate the hours of congestion; however, there are a few locations not currently addressed through reliability upgrades. Transmission system constraints that limit the availability of transmission service generally represent limitations to the commercial use of the system, rather than limitations to the reliability of the system.

8.2 History of Congestion

Overview

This historical congestion review will focus on Real-Time operations in the four year period since April 2005, where congestion has been managed through a combination of Transmission Loading Relief (TLR) and by binding elements in the Midwest ISO market. The Midwest ISO uses centrally controlled, security constrained, economic dispatch as a part of the LMP-based market. This 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.

To have an element or flowgate "bound" means that a defined flow limit has been set (i.e., a bound) for the element within the Midwest ISO market security constrained economic dispatch program. The market will then be re-dispatched at some resulting higher cost level in order to maintain the flow within the set limit. The TLR (through curtailment of scheduled transactions) and market re-dispatch (via binding elements) are available for implementation when warranted by system conditions. Both processes are targeted to prevent system security violations if a contingency were to occur. Commercial limitations to use of the transmission system give rise, however, 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 simply reflects proper management of the system within reliability limits, and is not reflective of other eminent problems or expansion needs. Given adequate generation reserves, the transmission system becomes the "ultimate sentinel" for reliability. Any subsequently realized transmission congestion has two faces.

When transmission limits are reached, and there are adequate generation resources to shift supply, the reliability risk is very low. This situation occurs the majority 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. Limited dispatch can result if there is insufficient generation or when adequate generation exists system wide but is restricted by transmission congestion. Such generation would not then be effective to meet overall Planning Reserve levels. Findings from the 2009-2010 Loss of Load Expectation (LOLE) Study Report for future planning reserve requirements (see Section 8.2.2) 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.

Historical Congestion Analysis

The following discussion provides information about constraints that have been most frequently involved in either limiting transactions via TLR, been bound in the Midwest ISO market dispatch, or both. Both TLR and Midwest ISO market re-dispatch measures are used to maintain system reliability.

Summarizing congestion history provides a consistent metric of system performance. This summary does not include tracking the interactive impacts among flowgates, or of new flowgates being introduced, or other dynamics as the physically installed generation and transmission system itself changes over time. While no particular attempt has been made in MTEP report to dissect specific historical data, or merge commonly impacted flowgates, this summary (particularly the individual flowgate charts in Appendix_F2_Congestion_History_061509.pdf) provides a basis for such detailed investigations. This type of information is commonly utilized, along with further local knowledge incorporated into more detailed discussions, for specific projects' needs, or in addressing stakeholder questions about the transmission system. The Independent Market Monitor (IMM) has done work on tracking the congestion on sets of flowgates that have common patterns of generation response. That was the subject of Narrow Constrained Areas (NCA) in MTEP 08. An updated summary of the NCAs is in Appendix_F2_Congestion_Summary_061609.xls as a follow up to track performance.

It should be recognized that the historical congestion realized by TLR, or binding in the Midwest ISO market, has predominantly functioned as a security operating mechanism where expansion solutions were not necessary. Therefore, historically predominant congestion locations may or may not be associated with need for transmission facility expansion.

Since MTEP 07, emphasis has been placed on the post-market timeframe which has now matured to 48 months of the Midwest ISO market operations (April 1, 2005 through March 31, 2009). Aggregated, or averaged summaries, can be misleading in that they 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 over a short time, but not represent an issue going forward. Therefore, the reader is urged to reflect upon the detailed monthly congestion patterns for the more active flowgates, as illustrated in Appendix F2 Congestion History 061509.pdf. It is intended that the charts in Appendix F2 Congestion History 061509.pdf will provide a basis for further insight. 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 such forums or targeted study efforts beyond MTEP reports.

This historical review is based on including a flowgate as a Midwest ISO flowgate if the facility is under the Midwest ISO Reliability Authority (RA). For example, this includes flowgates owned by Midwest ISO Transmission Owners (TOs) and includes flowgates of non-member systems in the Mid-Continent Area Power Pool (MAPP) group of transmission companies that have their RA functions contracted to Midwest ISO. Prior to MTEP 06, congestion was tracked 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) Locational Marginal Pricing (LMP). The term "bound" is used to refer to an element or flowgate that is requiring out-of-order dispatch of generation resulting in a Marginal Congestion Component (MCC) within the calculated LMP price. The following discussion will relate to TLR activity, or to bound activity, and sometimes to both TLR and bound.

Figure 8.2-1 illustrates the sum of monthly flowgate hours of congestion and the relative method of managing congestion since January 2001 through March 2009. Note the exclusive use of TLR for congestion management in the pre-Midwest ISO market period versus the post-Midwest ISO market period when both TLR and bound constraints in the LMP central dispatch were utilized. The legend term "Bound Only" refers to flowgate congested hours that were managed through re-dispatch by adjusting LMP prices while no assistance was realized from TLR. The term "TLR Only" refers to the flowgate congested hours that were exclusively managed by the NERC TLR process only. The legend term "Bound and TLR" refers to flowgate congested hours in which the TLR and Bound re-dispatch were utilized concurrently.

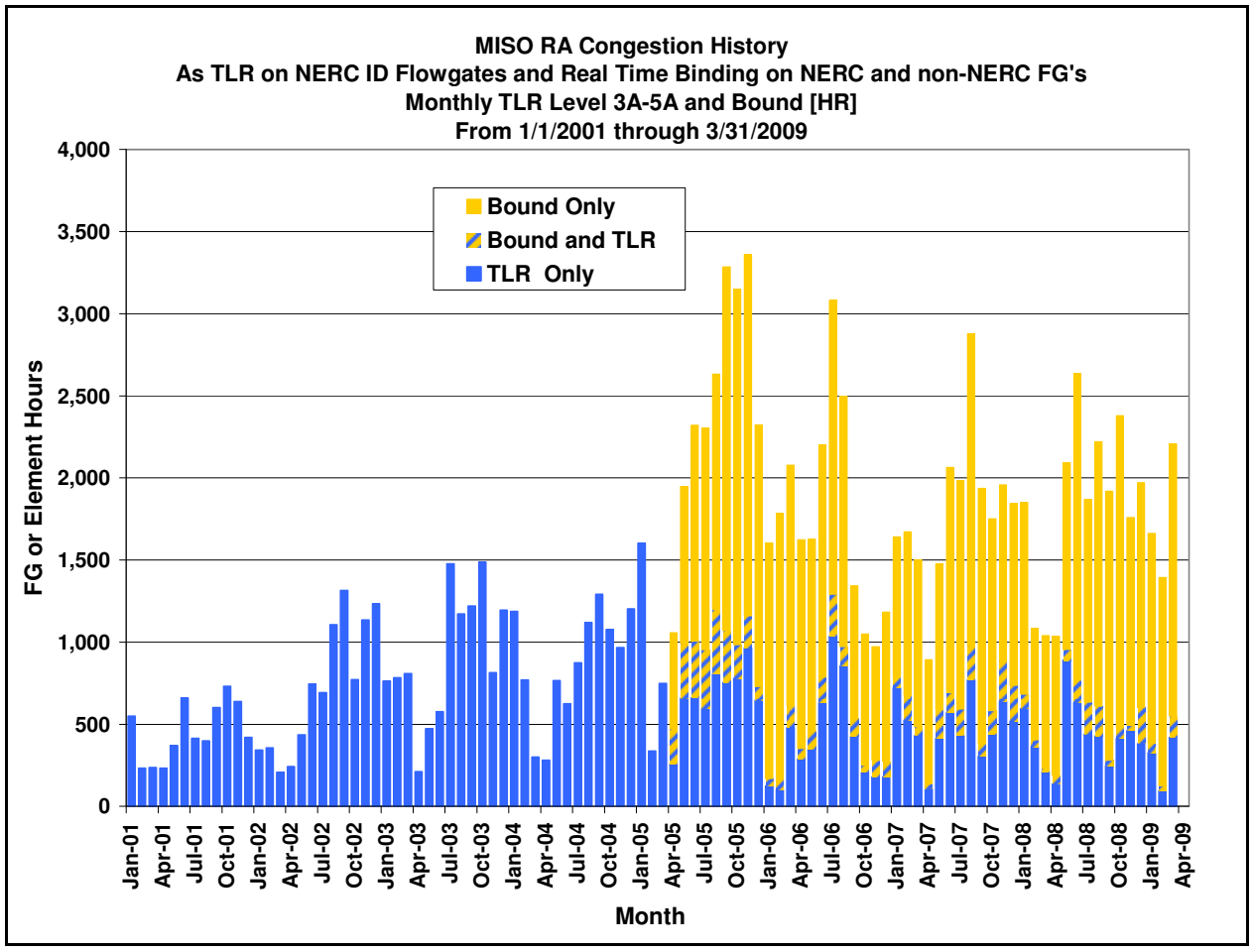

Figure 8.2-1: Overview History of Midwest ISO Congestion and Method

Similarly, Figure 8.2-2 shows the itemization, by TLR Level, for hours that were affected exclusively or in part by TLR. The "Bound Only" portions in Figure 8.2-2 are the same as the "Bound Only" portions plotted in Figure 8.2-1. As shown by 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. Market analysis has shown that the predominant factor was a lag in business activity between the Midwest ISO market footprint and the bordering non-Midwest ISO market participant areas. In effect, the two adjoining groups tended to conduct business as if they were segregated systems. After those first six months, increased familiarity with new systems and business practices that permit transactions into and out of the Midwest ISO market brought on a reduction in the congestion activity.

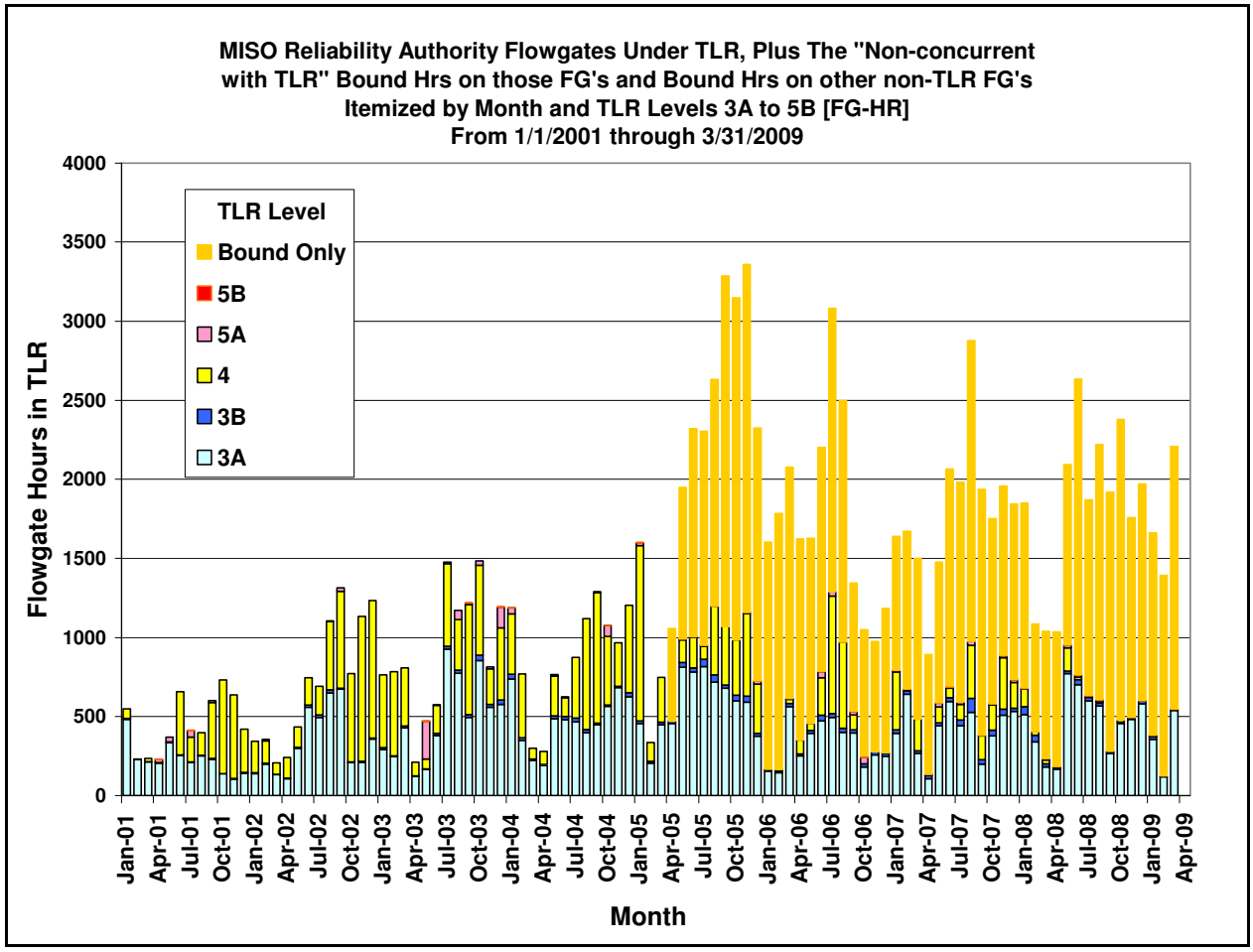

Figure 8.2-2: Overview History with TLR Affected Hours Itemized by TLR Level

Nine levels of TLR are listed below. Figures and other summaries that reference TLR in this report are inclusive of the TLR levels ranging from curtailing transactions (Level 3a) to taking Emergency action (Level 6). This range of TLR is consistent with the RT implementation of bound elements. Both this TLR range and the binding of elements by the RT Midwest ISO market, represent actions upon actually observing 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. The process of Transmission Service Requests on the Open Access Same-Time Information System (OASIS) is also an anticipation type of process that is implemented before high flows are observed on the system. Most of the flow reductions obtained through TLR are achieved in the range of levels from 3a to 4; seldom is flow relief achieved by use of level 5 schedule reductions.

Level 0:	Level 0 refers to normal operation. This level accounts for transactions that were 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:	Emergency action.

Table 8.2-1 lists 44 flowgates that, on the average, were congested more than 1% of the time in the post-Midwest ISO market period (over 351 hours in the four year period). Table 8.2-1 shows the average annual hours of congestion for the pre-Midwest ISO market period, and each of the four Market years. The green highlighted rows in Table 8.2-1 indicate seven flowgates (among the top 25 most active FGs) that had 4th Market year congestion greater than previous Market years, and are illustrated in Figure 8.2-8.

Table 8.2-1: The 44 Post Market Flowgates that on the average were congested more than 1% of the time

(see Figure 8.2-3 for long-term Bound versus TLR breakdown of the 44 Congested FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	3rd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	4th Year Market Congestion FG-Hr/YR Apr 08 to Apr 09	BA	MTEP Map Grid
1, 100	Kammer 765/500 kV XFMR (flo) Belmont - Harrison 500 kV	0	1733	338	938	1,457	PJM	Q9
2, 2353	Black Oak - Bedington 500 kV (flo) Pruntytown - Mt. Storm 500 kV	0	914	1,157	909	152	PJM	Q10
3, 3006	Eau Claire - Arpin 345 kV	145	1529	245	794	362	ALTE,NSP, WEC,WPS	J6
4, 3270	State Line - Wolf Lake 138 kV (flo) Burnham - Sheffield 345 kV	21	151	481	847	425	PJM, NIPS	L8
5, 2245	Blue Lick - Bullitt Co. 161 kV (flo) Baker - Broadford 765 kV	48	1699	44	6	0	LGEE	N11
6, 2352	Pruntytown - Mt. Storm 500 kV (flo) Black Oak - Bedington 500 kV	0	468	395	142	670	PJM	Q9
7, 3012	Paddock 345/138 kV XFMR (flo) Paddock - Rockdale 345 kV	161	405	420	477	261	ALTE	K7
8, 6007	Gerald Gentleman - Red Willow 345 kV	22	271	186	312	623	NPPD	D9
9, 6126	S1226-Tekamah 161 kV flo S3451-Raun 345 kV	76	36	0	714	640	MEC,OPPD	
10, 3145	Pana 345/138 kV XFMR (flo) Coffeen - Coffeen North 345 kV	0	24	164	230	947	AMIL	
11, 2872	Frankfort East - Tyrone 138 kV (flo) Ghent - West Lexington 345 kV	49	1151	132	0	0	LGEE	M11
12, 3167	St. Francois - Lutesville 345 kV	6	39	18	217	936	AMMO	K11
13, 6009	Cooper South Interface	15	696	234	76	172	NPPD,MPS,AECI,OPPD	G9
14, 6004	Minnesota Wisconsin Stability Interface (MWSI)	49	806	212	144	0	NSP	I6

Table 8.2-1: The 44 Post Market Flowgates that on the average were congested more than 1% of the time

(see Figure 8.2-3 for long-term Bound versus TLR breakdown of the 44 Congested FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	3rd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	4th Year Market Congestion FG-Hr/YR Apr 08 to Apr 09	BA	MTEP Map Grid
15, 2980	Dune Acres -Michigan City 138 kV ckts 1&2 (flo) Wilton Center - Dumont 765 kV	261	241	107	59	742	NIPS	L8
16, none	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	0	539	284	189	0	SIGE	L11
17, 122	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	0	573	375	31	0	PJM	Q9
18, 3567	ATC LLC Flow South Interface	1229	646	172	25	117	WEC	K5
19, 9160	ONT-NYIS	0	0	0	21	923	ONT,NYIS	
20, 2463	Kokomo HP 230/138 kV XFMR (flo) Jefferson - Greentown 765 kV	0	132	750	0	0	CIN	K9
21, 9159	Ontario - ITC Interface	8	79	251	475	60	ONT,DECO	O7
22, 3706	Arnold - Hazleton 345 kV	26	112	480	156	46	ALTW	I7
23, none	Culley - Grandview 138 kV (flo) Henderson - A.B. Brown 138 kV	0	586	84	30	0	SIGE	L11
24, 111	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	2	58	92	172	364	PJM,FE	P9
25, 2086	Newtonville 161/138 kV Transformer #1	1	28	8	502	103	SIGE	
26, 6164	Plymouth-Sioux City 161 kV flo Raun-Sioux City 345 kV	0	0	139	470	2	MEC,WAUE	G7
27, none	AMCBV158_RIV_RIV_NOFM_1_A	0	22	109	68	401	AMMO	
28, 3102	Bland - Franks 345 kV	51	347	206	0	0	AMRN	I11
29, 2934	Sammis_Wylie_Ridge_345_flo_Tidd_Wylie_Ridge_345	0	2	0	133	398	FE, PJM	
30, 6006	Gerald Gentleman Station	4	0	531	0	0	NPPD	D9
31, 3724	Arnold - Vinton 161 kV (flo) Arnold - Hazelton 345 kV	180	105	216	135	72	ALTW	I7
32, 6085	Genoa - Coulee 161 kV (flo) Genoa-LaCrosse-Marshland 161 kV	51	158	344	4	0	DPC	J7
33, 3186	West Mt. Vernon - E W Frankfort 345 kV	0	188	12	119	156	AMIL	L10
34, 140	Elrama_Mitchell_138 kV_flo_Ft_Martin_Ronco_500 kV	0	72	12	382	7	PJM	
35, 2131	Wylie Ridge-Sammis 345 kV line	3	40	41	15	369	FE,PJM	P9

Table 8.2-1: The 44 Post Market Flowgates that on the average were congested more than 1% of the time

(see Figure 8.2-3 for long-term Bound versus TLR breakdown of the 44 Congested FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	3rd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	4th Year Market Congestion FG-Hr/YR Apr 08 to Apr 09	BA	MTEP Map Grid
36, 3532	Ellington_Hintz_138_flo_N Appleton_WernerWest_345	0	0	86	286	71	WEC	
37, 291	Pierce B 345/138 kV transformer l/o Pierce-Foster 345 kV	0	4	31	393	8	CIN	
38, 1649	Avon 345/138 kV XFMR	0	147	260	1	0	EKPC	N11
39, 3745	Lime Creek - Emery 161 kV (flo) Adams - Hazleton 345 kV	1	30	291	70	0	ALTW	H7
40, 3108	Overton - Sibley 345 kV	0	160	189	20	17	AMMO,MPS	H10
41, 14341	Oak_Grove_Galesburg_flo _Nelson_ElectricJct	0	0	0	53	318	AMIL	
42, 2557	Northeast Kentucky Interface	0	249	111	7	0	LGEE	M11
43, none	IPS05_COT_HLS_IP-1456_3	0	0	0	262	99	AMIL	
44, 3641	Schahfer_BurrOak345_flo_ WiltonCenter_Dumont765	0	0	0	0	355	NIPS	

Note: The abbreviation (flo) in table 8.2-1 is for “for loss of”. Certain flowgates have both a limiting or monitored element listed first and a contingent element after the flo.

Figure 8.2-3 itemizes, for the 44 flowgates contained in Table 8.2-1, the total exclusive hours bound and hours at each TLR Level. Approximately half of the congestion from the top 44 FG is due to FGs that are not under the direct influence of the Midwest ISO Planning Authority (PA).

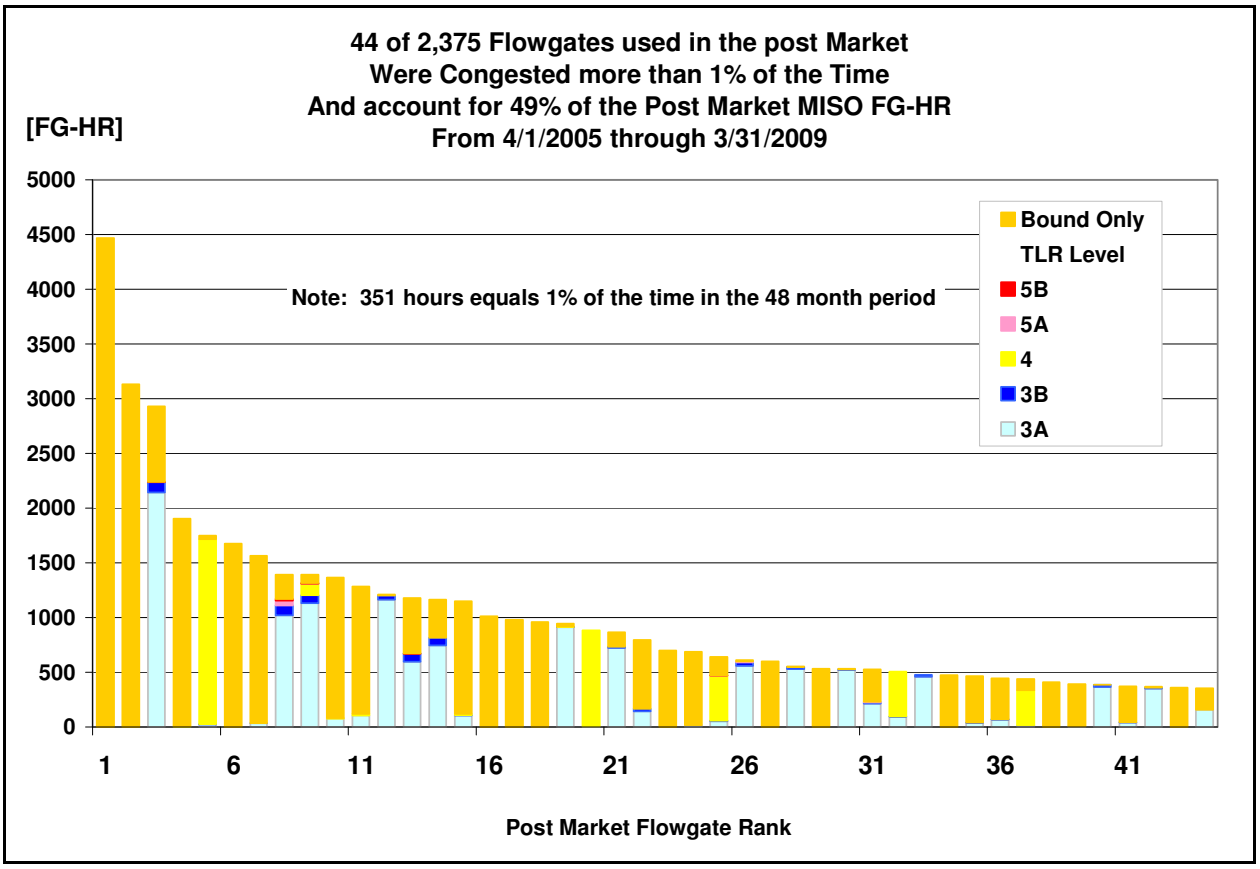

Figure 8.2-3: Top 44 Most Congested Post Market FGs
See Table 8.2-1 for Identification of a Specifically Ranked FG

The lag in business activity between the Midwest ISO market footprint and the bordering non-Midwest ISO market participant precipitated an elevated amount of congestion during the first six months of the Midwest ISO market. Therefore, the following review will separate congestion during each of the four Midwest ISO market years, and discuss changes through the 4th year. For the 25 most congested post-Midwest ISO market flowgates, Figure 8.2-4 illustrates the average annual congestion hours for five periods of time: the pre-Midwest ISO market period, 1st Market year, 2nd Market year, 3rd Market year and 4th Market year. Blue font color coding of the legend font in Figure 8.2-4 identifies 10 of the 25 FG that are not within direct influence of the Midwest ISO PA.

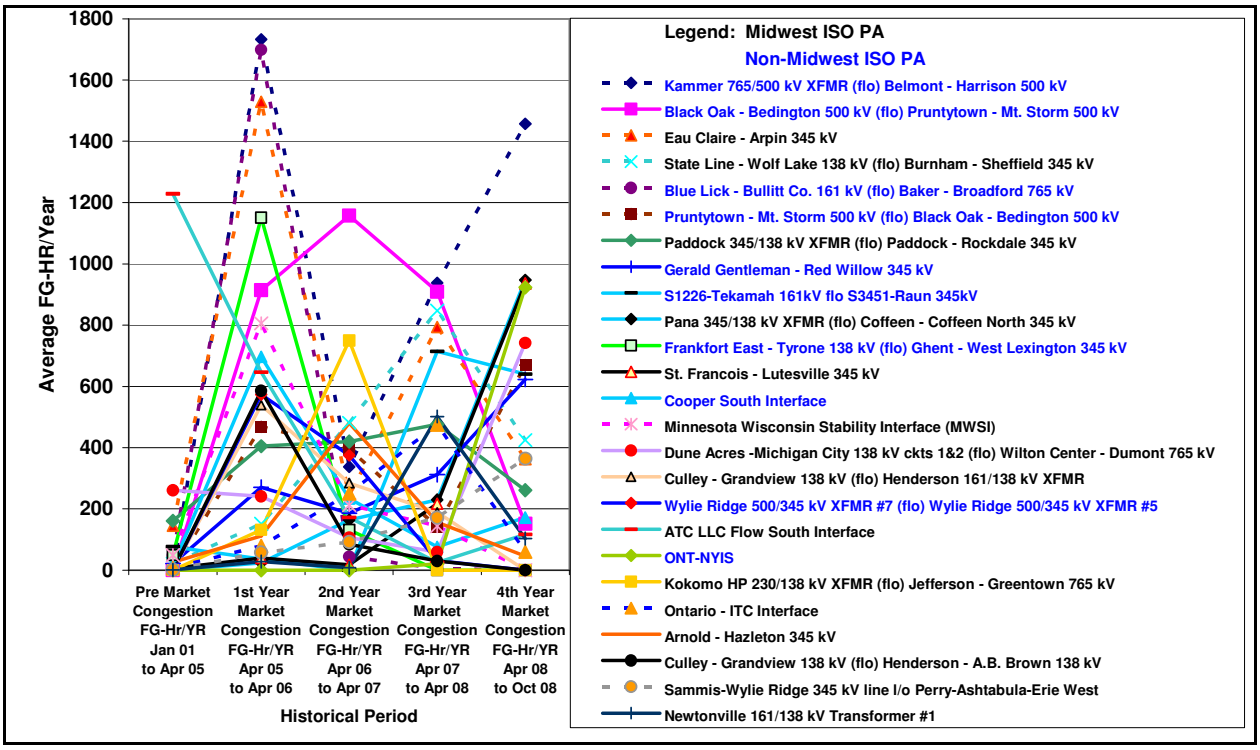

Figure 8.2-4: Top 25 Most Congested Post Market FGs
Annualized Congestion Averages Categorized into Different Historical Periods

When evaluated on a year by year basis:

- Ten of the top 25 most congested post Midwest ISO market flowgates had their greatest annual congestion during the 1st market year (see Figure 8.2-5)
- Three of the top 25 most congested post Midwest ISO market flowgates realized their greatest annual congestion during the 2nd Market year (see Figure 8.2-6)
- Eight of the top 25 most congested post Midwest ISO market flowgates realized 3rd year congestion equal to or greater than previous market years (see Figure 8.2-7)
- Seven of the top 25 most congested post Midwest ISO market flowgates realized 4th year congestion equal to or greater than previous market years (see Figure 8.2-8)

A review of the trends suggested from these figures and possible review of other aspects of operation would be needed before committing specific expansion alternatives as a solution.

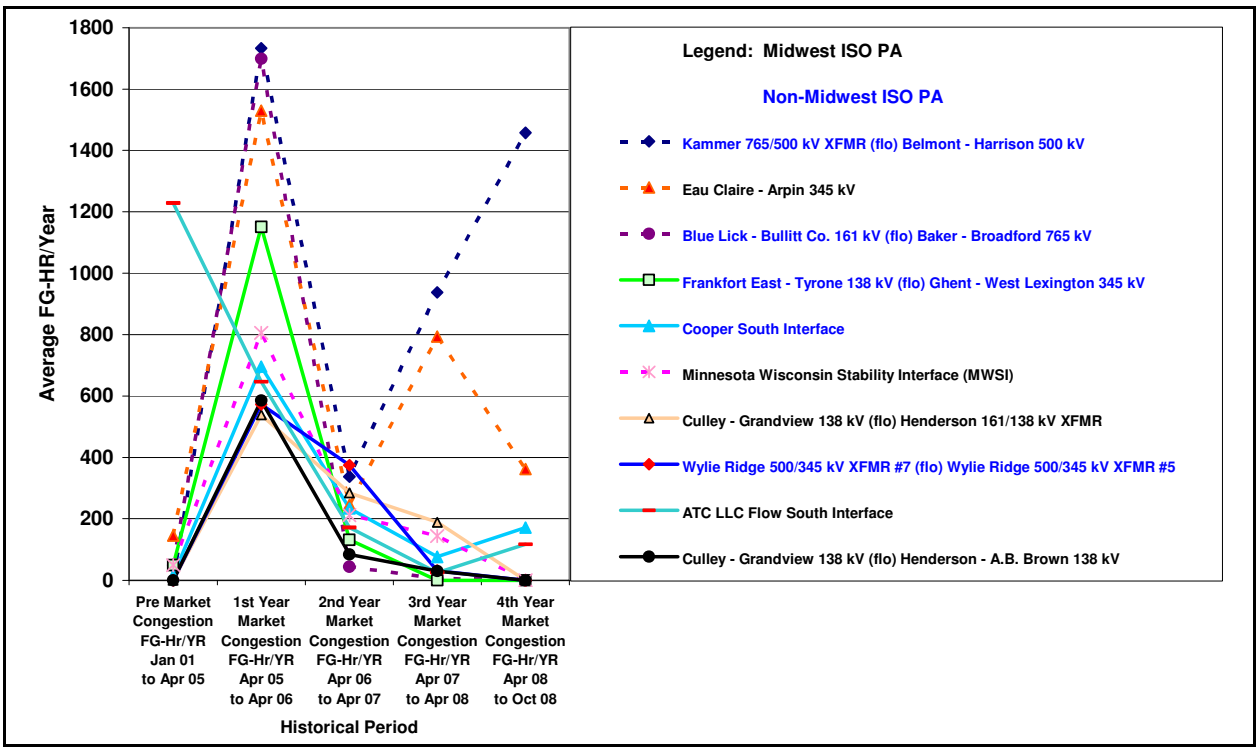

Figure 8.2-5: Ten of the Top 25 Most Congested Post Market FGs That had their Greatest Annual Congestion during the 1st Market Year Annualized Congestion over Different Historical Periods

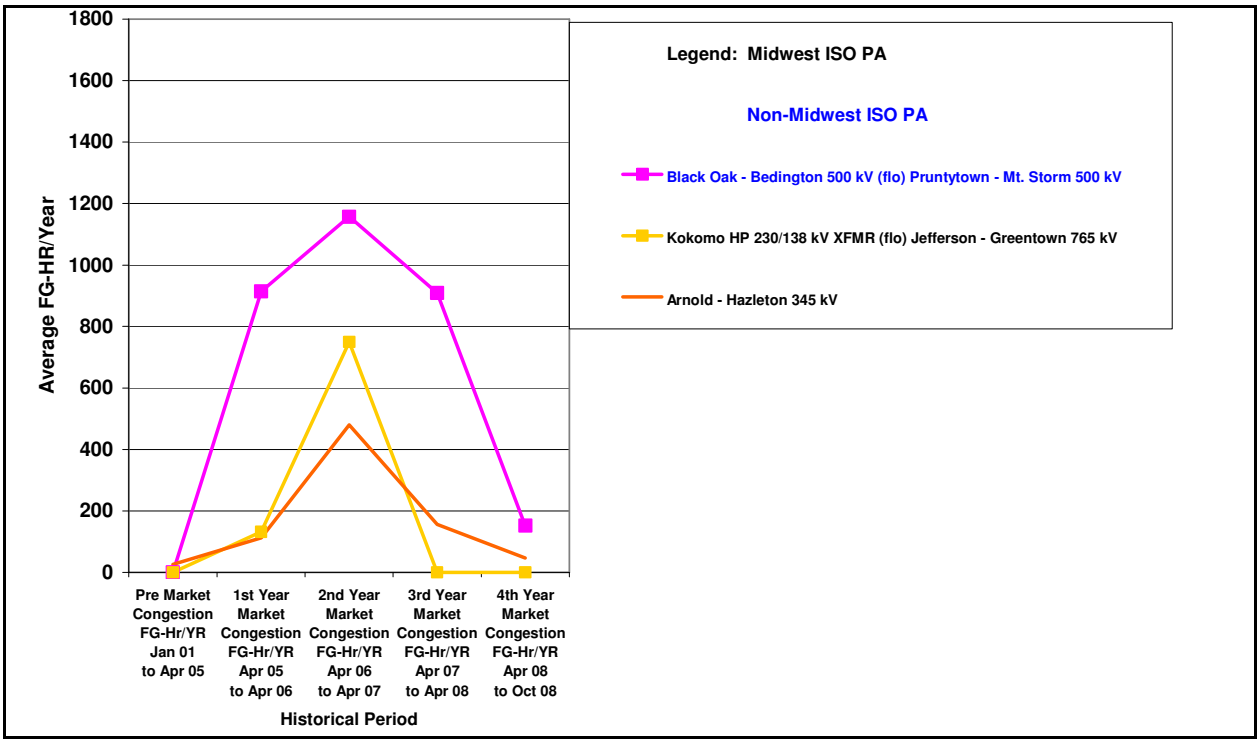

Figure 8.2-6: Three of the Top 25 most congested Post Market FGs That had their Greatest Annual Congestion during the 2nd Market Year Annualized Congestion over Different Historical Periods

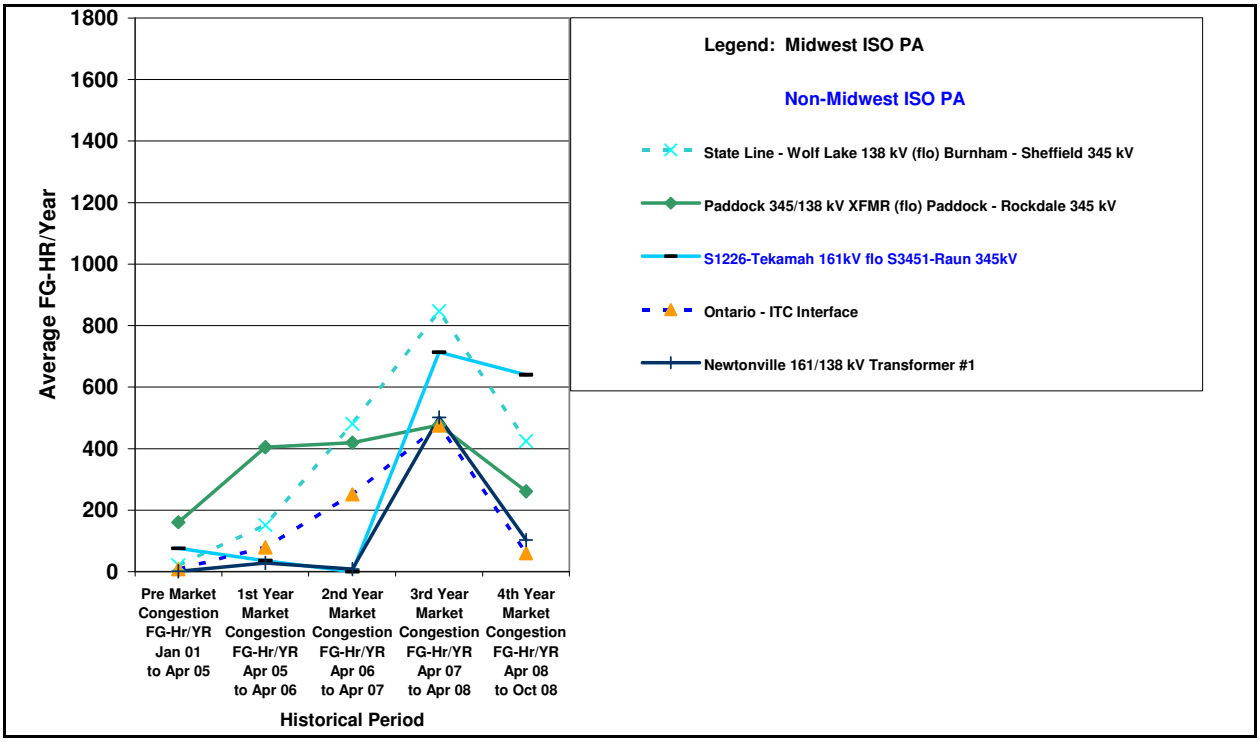

Figure 8.2-7: Five of the Top 25 most Congested Post Market FGs that had their Greatest Annual Congestion during the 3rd Market Year Annualized Congestion over Different Historical Periods

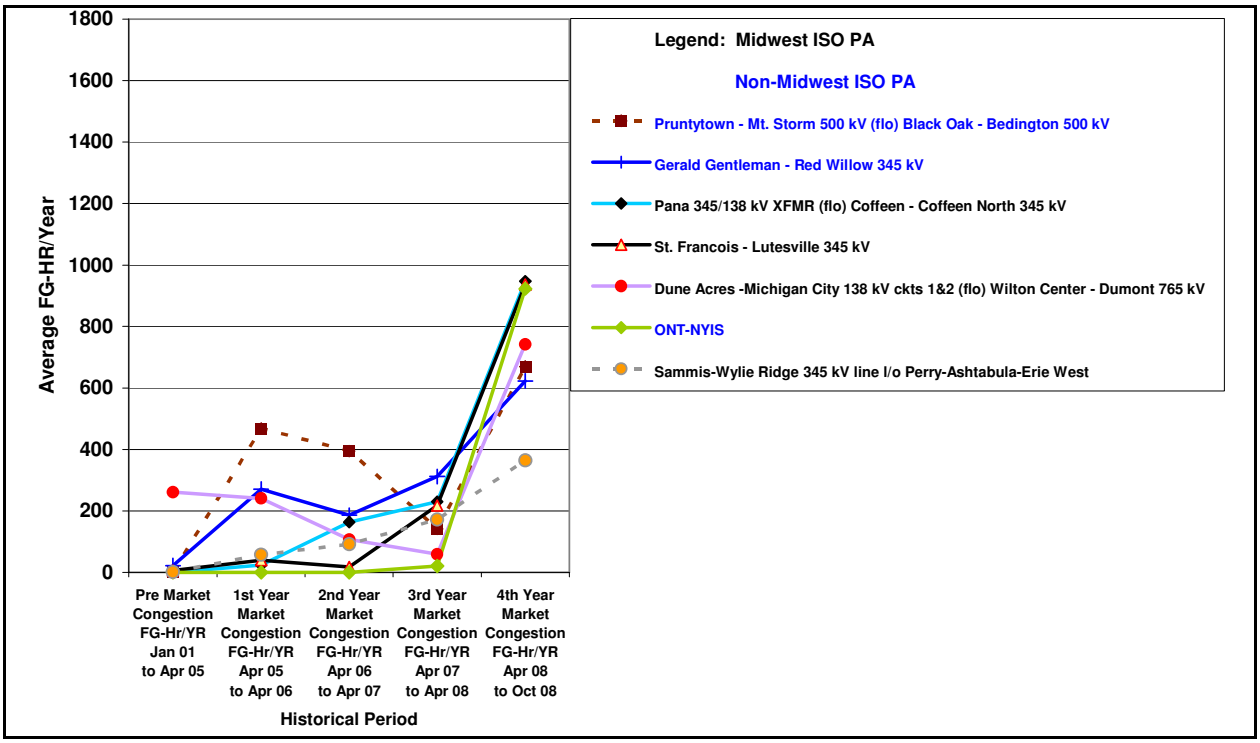

Figure 8.2-8: Seven of the Top 25 Most Congested Post Market FGs That had their Greatest Annual Congestion during the 4th Market Year

Figure 8.2-9 is an alternative sorting of the Top 25 most post-Midwest ISO market congested FGs. The sorting is done on the basis of each FG's rank across all four market years, and applies the median rank of each FG as the basis for sorting. This helps to communicate the relative volatility of annual congestion, and shows if there tends to be movement to a higher or lower ranking position (i.e., it helps show if the situation is getting worse or improving with time). The FG that has most consistently been ranked high is at the top of the list. This sorting method tends to discount any given year where the individual FG's ranking was affected by an extremely low or high rank in any one year.

The label on the vertical axis in Figure 8.2-9 reflects the FGs:

- NERC ID number
- Sum of the post Midwest ISO shadow prices
- FG Name or Description
- Rank on the basis of total post Midwest ISO FG-Hr.

Each row in Figure 8.2-9 pertains to a specific flowgate. The 4th row for example pertains to "EAU CLAIRE-ARPIN 345 kV", FG # 3006 and:

- In the supporting data the 1st, 2nd, 3rd, and 4th year Rankings were: 3, 17, 4, 15
- Minimum Annual Ranking = 3, Median = 9.5, Maximum = 17
- Four year Sum of hourly Shadow Prices = $ 292,255
- Is a FG under the Midwest ISO Planning Authority (PA), therefore in black font
- The FG was congested the most in the 1st year, and is marked with a blue box (A red box indicates FGs with the highest congestion in the 4th year).

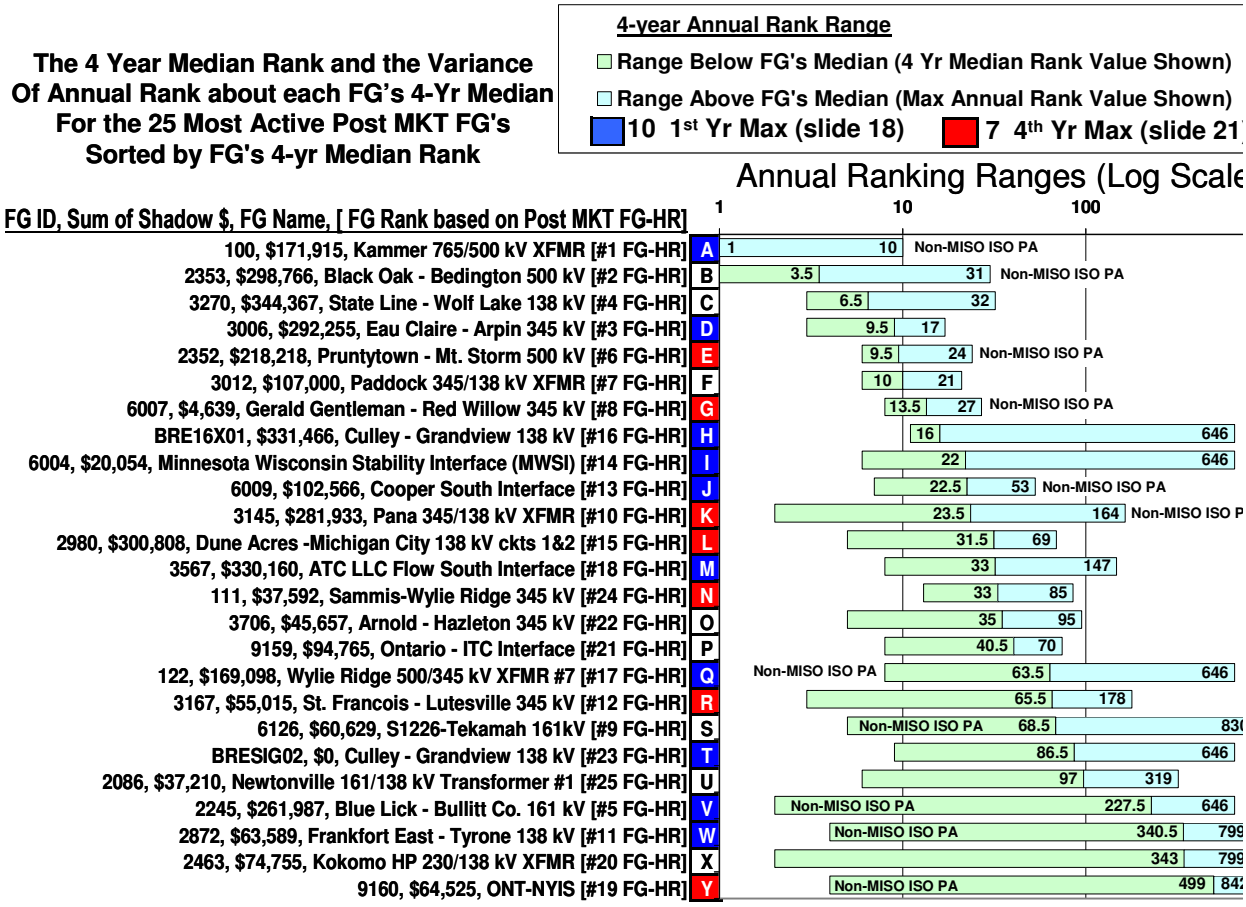

Figure 8.2-9: Alternative Sorting Method for Top 25 Most Congested FG Based on Each FG's Median Rank across all 4 Market Years

Using the same legend convention from Figure 8.2-9, Figure 8.2-10 illustrates the general location of the Top 25 most congested post Midwest ISO market flowgates; and, the legend contains all metrics as described in the last three **(blue)** bullets in the preceding paragraph.

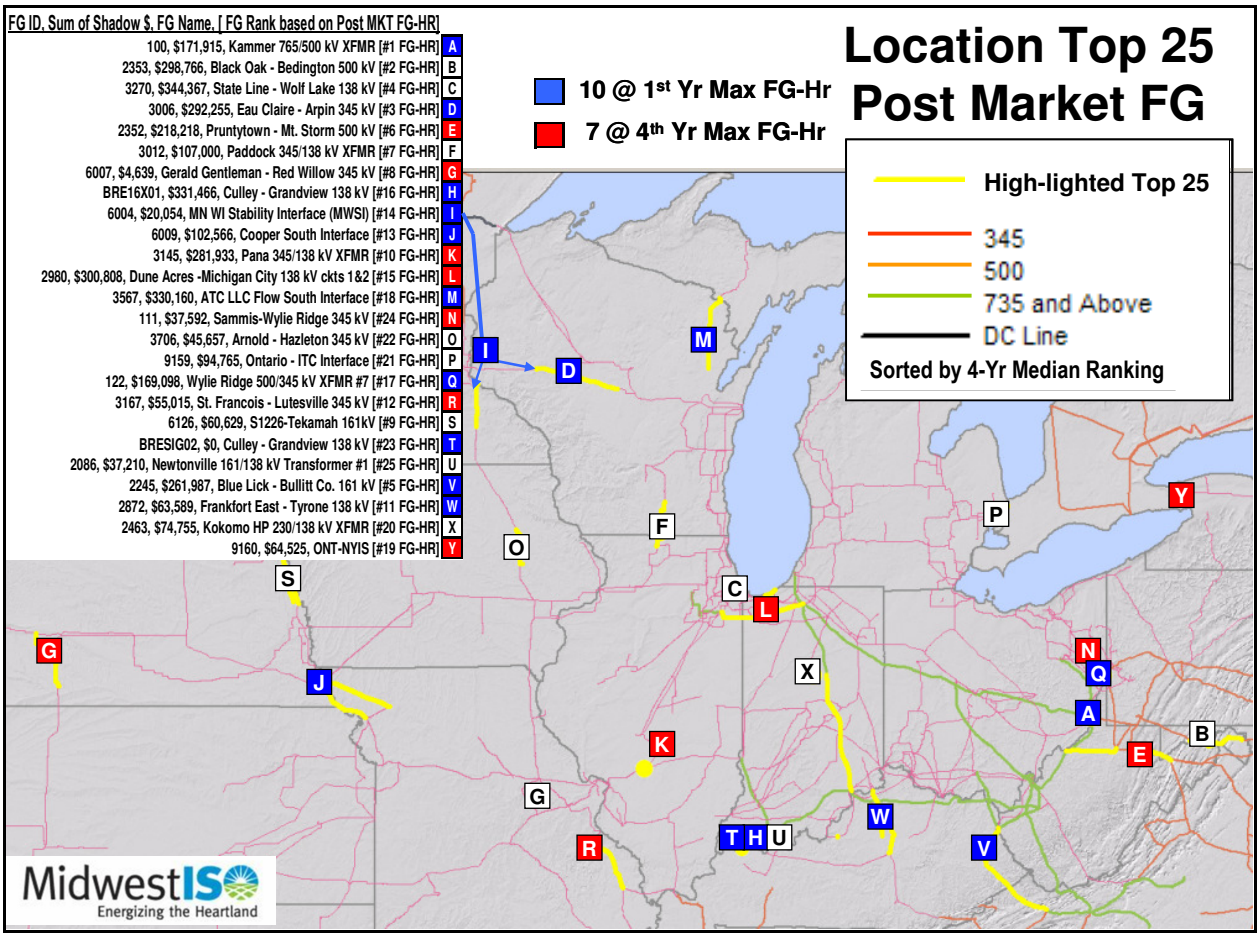

Figure 8.2-10: Location of the Top 25 Most Congested Post Market FGs

Using the top four flowgates, Figures 8.2-11 through 8.2-14 are examples of the itemized monthly congestion history. The itemized monthly congestion histories for each of the 25 top flowgates are shown in Appendix F2. Appendix F2 "Appendix F2 Congestion History 061509.pdf" is a compendium of additional individual flowgate histories, like Figures 8.2-11 through 8.2-14 and other charts, including a lookup table "Appendix F2 Congestion Summary 061609.xls" spread sheet for hours congested on each of 2,604 flowgates since January, 2001.

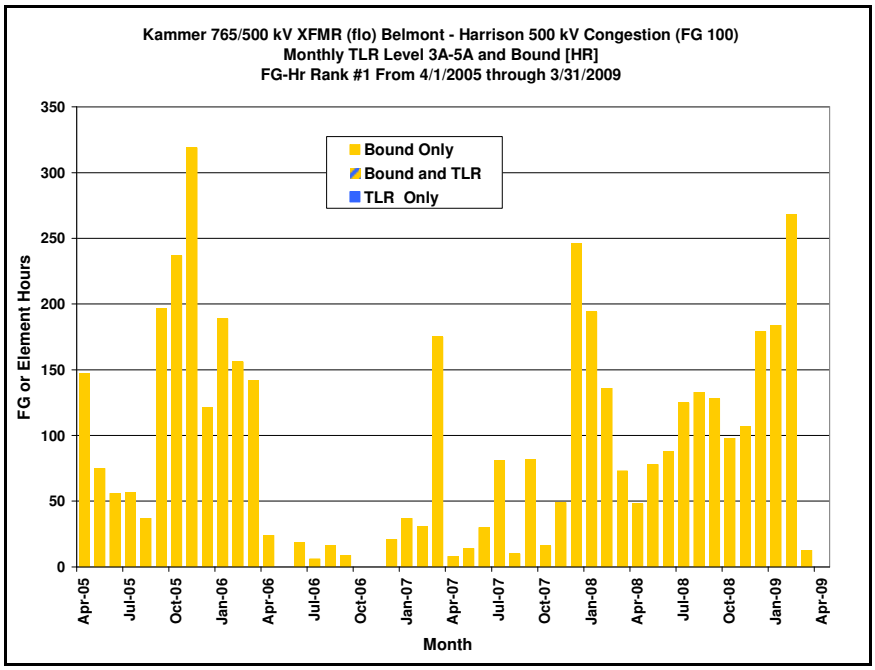

Figure 8.2-11: Itemization of Kammer 765/500 kV XFMR TLR versus Bound, Post Market Rank =1

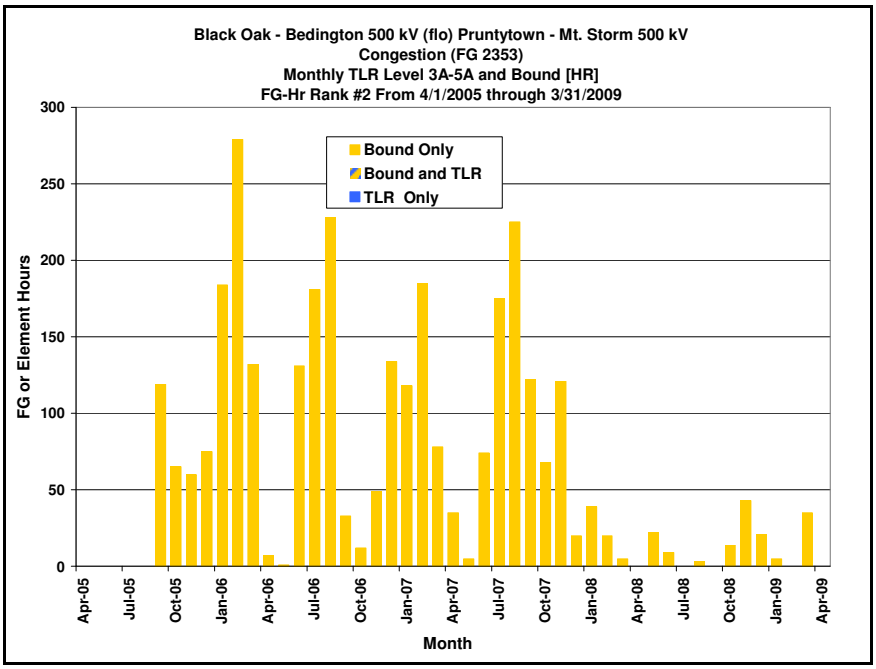

Figure 8.2-12: Itemization of Black Oak - Bedington 500 kV TLR versus Bound, Post Market Rank = 2

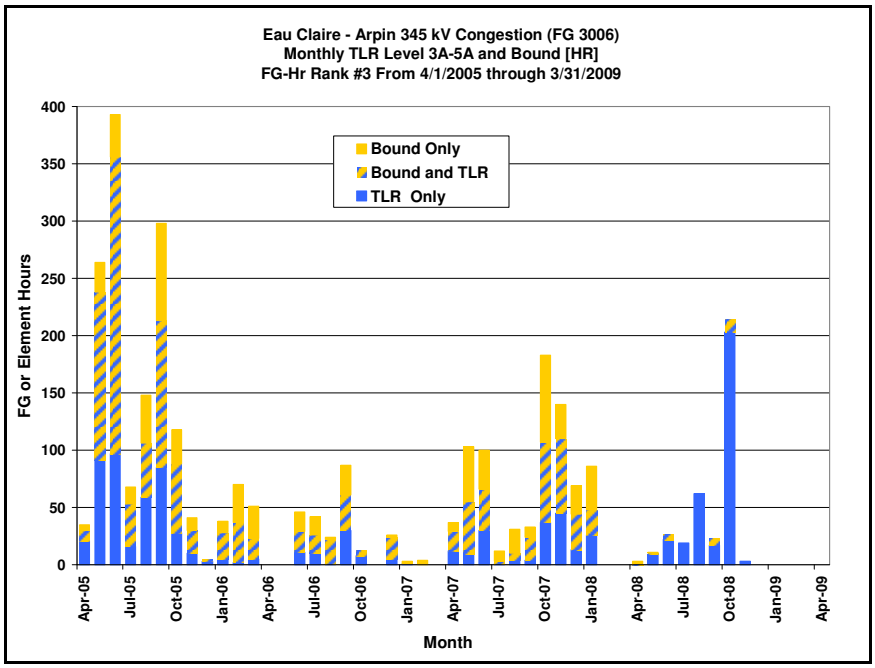

Figure 8.2-13: Itemization of Eau Claire - Arpin 345 kV TLR versus Bound, Post Market Rank =3

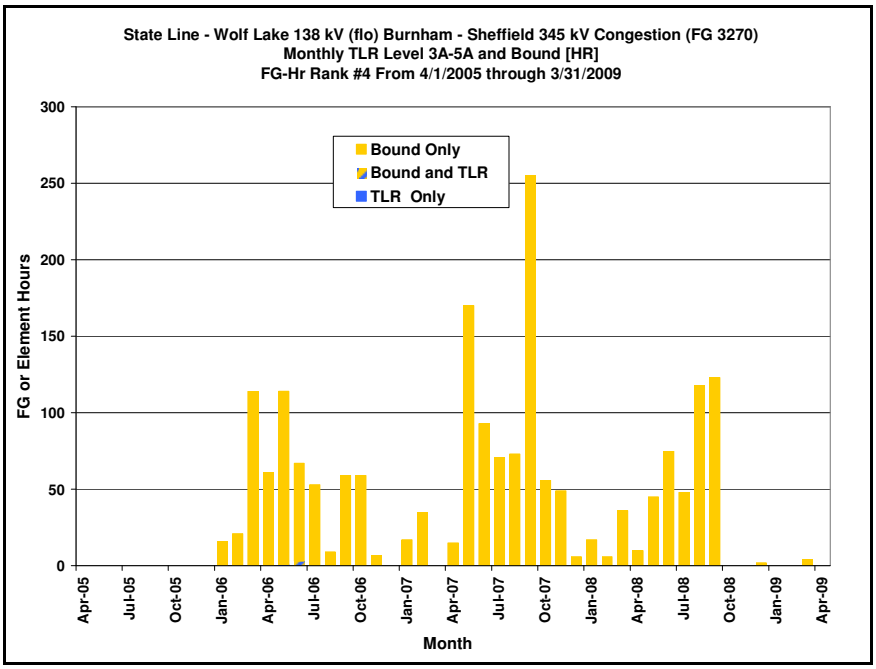

Figure 8.2-14: Itemization of State Line - Wolf Lake 138 kV TLR Versus Bound, Post Market Rank = 4

8.2.1 Upgrades from Prevailing MTEP Planning

The historical constraint overview suggests that there are opportunities for improving the performance of the energy market. Given the observed historical congestion, this section address how projects already planned, or the Top Congested Flowgate Study (TCFS) projects identified in Section 8.3, might mitigate the historically observed congestion situations. Significant transmission system upgrades are planned, primarily to address baseline reliability concerns, in future years. Table 8.2-2 lists the future planned facilities or indicates where CRST facilities are expected to mitigate congestion on some of the top 44 historically most congested post-Midwest ISO market flowgates (FGs also previously listed in Table 8.2-1, but with different metrics).

Table 8.2-2: The 44 Post Market Flowgates that, on the average, were congested more than 1% of the time with correlation to expansion projects which may mitigate Constrained Hours in the future

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Post Market Congested Hours = 1st, + 2nd + 3rd + 4th Year Hours	Related Appendix A or B Upgrades, Top Congested Flowgate Study (TCFS) reviewed, or Comments
1, 100	Kammer 765/500 kV XFMR (flo) Belmont-Harrison 500 kV	4,466= 1733+338+938+1457	Not Midwest ISO flowgate
2, 2353	Black Oak-Bedington 500 kV (flo) Pruntytown-Mt. Storm 500 kV	3,132= 914+1157+909+152	Not Midwest ISO flowgate
3, 3006	Eau Claire-Arpin 345 kV	2,930= 1529+245+794+362	P1: Arrowhead-Gardner Park 345 kV line (ISD January 2008), and P574: Monroe County-Council Creek 161 (ISD June 2013)
4, 3270	State Line-Wolf Lake 138 kV (flo) Burnham-Sheffield 345 kV	1,904= 151+481+847+425	P2798: Proposed project to Reconductor State Line-Wolf Lake-Sheffield 138 kV line, Estimated ISD pending at mid 2010.
5, 2245	Blue Lick-Bullitt Co. 161 kV (flo) Baker-Broadford 765 kV	1,749= 1699+44+6+0	Not Midwest ISO flowgate
6, 2352	Pruntytown-Mt. Storm 500 kV (flo) Black Oak-Bedington 500 kV	1,675= 468+395+142+670	Not Midwest ISO flowgate
7, 3012	Paddock 345/138 kV XFMR (flo) Paddock-Rockdale 345 kV	1,563= 405+420+477+261	2nd Wempletown-Padock 345 kV line (in service in 2005) and P1256 (Paddock Rockdale 345 kV circuit #2 ISD 4/1/2010)
8, 6007	Gerald Gentleman-Red Willow 345 kV	1,392= 271+186+312+623	Coordinated Non-Midwest ISO flowgate
9, 6126	S1226-Tekamah 161 kV flo S3451-Raun 345 kV	1,390= 36+0+714+640	Not Midwest ISO flowgate. Reviewed in TCFS
10, 3145	Pana 345/138 kV XFMR (flo) Coffeen-Coffeen North 345 kV	1,365= 24+164+230+947	Reviewed in TCFS
11, 2872	Frankfort East-Tyrone 138 kV (flo) Ghent-West Lexington 345 kV	1,283= 1151+132+0+0	Not Midwest ISO flowgate.
12, 3167	St. Francois-Lutesville 345 kV	1,210= 39+18+217+936	Reviewed in TCFS
13, 6009	Cooper South Interface	1,178= 696+234+76+172	Not Midwest ISO flowgate.
14, 6004	Minnesota Wisconsin Stability Interface (MWSI)	1,162= 806+212+144+0	P1: Arrowhead-Gardner Park 345 kV line, ISD January 2008, and P1024: SE Twin Cities-Rochester, MN-LaCrosse, WI 345 kV project, and P574: Monroe County-Council Creek 161 (ISD June 2013)

Table 8.2-2: The 44 Post Market Flowgates that, on the average, were congested more than 1% of the time with correlation to expansion projects which may mitigate Constrained Hours in the future

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Post Market Congested Hours = 1st, + 2nd + 3rd + 4th Year Hours	Related Appendix A or B Upgrades, Top Congested Flowgate Study (TCFS) reviewed, or Comments
15, 2980	Dune Acres-Michigan City 138 kV ckts 1&2 (flo) Wilton Center-Dumont 765 kV	1,149= 241+107+59+742	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. Reviewed in TCFS
16, none	Culley-Grandview 138 kV (flo) Henderson 161/138 kV XFMR	1,012= 539+284+189+0	P1259: New transmission line Dubois to Newtonville, ISD June 2006
17, 122	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	979= 573+375+31+0	Not Midwest ISO flowgate; however, congestion trend is downward.
18, 3567	ATC LLC Flow South Interface	960= 646+172+25+117	Stiles-Plains 138 kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park-Highway 22 345 kV line projects) and P345 (Morgan-Werner West 345 kV line) connect Morgan-Plains 345 kV line to the pre-existing 345 kV system, hence increase voltage stability. P352 (Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV) will also help increase the FG limit.
19, 9160	ONT-NYIS	944= 0+0+21+923	Not Midwest ISO flowgate
20, 2463	Kokomo HP 230/138 kV XFMR (flo) Jefferson-Greentown 765 kV	882= 132+750+0+0	No reliability project identified; however, congestion trend is downward.
21, 9159	Ontario-ITC Interface	865= 79+251+475+60	No reliability project identified.
22, 3706	Arnold-Hazleton 345 kV	794= 112+480+156+46	P1340: Build a new Hazleton-Lore-Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer ISD: December 2011
23, none	Culley-Grandview 138 kV (flo) Henderson-A.B. Brown 138 kV	700= 586+84+30+0	P1259: New transmission line Dubois to Newtonville,
24, 111	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	686= 58+92+172+364	No reliability project identified. Reviewed in TCFS
25, 2086	Newtonville 161/138 kV Transformer #1	641= 28+8+502+103	Driven by ice storm related damage in early 2007
26, 6164	Plymouth-Sioux City 161 kV flo Raun-Sioux City 345 kV	611= 0+139+470+2	Future Midwest ISO flowgate. It was upgraded in early 2008 and was congested only 2 hrs during the 4th Market Year.
27, none	AMCBV158_RIV_RIV_NOFM_1_A	600= 22+109+68+401	No reliability project identified
28, 3102	Bland-Franks 345 kV	553= 347+206+0+0	No congestion since Callaway-Franks line ISD 2006; See chart in Appendix F2
29, 2934	Sammis_Wylie_Ridge_345_flo_Tidd_Wylie_Ridge_345	533= 2+0+133+398	No reliability project identified. Reviewed in TCFS
30, 6006	Gerald Gentleman Station	531= 0+531+0+0	Coordinated Non-Midwest ISO flowgate. Rank is driven by ice storm related damage in early 2007. 4-year median Ranking is 726

Table 8.2-2: The 44 Post Market Flowgates that, on the average, were congested more than 1% of the time with correlation to expansion projects which may mitigate Constrained Hours in the future

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Post Market Congested Hours = 1st, + 2nd + 3rd + 4th Year Hours	Related Appendix A or B Upgrades, Top Congested Flowgate Study (TCFS) reviewed, or Comments
31, 3724	Arnold-Vinton 161 kV (flo) Arnold-Hazelton 345 kV	528= 105+216+135+72	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
32, 6085	Genoa-Coulee 161 kV (flo) Genoa-LaCrosse-Marshland 161 kV	506= 158+344+4+0	P584: Genoa-Coulee 161 kV rebuild. In Service
33, 3186	West Mt. Vernon-E W Frankfort 345 kV	475= 188+12+119+156	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
34, 140	Elrama_Mitchell_138 kV_flo_Ft_Martin_Ronco_500 kV	473= 72+12+382+7	Not Midwest ISO flowgate
35, 2131	Wylie Ridge-Sammis 345 kV line	465= 40+41+15+369	No reliability project identified. Reviewed in TCFS
36, 3532	Ellington_Hintz_138_flo_NAppleton_WernerWest_345	443= 0+86+286+71	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, P177: Gardner Park-Highway 22 345 kV line and P345: Morgan-Werner West 345 kV line will assist.
37, 291	Pierce B 345/138 kV transformer l/o Pierce-Foster 345 kV	436= 4+31+393+	P625: Add a third transformer rated 400 MVA
38, 1649	Avon345_138Xfmr	408= 147+260+1+0	Non-Midwest ISO flowgate. Planned 2nd Avon 345/138 kV transformer.
39, 3745	Lime Creek-Emery 161 kV (flo) Adams-Hazleton 345 kV	391= 30+291+70+0	No reliability project identified
40, 3108	Overton-Sibley 345 kV	386= 160+189+20+17	No reliability project identified
41, 14341	Oak_Grove_Galesburg_flo_Nelson_ElectricJct	371= 0+0+53+318	No reliability project identified
42, 2557	Northeast Kentucky Interface	367= 249+111+7+0	No reliability project identified
43, none	IPS05_COT_HLS_IP-1456_3	361= 0+0+262+99	Not Midwest ISO flowgate
44, 3641	Schahfer_BurrOak345_flo_Wilton Center_Dumont765	355= 0+0+0+355	No reliability project identified

There are many flowgates listed in Table 8.2-2 which are not on the Midwest ISO system, yet they are listed to show the opportunity for coordinating with neighboring systems to improve energy market performance. 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.

8.2.2 Indications of Future Congestion

In addition to the historical analysis, it is also important to consider the impacts of future congestion relative to the ability to share generation reserves throughout the Midwest ISO market area. The 2009-2010 LOLE Study Report is the first Midwest ISO report performed to study the reliability driven level for the Planning Reserve Requirement (PRM). The Resource Adequacy Requirement (RAR) was determined for the Planning Year (PY) 2009. The study also provides an indication of planning reserve requirements as far out as 2018. While the LOLE study found the system to be reliable in all years and to meet the loss of load expectation standards, the study also quantified estimates for the additional PRM that is needed because the transmission system does not provide unlimited transfer capability.

For LOLE study execution, for a given future year, the appropriate future Appendix A and Appendix B facilities having in service dates the given future year are included. Top Congested Flowgate Study (TCFS) mitigating projects from Section 8.3 are not included. The LOLE study will be repeated annually and each time provides a look ten years into the future; therefore, as TCFS projects, or projects from other targeted transmission become committed, the first Planning Year of an annual LOLE study will always include the up-to-date complement of transmission plans. The full study methodology was used for book-end years 2009 and 2018, and partial assessments and interpolation techniques were applied to intervening years. The assessment includes modeling the transmission system so that any limitations to sharing generator reserves are recognized in the process.

Table 8.2-3 is taken directly from the 2009 LOLE report and it shows the Planning Reserve Margin (PRM) found necessary to maintain the reliability standard of Loss of Load Expectation (LOLE) of less than 1 day in 10 years. $PRM_{SYSIGEN}$ is the reserve margin requirement based on installed generation capacity. The table shows the total LOLE itemized by the impact of transmission congestion (labeled as "Congestion Adder" but is a calculated impact due to congestion) in the second line, and all other factors (generation outage rates, load forecast uncertainty, etc.) in the top row. The congestion impact drives the Congestion Adder to the PRM from 0.6% in 2009 to 2.3 % by 2018. This corresponds to an approximately 675 additional MW in 2009 and, with no further refinement of transmission plans, would appear to increase to about 2,600 MW by 2018.

Table 8.2-3: Expected $PRM_{SYSIGEN}$ for 2010-2018

YEAR →	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PRM_{SYSGEN} (No Congestion)	14.8%	14.8%	14.7%	14.6%	14.5%	14.6%	14.6%	14.6%	14.7%	14.7%
PRM_{SYSGEN} (Congestion Adder)	0.6%	0.8%	1.0%	1.2%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%
PRM_{SYSGEN} (With Congestion)	15.4%	15.6%	15.7%	15.8%	15.8%	16.1%	16.3%	16.5%	16.8%	17.0%

Since the LOLE process incorporates the current outlook for planned transmission facilities, the question of which additional transmission plans may reduce the future congestion levels becomes a targeted task related to further MTEP study going forward. While adequate reserve is a reliability driven metric, the solution has economic considerations. Because either more generation or more transmission could be placed to maintain the needed reliability, the optimal balance will be affected by the cost of the additional generation or transmission. Also, while the Midwest ISO has authority to plan and commit to the required transmission facilities, it is important that the proper signals be communicated to the entities building generation as to the most effective locations to site that generation. The generation interconnection process is one such forum for this communication, along with the general MTEP transmission planning cycle.

To illustrate the information input to the LOLE study process going forward, the blue areas in Figure 8.2-15 indicate areas where, in the 2009 study year, the full rating of generation is statistically not deliverable to the aggregate of the Midwest ISO market area, potentially impacting reliability during summer peak load times. In the figure, the blue shading is associated with the legend phrase "Always 0 or Negative." This refers to the congestion component of the LMP. Within the specific steps in the LOLE study process, congestion on the system always impacted those areas by striving to re-dispatch the internal generation downward during peak load times. This means that the full amount of capacity was not always deliverable to the balance of the system and, therefore, is not a reliable amount to count toward the PRM requirement. The red areas, associated with the label "Always 0 or Positive," are locations where the LOLE study process has indicated an area does not have sufficient internal generation resources to meet peak load demands. Specific analyses are performed to determine if the potential exists for load in those areas to not be reliably served by internal generation or imports from other zones, even when adequate generation supply exists throughout the entire Midwest ISO system. Compared to a theoretical transmission system free of all congestion, the blue areas of Figure 8.2-15 represent a shortfall in effectively sharing about 675 MW of installed capacity in 2009.

This same analysis is conducted for the 2018 study year to identify load deliverability issues in that period. The results of that effort are shown by Figure 8.2-16. Results between the two years are driven mainly by the incorporation of new generation and planned transmission that is included in the 2018 analysis. The large blue area (zones 4 and 5) in Figure 8.2-15 is not sustained in Figure 8.2-16 as the amount of generation expected to be added in those zones between 2009 and 2018 is lower than the estimated load growth in those areas, resulting in less trapped generation as it will instead be consumed by the loads. The remaining blue areas in both figures may be caused in part by constraints outside of the Midwest ISO, and therefore coordination and associated cost sharing over a large area will likely be an emerging issue.

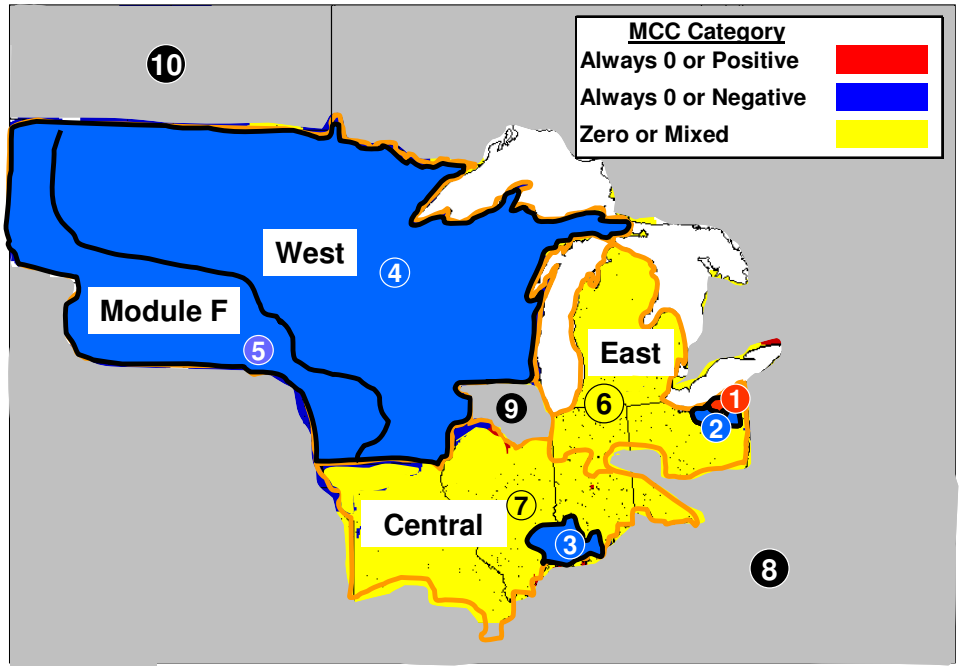

Figure 8.2-15 Congestion Based Zones Modeled in 2009

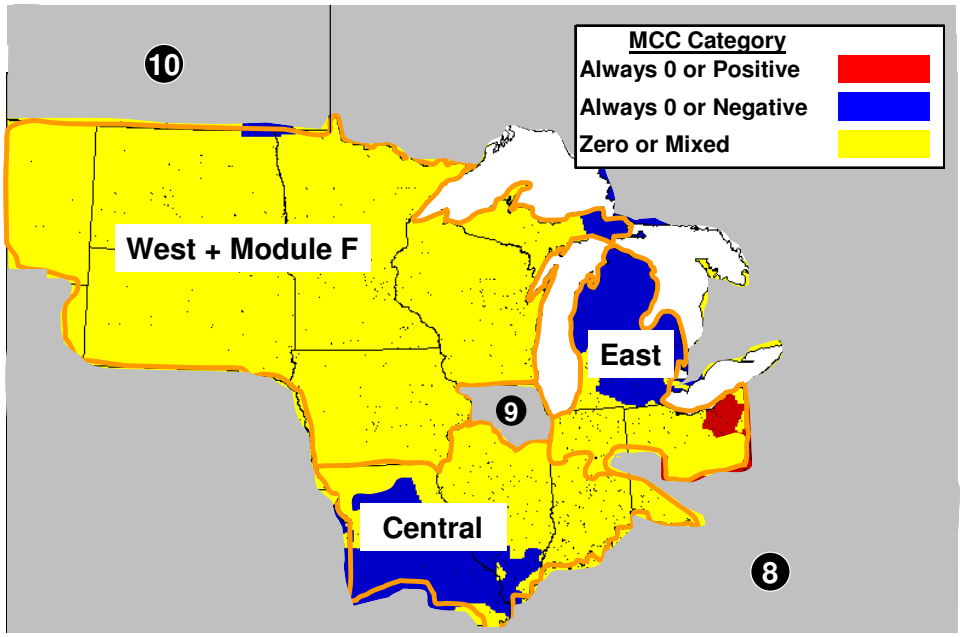

Figure 8.2-16 Congestion Based Zones Modeled in 2018

8.3 Midwest ISO Top Congested Flowgate Study

The Midwest ISO Top Congested Flowgate Study (MTCFS) is an annual process in its second year. Originating in MTEP 08, the objective of the MTCFS is to identify highly congested flowgates within the Midwest ISO Market Footprint and test flowgate specific transmission mitigation plans under the current RECB II criteria which are targeted at transmission projects meant to address market congestion. RECB II eligible projects will be recommended to MTEP Appendix B in the MTEP 09 report cycle.[1] The MTCFS utilizes an annual economic production model (PROMOD IV®) and no reliability analysis was performed.

The MTCFS was open to all stakeholders and interested parties. A stakeholder Technical Review Group (TRG) was an integral part of the study and involved in all decisions and discussions. The TRG originated nearly all of the flowgate mitigation plans and provided input and model verification.

Top congested flowgates were identified using two separate data sources: historical data from Midwest ISO Real-Time Operations (the data discussed in Section 8.2), and the 2014 MTEP 09 production cost model. Merging the two sources' flowgate congestion rankings, the TRG identified fourteen flowgates for further analysis. Through numerous meetings, multiple transmission mitigation plans were developed for each flowgate and Midwest ISO economic benefits were calculated through 2014 PROMOD® simulations. Mitigation plans yielding a high benefit to cost ratio were further analyzed through 2019 and 2024 production cost model simulations. An eleven year total Net Present Value (NPV) benefit was calculated by linearly interpolating the three years of data and was tested against the current RECB II criteria.

The MTCFS not only considered individual plans for RECB II eligibility, but was the first study to explore the option of using portfolios - a group of mitigation plans- as a method for meeting RECB II criteria. The objective of a portfolio is to achieve synergistic benefits, whereby the benefits of the portfolio exceed the summation of individual plans' benefits.

Throughout the 2009 MTCFS, a total of forty-five different mitigation plans were proposed and studied. The MTCFS used an iterative process to refine many of the projects. Over 350 PROMOD® simulations were performed totaling over 18,000 hours of computation time. Throughout this write-up, only final results are included unless specifically noted.

Through the 2009 MTCFS work, three projects qualified for MTEP Appendix B: Rising - Sidney 345 kV, Lakefield Junction - Rutland 345 kV, and Bloomington - Hanna 345 kV. Rigorous economic sensitivity and reliability analysis must be performed before any of these plans can be moved to MTEP Appendix A. Projects within the MTCFS not currently meeting the RECB II criteria will be retested in future Midwest ISO Top Congested Flowgate studies.

[1] MTEP Appendices A, B, and C are defined in Section 2.2.

8.3.1 MTCFS Model Development

MTEP 09 developed 2014 and 2019 power flow models were used as the starting point for the MTCFS effort. The same transmission network topology in the 2019 power flow model was used to create the 2024 economic production cost model.

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

The PROMOD® study footprint includes the majority of the Eastern Interconnection excluding ISO-New England, Eastern Canada, and Florida. A total of nine pools are defined in the PROMOD® study footprint: Midwest ISO, PJM, SPP, MAPPCOR, SERCNI, TVASUB, MHEB, NYISO, and IESO. Fixed transactions are modeled to represent the purchases/sales between the study footprint and external regions. MidAmerican Energy Co. and Muscatine Power & Water are included in the Midwest ISO pool and Nebraska companies are 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.

In long-term transmission planning, a resource forecasting model is required to develop different future generation portfolios needed to maintain adequate regional reserve margins and meet various political, economical, and environmental goals. Four scenarios were defined in MTEP 09 Step 1 and 2. The MTCFS utilized the MTEP 09 Reference Scenario, which essentially maintains the status quo. Please refer to Section 10.2, Generation Futures Development, and Appendix E1 for details including RRF siting, fuel price forecasts, and generation assumptions. The location of Regional Resource Forecasting (RRF) units can impact flowgate congestion and therefore can affect the potential benefits of transmission upgrades. Due to time constraints, RRF generation sensitivity studies were performed on only a selected group of transmission plans. The RRF sensitivities performed as part of the 2009 MTCFS are not a replacement for the full rigorous sensitivity analysis required to move a project to Appendix A, but rather an analysis to provide additional insight for this study.

8.3.2 Benefit/Cost Assumptions and Calculations

Throughout the MTCFS a common set of assumptions and formulas were utilized to calculate economic benefits. The following subsections detail those assumptions and calculations.

Economic Benefit Savings

To calculate the economic benefit savings for transmission mitigation plans, two cases are defined - a base case and a project case. All aspects of the base case and project case are identical with the exception of the congestion mitigation plan contained within the project case. For each case, the 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 are obtained by calculating the difference between the base case and project case. The benefit value metric utilized in the 2009 MTCFS is the RECB II benefit which is calculated as follows:

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

Benefit/Cost Ratio

Table 8.3-1 summarizes the transmission cost per mile assumptions by voltage class. The cost per mile assumptions from Regional Generation Outlet Study (RGOS) Phase I and Joint Coordinated System Plan 2008 (JCSP08) were used as a starting point and then updated to reflect feedback from the MTCFS TRG. Unless a project's cost is directly stakeholder supplied, the total project cost includes a 25% adder to approximate the costs of substations, transformers, and transmission routing. The 25% adder is consistent with other Midwest ISO studies and was approved by the TRG for the 2009 MTCFS.

Table 8.3-1: MTCFS Transmission Cost per Mile Assumptions

Transmission Cost $M/Mile (2009$)							
kV	**MN/Dak**	**IA**	**WI**	**IL (ComEd)**	**IL (Ameren)**	**MO**	**AEP**
115	0.5		0.6				
115-2	0.9		0.9				
138			0.8				0.8-1.3
138-2			1.1				1.0-1.7
161	0.65						
230	0.75						
345	2	1.5	2.2	1.8	1.75	1	1.5-2.0
345-2	2.5	2.1	3	2.6	2.5	1.5	2.0-2.5
500							2.7-3.5
765							3.0-4.0

In the 2009 MTCFS all projects are assumed to be in-service in 2014. The benefits and costs applied in the Benefit to Cost (B/C) ratio calculations are the present value for the first ten years of the project life after the in-service year. Three years of PROMOD® production cost simulations, 2014, 2019, and 2024, were performed to calculate benefits spanning across an eleven year timeframe. The benefit savings for years between the three simulated years are derived using linear interpolation. Eleven year Net Present Value (NPV) RECB II benefit savings from 2014 to 2024 are calculated using a 10% discount rate.

A 15% Levelized Fixed Charge Rate (LFCR) is used in the 2009 MTCFS to determine the annual cost of the transmission projects. This is a study assumption and is subject to change depending on the constructing transmission owner. To evaluate cost sharing eligibility, and to move a project to Appendix A, the transmission owner specific fixed charge rate must be used in the RECB II calculation. The 2009 project costs are escalated to 2014 dollars using a 3% inflation rate. The NPV B/C ratio is calculated by 11 year NPV benefits divided by 11 year NPV project costs. The B/C ratio calculation assumptions described in this section carry though all case studies.

8.3.3 Top Congested Flowgate Identification

Two sources were used to identify flowgates with the most congestion or highest prices in the Midwest ISO Market: historical Real-Time Market data, and the 2014 MTEP 09 production cost model. Flowgate congestion was measured and ranked in terms of the number of binding hours and total shadow price.

The historical Real-Time information utilizes the data and rankings from Section 8.2. The purpose of the MTCFS is to identify future projects to mitigate both present and future congestion; therefore, only congestion history from Market years three and four (to the extent it was available), April 1, 2007 through October 1, 2008, was utilized. As detailed in Section 8.2, many of the most congested flowgates from years one and two have been mitigated. Only flowgates within the Midwest ISO Market Footprint were included.

The second source of information was the 2014 MTEP 09 PROMOD® model detailed in Section 8.3.1. An annual 2014 simulation was performed utilizing TRG supplied ratings. The MTEP 09 PROMOD® model includes data for most of the Eastern Interconnect; however, only flowgates in the Midwest ISO Market were included in the rankings.

Table 8.3-2 displays the Midwest ISO Market flowgate rankings from both the historical Real-Time information and the 2014 PROMOD® model. A blank cell indicates a ranking greater than twenty. Rankings are in ascending order, meaning if a cell has a ranking of one it possesses the highest total shadow price or number of binding hours.

Table 8.3-2: Historical Real-Time and 2014 PROMOD® Simulation Flowgate Rankings				
Flowgate Name	2014 PROMOD® Rankings		Historical RT Rankings	
	Shadow Price	Binding Hours	Shadow Price	Binding Hours
Johnson Jct.-Ortonville 115 kV FLO Bigstone-Blair 230 kV	1	2		17
Indian Lake 138/69 kV	2	4		
Fox Lake-Rutland 161 kV FLO Lakefield Jct.-Nobles 345 kV	3	12	14	
Fredricktown-FredricktownT 161 kV FLO Lutesville-St Fran. 345 kV	4	19		
Rising 345/138 kV FLO Brokaw-Clinton 345 kV	5	8		
Dune Acres-Michigan City 138 kV 1&2 FLO WCenter-Dumont 765 kV	6	6	4	11
Ontario-ITC Interface	7	1	17	6
Kewanee STP-Kewanee IP	8	3		
Beulah-Coyote 115 kV	9	10		
Hoytdale-Maple 138 kV FLO Wylie Ridge-Cranberry 500 kV	10	17		
Pana 345/138 kV FLO Coffeen-Coffeen N 345 kV	11	16	2	7
Nason Point-Ina FLO West Mt. Vernon-E W Frankfort 345 kV	12			
Pleasant Prairie-Zion 345 kV FLO Cherry-Silver 345 kV	13	5		
Sammis-Wylie Ridge 345 kV FLO Wylie Ridge-Tidd 345 kV	14	15		16
Sammis-Wylie Ridge 345 kV	15	14		12
Fondulac-Hibbard 115 kV	16	7		
Dune Acres-MI City 1 138 kV FLO Dune Acres-MI City 2 138 kV	17	13		
Genoa-Coulee 161 kV FLO Genoa-Lacrosse Tap 161 kV	18			
Wheatland-Breed 345 kV FLO Jefferson-Rockport 765 kV	19	20		
Dickinson-ND-Dickinson-WH 115 kV FLO Beulah-Coyote 115 kV	20			
Rivermines-Farmington 138 kV FLO Lutesville-St. Francois 345 kV			3	9
Greenfield-Lakeview 138 kV FLO Beaver-David Besse 345 kV			19	
Eau Claire-Arpin 345 kV			8	3
Arnold-Vinton 161 kV FLO Hzltn-Arnld; Cggn-Lkfield-SFx 115 kV			11	
Sub 56 (Davenport)-E Calamus161 kV FLO Quad-Rock Cr 345 kV			12	
Dig Tap-Waterman 230 kV		9		
St. Clair PP 345/220 kV FLO Lambton-St. Clair PP 345 kV		11		
State Line-Wolf Lake 138 kV FLO Burnham-Sheffield 345 kV		18	1	1
Sammis-Wylie Ridge 345 kV FLO Perry-Ashtabula-Erie W 345 kV				15
Paddock 345/138 kV FLO Paddock-Rockdale 345 kV			5	4
Ellington-Hintz 138 kV FLO N Appleton-Werner West 345 kV			6	13
Pierce B 345/138 kV FLO Pierce-Foster 345 kV			7	8
Whitcomb-Caroline 115 kV FLO Rocky Run-Werner West 345 kV			9	14
Boone Jct.-Huxley 161 kV FLO Webster-Lehigh 345 kV			10	
Hazelton-Dundee 161 kV			13	
Duff-Dubois 138 kV FLO Ratts-Victory 161 kV			15	
Arnold-Vinton 161 kV FLO Arnold-Hazelton 345 kV			16	18
Mason-Wildwood 345 kV FLO Labadie-Mason 345 kV			18	
St. Francois-Lutesville 345 kV				2
Newtonville 161/138 kV 1				5
Cottage Hills-Wanda 138 kV FLO Wood River-Roxford 138 kV				10
Arnold-Hazleton 345 kV			20	
Duff-Dubois 138 kV FLO Duff-Ramsey 345 kV				19
Culley-Grandview 138 kV FLO Henderson 161/138 kV				20

Table 8.3-2 displays some differences between the historical Real-Time rankings and the 2014 simulation rankings; these differences are expected and can be attributed to multiple reasons. As detailed in Section 8.2, many flowgates have a declining congestion trend as a result of a change in infrastructure or operating schemes. Additionally, many of the flowgates that had a high shadow price or high number of congestion hours in years three and four will be relieved of congestion through future MTEP Appendix A or B projects. The 2014 MTEP 09 production cost model includes all Appendix A and B projects as part of its base transmission infrastructure. Another difference between historical congestion and 2014 PROMOD® simulated congestion is that the historical congestion included numerous outages that were not modeled in the 2014 topology for each of the 8,760 hours studied. Production cost models utilize outage rates and Monte Carlo draws to determine a unit outage schedule. A final reason for differences between the two sources is different regional demands levels. Demand on a granular geographic basis is forecasted to change in the next ten years; these demand changes will also cause a change in line flows.

During the May 8th, 2008 kick-off meeting, the Midwest ISO Market Flowgate rankings (Table 8.3-2), as well as the congestion rankings for the Midwest ISO Market, plus first-tier balancing authorities, were presented to the MTCFS TRG. The TRG was tasked to narrow the list of congested flowgates, to a manageable subset that could be examined further. The primary focus of the MTCFS was to develop flowgate mitigation plans internal to the Midwest ISO Market; however, first-tier flowgates would be examined through a coordinated effort if the flowgate strongly affected Midwest ISO Market economics. The TRG, in conjunction with Midwest ISO staff, nominated fourteen top congested flowgates for study. Thirteen of the fourteen flowgates were within the Midwest ISO Market footprint, and one flowgate was just outside of the footprint on the Nebraska - Iowa border. Figure 8.3-1 and Table 8.3-3 display each of the fourteen flowgates. Only the monitored elements of each flowgate are used to identify each flowgate.

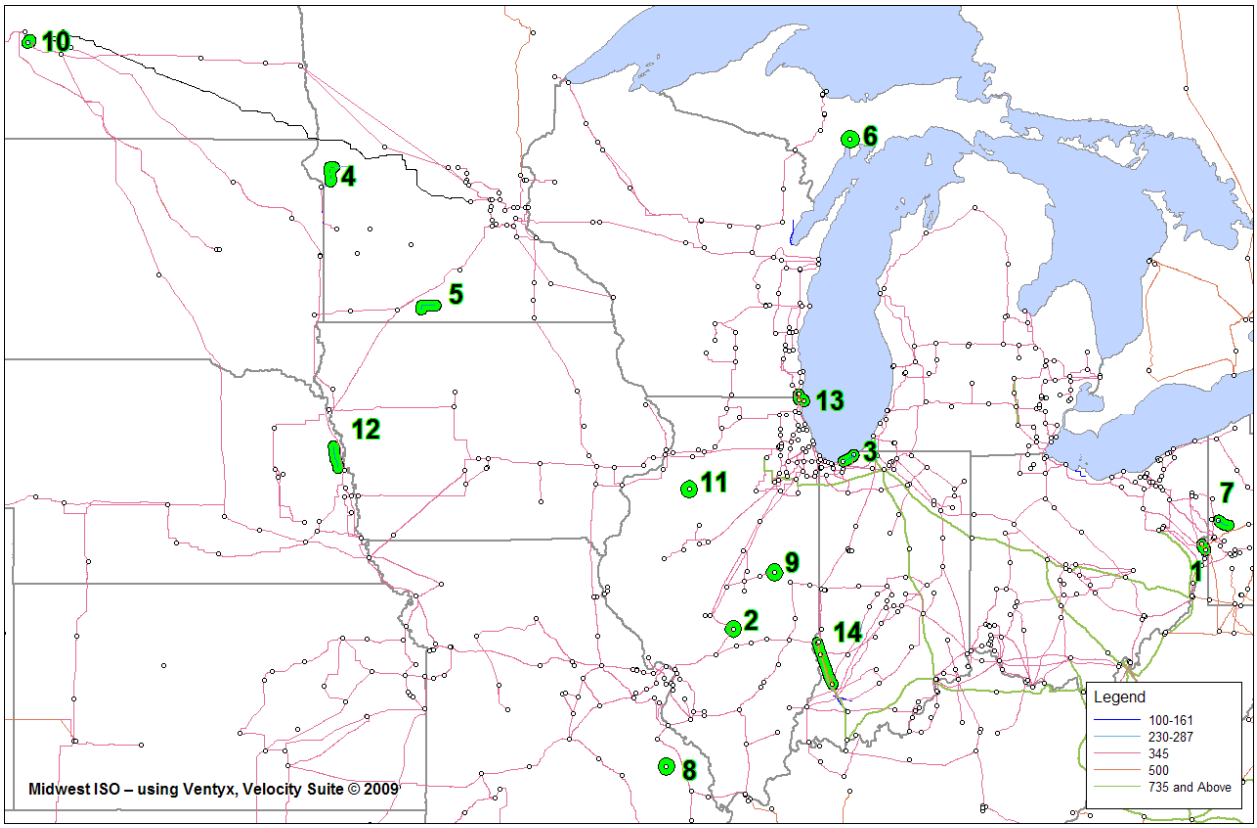

Figure 8.3-1: Top Congested Flowgates for 2009 MTFCS

Table 8.3-3: Top Congested Flowgate (Figure 8.3-1 Key)	
Flowgate #	**Flowgate Name**
1	Sammis - Wylie Ridge 345 kV
2	Pana Transformer 345/138 kV
3	Dune Acres - Michigan City 1&2 138 kV
4	Johnson Junction - Ortonville 115 kV
5	Fox Lake - Rutland 161 kV
6	Indian Lake Transformer 138/69 kV
7	Hoytdale - Maple 138 kV
8	Fredricktown - Fredricktown Tap 161 kV
9	Rising Transformer 345/138 kV
10	Coyote - Beulah 115 kV
11	Kewanee IP - Kewanee STP 138 kV
12	S1226 - Tekamah 161 kV
13	Pleasant Prairie - Zion 345 kV
14	Wheatland - Breed 345 kV

To determine the potential economic benefit to the Midwest ISO Market through flowgate congestion mitigation, a simulation separately relieving each constraint was performed for each flowgate. The potential benefits aid in providing a design budget.

Each flowgate was relieved by essentially giving the monitored element(s) an infinite rating. The 2014 one-year total potential economic benefits for each flowgate are listed in Table 8.3-4. Flowgate numbers were assigned arbitrarily as identifiers and are not indicative of a flowgate's congestion ranking.

Table 8.3-4: Top Congested Flowgate Potential Benefits through Mitigation			
Flowgate	**Load Cost Saving (2014$)**	**Adj Production Cost Saving (2014$)**	**RECB II Benefit (2014$)**
Flowgate 1:Sammis - Wylie Ridge 345 kV	-127,266,348	34,269,051	-14,191,569
Flowgate 2: Pana Transformer 345/138 kV	-6,619,107	22,069,553	13,462,955
Flowgate 3: Dune Acres - Michigan City 1&2 138 kV	18,248,948	17,092,290	17,439,287
Flowgate 4: Johnson Jct. - Graceville 115 kV	26,081,597	16,292,668	19,229,346
Flowgate 5: Fox Lake - Rutland 161 kV	34,265,585	23,542,266	26,759,262
Flowgate 6: Indian Lake Transformer 138/69 kV	34,868,883	-11,275,184	2,568,036
Flowgate 7: Hoytdale - Maple 138 kV	-24,295,945	-13,662,506	-16,852,537
Flowgate 8: Fredricktown - Fredricktown Tap 161 kV	-32,321,894	2,130,049	-8,205,534
Flowgate 9: Rising Transformer 345/138 kV	946,582	31,643,608	22,434,500
Flowgate 10: Coyote - Beulah 115 kV	10,912,543	7,449,802	8,488,625
Flowgate 11: Kewanee IP - Kewanee STP 138 kV	5,600,793	11,015,801	9,391,298
Flowgate 12: S1226 - Tekamah 161 kV	98,453	-33,085	6,377
Flowgate 13: Pleasant Prairie - Zion 345 kV	-89,934,589	21,569,792	-11,881,522
Flowgate 14: Wheatland - Breed 345 kV	21,488,207	27,621,373	25,781,423

8.3.4 MTCFS Mitigation Plans

A first TRG meeting was held on May 21st, 2009 in St. Paul, Minnesota to address the essential background information and facilitate the development of transmission mitigation plans for the top fourteen congested flowgates selected by TRG. The total achievable benefits described in Section 8.3.3 provide a rough estimate of potential budget available for transmission development. Both short term and long term solutions were considered in the initial design process. The results of the first TRG meeting allowed evaluation of the initial transmission plans using the 2014 production cost model.

The second TRG meeting was held on June 19th to review the 2014 results for the proposed mitigation plans and to discuss the benefit/cost calculation assumptions. Based on the comments and feedback, additional adjustments and new alternatives were included in the mitigation plan evaluation process. The detailed results for all mitigation plans are described in the following section. Appendix F3 provides maps and detailed results for each of the mitigation plans.

MTCFS 2014 Mitigation Plan Results

Each mitigation plan was evaluated using the 2014 production cost model. Table 8.3-5 provides the adjusted production cost savings, load cost savings and RECB II benefits brought by each mitigation plan for the Midwest ISO Market.

Flowgate 7: Hoytdale - Maple 138 kV was studied in conjunction with Flowgate 1: Sammis - Wylie Ridge 345 kV. Throughout this report, the mitigation plans for these flowgates are listed under Flowgate 1, even though the plans mitigate congestion at both flowgates.

On July 31, 2009 the NIPSCO-EME Agreement was filed with the Federal Energy Regulatory Commission (FERC), which includes upgrades of the terminal equipment associated with reconductoring of the State Line - Wolf Lake - Sheffield 138 kV circuits, breaker upgrades at Michigan City for the Dune Acres - Michigan City 138 kV, and breaker upgrades at Trail Creek for the Michigan City - Trail Creek 138 kV. Outside of the agreement, NIPSCO will be reconductoring the aforementioned circuits in the same timeframe. These upgrades are expected to be in-service in Summer 2010, and were not modeled as base transmission in the 2009 MTCFS study because final simulations had already begun. These upgrades have the potential to change the simulated benefits of projects impacted by Flowgate 3: Dune Acres - Michigan City 1&2 138 kV.

Table 8.3-5: MTCFS Mitigation Plan 2014 Midwest ISO Market Benefits			
Flowgate Mitigation Plans	**Load Cost Savings (2014$)**	**Adj Production Cost Savings (2014$)**	**RECB II Benefits (2014$)**
Flowgate 1: Sammis - Wylie Ridge 345 kV			
LT1: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV	-65,362,583	-505,716	-19,962,776
LT1B: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV + Erie W 345/115 kV 2	-58,931,814	-269,730	-17,868,355
LT2: 2nd Ckt. Sammis - Wylie Ridge 345 kV	-183,230,413	35,480,684	-30,132,645
Flowgate 2: Pana Transformer 345/138 kV			
ST2: 2nd Ckt. Coffeen - Coffeen North 345 kV	-575,130	9,960,992	6,800,155
LT1: Pana - Mt. Zion - Kansas 345 kV	21,431,941	35,427,943	31,229,143
LT1+: Pana - Mt. Zion - Kansas 345 kV with "+" projects	59,879,938	87,308,373	79,079,843
LT2: Pana - Mt. Zion - Kansas - Tap(Darwin - Eugene) 345 kV	51,006,732	58,652,281	56,358,616
Flowgate 3: Dune Acres - Michigan City 1&2 138 kV			
ST1: Increase Dune Acres - Michigan City 1&2 line rating to 222 MVA	-5,816,917	3,060,736	397,440
LT1: Michigan City - Olive 345 kV	3,953,671	10,330,352	8,417,348
LT2: Wilton Center - Dequine - Greentown 765 kV	13,918,416	11,397,294	12,153,631
Flowgate 4: Johnson Jct. - Ortonville 115 kV			
LT1A: Alexandria - Morris - Johnson Jct. - Big Stone - Canby - Gr. Falls 345 kV	249,327,751	58,977,491	116,082,569
LT1B: Alexandria - Morris - Johnson Jct. - Big Stone 345 kV	236,677,761	57,795,347	111,460,071
LT1C: Morris - Johnson Jct. - Big Stone 345 kV	120,479,549	17,721,463	48,548,889
Flowgate 5: Fox Lake - Rutland 161 kV			
ST1: 2nd Circuit Fox Lake - Rutland - Winnebago 161 kV	83,133,461	24,165,327	41,855,767
LT1: Lakefield Jct - Fox Lake - Rutland - Winnebago - Adams 345 kV	86,231,053	26,568,118	44,466,999
LT1B: Lakefield Jct - Rutland 345 kV	84,416,559	25,607,138	43,249,964
Flowgate 6: Indian Lake Transformer 138/69 kV			
Indian Lake - Hiawatha 138 kV	42,361,869	15,918,595	23,851,577
Flowgate 8: Fredricktown - Fredricktown Tap 161 kV			
ST1: Increase line rating to 317 MVA	-29,622,209	2,982,372	-6,799,003
LT1: Baldwin - Grand Tower - Joppa 345 kV	-27,202,078	20,719,083	6,342,735
LT2B: Baldwin - Grand Tower - W Cape - Lutesville 345 kV	-62,635,763	26,858,985	10,561
Flowgate 9: Rising Transformer 345/138 kV			
ST1: Increase Transformer Size to 560 MVA	1,059,079	32,437,579	23,024,029
LT1: Rising - Sidney 345 kV	-3,439,573	31,661,485	21,131,168
Flowgate 10: Coyote - Beulah 115 kV			
Coyote - Beulah - Heskett 230 kV	3,526,142	2,341,774	2,697,084
Flowgate 11: Kewanee IP - Kewanee STP 138 kV			
Duck Creek - Fargo - Galesburg - Barstow 345 kV	-24,634,504	-4,425,083	-10,487,909
Flowgate 12: S1226 - Tekamah 161 kV			
Increase line rating to 558 MVA	4,344,356	553,967	1,691,083
Flowgate 13: Pleasant Prairie - Zion 345 kV			
Bain - Zion Energy Center 345 kV	-197,892,227	13,730,796	-49,756,111
Flowgate 14: Wheatland - Breed 345 kV			
ST1: Increase rating to 1195MVA	15,211,738	7,617,542	9,895,801
LT1: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV	24,673,222	14,074,315	17,253,987
LT1+: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV; "+" projects	66,514,941	54,259,573	57,936,183
LT1B: Bloomington - Franklin Township - Hanna 345 kV	32,738,573	15,522,079	20,687,027
LT2: Sullivan - Greentown 765 kV	19,347,781	772,348	6,344,978
"+" Projects			
Merom - Netwon 345 kV	20,019,258	32,308,891	28,622,001
Norris City - Albion 345 kV	17,590,842	19,500,947	18,927,916
Palmyra - Ipava 345 kV	14,205,257	4,842,528	7,651,347

Table 8.3-6 lists the total estimated line mileage, the applicable cost per mile assumption, estimated line cost, and the total project cost in 2009 dollars for each mitigation plan. Total project costs include a 25% adder to the line costs accounting for the additional costs of substations, transformers, and line routing, unless the total project costs were directly stakeholder provided.

Table 8.3-6: MTCFS Mitigation Plan Project Costs

Flowgate Mitigation Plan	Total Line Length (Miles)	Line Cost (M$/mile)	Project Cost (M$ 2009)	Total Project Cost (M$ 2009)
Flowgate 1: Sammis - Wylie Ridge 345 kV				
LT1: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV	46.7	2	93.4	116.75
LT1B: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV + Erie W 345/115 kV 2	46.7	2	93.4	116.75
LT2: 2nd Ckt. Sammis - Wylie Ridge 345 kV	7.4	2	14.8	18.5
Flowgate 2: Pana Transformer 345/138 kV				
ST2: 2nd Ckt. Coffeen - Coffeen North 345 kV	0.23	Supplied Cost	5.456	5.456
LT1: Pana - Mt. Zion - Kansas 345 kV	86	1.75	150.5	188.13
LT1+: Pana - Mt. Zion - Kansas 345 kV with "+" projects	254.2	1.75	444.85	556.06
LT2: Pana - Mt. Zion - Kansas - Tap(Darwin - Eugene) 345 kV	120	1.75	210	262.5
Flowgate 3: Dune Acres - Michigan City 1&2 138 kV				
ST1: Increase Dune Acres - Michigan City 1&2 line rating to 222 MVA	-	Supplied Cost	0.345	0.345
LT1: Michigan City - Olive 345 kV	23	1.5	34.5	43.125
LT2: Wilton Center - Dequine - Greentown 765 kV	174	3	522	652.5
Flowgate 4: Johnson Jct. - Ortonville 115 kV				
LT1A: Alexandria - Morris - Johnson Jct. - Big Stone - Canby - Gr. Falls 345 kV	155.4	2	310.8	388.5
LT1B: Alexandria - Morris - Johnson Jct. - Big Stone 345 kV	75.3	2	150.6	188.25
LT1C: Morris - Johnson Jct. - Big Stone 345 kV	39.3	2	78.6	98.25
Flowgate 5: Fox Lake - Rutland 161 kV				
ST1: 2nd Circuit Fox Lake - Rutland - Winnebago 161 kV	31.2	0.65	20.28	25.35
LT1: Lakefield Jct - Fox Lake - Rutland - Winnebago - Adams 345 kV	139.6	2	279.2	349
LT1B: Lakefield Jct - Rutland 345 kV	39.4	2	78.8	98.5
Flowgate 6: Indian Lake Transformer 138/69 kV				
Indian Lake - Hiawatha 138 kV	40.9	Supplied Cost	2.5	2.5
Flowgate 8: Fredricktown - Fredricktown Tap 161 kV				
ST1: Increase line rating to 317 MVA	-	Supplied Cost	2.09	2.09
LT1: Baldwin - Grand Tower - Joppa 345 kV	95	1.75	166.25	207.81
LT2B: Baldwin - Grand Tower - W Cape - Lutesville 345 kV	83	1.75; 1; $7M River Crossing	126	155.75
Flowgate 9: Rising Transformer 345/138 kV				
ST1: Increase Transformer Size to 560 MVA	-	Supplied Cost	5.3	5.3
LT1: Rising - Sidney 345 kV	30	1.75	52.5	65.625
Flowgate 10: Coyote - Beulah 115 kV				
Coyote - Beulah - Heskett 230 kV	54.8	0.75	41.1	51.375
Flowgate 11: Kewanee IP - Kewanee STP 138 kV				
Duck Creek - Fargo - Galesburg - Barstow 345 kV	112.4	1.75	196.7	245.88
Flowgate 12: S1226 - Tekamah 161 kV				
Increase line rating to 558 MVA	-	Supplied Cost	17	17
Flowgate 13: Pleasant Prairie - Zion 345 kV				
Bain - Zion Energy Center 345 kV	6	Supplied Cost	18	18
Flowgate 14: Wheatland - Breed 345 kV				
ST1: Increase rating to 1195MVA	-	Supplied Cost	1	1
LT1: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV	118	Supplied Cost	138	138
LT1+: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV; "+" projects	286.2	Sup. Cost; 1.75	432.35	505.94
LT1B: Bloomington - Franklin Township - Hanna 345 kV	45	Supplied Cost	68.1	68.1
LT2: Sullivan - Greentown 765 kV	125	3	375	468.75
"+" Projects				
Merom - Netwon 345 kV	49.5	1.75	86.625	108.28
Norris City - Albion 345 kV	26.5	1.75	46.375	57.969
Palmyra - Ipava 345 kV	92.2	1.75	161.35	201.69

B/C ratios are provided in Table 8.3-7 for each mitigation plan. The B/C ratio is calculated based only upon 2014 production cost simulation results.

Table 8.3-7: MTCFS Mitigation Plan 2014 Midwest ISO Market Benefit to Cost Ratios

Flowgate Mitigation Plans	RECB II Benefits ($ 2014)	Total Project Cost (M$ 2009)	Annual Cost (M$ 2014)	B/C ratio
Flowgate 1: Sammis - Wylie Ridge 345 kV				
LT1: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV	-19,962,776	116.75	20.30	-0.98
LT1B: 2nd Ckt. Erie W - Ashtabula - Perry 345 kV + Erie W 345/115 kV 2	-17,868,355	116.75	20.30	-0.88
LT2: 2nd Ckt. Sammis - Wylie Ridge 345 kV	-30,132,645	18.50	3.22	-9.37
Flowgate 2: Pana Transformer 345/138 kV				
ST2: 2nd Ckt. Coffeen - Coffeen North 345 kV	6,800,155	5.456	0.95	7.17
LT1: Pana - Mt. Zion - Kansas 345 kV	31,229,143	188.13	32.71	0.95
LT1+: Pana - Mt. Zion - Kansas 345 kV with "+" projects	79,079,843	556.06	96.69	0.82
LT2: Pana - Mt. Zion - Kansas - Tap(Darwin - Eugene) 345 kV	56,358,616	262.50	45.65	1.23
Flowgate 3: Dune Acres - Michigan City 1&2 138 kV				
ST1: Increase Dune Acres - Michigan City 1&2 line rating to 222 MVA	397,440	0.35	0.06	6.62
LT1: Michigan City - Olive 345 kV	8,417,348	43.13	7.50	1.12
LT2: Wilton Center - Dequine - Greentown 765 kV	12,153,631	652.50	113.46	0.11
Flowgate 4: Johnson Jct. - Ortonville 115 kV				
LT1A: Alexandria - Morris - Johnson Jct. - Big Stone - Canby - Gr. Falls 345 kV	116,082,569	388.50	67.56	1.72
LT1B: Alexandria - Morris - Johnson Jct. - Big Stone 345 kV	111,460,071	188.25	32.74	3.40
LT1C: Morris - Johnson Jct. - Big Stone 345 kV	48,548,889	98.25	17.08	2.84
Flowgate 5: Fox Lake - Rutland 161 kV				
ST1: 2nd Circuit Fox Lake - Rutland - Winnebago 161 kV	41,855,767	25.35	4.41	9.50
LT1: Lakefield Jct - Fox Lake - Rutland - Winnebago - Adams 345 kV	44,466,999	349.00	60.69	0.73
LT1B: Lakefield Jct - Rutland 345 kV	43,249,964	98.50	17.13	2.53
Flowgate 6: Indian Lake Transformer 138/69 kV				
Indian Lake - Hiawatha 138 kV	23,851,577	2.50	0.43	54.87
Flowgate 8: Fredricktown - Fredricktown Tap 161 kV				
ST1: Increase line rating to 317 MVA	-6,799,003	2.09	0.36	-18.71
LT1: Baldwin - Grand Tower - Joppa 345 kV	6,342,735	207.81	36.14	0.18
LT2B: Baldwin - Grand Tower - W Cape - Lutesville 345 kV	10,561	155.75	27.08	0.00
Flowgate 9: Rising Transformer 345/138 kV				
ST1: Increase Transformer Size to 560 MVA	23,024,029	5.30	0.92	24.98
LT1: Rising - Sidney 345 kV	21,131,168	65.63	11.41	1.85
Flowgate 10: Coyote - Beulah 115 kV				
Coyote - Beulah - Heskett 230 kV	2,697,084	51.38	8.93	0.30
Flowgate 11: Kewanee IP - Kewanee STP 138 kV				
Duck Creek - Fargo - Galesburg - Barstow 345 kV	-10,487,909	245.88	42.76	-0.25
Flowgate 12: S1226 - Tekamah 161 kV				
Increase line rating to 558 MVA	1,691,083	17.00	2.96	0.57
Flowgate 13: Pleasant Prairie - Zion 345 kV				
Bain - Zion Energy Center 345 kV	-49,756,111	18.00	3.13	-15.90
Flowgate 14: Wheatland - Breed 345 kV				
ST1: Increase rating to 1195MVA	9,895,801	1.00	0.17	56.91
LT1: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV	17,253,987	138.00	24.00	0.72
LT1+: Wheatland - Bloomington - Franklin Tsp - Hanna 345 kV; "+" projects	57,936,183	505.94	87.98	0.66
LT1B: Bloomington - Franklin Township - Hanna 345 kV	20,687,027	68.10	11.84	1.75
LT2: Sullivan - Greentown 765 kV	6,344,978	468.75	81.51	0.08
"+" Projects				
Merom - Netwon 345 kV	28,622,001	108.28	18.83	1.52
Norris City - Albion 345 kV	18,927,916	57.97	10.08	1.88
Palmyra - Ipava 345 kV	7,651,347	201.69	35.07	0.22

MTCFS "Selected" Mitigation Plan RECB II Results

A separate conference meeting was held one week after the 2nd TRG meeting to provide additional discussion on the results and select the mitigation plans for RECB II evaluation. The criteria used in the selection process was: the project's voltage level was at least 345 kV, the total project costs were at least $5M, and the project provided positive economic benefits to the Midwest ISO Market. A total of twelve mitigation plans were selected for RECB II evaluation.

The Coffeen - Coffeen North 345 kV second circuit project to mitigate the Pana 345/138 kV Transformer flowgate was not included in the "selected" group of flowgates in the 2009 MTCFS, because a separate detailed study requested by stakeholders is underway to determine if the project should move to Appendix A. The Coffeen - Coffeen North 345 kV project is detailed in Section 8.4. [To be provided at a later date]

The RECB II benefit evaluation process necessitates the calculation of benefits for the first ten years of service life after the in-service year. For each selected mitigation plan, 2019 and 2024 PROMOD simulations were performed in addition to 2014. Using the methodology described in Section 8.3.2, the B/C ratios based on eleven year NPV values are provided in Table 8.3-8. Appendix F3 provides 2014, 2019, and 2024 results for each of the "selected" mitigation plans.

Table 8.3-8: MTCFS "Selected" Mitigation Plan 11 year Annual NPV

Flowgate Mitigation Plan	Load Cost Saving ($)	Adj. Prod. Cost Saving ($)	RECB II Benefit ($)	Total NPV Cost ($)	B/C Ratio
Flowgate 2: Pana Transformer 345/138 kV					
LT1: Pana - Mt. Zion - Kansas345 kV	85,443,392	187,975,960	157,216,189	233,722,119	0.67
Flowgate 3: Dune Acres - Michigan City 1&2 138 kV					
LT1: Michigan City - Olive 345 kV	24,691,556	59,528,438	49,077,373	53,577,496	0.92
Flowgate 4: Johnson Jct. - Ortonville 115 kV					
LT1A: Alexandria -Morris –J.Jct. –B.Stone -Canby -G.Falls 345	641,077,779	164,361,201	307,376,174	482,663,353	0.64
LT1B: Alexandria - Morris - Johnson Jct. - Big Stone 345 kV	595,793,048	147,261,580	281,821,020	233,877,416	1.20
LT1C: Morris - Johnson Jct. - Big Stone 345 kV	163,484,821	39,846,970	76,938,325	122,063,512	0.63
Flowgate 5: Fox Lake - Rutland 161 kV					
LT1: Lakefield Jct -Fox Lake -Rutland -Winnebago -Adams 345	850,261,912	190,794,705	388,634,867	433,589,473	0.90
LT1B: Lakefield Jct - Rutland 345 kV	619,999,265	175,120,080	308,583,835	122,374,106	2.52
Flowgate 9: Rising Transformer 345/138 kV					
LT1: Rising - Sidney 345 kV	760,196,130	1,401,485,023	1,209,098,355	81,530,972	14.83
Flowgate 14: Wheatland - Breed 345 kV					
LT1B: Bloomington - Franklin Township - Hanna 345 kV	380,813,815	256,474,387	293,776,215	84,605,854	3.47
"+" Projects					
Merom - Netwon 345 kV	287,110,924	310,913,836	303,772,963	134,524,550	2.26
Norris City - Albion 345 kV	102,726,000	84,914,723	90,258,106	72,020,578	1.25
Palmyra - Ipava 345 kV	481,030,101	150,595,722	249,726,036	250,574,959	1.00

For projects with in-service dates 5 or more years in the future, the threshold for cost sharing eligibility is 2.0. Four projects had B/C ratios in excess of the threshold: Sidney - Rising 345 kV, Bloomington - Hanna 345 kV, Merom - Newton 345 kV, and Lakefield Junction - Rutland 345 kV under the MTEP 09 reference scenario input assumptions. Each of these projects is detailed in the following sections.

Lakefield Junction to Rutland 345 kV

Figure 8.3-2 shows the geographic location of the Lakefield Junction - Rutland 345 kV mitigation plan designed to relieve the Lake - Rutland 161 kV flowgate. The annual and eleven year NPV adjusted production cost savings, load cost savings, RECB II benefits, and B/C ratios are provided in Table 8.3-9, and the cost allocations for the three Midwest ISO regions are listed in Table 8.3-10.

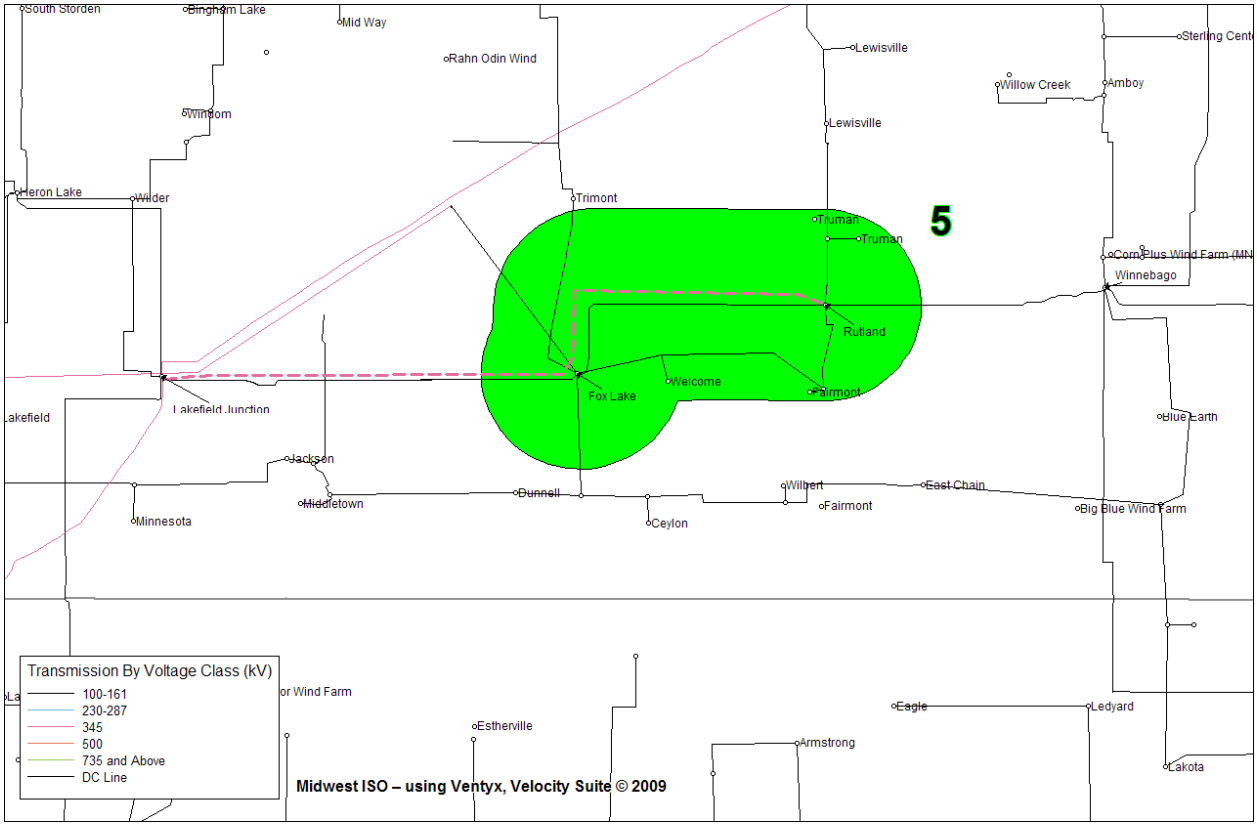

Figure 8.3-2: Lakefield Junction - Rutland 345 kV Mitigation Plan[2]

[2] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

Table 8.3-9: Lakefield Junction - Rutland 345 kV Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	84,416,559	25,607,138	43,249,964	17.13	2.53
2019	64,734,769	16,870,913	31,230,070	17.13	1.82
2024	144,211,516	40,564,603	71,658,677	17.13	4.18
Total NPV	**619,999,265**	**175,120,080**	**308,583,835**	**122.37**	**2.52**

Table 8.3-10: Lakefield Junction - Rutland 345 kV Midwest ISO Regional Benefit Allocations		
Region	NPV of RECB II ($)	Allocation Share
West	251,256,023	81%
Central	18,487,943	13%
East	8,839,869	6%

One concern raised by the TRG was the potential overload of the Rutland - Winnebago 161 kV line, with the 345 kV upgrade ending at the Rutland substation. Additional economic sensitivity analysis was performed with the Rutland - Winnebago 161 kV included in the list of monitored elements. The economic benefit results are provided in Table 8.3-11. Compared to the original case the total benefits go down slightly as expected; however, the project still exceed the 2.0 B/C ratio threshold and is qualified for Appendix B consideration. Additional sensitivities are required to determine what effects this plan has on the surrounding system's low voltage line flows. Those sensitivities along with reliability analysis must be performed prior to Appendix A recommendation.

Table 8.3-11: Lakefield Junction - Rutland 345 kV Sensitivity Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	63,134,339	21,238,721	33,807,406	17.13	1.97
2019	83,537,908	11,246,857	32,934,172	17.13	1.92
2024	99,141,198	30,128,034	50,831,983	17.13	2.97
Total NPV	**563,204,547**	**131,912,576**	**261,300,167**	**122.37**	**2.14**

Sidney to Rising 345 kV

Figure 8.3-3 displays the mitigation plan Sidney - Rising 345 kV to relieve the Rising 345/138 kV Transformer flowgate. This project is located in north-central Illinois. The annual and eleven year NPV adjusted production cost savings, load cost savings, RECB II benefits, and B/C ratios are provided in Table 8.3-12, and the cost allocations for the three Midwest ISO regions are provided in Table 8.3-13.

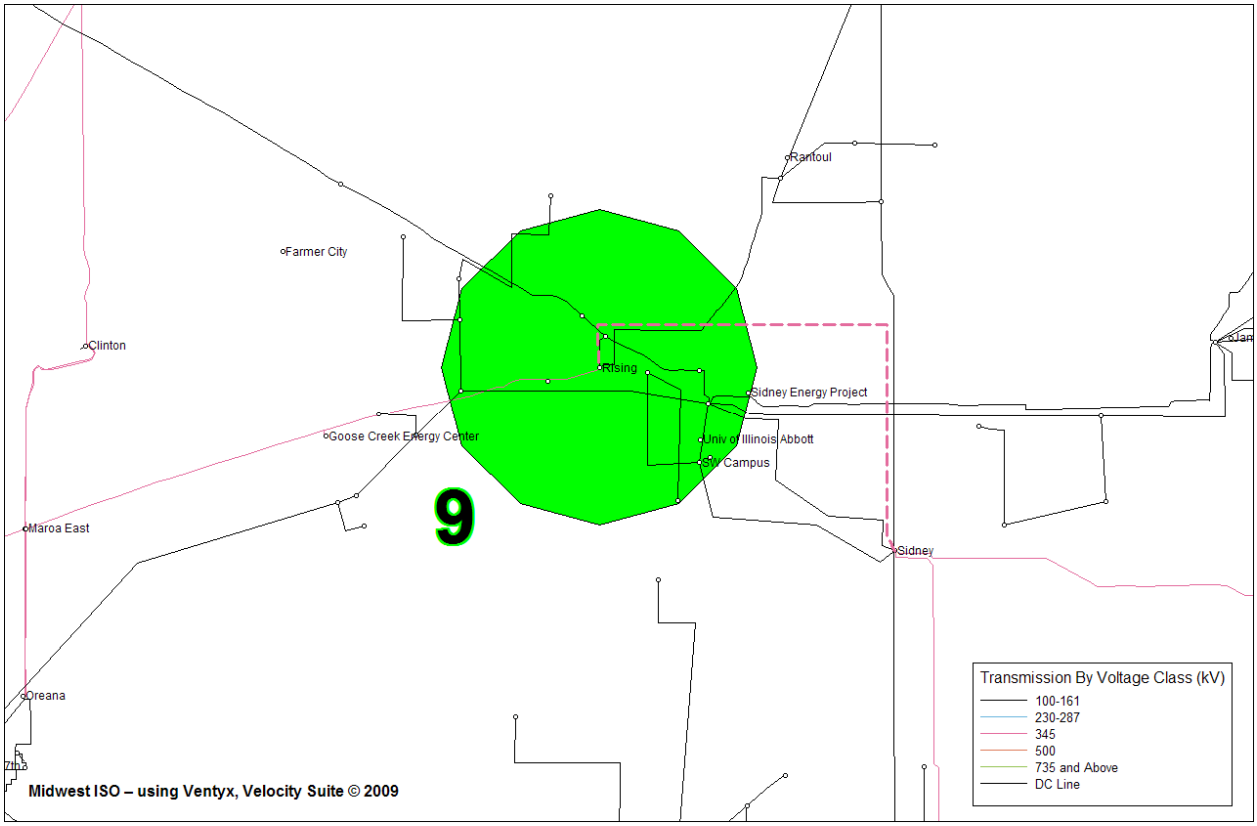

Figure 8.3-3: Sidney - Rising 345 kV Mitigation Plan[3]

[3] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

Table 8.3-12: Sidney - Rising 345 kV Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	-3,439,573	31,661,485	21,131,168	11.41	1.85
2019	201,289,509	329,462,785	291,010,803	11.41	25.50
2024	100,527,962	208,399,733	176,038,201	11.41	15.43
Total NPV	706,196,130	1,401,485,023	1,209,098,355	81.53	14.83

Table 8.3-13: Sidney - Rising 345 kV Midwest ISO Regional Benefit Allocations		
Region	NPV of RECB II ($)	Allocation Share
West	-134,374,502	0%
Central	1,329,195,388	99%
East	14,277,469	1%

To address the potential impact on the achieved benefits due to RRF unit locations included in the long-term planning years 2019 and 2024, a separate sensitivity analysis removing selected RRF units was performed on selected mitigation plans in Illinois. Shift factor is the sensitivity of line flows to a change in the injection at a bus and is used to calculate the flows on monitored lines. Through evaluating each RRF unit flow contribution on the selected top congested flowgates in Illinois, the RRF units with the shift factors larger than 0.05 were removed. This sensitivity study only intends to provide additional insight and further comprehensive sensitivity analysis is required to justify the plan as a regionally beneficial project eligible for cost sharing (Appendix A consideration).

The benefit savings and B/C ratios for the Sidney - Rising 345 kV project with select RRF units removed are detailed in the Table 8.3-14. Because the system is less congested by removing the RRF units with high shift factors associated with the top binding constraints, less economic benefits can be achieved with the mitigation plan and the B/C ratio dropped to 11.60 from 14.86. Sidney - Rising 345 kV is qualified for Appendix B consideration; however, rigorous economic sensitivities and reliability analysis must be performed before this plan can be moved to Appendix A.

Table 8.3-14: Sidney - Rising 345 kV RRF Sensitivity Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	5,607,001	2,820,718	3,656,603	11.41	0.32
2019	155,451,405	289,967,329	249,612,552	11.41	21.87
2024	-121,453,140	211,075,632	111,317,001	11.41	9.75
Total NPV	**345,694,006**	**1,203,439,230**	**946,115,663**	**81.53**	**11.60**

Bloomington to Hanna 345 kV

Figure 8.3-4 provides the mitigation plan Bloomington - Hanna 345 kV designed to relieve the Wheatland - Breed 345 kV flowgate. Increasing the rating on the Petersburg - Wheatland - Breed 345 kV line to 1,386 MVA and closing the Wheatland break tie is included as part of this mitigation plan and is in the $68.1M total project cost (Section 8.3.4.1). The annual and eleven year NPV adjusted production cost savings, load cost savings, RECB II benefits, and B/C ratios are provided in Table 8.3-15, and the cost allocations for the three Midwest ISO regions are listed in Table 8.3-16.

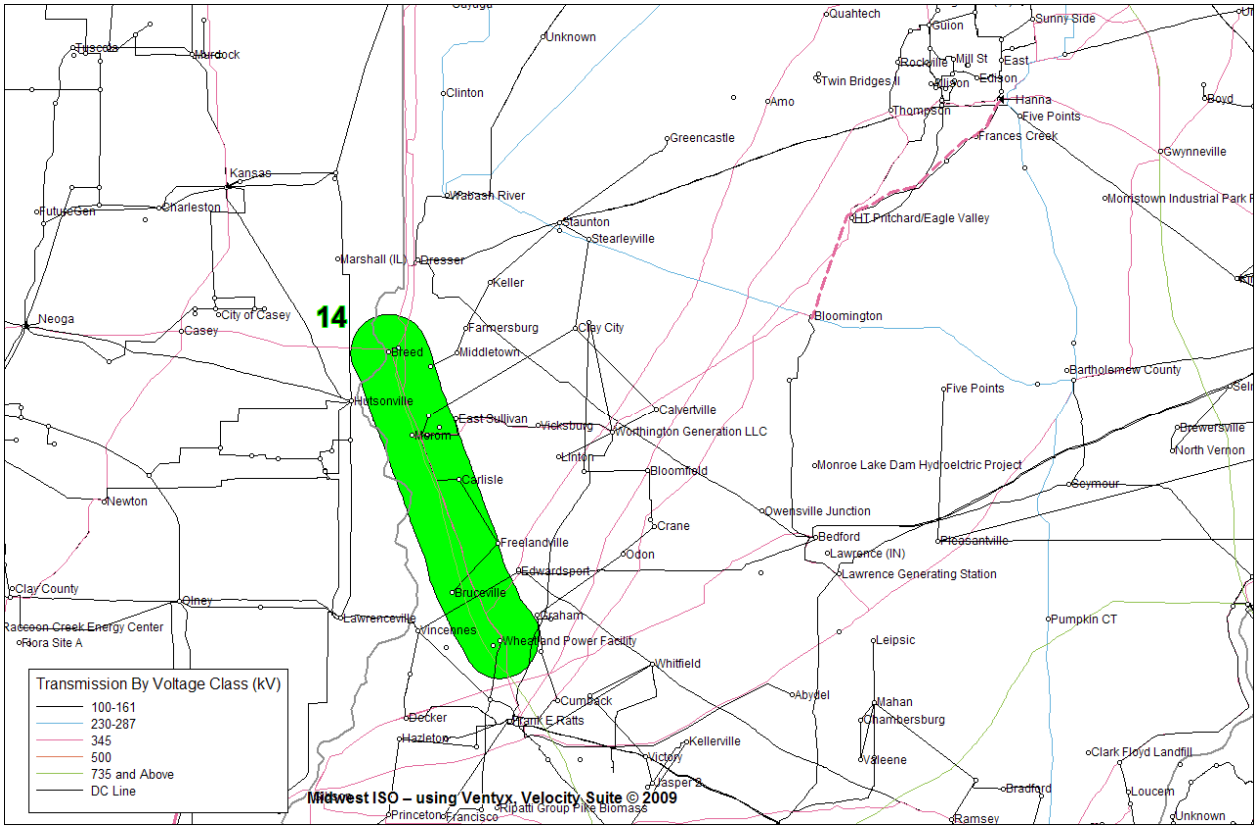

Figure 8.3-4: Bloomington - Hanna 345 kV Mitigation Plan[4]

Table 8.3-15: Bloomington - Hanna 345 kV Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	32,738,573	15,522,079	20,687,027	11.84	1.75
2019	51,924,579	29,348,587	36,121,385	11.84	3.05
2024	97,941,556	92,523,951	94,149,232	11.84	7.95
Total NPV	380,813,815	256,474,387	293,776,215	84.61	3.47

[4] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

Table 8.3-16: Bloomington - Hanna 345 kV Midwest ISO Regional Benefit Allocations		
Region	**NPV of RECB II ($)**	**Allocation Share**
West	-45,484,238	0%
Central	270,504,348	80%
East	68,756,105	20%

No additional sensitivities beyond the alternative Wheatland - Breed 345 kV flowgate mitigation plans were considered as part of the 2009 MTCFS. Wheatland - Breed 345 kV together with Petersburg - Wheatland - Breed 345 kV line rating increase and the Wheatland break tie close is qualified for Appendix B consideration; however, rigorous economic sensitivities and reliability analysis must be performed before this plan can be moved to Appendix A.

Merom to Newton 345 kV

Figure 8.3-5 shows a graphical representation for the Merom - Newton 345 kV transmission project. This plan was first proposed during the MTEP 08 long-term conceptual transmission overlay development process and was included in the transmission portfolio development in MTEP 08 Section 8.5 as a means to mitigate the top four transmission constraints in the Midwest ISO Market for year 2021. Under the MTEP 08 study assumptions, Merom - Netwon 345 kV provided significant value to the Midwest ISO Market.

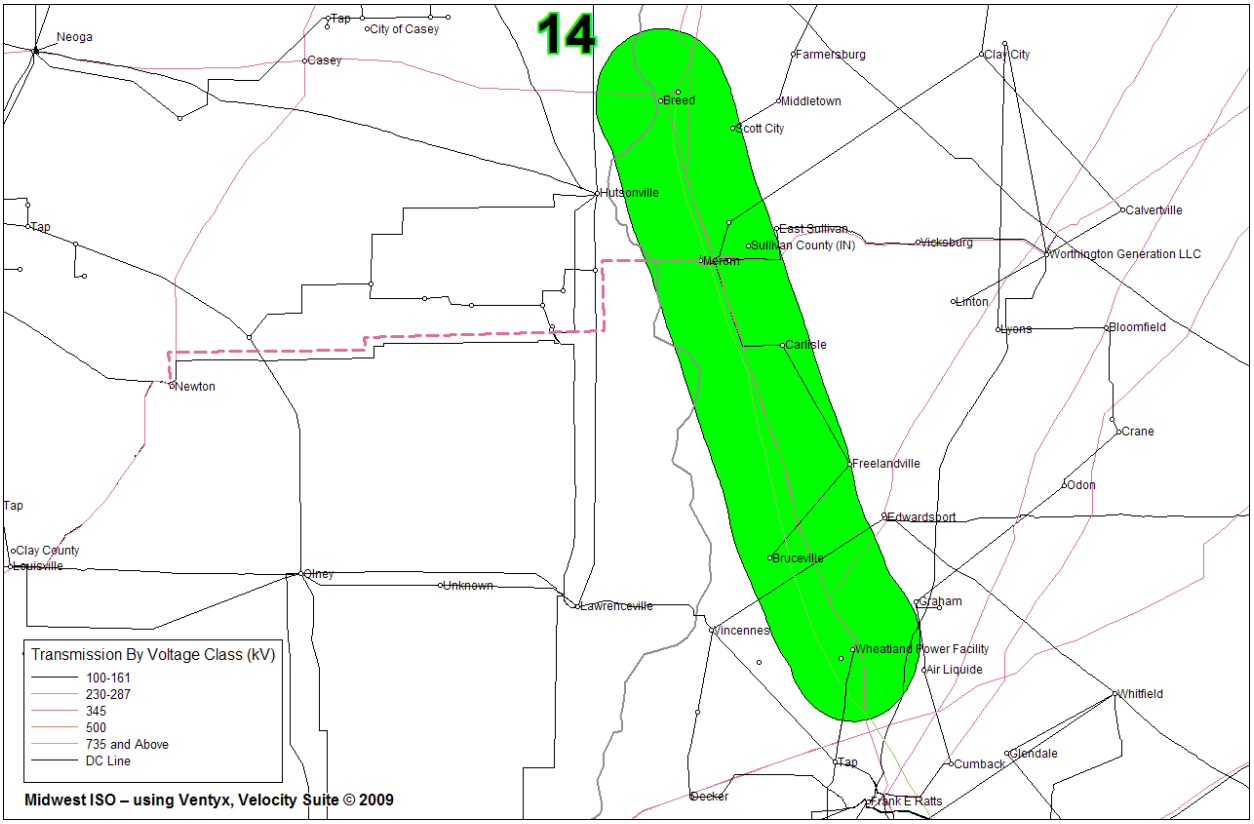

Figure 8.3-5: Merom - Newton 345 kV Mitigation Plan[5]

The annual and 11 year NPV adjusted production cost savings, load cost savings, RECB II benefits, and B/C ratios are provided in Table 8.3-17, and the cost allocations for the three Midwest ISO regions are listed in Table 8.3-18.

[5] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

Table 8.3-17: Merom - Newton 345 kV Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	20,019,258	32,308,891	28,622,001	18.83	1.52
2019	32,904,521	38,647,901	36,924,887	18.83	1.96
2024	98,141,264	77,695,009	83,828,886	18.83	4.45
Total NPV	**287,110,924**	**310,913,836**	**303,772,963**	**134.52**	**2.26**

Table 8.3-18: Merom - Newton 345 kV Midwest ISO Regional Benefit Allocations		
Region	NPV of RECB II ($)	Allocation Share
West	-36,679,555	0%
Central	206,971,041	61%
East	133,481,476	39%

The sensitivity analyses described in Section 8.3.4.2.2 was also performed on the Merom - Newton 345 kV plan to determine if the achieved benefits are significantly impacted by the siting assumptions of RRF units. The results of this sensitivity are provided in the Table 8.3-19. By removing the Illinois RRF units with a shift factor higher than 0.05, there is a RECB II benefit reduction of approximately $55M. This benefit reduction causes the B/C ratio to drop below the 2.0 threshold. Further sensitivity analyses are required to determine if this project meets the RECB II criteria for inclusion in Appendix B as a regionally beneficial project. This project won't be considered for Appendix B during the MTEP 09 study cycle.

Table 8.3-19: Merom - Newton 345 kV RRF Sensitivity Economic Benefits					
Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)	Annual Cost ($M)	B/C Ratio
2014	37,035,151	25,666,673	29,077,217	18.83	1.54
2019	19,891,450	34,812,503	30,336,187	18.83	1.61
2024	71,467,111	50,656,060	56,899,376	18.83	3.02
Total NPV	255,951,268	245,349,082	248,529,738	134.52	1.85

8.3.5 MTCFS Portfolios

The MTCFS is the first study to explore the option of using portfolios - a group of mitigation plans - as a means to evaluate RECB II benefits. As with all transmission plans proposed through the MTCFS, the end goal for a portfolio is Appendix B consideration. The portfolio methodologies detailed throughout this section are in developmental stages and have not been vetted through the required committees and legal proceedings.

The objective of a portfolio is to achieve synergistic benefits, where the benefits of the portfolio exceed the summation of individual plans' benefits. It should be clearly stated that the intention of each portfolio is not to "push" a non-beneficial project through the RECB process by pairing it with projects that far exceed RECB benefit criteria. Each project in the portfolio must be incrementally beneficial. Two separate methodologies were developed to deal with two types of portfolios.

The first type of portfolio is one consisting entirely of projects that individually do not meet RECB II benefit requirements. In this method, Method 1, a number of individual projects with a B/C ratio lower than 2.0 are paired and combined as a single portfolio. If the portfolio passes the RECB II benefit to cost criteria then (if applicable) each sub-combination is tested to ensure that each project "pays its own way." If each individual mitigation plan's incremental net present value (NPV) benefit exceeds the NPV costs then the portfolio is viable. If the initial portfolio does not meet RECB II benefit to cost criteria then (if applicable) the portfolio is broken down into smaller combinations and the Method 1 procedure starts over. The Method 1 portfolio testing process is diagramed in Figure 8.3-6. In Figure 8.3-6, A, B, and C represent individual RECB II non-eligible mitigation plans.

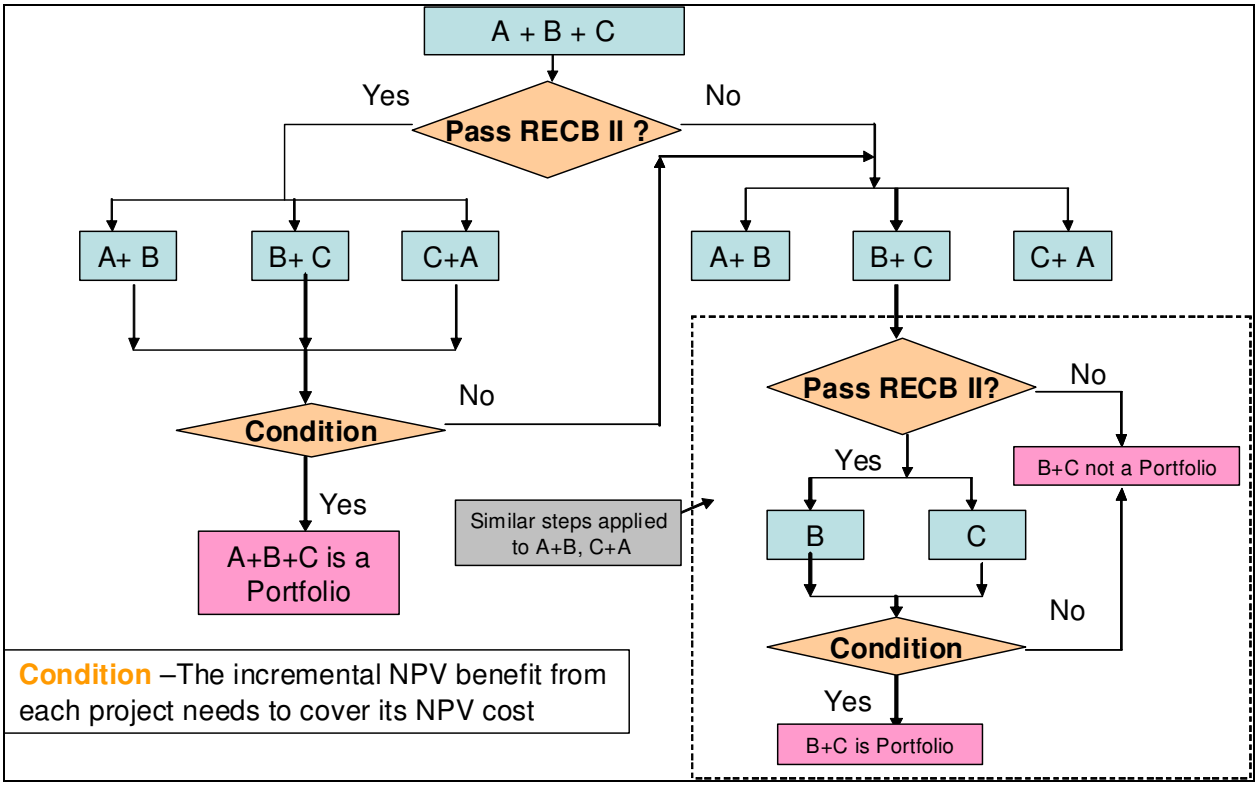

Figure 8.3-6: MTCFS Portfolio Economic Evaluation Method 1 Process Diagram

The second type of portfolio is one consisting of a single project that does not meet the RECB II benefit requirements and one or more projects individually meeting RECB II criteria. Because in most cases, the RECB II eligible plans allow for nearly any portfolio to meet benefit to cost ratio requirements (as a whole), the focus is shifted to the incremental benefit from the non-eligible mitigation plan. In this method, Method 2, at least two simulations must be performed. The first simulation calculates the benefits of the combined RECB eligible projects and the second simulation calculates the benefits of the combined RECB eligible projects and non-eligible project. The incremental benefit of the non-eligible project is the difference between the two simulations, and must have an incremental benefit to cost ratio in excess of RECB II B/C ratio threshold for the portfolio to be viable. The Method 2 portfolio testing process is diagramed in Figure 8.3-7. In Figure 8.3-7, A, B, and C are individual RECB II eligible mitigation plans, while D and E are RECB II non-eligible projects.

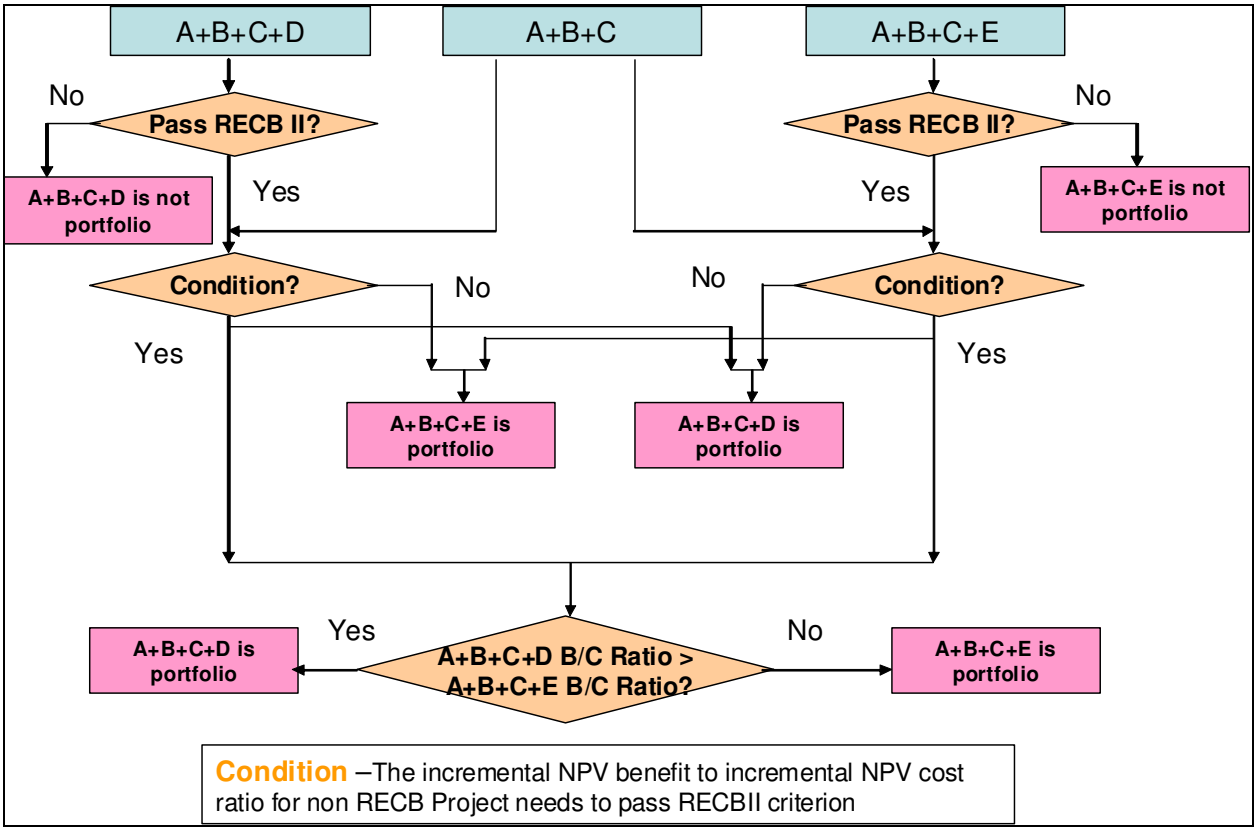

Figure 8.3-7: MTCFS Portfolio Economic Evaluation Method 2 Process Diagram

In the MTCFS, individual mitigation plans were given portfolio consideration if they were in a common geographic area. In the MTCFS the Illinois/Western Indiana area yielded itself as a common area that included numerous projects both RECB II eligible and non-eligible to be tested under both methods. Figure 8.3-8 displays the flowgate mitigation plans that were considered for portfolios in the 2009 MTCFS.

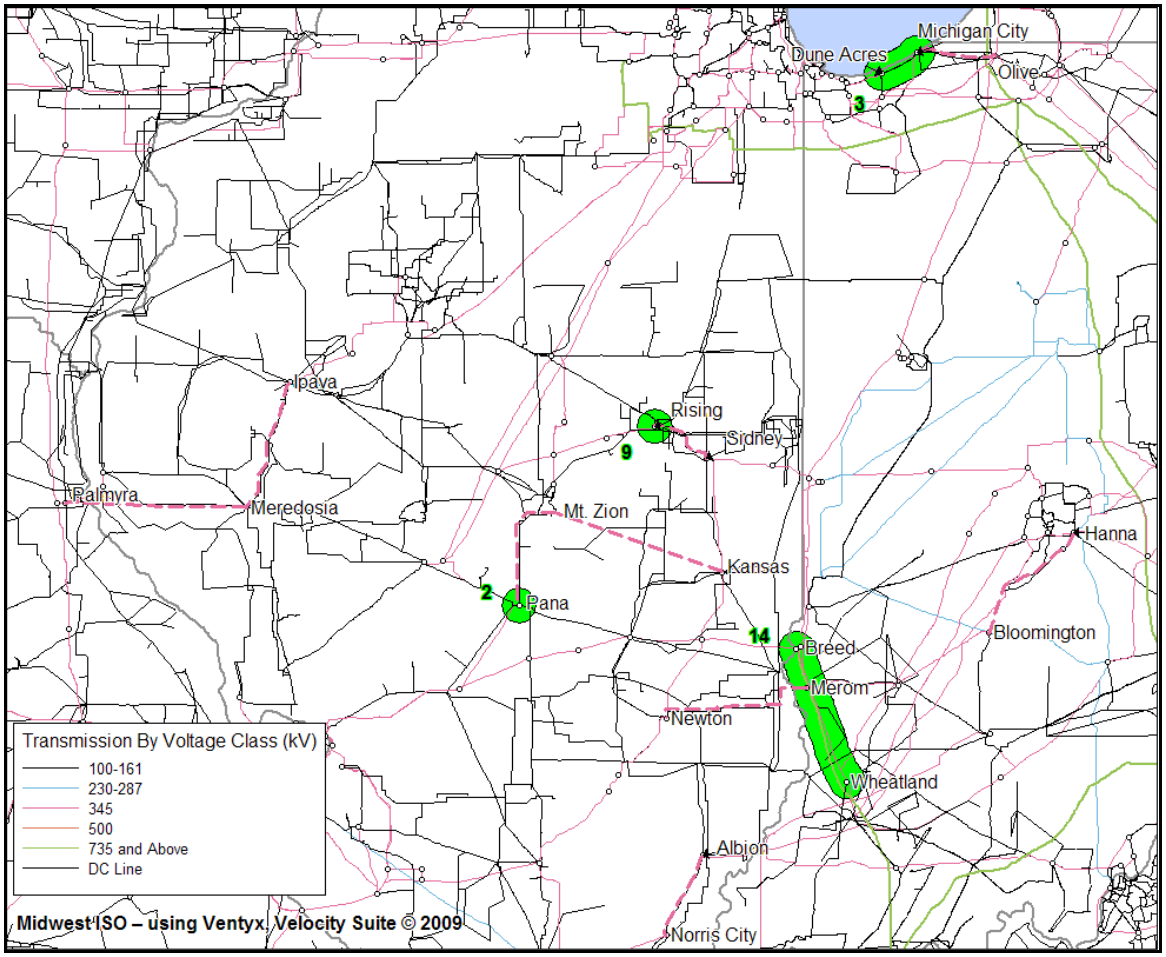

Figure 8.3-8: Portfolio Mitigation Plans6

Of the mitigation plans displayed in Figure 8.3-8, three are RECB II eligible based on the MTEP 09 Reference Scenario assumptions: Rising - Sidney 345 kV, Bloomington - Hanna 345 kV, and Merom - Newton 345 kV. In addition there are four RECB II non-eligible projects: Michigan City - Olive 345 kV, Pana - Mt. Zion - Kansas 345 kV, Palmyra - Meredosia - Ipava 345 kV, and Norris City - Albion 345 kV. Utilizing testing Method 1, the RECB II non-eligible projects were all combined and then combined in groups of three. To test each non-eligible plan under Method 2, the three RECB II eligible projects were grouped with each individual non-eligible projects. The benefits to the Midwest ISO Market are detailed in Table 8.3-20. Appendix F3 provides 2014, 2019, and 2024 results for each portfolio.

[6] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

Table 8.3-20: Portfolio 11 year NPV Benefits					
Portfolio	Load Cost Saving ($)	Adj. Prod. Cost Saving ($)	RECB II Benefit ($)	Total NPV Cost ($)	B/C Ratio
Method 1: Combine Non-Regionally Beneficial Projects					
Pana - Mt. Zion - Kansas 345 kV; Michigan City - Olive 345 kV; Norris City - Albion 345 kV; Palmyra - Ipava 345 kV	791,511,460	571,575,497	637,556,286	609,890,493	1.05
Pana - Mt. Zion - Kansas 345 kV; Michigan City - Olive 345 kV; Norris City - Albion 345 kV	623,197,548	482,098,608	524,428,290	359,318,640	1.46
Pana - Mt. Zion - Kansas 345 kV; Michigan City - Olive 345 kV; Palmyra - Ipava 345 kV	499,588,871	354,333,128	397,909,851	537,871,468	0.74
Michigan City - Olive 345 kV; Norris City - Albion 345 kV; Palmyra - Ipava 345 kV	746,913,047	373,258,810	485,355,081	376,168,374	1.29
Pana - Mt. Zion - Kansas 345 kV; Norris City - Albion 345 kV; Palmyra - Ipava 345 kV	570,502,581	501,103,770	521,923,413	556,312,997	0.94
Method 2: Combine Regionally Beneficial Projects with Non-Regionally Beneficial					
Rising - Sidney 345 kV; Bloomington - Hanna 345 kV; Merom - Newton 345 kV; Pana - Mt. Zion - Kansas 345 kV	2,223,684,847	2,375,950,615	2,330,270,885	534,383,495	4.36
Rising - Sidney 345 kV; Bloomington - Hanna 345 kV; Merom - Newton 345 kV; Michigan City - Olive 345 kV	1,918,343,154	2,332,577,508	2,208,307,202	354,240,425	6.23
Rising - Sidney 345 kV; Bloomington - Hanna 345 kV; Merom - Newton 345 kV; Norris City - Albion 345 kV	1,995,050,963	2,394,700,249	2,274,805,463	372,681,954	6.10
Rising - Sidney 345 kV; Bloomington - Hanna 345 kV; Merom - Newton 345 kV; Palmyra - Ipava 345 kV	2,262,824,701	2,407,916,755	2,364,389,139	551,234,783	4.29
Rising - Sidney 345 kV; Bloomington - Hanna 345 kV; Merom - Newton 345 kV	1,829,119,321	2,216,227,910	2,100,095,333	300,667,588	6.98

From Table 8.3-20, no four or three project portfolios are viable for MTEP Appendix B qualification under Method 1. Smaller combinations may be eligible but were not tested because of time constraints.

Under the Method 2 testing process, all portfolios exceeded the 2.0 benefit to cost ratio; however, in this method the focus is on the non-eligible mitigation plan's incremental benefits. The Method 2 incremental benefits are displayed in Table 8.3-21.

Table 8.3-21: Illinois Portfolio Incremental 11-Year NPV Benefits					
Portfolio - Method 2 Non-Regionally Beneficial Plan	Incremental Load Cost Saving ($)	Incremental Adj. Prod. Cost Saving ($)	Incremental RECB II Benefit ($)	Incremental Total NPV Cost ($)	Incremental B/C Ratio
Pana - Mt. Zion - Kansas 345 kV	394,565,526	159,722,705	230,175,552	233,722,119	0.98
Michigan City - Olive 345 kV	89,223,833	116,349,598	108,211,868	53,577,496	2.02
Norris City - Albion 345 kV	165,931,641	178,472,338	174,710,129	72,020,578	2.43
Palmyra - Ipava 345 kV	433,705,380	191,688,845	264,293,805	250,574,959	1.05

Under portfolio evaluation Method 2 two projects exceeded the 2.0 incremental B/C criteria to be determined viable. The portfolio containing Rising - Sidney 345 kV, Bloomington - Hanna 345 kV, Merom - Newton 345 kV, and Michigan City - Olive 345 kV had the highest B/C ratio and was considered the "best" portfolio. This portfolio contained the Merom - Newton 345 kV line as a RECB II eligible project. Sensitivity analysis around RRF unit siting assumptions provided uncertainty around its RECB II eligibility, therefore no portfolio will be recommended for Appendix B inclusion in the MTEP 09 study cycle.

Because of time constraints, only a limited number of mitigation plans were considered for combination into a portfolio. As the process is refined, future studies should allow for additional combinations as well as more/larger geographic areas.

8.3.6 Conclusions and Going Forward

Through the 2009 MTCFS work, three projects qualified for MTEP Appendix B: Rising - Sidney 345 kV, Lakefield Junction - Rutland 345 kV, and Bloomington - Hanna 345 kV. Before any of these three plans can be moved to MTEP Appendix A, rigorous economic sensitivity and reliability analysis must be performed. One additional project, Merom - Newton 345 kV, and two portfolios tested under portfolio evaluation Method 2 also met RECB II criteria on the first pass. Sensitivity work illustrates that the MTEP 09 resource forecast potentially has an impact on the benefits of each of these three projects. Further sensitivity analysis is required to ensure that these projects will meet RECB II benefit criteria under a wider range of study assumptions. In addition to further testing, the portfolio methodology will be examined in more detail before a portfolio is recommended to Appendix B. Projects within the MTCFS not meeting the RECB II criteria will be retested in future Midwest ISO Top Congested Flowgate studies.

The MTCFS is an annual process in only the second year of existence. From 2008 to 2009 the scope, level of detail, and stakeholder participation increased significantly, a trend the Midwest ISO would like to continue going forward. To ensure this goal is met in future studies, and that future studies continue to improve on the current framework, several suggestions were made by the Midwest ISO and MTCFS TRG:

- An ongoing theme throughout the 2009 MTCFS study was the effect of RRF units or the MTEP resource forecast on specific project's economic benefits. A consistent method must be developed to determine the economic effect RRF units and their siting assumptions have on each mitigation plan. Mitigation plans that are only beneficial because of RRF unit siting assumptions should not be considered RECB II eligible.
- The portfolio methodology used in the MTCFS study is in a developmental phase. Refinement, further testing, and review by the appropriate parties is required before portfolios can be eligible for cost sharing. Additionally, portfolios should also include projects that did pass the first selection process of the study but did not meet the voltage or total project cost criteria.
- In the 2009 MTCFS, numerous projects were on the border between the Midwest ISO and a neighboring RTO. Many of these plans provided benefits to both markets; however, only Midwest ISO benefits were considered in the selection process. In future studies, projects on RTO seams should be presented for joint study between the Midwest ISO and the neighboring RTO.
- Under the current RECB II criteria, projects at sub-345 kV voltages or with a total cost estimate below $5M are not eligible for cost sharing, and therefore were not included in the later stages of analysis; however, when making permitting determinations regulatory agencies like to compare projects to various alternatives. RECB II eligible mitigation plans should have their non-eligible alternatives studied for all later years to provide that comparison.
- In the 2009 MTCFS, two sources of information were utilized to identify the top congested flowgates in the Midwest ISO Market footprint. Additional sources can only aid in determining which flowgates are the most congested. One suggestion that will be considered is to utilize data from the Midwest ISO Day-Ahead Market.

The 2009 MTCFS was grateful to have a dedicated TRG; this single aspect is the key for present and future Midwest ISO Top Congested Flowgate Study success.

8.4 Coffeen – Coffeen North 345kV Project Evaluation

The Sub Regional Planning Meetings (SPMs) instituted in 2008 as a part of FERC Order 890 open and transparent planning protocols continued in the MTEP 09 cycle of 2009. The SPMs offer an opportunity for market participants to raise transmission planning issues of concern. In this process a market participant requested that the Midwest ISO evaluate solutions to congestion at the Pana Transformer in central Illinois. The FERC approved Midwest ISO planning protocols for evaluating congestion issues and identifying market efficiency upgrades that may qualify as Regionally Beneficial Projects is to address congestion within a "top-down" process in which the Midwest ISO evaluates the most critical and persistent congestion points from analyses of historical market performance as well as projected future system performance. This congestion analysis process has been described in Section 8.3 as the Midwest ISO Top Congested Flowgate Study (MTCFS). Market participant input received at the SPMs is taken into consideration in this top-down prioritization process.

As part of the MTEP 09 MTCFS effort, the Pana 345/138kV transformer for the loss of Coffeen – Coffeen North 345kV line had been identified as one of the top highly congested flowgates within the Midwest ISO market footprint using both Midwest ISO Real-Time market historical data and MTEP 09 2014 production cost simulation results. Additional detail on the data used and a listing of the flowgates and their ranking is included in Section 8.3.3. A 2nd Coffeen – Coffeen North 345kV tie line was proposed as a potential solution to mitigate the congestion of the Pana 345/138kV transformer. As this congested flowgate was already under consideration as one of the most congested market flowgates, and the SPM process had revealed explicit stakeholder interest in this flowgate, the Coffeen – Coffeen North solution was further evaluated for qualification as a Regionally Beneficial project using the Regional Expansion Criteria and Benefits (RECB) II metrics, in parallel with the ongoing MTCFS analysis of the other top congested flowgates. The results of the analysis to confirm qualification of this project under the economic planning criteria provided under the tariff were shared with stakeholders in a manner consistent with all other Appendix A projects being recommended for approval. This included discussions of the project with the Planning Subcommittee, Planning Advisory Committee, and at a general stakeholder meeting to discuss cost allocation.

The remainder of this section discusses the analysis of the Coffeen – Coffeen North project. The purpose of this analysis was to evaluate the economic benefits of the proposed 345kV Coffeen – Coffeen North tie line under various future generation and demand scenarios, and determine the eligibility of the project for regional cost sharing per provisions in the tariff. This project was initially analyzed under the MTEP 09 Reference future only. Preliminary results under that scenario were presented at the MTEP 09 RECB Cost Allocation meeting held on September 09, 2009 to facilitate the discussion on the robustness testing of this proposed solution. From those results it was determined that further analysis was justified and that a more thorough evaluation, incorporating a broader set of future scenarios, would be performed.

The additional scenarios considered in the second phase of analyses were 20% federal wind energy, environmental, gas futures and a low load forecast scenario developed based on the reference future. Multi-year production cost analyses were performed for all scenarios and ten year total net present values were calculated for both economic benefits and total project costs.

Production cost simulation results indicate that this project can provide market efficiency benefits via congestion relief that exceed the current RECB II threshold for projects having the characteristics of this proposed solution. Figure 8.4-1 shows the relationship between project in-service date and the benefit to cost (B/C) ratio threshold.

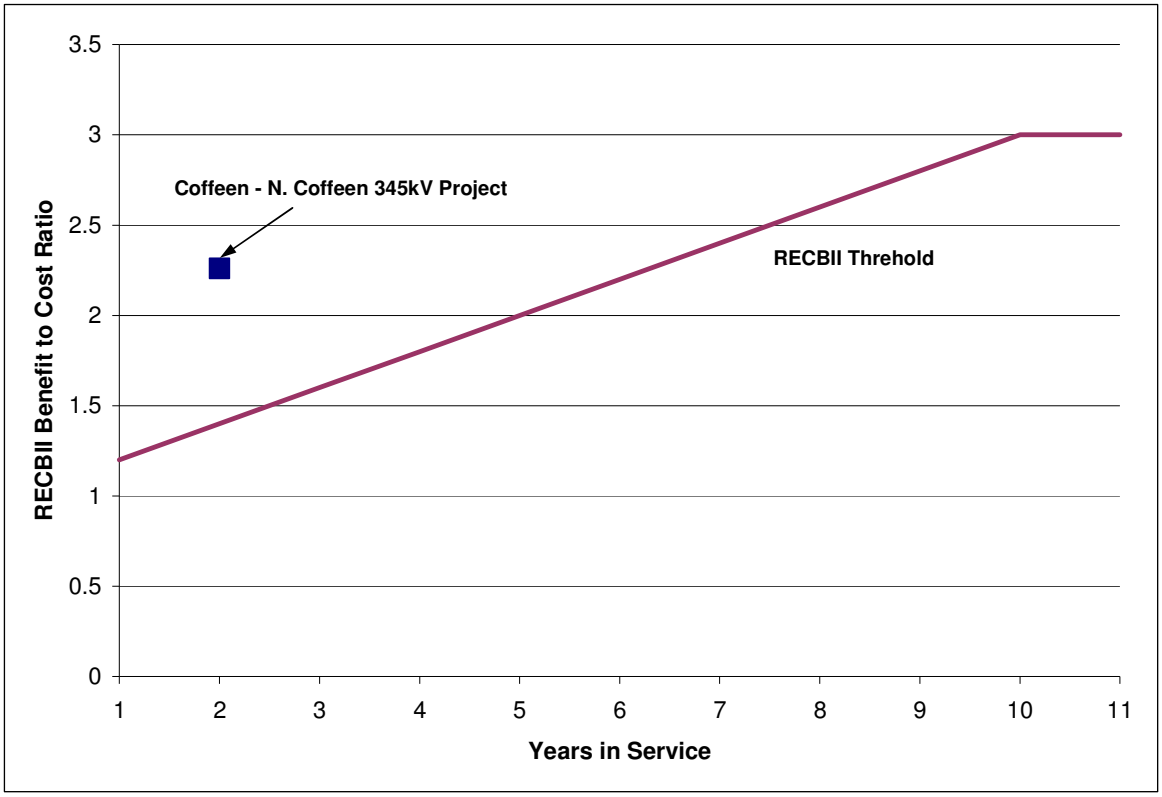

Figure 8.4-1: RECB II Benefit to Cost Ratio

The threshold that a project must exceed to be cost shared under the RECB II methodology ranges from 1.2 for a project that is one year out to 3.0 for a project having an in-service date that is 10 year or more in the future. The analysis of the Coffeen project resulted in a benefit to cost ratio of 2.26 when equal weighting was assigned to all the sensitivity scenarios. The project has an expected in service date of January 2011, so the B/C ratio exceeds the 1.4 threshold for such near-term solutions.

As a follow up, a separate stakeholder meeting was held on Oct. 2nd, 2009 to review the final economic analysis results and cost allocations of this project. The allocation of project costs to Midwest ISO sub regions and pricing zones are provided Section 8.4.4. With the B/C ratio exceeding the RECB II threshold, this project will be recommended to MTEP 09 Appendix A as a Regionally Beneficial Project.

8.4.1 Project Description

Project 2829 will extend a second 345kV tie line approximately 1,200 feet between the Coffeen and the Coffeen North substations. In addition to the new tie line, the project includes upgrading a 345kV wave trap at Coffeen North and a line disconnect switch at the Ramsey East Substation to increase the rating of the 345 kV line section from Coffeen North to Ramsey East.

Provided by the transmission owner, the total estimated cost for the new tie line and transmission line upgrades is $5,655,000 ($5,500,000 for the 345kV tie line, $155,000 for the additional equipments). The expected in service date for this project is January 2011. Figure 8.4-2 shows the geographical location of this project.

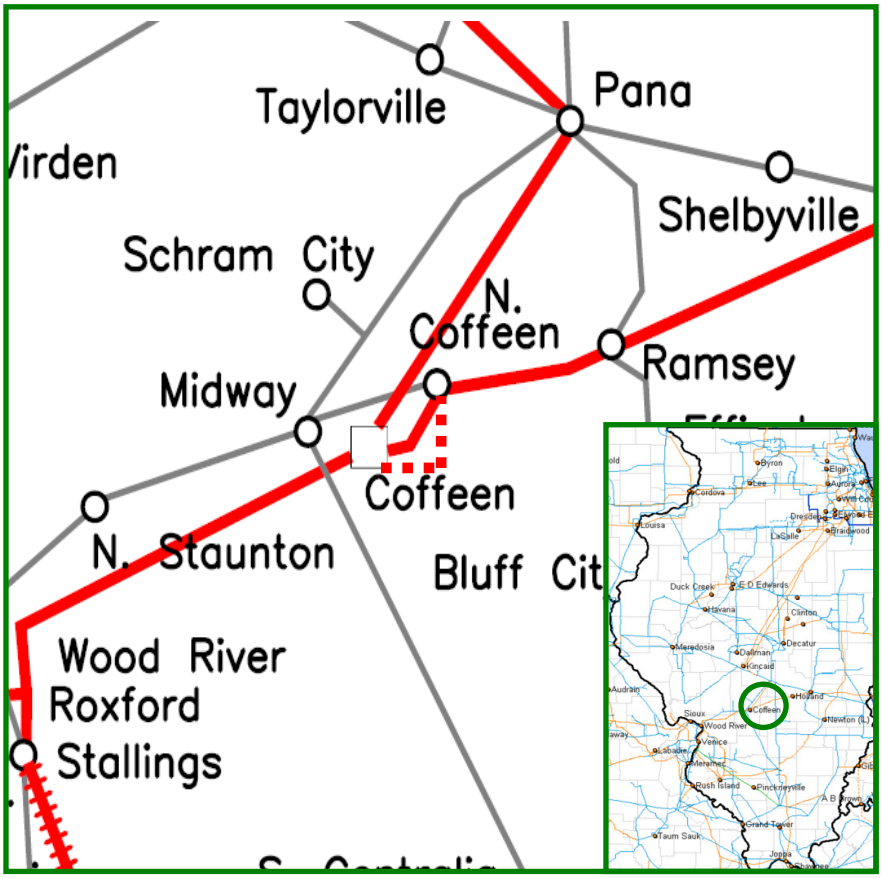

Figure 8.4-2: Coffeen to Coffeen North 345kV Tie Line[7]

8.4.2 Study Methodology and Assumptions

Model Development

The same input assumptions for power flow and production cost models used in the MTCFS study were served as the starting point for this analysis. Section 8.3.1 includes a detailed discussion of those assumptions. To alleviate congestion across the Pana transformer flowgate, an additional alternative was considered to replace the existing 345/138kV Pana transformer with a larger transformer bank. As two market participants have agreed to fund the construction of this option, the transformer upgrade was included in the production cost base models prior to the Coffeen project economic analysis. Preliminary studies show that greater benefit can be achieved by the Coffeen – Coffeen North project without the

[7] Figure may have some inaccuracies and is not indicative of the transmission topology used in the production cost models. Line routing is for illustration purposes only and is not final.

inclusion of the Pana transformer upgrade, as the upgraded transformer alleviates a portion of the congestion in the base condition that otherwise would have been mitigated by the Coffeen project. Therefore, it could reasonably be expected that the B/C ratio for the Coffeen project would be higher than determined in this analysis if the Pana transformer upgrade were to be excluded.

Future Generation and Demand Scenarios

Per Attachment FF of the Tariff, to evaluate the anticipated benefits of a potential Regionally Beneficial Project, sensitivity analyses shall include, among other factors, consideration of:

i. Variations in amount, type, and location of future generation supplies as dictated by future scenarios developed with stakeholder input and guidance;

ii. Alternative transmission proposals;

iii. Impact of variations in load growth;

iv. Effects of demand response resources on transmission benefits.

Several potential future generation scenarios are currently available and developed through interactive stakeholder workshops in the MTEP 08 integrated transmission planning process as well as the Joint Coordinated System Plan (JCSP) process. A resource forecasting model was used to develop different future generation portfolios needed to maintain adequate regional reserve margins and meet various political, economical, and environmental goals. Please refer to Section 10.1, Generation Futures Development, and Appendix E1 for the detailed definition of each scenario.

To comply with the tariff requirements for sensitivity analyses described above, four existing future generation scenarios were utilized, the reference, 20% federal wind energy, environmental and gas scenarios. In addition, a low load forecast scenario was included, which is essentially the reference scenario with a reduced demand forecast at 10/90 level instead of 50/50 forecast used in the reference scenario. A 10/90 forecast is the load level that has a 90% probability of being exceeded by actual load.

Benefit/Cost Assumptions and Calculations

The RECB II metrics and methodology were utilized in this evaluation of forecasted benefits. RECB II benefits are determined via the following formula:

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

Section 8.3.2 includes a detailed discussion of the calculation of the adjusted production cost savings and load cost savings.

The Coffeen – Coffeen North 345kV project is expected to be in service in 2011 and the resulting threshold for cost sharing eligibility is 1.4. The benefits and costs applied in the benefit to cost (B/C) ratio calculations are the net present values for the first ten years of the project life starting at the in-service year. Three years of PROMOD production cost simulations, 2014, 2019, and 2024, were performed for all sensitivity scenarios to calculate benefits spanning across a ten year timeframe. The benefit savings for years other than the three simulated years are derived using the linear interpolation or extrapolation. Ten year net present value (NPV) of RECB II benefit savings from 2011 to 2020 are calculated using a 10% discount rate, which was set by a stakeholder consensus during the MTEP 09 process.

An 18.65% levelized fixed charge rate (LFCR) provided in 2009 Attachment O for Ameren Illinois is used to determine the annual cost of the transmission project. The 2009 project costs are escalated to 2011 dollars using a 3% inflation rate. The B/C ratio is calculated by 10 year NPV of the benefits divided by 10

year NPV of the project costs. The B/C ratio calculation assumptions described in this section carry though all sensitivity analyses.

As there is no formal definition on how to weight the sensitivity scenarios in the current Tariff, equal weighting is applied towards each scenario to calculate the total NPV of the RECB II benefits and cost allocations for sub regions.

8.4.3 Economic Analysis Results

For each scenario production cost simulations for 2014, 2019 and 2024, were performed to determine the benefit to cost ratio of the Coffeen to Coffeen North 345kV project. Ten year NPV of RECB II benefits, project costs, and B/C ratios for all sensitivity scenarios are summarized in Table 8.4-1. Utilizing an equal weighting factor of 0.2 for each scenario, the weighted NPV of the total RECB II benefits is approximately $17 million. The benefit to cost ratio is 2.26 and passes the RECB II threshold of 1.4.

Table 8.4-1: 10 year NPV RECB II Economic Benefits

	Reference	Wind	Environmental	Gas	Low Load Forecast	Weighted Total
NPV of 10 Years Total RECB II Benefits ($)	28,796,418	27,892,415	689,773	39,820,481	(11,842,645)	17,071,288
NPV of 10 Years Total Project Costs ($)	7,562,578	7,562,578	7,562,578	7,562,578	7,562,578	7,562,578
Benefits/Cost Ratios	3.81	3.69	0.09	5.27	(1.57)	2.26
Weighting factors	0.2	0.2	0.2	0.2	0.2	1.0

The annual and ten year NPV of the adjusted production cost savings, load cost savings, and RECB II benefits are provided in Tables 8.4-2 through 8.4-6 for each scenario respectively. As can been seen, load cost savings are the predominate elements driving the total RECB II benefits. The ten year NPV of the RECB II benefits brought by the Coffeen project vary between scenarios and range from a low of negative $12 million in the low load forecast scenario up to a high of approximately $40 million in the gas scenario. Note that while the simulation results shown are for 2014, 2019, and 2024, a linear interpolation of the results was used to determine the benefit values for each of the years from 2011 through 2020. Those values were then used to determine the NPV.

Table 8.4-2: Reference Scenario RECB II Economic Benefits

Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)
2014	14,102,983	789,649	4,783,649
2019	(704,835)	901,880	419,866
2024	17,561,147	(644,731)	4,817,033
Total NPV	**83,605,954**	**5,306,616**	**28,796,418**

Table 8.4-3: 20% Federal Wind Scenario RECB II Economic Benefits

Year	Load Cost Saving ($)	Adj Production Cost Saving ($)	RECB II ($)
2014	11,696,168	789,818	4,061,723
2019	8,628,338	1,916,877	3,930,315
2024	17,060,970	7,681,743	10,495,511
Total NPV	**77,021,577**	**6,837,061**	**27,892,415**

Table 8.4-4: Environmental Scenario RECB II Economic Benefits			
Year	**Load Cost Saving ($)**	**Adj Production Cost Saving ($)**	**RECB II ($)**
2014	(2,994,945)	2,285,154	701,125
2019	(3,353,381)	(1,657,729)	(2,166,425)
2024	(50,185,302)	(6,517,460)	(19,617,812)
Total NPV	**(24,536,272)**	**11,500,935**	**689,773**

Table 8.4-5: Gas Scenario RECB II Economic Benefits			
Year	**Load Cost Saving ($)**	**Adj Production Cost Saving ($)**	**RECB II ($)**
2014	12,049,247	1,414,990	4,605,267
2019	35,609,947	5,699,503	14,672,636
2024	38,456,154	(1,004,141)	10,833,947
Total NPV	**102,789,683**	**12,833,680**	**39,820,481**

Table 8.4-6: Low Load Forecast Scenario RECB II Economic Benefits			
Year	**Load Cost Saving ($)**	**Adj Production Cost Saving ($)**	**RECB II ($)**
2014	(7,978,814)	585,143	(1,984,044)
2019	(1,117,035)	(350,513)	(580,470)
2024	6,325,981	1,683,259	3,076,076
Total NPV	**(47,150,476)**	**3,289,283**	**(11,842,645)**

8.4.4 Cost Allocation

For Regionally Beneficial Projects, twenty percent of the project costs are allocated on a system-wide basis using a load ratio share, and eighty percent of the costs are allocated on a sub region-wide basis in the three pre-defined planning sub-regions using the benefit share determined through the production cost simulations. The sub-regional share is spread among each sub-regional zone by the sub- regional load share ratio. Table 8.4-7 illustrates the sub regional ten year NPV of the total RECB II benefits for each scenario as well as the total weighted regional benefits and associated cost allocation. A further breakdown by pricing zone of the total project costs assigned to the zone is provided in Table 8.4-8.

Table 8.4-7: Sub Region Cost Allocation							
NPV of 10 Years Total RECB II Benefits ($)	**Reference**	**Wind**	**Environmental**	**Gas**	**Low Load Forecast**	**Weighted Total**	**Cost Allocation**
West Region	1,854,351	1,620,430	4,697,842	10,812,199	(8,161,879)	2,164,588	12.68%
Central Region	17,591,603	4,983,125	12,769,434	14,111,186	(6,360,442)	8,618,981	50.49%
East Region	9,350,464	21,288,860	(16,777,503)	14,897,096	2,679,676	6,287,719	36.83%
Weighting factors	0.2	0.2	0.2	0.2	0.2	1.0	100%

Table 8.4-8: Cost Allocation Breakdown by Pricing Zone[8]								
Pricing Zone	12 CP LoadkW	Load Ratio Share	Regional		Sub-regional		Allocation Total	
			%	$	%	$	%	$
FE	10,769,416	12.7%	2.53%	143,199	10.67%	603,218	13.20%	746,417
METC	6,776,000	8.0%	1.59%	90,099	6.71%	379,538	8.30%	469,637
MI13AG	483,172	0.6%	0.11%	6,425	0.48%	27,064	0.59%	33,488
MI13ANG	126,500	0.1%	0.03%	1,682	0.13%	7,086	0.16%	8,768
ITC	8,787,000	10.3%	2.07%	116,839	8.70%	492,179	10.77%	609,018
NIPS	2,804,833	3.3%	0.66%	37,295	2.78%	157,105	3.44%	194,400
HE	538,234	0.6%	0.13%	7,157	0.76%	42,790	0.88%	49,946
CIN	9,833,290	11.6%	2.31%	130,751	13.82%	781,746	16.14%	912,497
VECT	1,057,167	1.2%	0.25%	14,057	1.49%	84,045	1.73%	98,102
IPL	2,505,000	2.9%	0.59%	33,308	3.52%	199,147	4.11%	232,456
CWLD	231,000	0.3%	0.05%	3,072	0.32%	18,364	0.38%	21,436
AMMO	6,928,970	8.1%	1.63%	92,133	9.74%	550,852	11.37%	642,985
AMIL	6,916,041	8.1%	1.63%	91,961	9.72%	549,825	11.35%	641,786
CWLP	345,000	0.4%	0.08%	4,587	0.49%	27,427	0.57%	32,015
SIPC	377,000	0.4%	0.09%	5,013	0.53%	29,971	0.62%	34,984
ALTW	2,949,630	3.5%	0.69%	39,221	1.13%	63,659	1.82%	102,880
ATC	10,915,162	12.8%	2.57%	145,137	4.17%	235,572	6.73%	380,709
NSP	8,380,737	9.9%	1.97%	111,437	3.20%	180,874	5.17%	292,311
MP	1,760,738	2.1%	0.41%	23,412	0.67%	38,000	1.09%	61,413
SMMPA	249,620	0.3%	0.06%	3,319	0.10%	5,387	0.15%	8,706
GRE	972,141	1.1%	0.23%	12,926	0.37%	20,981	0.60%	33,907
OTP	747,275	0.9%	0.18%	9,936	0.29%	16,128	0.46%	26,064
MDU	604,237	0.7%	0.14%	8,034	0.23%	13,041	0.37%	21,075
	85,058,163	**100%**		**1,131,000**	**80.0%**	**4,524,000**	**100%**	**5,655,000**

In summary, 47% of the total project costs, approximately $2.7 million, is allocated to the Central region, 36% of the costs, approximately $2.1, is allocated to East region, and the remainder of the costs, approximately $1 million, are allocated to West region.

Figure 8.4-3 shows the cost allocation by prizing zone.

[8] Note that dollars shown represent the capital cost of the project. The annual revenue requirement charged to each zone will be function of the constructing Transmission Owner's Fixed Charge Rate. For the footprint, Fixed Charge Rates currently average approximately 20%.

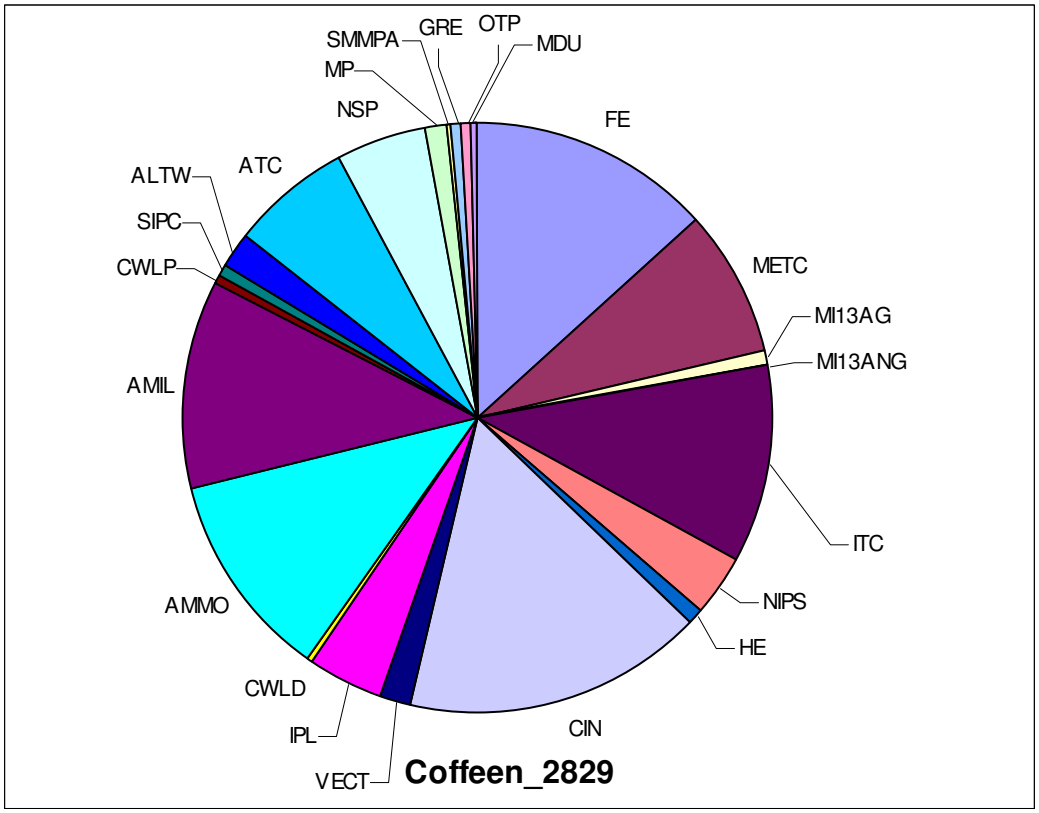

Figure 8.4-3: Cost Allocation Breakdown by Pricing Zone

8.4.5 Conclusions

Midwest ISO has applied the process required by Attachment FF of the tariff to move the proposed Coffeen – Coffeen North 345kV tie line project to Appendix A and the following steps have been accomplished:

- A rigorous multi-year economic analysis, including various sensitivity analyses, has been done to justify the Coffeen project for regional cost sharing eligibility. The results show that this project passes the RECB II test and is eligible for regional cost sharing.
- As part of MTCFS study process, several alternatives to relieve the Pana transformer flowgate were considered and reviewed by the Technical Review Group. Please see section 8.3.4 for a discussion of those alternatives.
- Numerous meetings were held with stakeholders to review and discuss results and cost estimates.
- A separate stakeholder meeting was held on Oct 2nd, 2009 to review the final results and cost allocation associated with this analysis.

As the final step, the results will be issued to Board of Directors System Planning Committee and this project will be considered by the Midwest ISO to the Board of Directors for approval as a Regionally Beneficial Project.

Section 9: Regional Energy Policy Driven Transmission Studies

9.1 Regional Generation Outlet Studies

9.1.1 Overview

The Midwest ISO is observing two significant drivers for transmission expansion, state Renewable Portfolio Standards (RPS) and the associated generation in the interconnection queue. States within the Midwest ISO footprint, including Montana, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Michigan, Ohio and Pennsylvania currently have Renewable Portfolio Standards (RPS) for eligible load serving entities to comply with. North and South Dakota do not have an RPS but do have renewable goals to be met by their load serving entities. The states of Kentucky and Indiana do not currently have an RPS or goal. These mandates vary in their requirements and timing but generally start around 2010 and continue into the 2020's. Also, the current Midwest ISO generation queue has around 60,000 MWs of wind requests. Understanding the innate issues with the queue process, a balance is needed to provide an efficient and cost effective transmission build-out over the next 5-10 year period and beyond.

To accomplish this, the Midwest ISO, its state Regulators and Stakeholders initiated the Regional Generator Outlet Study (RGOS). The purpose of the RGOS is to develop transmission portfolios needed to implement the Renewable Portfolio Standards, or goals, at the least cost for consumers while continuing to reliably serve load.

The RGOS is being addressed in two phases. Phase I of the RGOS looked at the transmission design alternatives for the states in the western part of the Midwest ISO (North and South Dakota, Minnesota, Wisconsin, Iowa and Illinois). At the time this study was initiated, those were the only states in the Midwest ISO area that had Renewable Portfolio Standards or goals. While Phase I of the RGOS was underway, more states began to develop, and sign into law, Renewable Portfolio Standards. Because of this, the scope of the RGOS needed to be expanded. This expansion is being addressed in Phase II of the RGOS. Phase II looks at developing transmission alternatives for the states in the eastern part of the Midwest ISO (Missouri, Illinois, Indiana, Michigan and Ohio) while incorporating the results of Phase I.

9.1.2 Process

The RGOS work is being performed under the Midwest ISO Transmission Expansion Plan (MTEP) process as a targeted study. Within that process, Phase I and II have several major elements. These elements include: renewable energy zone development (stakeholder survey, wind data analysis, and zone scenarios), indicative transmission design and economic analysis, and detailed transmission design. A discussion of each of these elements is contained in the subsequent sections.

An important part of the RGOS is the analysis of local versus regional generation sources relative to the loads being served by the renewable requirements. In the Midwest ISO footprint, higher capacity factor wind areas are located far from large load centers, requiring long transmission lines to serve the energy. On the other hand, shorter transmission lines can be built with energy zones near load centers; however, the wind capacity factors are less and thus require more generation to be installed. This sets up a need to understand the balance between higher transmission capital costs, associated with higher capacity factor energy zones, and higher generation capital costs, associated with lower capacity factor energy zones.

For this study, a stakeholder group was created and referred to as the Technical Review Group (TRG). A separate TRG exists for Phase I and Phase II. The TRG was created for the purpose of ensuring technical credibility of the RGOS by providing input to the study scope, feedback and direction, and review of assumptions, methods and results. The TRG has a sunset date commensurate with the conclusion of the study and is open to all stakeholders wishing to participate. A second stakeholder group, a subset of the TRG, called the Design Sub-Team (DST) was created as a working group to help with the indicative transmission design work, and to review transmission system analysis output. This group was comprised primarily of experienced transmission planning engineers from states under study, and was a key participant in conducting the detailed analysis in Phase I.

The TRG for both Phase I and Phase II have received significant participation from the stakeholder community including regulators, transmission owners, renewable energy developers, and market participants. Transmission owners from Mid-Continent Area Power Pool (MAPP) and PJM Interconnection (PJM) have also been active participants. Other stakeholder participation has been conducted at regular Midwest ISO committees, such at the Planning Advisory Committee and Planning Subcommittee.

In conjunction with the TRGs, additional stakeholder involvement was provided to RGOS Phase I by the Upper Midwest Transmission Development Initiative (UMTDI). The UMTDI was formed in September of 2008 by the Governors of the states of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin. The UMTDI was created for the purpose of encouraging transmission investment for renewable energy and developing an equitable cost sharing method for needed transmission. The UMTDI has provided policy direction to the RGOS Phase I study effort in helping to select a set of renewable energy zones for additional study work.

9.1.3 Renewable Energy Zone Development

The first major step in performing the RGOS is the development of a set of candidate Renewable Energy Zones. This was done with a survey of the regions Load Serving Entities (LSE) and receipt of wind data from the National Renewable Energy Laboratory (NREL), a part of the Department of Energy.

Stakeholder Survey

Survey Overview

In order to know the amount of renewable energy zones to develop, first you must know the energy requirements. To determine this, both Phase I and Phase II included a survey of the region's LSEs. The surveys determined the net energy needs of each entity per their respective states' RPS. The surveys were aggregated and used as the target for the number of renewable energy zones to create. The survey asked questions to determine the total energy required to meet the respective RPS and the amount of energy already in existence that complies with that RPS.

Requirements

RGOS Phase I

The total additional wind energy required to meet RGOS Phase I requirements is 41,491 GWh in 2027. This includes the states of Illinois, Iowa, Minnesota, and Wisconsin per their respective RPSs as of the spring of 2008. Illinois' requirements include both Midwest ISO and PJM members. Table 9.1-1 shows the total energy requirements for all four states.

Table 9.1-1: RGOS I Renewable Energy Requirements

Total (MN, IA, IL, WI) Potential Energy Required											
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Energy Reported	GWh	257,498	261,849	258.751	262,198	265,120	268,193	271,738	275,564	279,353	283,203
Total Retail Energy	GWh	205,985	216,523	216,601	218,796	221,314	224,254	227,197	230,412	233,565	236,828
Energy Required to Meet Mandates	GWh	6,296	8,040	13,919	14,561	18,027	20,673	21,709	25,935	31,595	33,139
Existing & Planned Renewable Energy	GWh	11973	13014	13014	13014	13014	13014	13014	13014	13014	13014
Additional Renewable Energy Required	GWh	(5,677)	(4,974)	904	1,536	5,012	7,658	8,695	12,921	18,581	20,124
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Energy Reported	GWh	287,335	291,518	295,761	300,019	304,358	308,742	313,268	317,764	322,453	324,922
Total Retail Energy	GWh	240,293	243,818	247,395	251,082	254,926	258,850	262,889	266,973	271,236	275,618
Energy Required to Meet Mandates	GWh	34,759	36,422	41,085	42,875	44,720	47,087	49,045	52,456	53,468	54,505
Existing & Planned Renewable Energy	GWh	13,014	13,014	13,014	13,014	13,014	13,014	13,014	13,014	13,014	13,014
Additional Renewable Energy Required	GWh	21,744	23,408	28,071	29,860	31,705	34,073	36,031	39,442	40,453	41,491

Depending on the capacity factor, or output level, of the wind developed, 41,291 GWh is in the range of 11-16 GW of capacity needed to meet the RPS.

RGOS Phase II

The total additional wind energy required for states included in RGOS Phase II is 65,000 to 67,000 GWh in 2027. This includes the states of Missouri, Illinois, Indiana, Michigan and Ohio. Illinois, a state included in RGOS Phase I, was also included in the Phase II effort due to the increase in its RPS requirement since the beginning of RGOS Phase I. Table 9.1-2 provides the additional total renewable energy requirements for both RGOS phases combined. Assuming the nearly 13,000 GWh of existing and planned renewable energy become reality, more than 90,000 GWh of additional renewable energy would need to be generated by 2027 to meet current mandates. This value is different from the sum of the additional requirements under each phase due to Illinois being included in both.

Table 9.1-2: RGOS II Renewable Energy Requirements

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Energy Reported	GWh		554,783	563,783	570,143	605,694	610,912	616,550	62,3200	629,671	636,600
Total Retail Energy	GWh		50,248	57,760	59,806	67,543	69,544	71,617	77,200	84,413	87,582
Energy Required to Meet Mandates	GWh		46,250	47,667	51,740	58,487	61,334	64,142	68,038	74,199	76,272
Existing & Planned Renewable Energy	GWh		12,806	12,806	12,806	12,806	12,806	12,806	12,806	12,806	12,806
Additional Renewable Energy Required	GWh		33,443	34,860	38,934	45,860	48,528	51,335	55,231	61,393	63,465
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Energy Reported	GWh	643,901	651,409	658,613	665,892	673,429	68,1031	688,778	696,385	703,499	711,289
Total Retail Energy	GWh	90,862	94,226	100,558	104,033	107,607	111,256	114,987	120,659	122,583	124,636
Energy Required to Meet Mandates	GWh	79,368	81,575	86,719	89,298	91,635	94,012	96,435	100,771	102,038	103,444
Existing & Planned Renewable Energy	GWh	12,806	12,806	12,806	12,806	12,806	12,806	12,806	12,806	12,806	12,806
Additional Renewable Energy Required	GWh	66,561	68,769	73,912	76,491	78,828	81,206	83,628	87,965	89,232	90,637

Depending on the capacity factor, or output level, of the wind developed, 19-29 GW of capacity is needed to meet RPS goals or mandates under RGOS II. This brings the expected combined total requirement for the Midwest ISO footprint to 30-45 GW under the current mandates and goals. This includes capacity associated with Transmission Owners (TOs) within the Midwest ISO footprint but that are not Midwest ISO members.

Wind Site Data

NREL Wind Data Overview

The National Renewable Energy Laboratory (NREL), Department of Energy (DOE), provided the Midwest ISO with wind site data stemming from the Eastern Wind Integration and Transmission Study (EWITS). EWITS is a DOE study of 20% and 30% wind energy penetration in the bulk of the Eastern Interconnection and the accompanying transmission. The data was developed using mesoscale (three dimensional numerical weather model) information.

The NREL wind site data set consisted of two primary pieces, the first being eleven-year average capacity factor for developable locations (sites) across most of the Eastern Interconnection totaling over 3,000,000 MW of wind sites. The second was the mesoscale data for the years 2004, 2005, and 2006 for 600,000 MW of wind sites. The 600,000 is a NREL selected subset of the 3,000,000. The thematic map in Figure 9.1-1 is a representation of the eleven-year average capacity factor distribution across the Eastern Interconnection based on this wind site data.

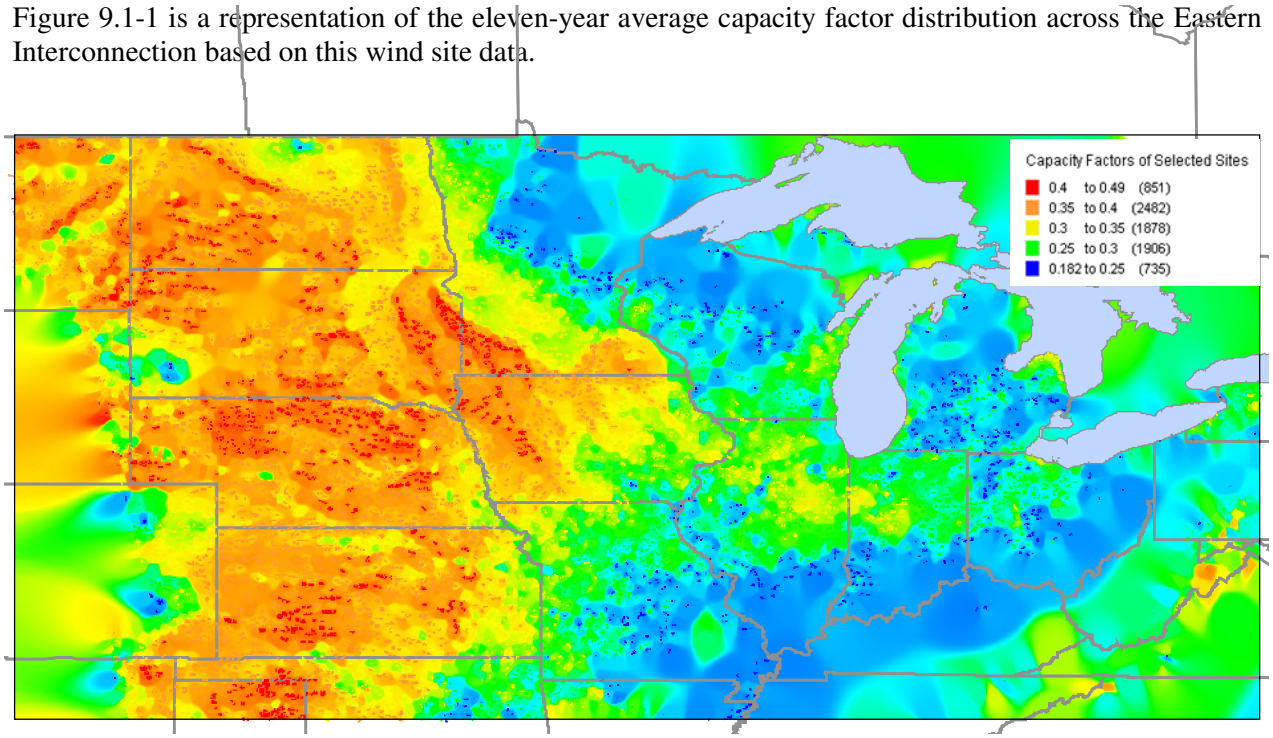

Figure 9.1-1: Thematic Map of the Eastern Interconnection: Eleven-Year Average Capacity Factor

The wind site data set accounts for exclusion areas. Exclusion areas are defined as areas where wind farms cannot be developed. Criteria for the exclusion areas include such items as open water, wetlands, parks, federal lands, airports, and others. The wind sites for which data was developed were outside of the exclusion areas.

The Midwest ISO selected 738 total sites to use in its analysis. Of the 738, 159 did not have mesoscale data. The Midwest ISO requested NREL to develop the necessary mesoscale data In order to ensure complete coverage of the footprint.

In summary, the mesoscale data consists of:

- Data developed for the years 2004, 2005, 2006, provided in 10 minute intervals
- Wind speeds at 80 and 100 meters
- Power output for three turbine classes (IEC Class 1, 2, 3): Class 1 is used in high wind areas, Class 3 in low wind areas
    - Class 1 and 2 at 80 meters
    - Class 3 at 100 meters
    - Losses modeled for each turbine class
- Geographic location

Candidate Zones Development

The renewable energy zones were developed on a state-by-state basis taking advantage of the highest eleven-year average capacity factor sites in each state. Sites were lumped together to achieve an energy zone that had an approximate capacity of 2,400 MW, while maximizing the overall capacity factor of the energy zone. Many energy zones were developed for each state in this manner.

Several statistics were calculated, site-by-site, to analyze the wind data to determine the appropriate measures for ranking the zones. A sampling of the statistics include: three-year average capacity factor, correlation of wind to load profile, distance to load centers, correlation of wind sites to each other, variability of wind, capacity factor during peak hours, afternoon on-peak, summer on-peak and summer afternoon on-peak, standard deviation and variance of output for each site, average ramp-up/down on an hourly basis.

Based on the measures, weighted values were created and used to rank the sites. The four weighted measures are as follows:

- **Weighted Capacity Factor (CF)**
  - 11-Year average CF 50%
  - 3-Year average CF 10%
  - On-Peak CF 10%
  - Afternoon On-Peak CF 10%
  - Summer On-Peak CF 10%
  - Summer Afternoon On-Peak CF 10%
- **On-peak hours are 6am-10pm**
  - Afternoon on-peak hours are 3pm-6pm
  - Summer months are June, July and August
- **Weighted Variability**
  - Variance of hourly wind output 25%
  - Standard Deviation 25%
  - Average hourly ramp-up 25%
  - Average hourly ramp-down 25%
- **Distance to load Center**
- **Distance to Infrastructure**
  - Distance to existing transmission (>300 kV) 33%
  - Distance to Railroads 33%
  - Distance to major highways 33%

Renewable Energy Zone Scenario Development

RGOS I

Using the previously mentioned process, wind zones were created in the states of Illinois, Iowa, Minnesota, North Dakota, South Dakota and Wisconsin. Even though North and South Dakota do not have RPSs per the RGOS scope, they do have extensive wind resources and thus were used to provide possible renewable energy to the study.

In order to establish local versus regional energy sources, per the study scope, seven energy zone scenarios were created. To create the energy zone scenarios, the zones in all states were used. A ranking was applied to the four measures from the last section to create a score from 0-100 for each energy zone. For the Phase I study, several rankings were created to capture regional versus local zone scenarios. This was accomplished by altering the values given to the weighted capacity factor and distance to load centers. By giving more weight to capacity factor, than distance to load centers, more 'regional' zones were selected. By giving more weight to the distance to load centers, more 'local' zones were selected near the load centers.

The seven zone scenarios, labeled T through Z were created in this fashion. An additional scenario, S, was also created by stakeholders as a blend of the seven scenarios for a total of eight.

RGOS II

Using the previously mentioned process, wind zones were created in the states of Missouri, Illinois, Indiana, Michigan, and Ohio. Even though Indiana does not have an RPS there is expected to be some development of the wind resources in that state.

RGOS II looked to model three energy zone scenarios: Local, Regional, and Combination in order to evaluate the differences between heavy transmission versus heavy generation investment. Below are the definitions of the three energy scenarios.

- **Local:** In the Local scenario, the renewable energy requirements and goals will be met with resources located within the same state as the load.
- **Regional:** In the Regional scenario, renewable energy requirements and goals will be met with resources located in the highest ranking renewable energy zones regardless of the zones location relative to the RGOS II load. This scenario will utilize the high capacity factor zones recommended by UMTDI from RGOS I.
- **Combination:** In the Combination scenario, renewable energy requirements and goals will be met with a combination of resources located within the RGOS II states and those outside of the RGOS II states with the highest ranking. Emphasis will be given to state requirements to locate part, or all, of their resources used to meet renewable energy requirements and goals within those states. Also, distance to load centers will be given more emphasis when determining zones than in the Regional scenario.

Following the indicative transmission design work, the Midwest ISO created two additional scenarios.

- **Regional Optimized:** The Regional scenario results in capacity in excess of what is needed to at least cover the renewable requirements/goals. In the optimized case the capacity in some zones is reduced such that there are just enough resources to cover the requirements/goals.
- **Combination 75/25:** In this scenario 75% of the RGOS II requirements are met with resources in the UMTDI zones and 25% of the RGOS II requirements are met within the RGOS II states

For these two additional scenarios the indicative transmission designs were left unchanged.

Figure 9.1-3 shows the renewable energy zones for RGOS I and RGOS II. The zones for RGOS I are shown in yellow and represent scenario B of the UMTDI set of zones. The UMTDI also selected another set of zones called A, which are not shown (see section 9.1.4 and 9.3.1 for further information on UMTDI and zones A and B). The RGOS II zones, in blue, represent the Combination set of zones.

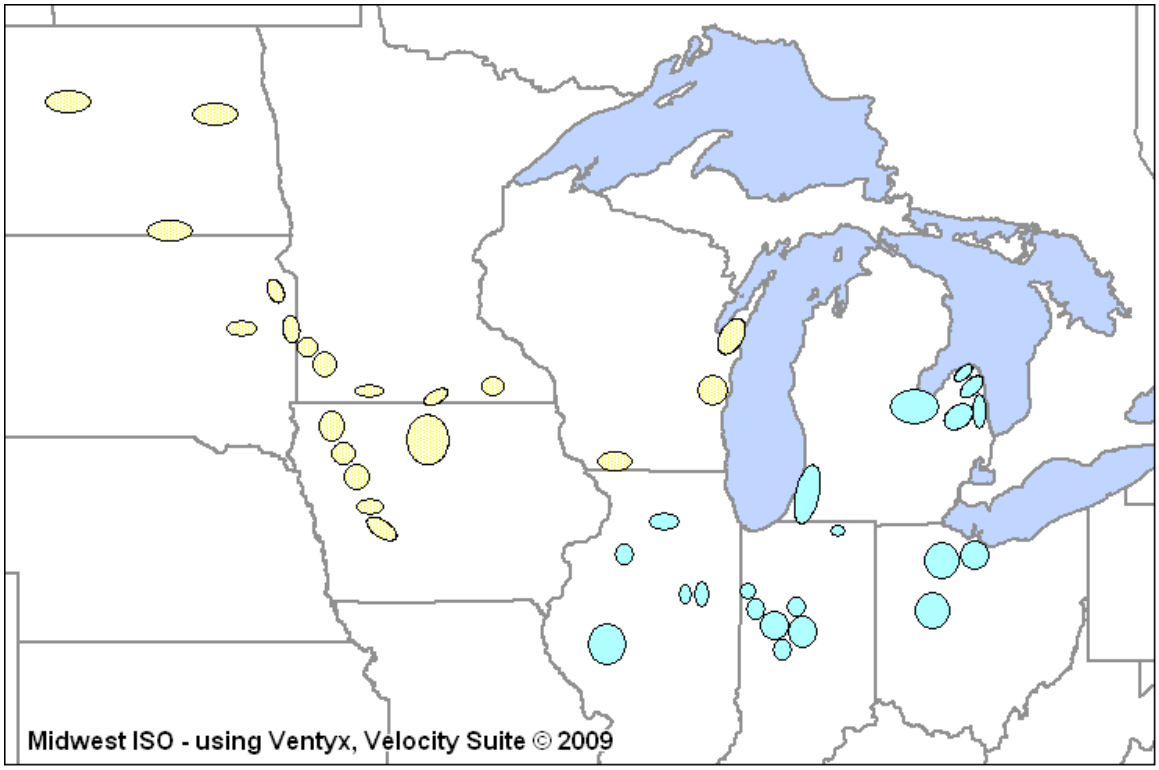

Figure 9.1-3 RGOS I and II Renewable Energy Zones

9.1.4. Indicative Transmission Designs

Once the prospective renewable energy zone scenarios are established for study, the next step is to design an indicative transmission system for those resources to connect to the grid and deliver energy to load. There are many different transmission designs that could be utilized to achieve this goal, all of which will have different costs and benefits associated with them. The purpose of the Indicative Transmission Design phase of the study is to analyze these different alternatives and quantify their costs/benefits for selection of a reduced set of energy zone scenarios for detailed transmission design work. The indicative transmission design was performed to provide policy makers with information to select one or two energy zone scenarios for detailed transmission design work.

Workshops

Indicative transmission designs were created in an open stakeholder process through the use of design workshops. In these workshops, stakeholders and Midwest ISO staff developed the different transmission alternatives for economic analysis. These workshops were open to all stakeholders, and experienced transmission planners from the states under study were requested to participate.

Assumptions

An assumption set was established by the stakeholders for developing the indicative transmission portfolios and for economic parameters to apply costs to them. The indicative transmission portfolios were developed without the benefit of transmission simulations (i.e. power flow), thus a methodology had to be employed to provide for a consistent set of transmission portfolios to compare one energy zone scenario's transmission portfolio against another.

The primary assumption for indicative transmission development was that the system would be considered self-healing, basically designing on a blank slate which would not depend on the underlying system in the indicative design phase. This was needed since we do not know the effects of any added transmission on the underlying system. Actual analysis of power flow, will be used in the detailed transmission design phases of work and underlying system impacts will be vetted there. Also, it was established that 750 MW of capacity would be exploited from each zone. Other assumptions used included the approximate range of capacity for 345 kV, and 765 kV transmission using Surge Impedance Loading (SIL) as a limiter.

Economic parameters were also developed for calculating the cost of the transmission and net present value work. Table 9.1-3 shows the capital costs applied to the transmission:

Table 9.1-3: RGOS Per Mile Transmission Line Installed Costs

Transmission (M$/Mi)								
kV	MN	IA	WI	IL	MO/Dak	IN	MI	OH/PA
345	2	1.5	2.5	2	1	1.8	1.8	2
2-345	2.5	2.1	3	2.6	1.5	2.3	2.3	2.5
500	3.5							
765	4.8	4.2	4.8	4.2	4.2	4.4	3.6	4

Wind generation at $2M/MW was used for the wind turbine capital costs. Along with these values, a 25% cost contingency was applied to the transmission to account for potential substation costs. Also, $7M per major river crossing was included to account for right of way impacts.

Other economic values, for net present value (NPV) work include: discount rate 8%, inflation rate 2%, before tax cost of capital 10.35%, and escalation rate 2.5%. These values are consistent for both transmission and generation. A fixed charge rate of 20% and 14% was applied to provide a range of potential costs. For the 20% fixed charge rate analysis, a 25% cost contingency was applied to the transmission for potential additional right of way needs of the transmission.

Indicative Transmission Portfolio Designs

RGOS I

For the indicative transmission designs, please see the posted materials on the Midwest ISO website at: http://www.midwestmarket.org/ Planning>Regional Generation Outlet

The economic analysis is shown in Table 9.1-4.

Table 9.1-4: RGOS I Indicative Scenario Economic Results

Strategy	Line Miles					Production Cost $/MWH	Cost Range *Total $/MWH		Cost Range ** Capital ($, MM)	
	345 kV	765 kV	DC	+ Gen MWs	# Zones		DST	Ref	DST	Ref
S-345	5170	0	0	13712	20	(38)	221	119	44,405	38,308
++S.1-345	5170	0	0	13541	19	(38)	225	121	45,063	38,966
T-765	2572	3162	0	12153	17	(25)	288	151	53,610	42,977
T-345	7095	0	0	12153	17	(27)	248	132	47,115	38,923
T.1-765	3092	2965	0	12245	18	(34)	283	144	54,325	43,492
T.1-345	6907	0	0	12245	18	(28)	244	130	46,611	38,677
W-765	2589	2321	0	12796	18	(47)	237	118	48,734	40,357
W-345	5383	0	0	12796	18	(42)	205	106	42,349	36,401
X-765	2601	2394	0	13131	18	(46)	243	122	49,496	41,133
X-345	5331	0	0	13131	18	(42)	207	109	42,682	36,896
Y-345	4263	0	0	14322	20	(36)	209	117	41,848	37,286
Z-765	3798	666	61	15387	22	(47)	236	128	48,539	42,958
Z-345	4305	0	61	15387	22	(47)	223	123	46,249	41,538

Transmission + Generation + Production cost (all 2018 $s)
** 2009 Investment Capital (if you paid cash today): Transmission + Generation + MWs calculated from exact energy needed and capacity factor
++ Used 500 MW for Lake Michigan

The indicative designs and associated economics work was presented to the TRG and to the UMTDI. A selection of energy zone scenarios, based on this work, was determined and is known as Scenarios A and B. These two energy zone scenarios were used for further detailed engineering analysis to develop transmission portfolios.

RGOS II

For the indicative transmission designs, please see the posted materials on the Midwest ISO website at: http://www.midwestmarket.org/ Planning> Regional Generation Outlet

The Economic analysis for RGOS II is currently ongoing.

9.2 Stakeholder alternatives

A number of specific transmission proposals, designed with the purpose of integrating wind energy into the transmission grid, have been proposed by individual or small groups of stakeholders. Consistent

with the overall Midwest ISO planning approach, those transmission projects which seek to address the same underlying need, in this case integration of wind, will be considered as transmission alternatives - in whole or in part - to the bottom-up study analysis performed by the Midwest ISO in conjunction with the Midwest ISO Stakeholder Technical Review Group (TRG). Each of these projects or variations will be considered in the detailed reliability based design of the RGOS transmission described in Section 9.1.5.

9.2.1 Green Power Express (ITC)

The Green Power Express (GPE), proposed by International Transmission Company, ITC Holding (ITC), is one such proposal. That project, currently reflected in MTEP Appendix C as project 2773, is a series of 765 kV lines intended to move renewable energy from the upper Midwest to load centers to the east. According to ITC, the GPE is "a broad network of 765 kV transmission facilities that has been designed to efficiently move up to 12,000 MW of renewable energy in wind-rich areas to major Midwest load centers. Once built, the Green Power Express transmission project will traverse portions of North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois and Indiana, and will ultimately include approximately 3,000 miles of extra high-voltage (765 kV) transmission. Project cost is estimated at between $10 and $12 billion."

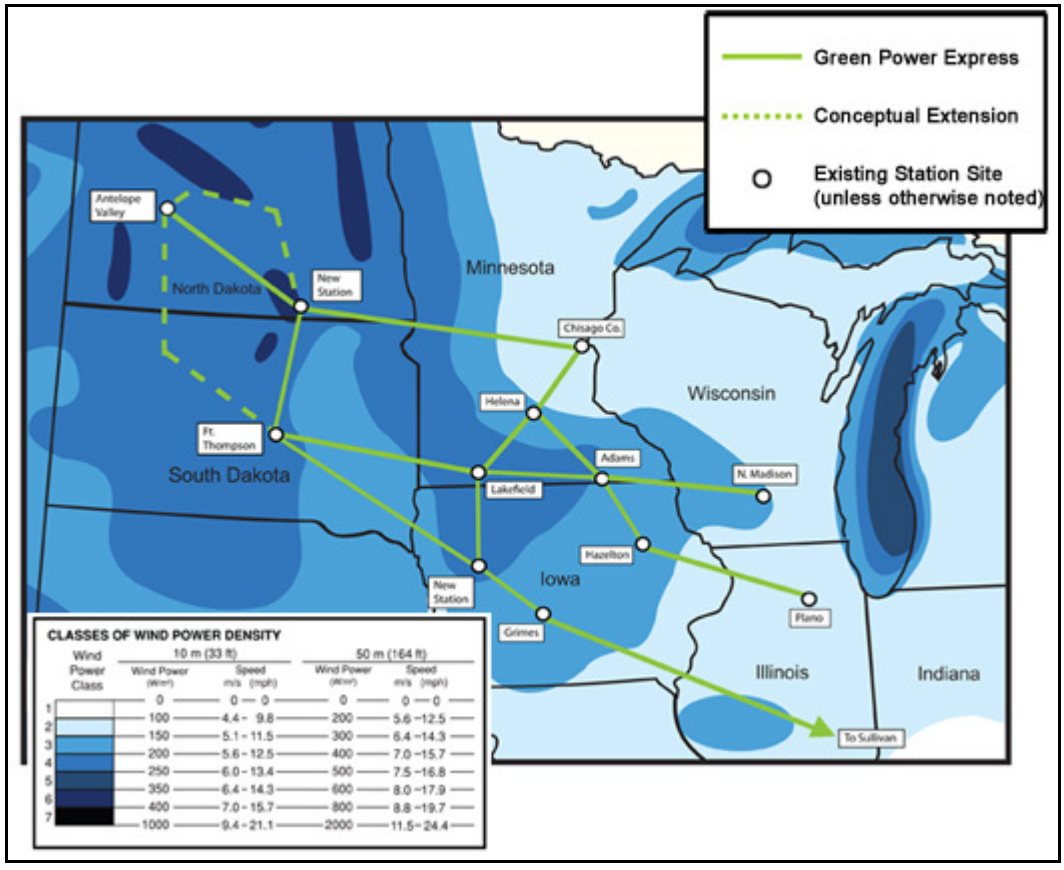

Figure 9.1-3: Green Power Express Proposal by ITC

The GPE, as proposed, contains a number of components which are similar to those identified in the initial Regional Generation Outlet Study I, 765 kV alternatives, an example of which is shown below. The 765 kV indicative lines are shown in light green in Figure 9.1-3.

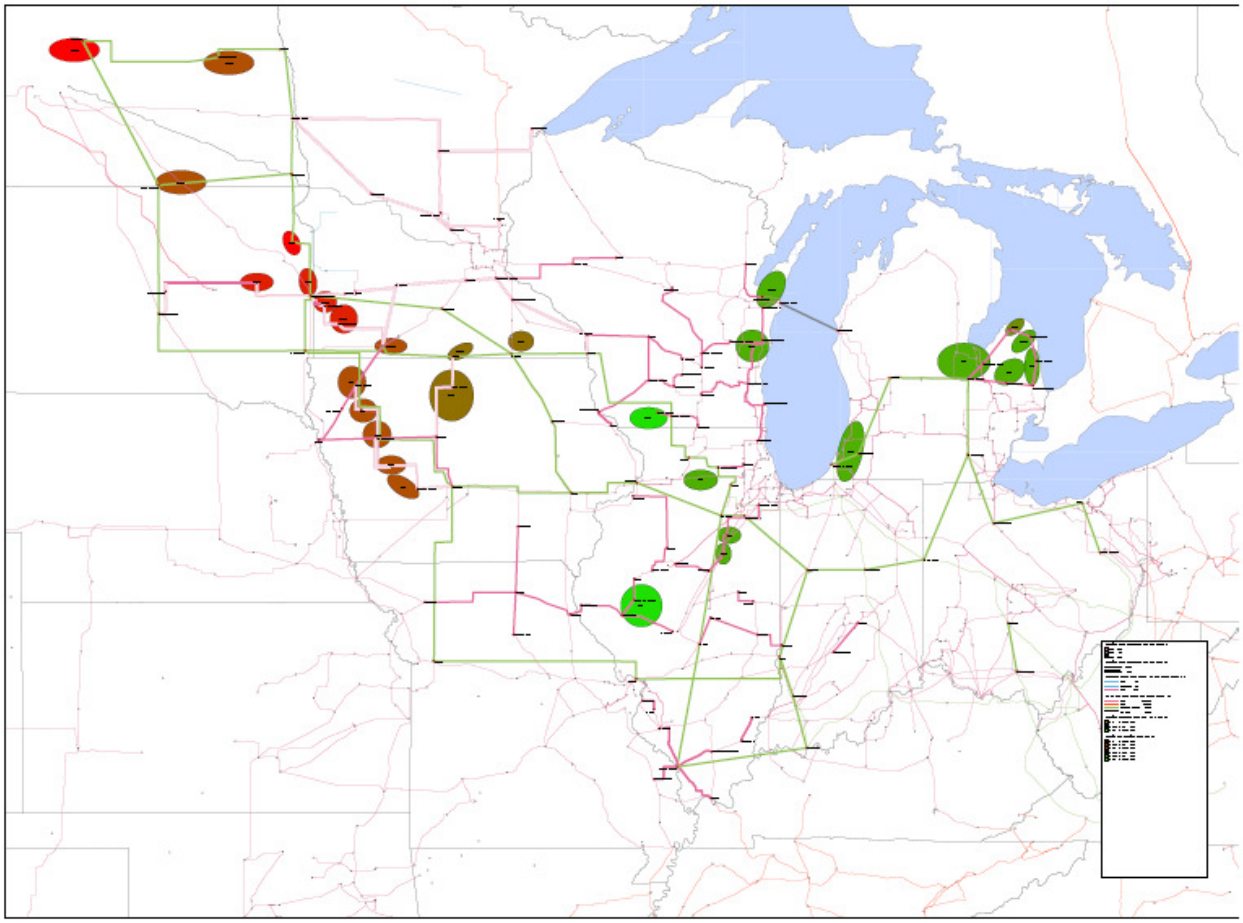

Figure 9.1-4: Indicative Design for RGOS II-765 kV Example

9.2.2 Central Illinois Area Proposals

Multiple stakeholders have proposed several 345 kV transmission expansions in the central Illinois area. These projects were identified in MTEP 08 as projects that have potential to provide for market efficiency under the economic planning criteria of the tariff (RECB II). They continue to be evaluated in that context in the Top Congested FG Targeted Study addressed in Section 8.3 of this report. The projects also may form a part of the transmission ultimately shown to be preferred for renewable generation outlet in the RGOS work, and are included in the indicative transmission designs under review in that context. These projects are currently reflected in MTEP Appendices B and C as project 1557, 2235, 2234, 2237, 2238, 2241, and 2783.

9.2.3 Republic LLC DC Line Proposals

Several DC line proposals have been proposed by Republic LLC to provide outlet capacity for upper Midwest area renewable energy. These proposals are also being integrated into the indicative transmission designs for RGOS. RGOS II Indicative designs, that include High Voltage Direct Current (HVDC) options, can be reviewed at the link provided above. These projects are currently reflected in MTEP Appendix C as projects 2785 and 2794.

9.2.4 Pioneer Project

The Pioneer Project, proposed as a joint venture between AEP and Duke, is another alternative that will be considered within the combined Regional Generation Outlet Study scope. The project involves connection between the Rockport and Greentown 765 kV stations in Indiana.

The project was initiated as a project with potential cross-border reliability and/or economic benefits, in addition to potential value in providing outlet for renewable energy within the Midwest ISO and PJM footprints. The study has been analyzed during 2009 through a joint Midwest ISO - PJM Inter-regional Planning Stakeholder Advisory Committee (IPSAC).

During 2009, analyses have focused on n-1 and n-2 reliability issues and the potential for the Pioneer Project to enhance the system's performance under those contingent conditions. Studies, thus far, have indicated that the systems meet reliability standards without the addition of the Pioneer Project, but that the project could provide some additional margins in that regard. These studies have focused on existing, or committed, generation on the system and have not yet analyzed its value in providing for reliable outlet for future expected generation. In addition, economic analyses have commenced to test the project for its value against the Midwest ISO and PJM economic planning criterion.

As the study has progressed, the Midwest ISO believes that the studies, thus far, reveal similarities with the goals sought to be achieved under the RGOS II effort. Thus, going forward, all or part of the project would be considered as transmission alternatives to the transmission being proposed in the Eastern portion of the Midwest ISO footprint through the Regional Generation Outlet Study II. One alternative path proposal for this project is the Rockport - Sullivan - Dequine - Greentown connection. This path is consistent with indicative plans, shown in Figure 9.1-3, as potentially strengthening the outlets at Sullivan which will likely be needed if additional renewable energy from points west of Indiana is supplied to Sullivan or nearby points. The IPSAC will be kept informed periodically of the effectiveness of this proposal in meeting the RGOS objectives.

This project is currently reflected in MTEP Appendix C as project 2795.

9.2.5 SMARTransmission Study

The Strategic Midwest Area Transmission Study (SMARTransmission Study) is a study of the transmission needed in the Upper Midwest to support renewable energy development and delivery while addressing the Midwest ISO and PJM seams. This study is expected to be completed in the first quarter of 2010.

SMARTransmission is sponsored by Electric Transmission America (ETA), a transmission joint venture of American Electric Power and MidAmerican Energy Holdings Company, American Transmission Company, Exelon Corporation, NorthWestern Energy, MidAmerican Energy Company, a subsidiary of MidAmerican Energy Holdings Company, and Xcel Energy.

9.3 Next Steps

9.3.1 RGOS I: Detailed Design Reliability Analysis

The direction provided to the study team for more detailed engineering analysis was to select two sets of renewable energy zones, A and B, for further analysis. Transmission design would be developed at both 345 kV and 765 kV and at injection levels of 15 GW and 25 GW of wind capacity. The 15 GW of injection is to provide for the UMTDI states only, thus additional zones (9) were selected for Illinois to serve their RPSs. The 25 GW work assumes 10GW of export from the UMTDI states to the rest of MISO. The Illinois zones were reduced to four assuming import from the UMTDI states.

The RGOS Phase I study is in the process of performing the detailed engineering design work. This work is primarily based on power flow/reliability analysis and the use of production cost analysis. MTEP09, 2019 peak and 2019 shoulder-peak (70%) models are being used for this analysis. Stability work is being performed on the MTEP09 stability data set (2014 shoulder peak case). A full report is expected to be published in October of 2009.

9.3.2 RGOS II: Renewable Energy Zone selection for detailed design

Following the completion of the indicative economic analysis, the Midwest ISO will work with its stakeholders, including State Regulators, to determine a subset of cases for detailed transmission design and analysis. These detailed designs will begin from the detailed design work performed in RGOS Phase I. Moving forward, the RGOS I and RGOS II work efforts are being integrated into one RGOS study.

Section 10: MTEP 09 Long Range Projects

10.1 Execution of Value-Based Approach

To accomplish long range economic transmission development, a planning horizon of at least 15 years is necessary to encompass the reality that large transmission projects nominally require ten years to complete. To be able to perform a credible economic assessment over this period, several analytical challenges have to be addressed; specifically, long-range sophisticated resource forecasting, powerflow and security constrained economic dispatch models are required to extend out at least 15 years. Since there isn't a single model that can perform all of the required functions needed for integrated transmission development, we take the best models and develop a process around the use of those models to integrate them together. The use of this integrated process enables the evaluation of the long-term transmission requirements to proceed.

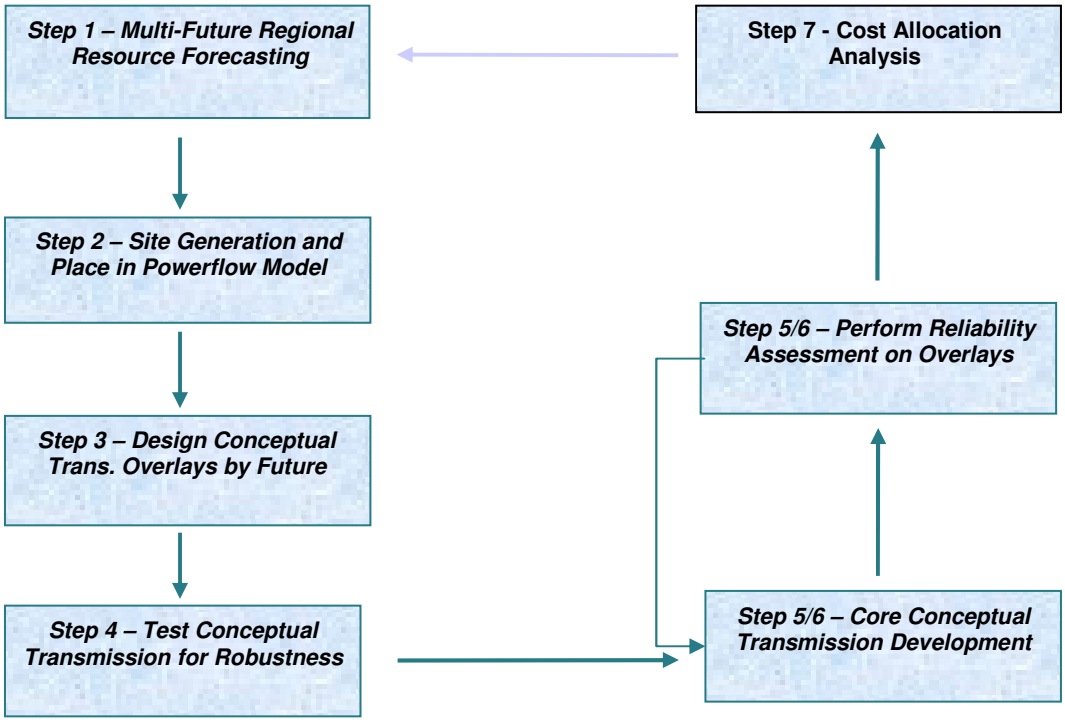

Figure 10.1-1: Best Models Integrated Process

Additional details on this process can be found in Section 6.2.

10.2 Generation Futures Development

This section summarizes steps one and two of the integrated transmission planning process where Regional Resource Forecasting (RRF) is performed using scenario based analysis to identify, and site, generation requirements over several potential future states. With the increasingly regional 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 we appear to be at the beginning of a major new investment cycle for generation and transmission driven by aging infrastructure and shifting energy policies. The analysis performed 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 performed.

It is important to note that the Future definitions and assumptions for the models for steps one and two were developed through stakeholder workshops and reporting to the Planning Advisory Committee from November 2007 to January 2008. The assumptions for the models and the results presented in this report were made during that time period and reflect the prices and policies at that time. The Midwest ISO recognizes that changes have occurred in many of these assumptions and they will continue to be updated through future MTEP 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 E of the MTEP 09 report.

10.2.1 Future Definitions

Scenario based analysis provides the opportunity to develop plans for different Futures yielding different "best plans." A Future is a prediction of what "could be" which guides the assumptions made about the variables within a model. The outcome of each Future modeled is a generation expansion plan referred to as a generation portfolio. The generation portfolios are the capacity expansion results from a "least cost" optimization of future generation requirements based on the specified resource adequacy criteria. It identifies the optimal "least cost" generation required to meet reliability criteria based on the assumptions for each Future scenario. MTEP 09 has looked at multiple Futures:

- Reference Future (coincident with Joint Coordinated System Plan work)
- 20% Federal Wind Energy Future (coincident with Joint Coordinated System Plan work)
- 30% Federal Wind Energy Future (coincident with Joint Coordinated System Plan work)
- Limited Investment Future
- Environmental Future
- Gas-only Expansion Future

The Reference Future is considered the status quo Future. This Future 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. Although Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply, it is assumed that all incremental needs to meet RPS requirements will come from wind resources.

The 20% Wind Energy Future requires that 20% of the energy consumption in the Eastern Interconnect come from wind by 2024. Wind Generation will begin to be forced in the models starting in 2010, accounting for the two year lead time assumed with the generator assumptions. A 33% capacity factor, for existing wind generators, and a regional capacity factor, ranging from 35%-45%, is applied toward future wind units. Wind requirements from the Reference Future are included in this future, without changes on size and location of units. Approximately one-third of the wind generation needed to meet the 20% national wind energy mandate was modeled within the Midwest ISO and Mid-Continent Area Power Pool (MAPP) regions.

The 30% Wind Energy Future requires that 30% of the energy consumption in the Eastern Interconnect come from wind by 2024. Wind Generation will begin to be forced in the models starting in 2010, accounting for the two year lead time assumed with the generator assumptions. A 33% capacity factor, for existing wind generators, and a regional capacity factor, ranging from 35%-45%, is applied toward future wind units. Wind requirements from the Reference Future are included in this future, without changes on size and location of units. This Future was not carried into the conceptual transmission development phase due to the difficulty in siting enough wind resources to meet the 30% energy requirement at the time of the analysis.

The Environmental Future assumes environmentally friendly legislation, including a carbon price of $25 per ton, and a 25% higher cost on mercury. It is expected that with such legislation, the demand and energy growth rates would decline due to upward price pressures along with an increase in the overall inflation rate from the impact of the increased cost of energy over all sectors of the economy.

The Limited Investment Future is limited by uncertainty, risk, cost control policies, siting limitations and limited transmission corridors. These limitations affect the ability to permit new transmission lines resulting in limited transmission corridors, to permit Greenfield sites, limiting siting of gas to load centers, and to permit coal/IGCC plants until clean technologies mature (5 years).

The Gas Expansion Future removes non-gas fired baseload capacity as an option to capacity expansion. It assumes siting of capacity will be load-center focused. It also assumes no conceptual transmission expansion based on economic criteria.

10.2.2 Generation Portfolio Development

A regional assessment was performed separately using Electric Generation Expansion Analysis System (EGEAS) on the Midwest ISO East, Central and West regions as indicated in Figure 10.2-1. Using assumed projected demand and energy by each company, and common assumptions for resource forecasting, models were developed to identify least cost generation portfolios needed to meet the resource adequacy requirements of the system for each future.

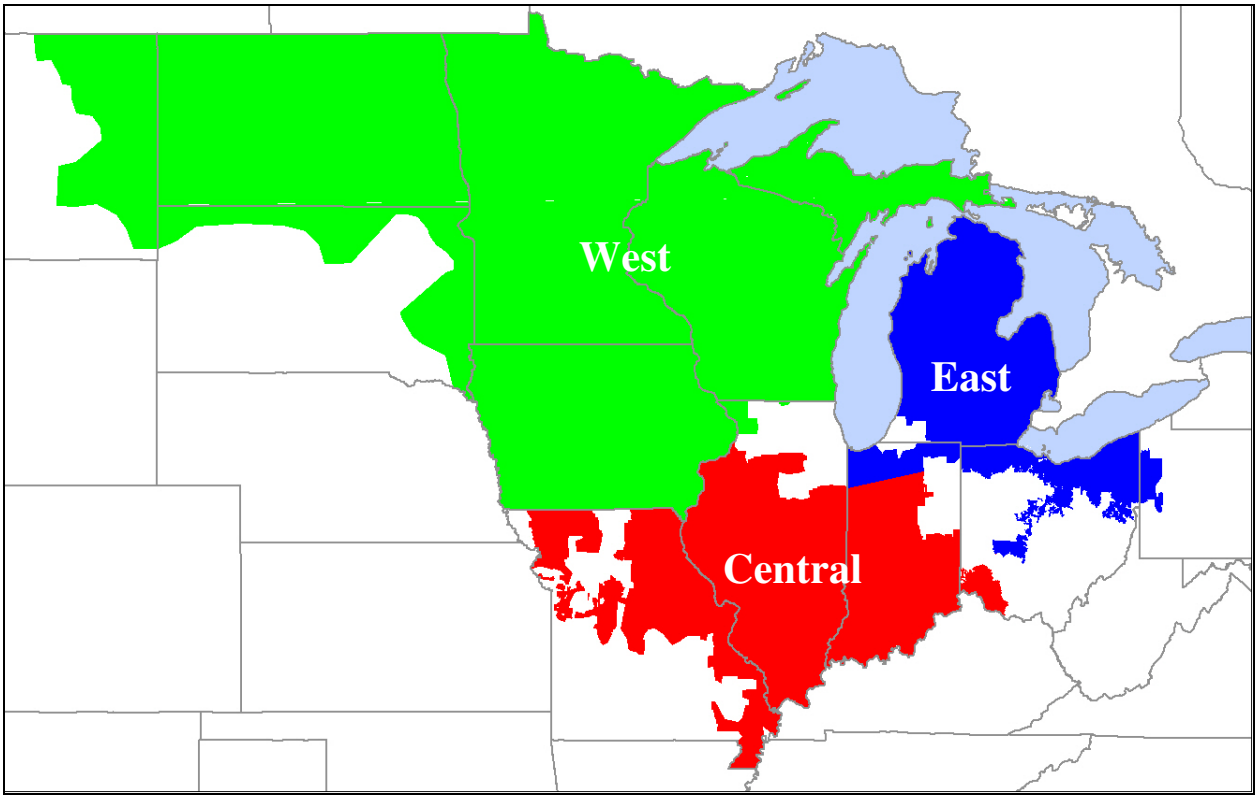

Figure 10.2-1: Midwest ISO Regions

Figure 10.2-2 represents the capacity expansions for each defined Future through the 2024 PROMOD® study year. The capacity added is required to maintain the stated reliability targets for each region. Stated targets for the Midwest ISO are defined through the Module E resource adequacy assessment, Section 5 of this report. Demand Response, listed as "DR" in the legend, is assumed at the same level under all scenarios.

The Reference Future represents a heavy base load steam capacity build-out. This is highly dependent on the definition of the Future that the economic and political conditions of the future will look much like the recent past. Adding a cost to carbon or increasing the fuel cost of coal would potentially shift base load expansion from coal to nuclear. Also, note that a significant reduction in the modeled natural gas fuel cost would potentially remove base load capacity and replace it with combined cycle and combustion turbine capacity.

As wind capacity requirements increase, it can be noticed that base load capacity decreases while the capacity contributions from wind and gas fired capacity increase. The model recognizes the off-peak energy contribution associated with wind and selects gas capacity more abundantly for resource adequacy needs due to its smaller capital investment and less need for off-peak production. Because wind capacity is only given a capacity credit of 15% of the nameplate installed capacity, additional capacity is needed to maintain resource adequacy criteria.

The Environmental Future results in less capacity being added for future reserve requirements. This is because of the assumption that this Future would represent a reduction in demand and energy growth compared to the other Futures. It is also interesting to note that the $25 per ton carbon cost creates a shift in base load capacity additions from coal to nuclear as soon as nuclear is available for addition.

It is important to note that at the beginning of the MTEP 09 economic analysis process, the Gas Only Future was not considered. It was expected that the Limited Investment Future would result in a heavier dependence on natural gas capacity to meet the future capacity needs of the system. However, it was recognized this Future resulted in expansions similar to the expansion in the Reference Future. There was not enough limitation put on the availability of coal capacity to make much of a difference. Because of this, the Midwest ISO staff added the Gas Only Future as an alternative to the economic analysis to offer more variety from the Reference Future case.

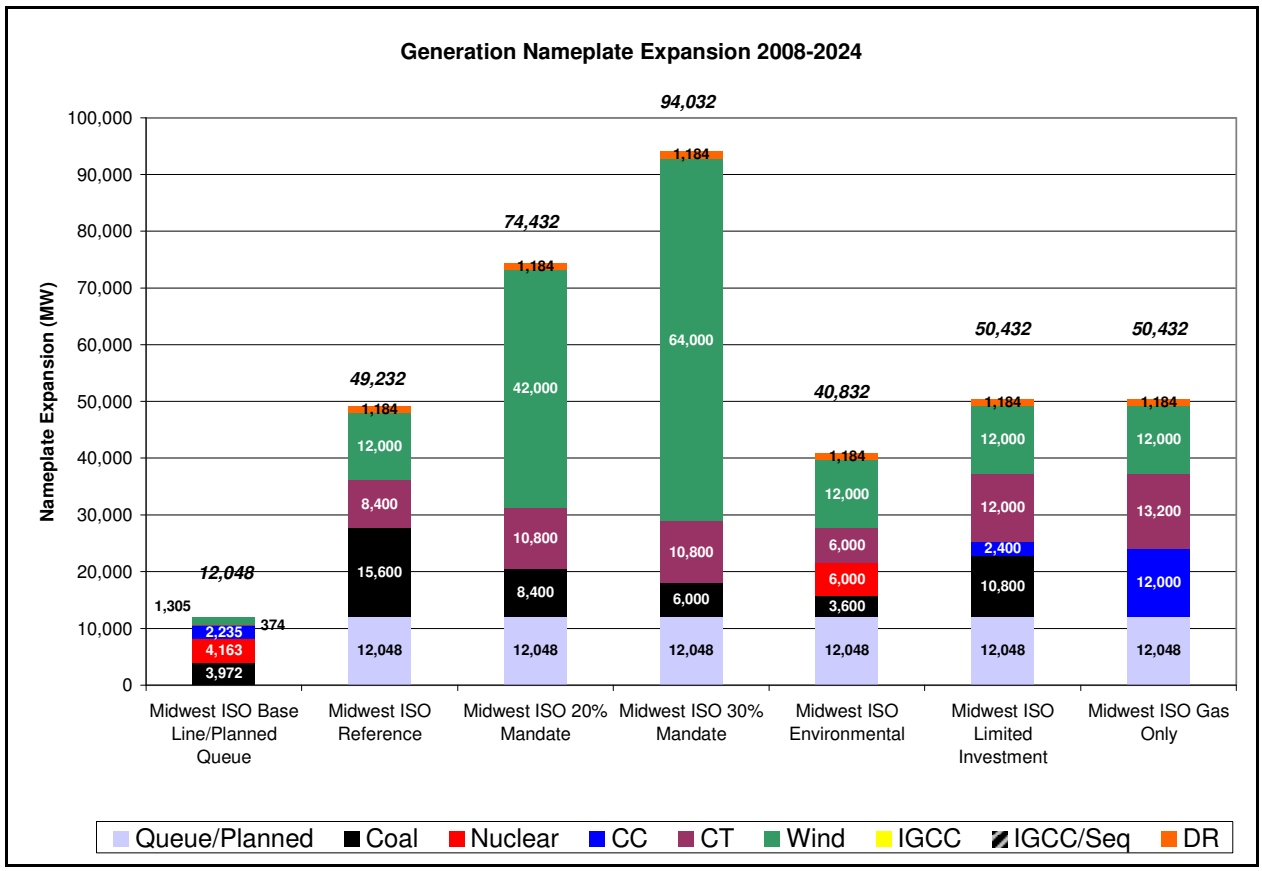

Figure 10.2-2: Midwest ISO Modeled Systems Aggregate Nameplate Installed MW for PROMOD® Study Year 2024

Figure 10.2-3 demonstrates the accumulative present value of costs for the study period through 2024. 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. The capital costs represent the annual revenue requirements associated with addition of new capacity. Although production costs reduce in the high wind penetration Futures, the increase of capital costs result in overall cost increases compared to the Reference Future. The Environmental Future sees a reduction in the capital costs compared to the Reference Future because of the reduced demand and energy growth. However, the addition of a cost to the production of carbon increases the production cost and overall system costs. Similarly, the Gas Only Future results in reduced capital costs because of the dependence on the lower capital intensive combined cycle and combustion turbine plants compared to base load coal capacity. But, because the cost of natural gas is higher than coal in these cases, the resulting higher dependence on the natural gas fleet results in higher production costs resulting in total system costs to be greater than the Reference Future.

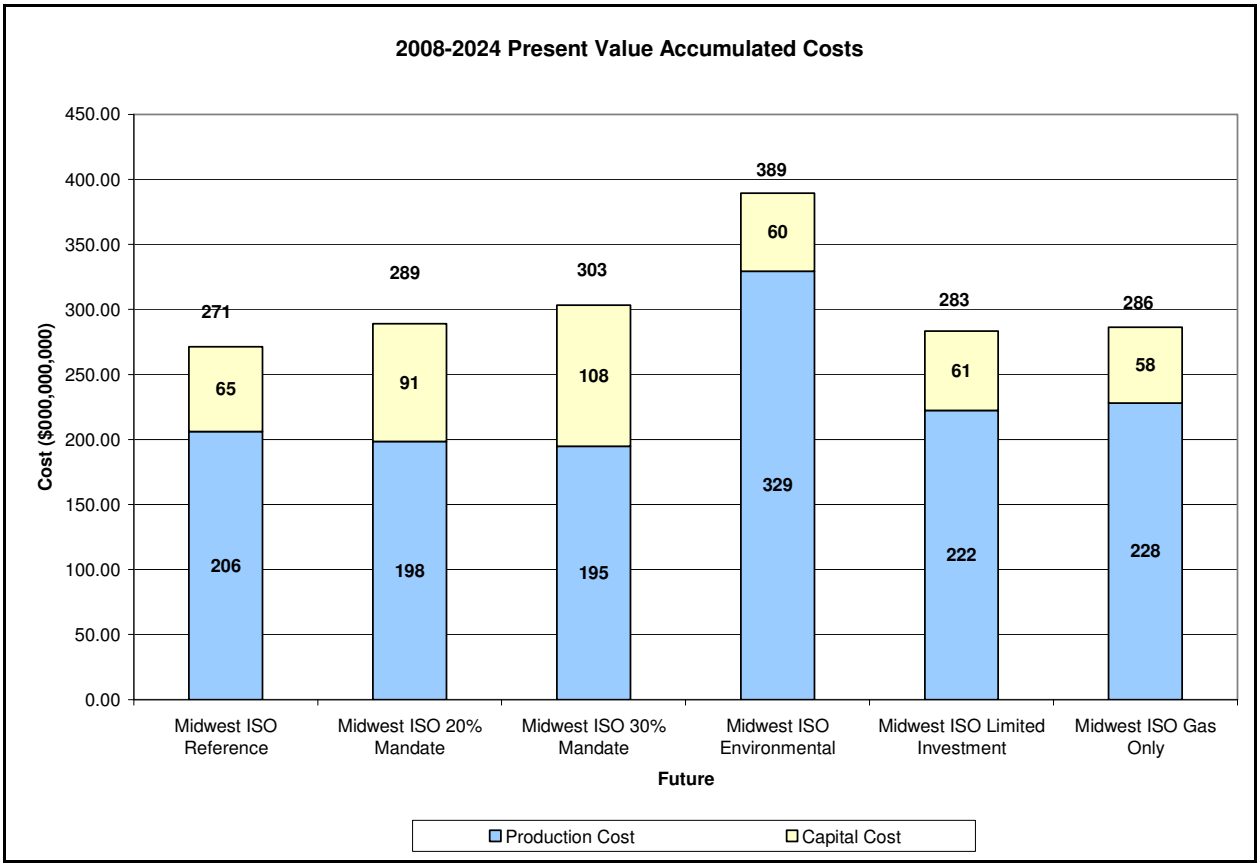

Figure 10.2-3: Midwest ISO Present Value of Accumulated Costs in 2008$

Each of the modeled Futures has its own impact of the output of carbon within the fleet. Figure 10.2-4 demonstrates this impact for each of the defined Futures. The chart compares the initial 2008 carbon production provided by the dispatch of the model, and the end year 2024 carbon production resulting from the capacity expansion associated with demand and energy growth, to maintain proper resource adequacy requirements.

It is interesting to notice that continued demand and energy growth at close to historic trends will result in the need for additional capacity. If this capacity is dominated by coal or natural gas, the system will continue to see an increase in the production of carbon on annual basis; however, the increased penetration of renewable resources, in this case wind, will result in a system reduction in carbon due to the greater dependence on the non-carbon producing resource. This represents the differences between the high wind penetration Future and the Reference Future.

The Environmental Future shows that simply adding a cost to carbon will reduce the annual carbon output of the system, but not to the levels seen in the higher wind penetration futures. The primary reason for reduction in the Environmental Future is the switch of future base load capacity from coal to nuclear. This provides more energy to be served from the carbon-neutral resources.

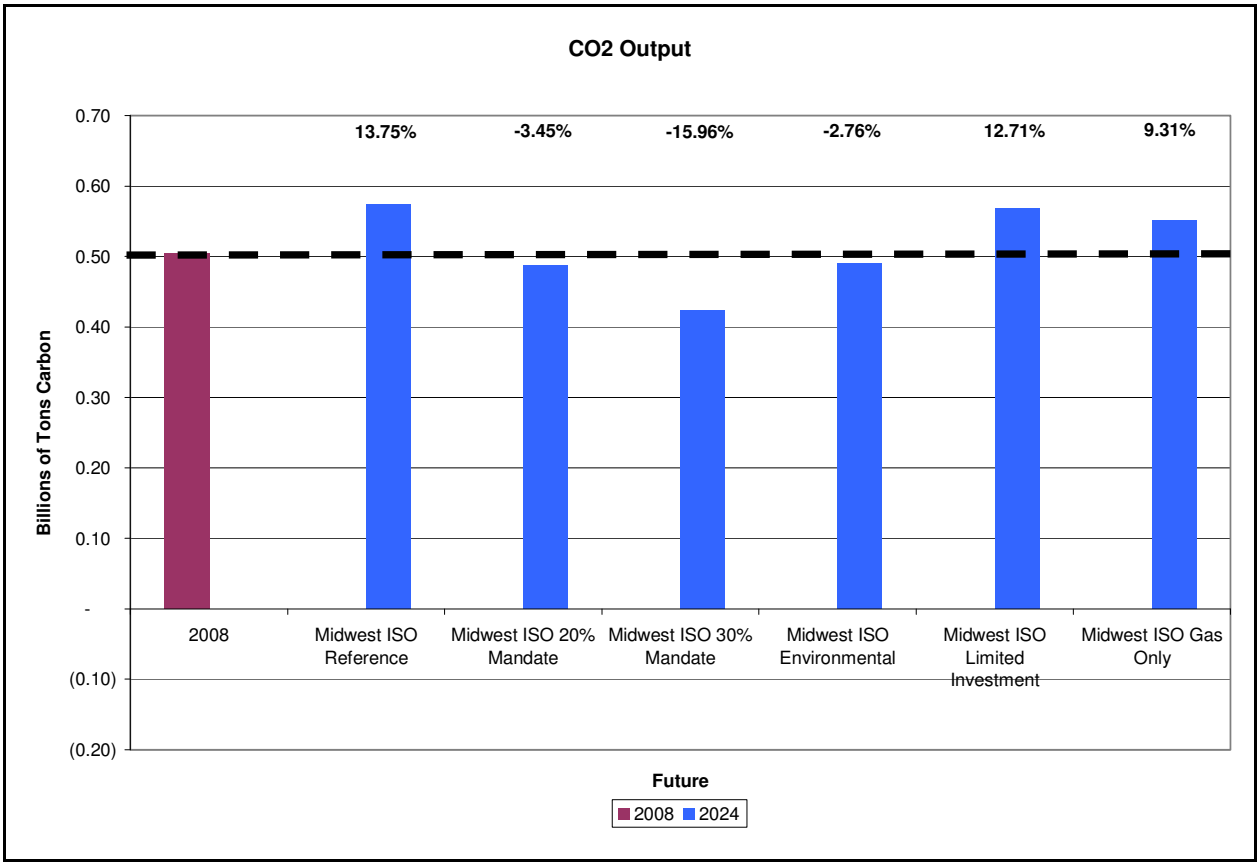

Figure 10.2-4: Midwest ISO Carbon Production

10.2.3 Sensitivity Analysis

The Midwest ISO performed two sensitivity analyses for the MTEP 09 cycle. The first sensitivity holds all assumptions common in the 20% Wind Energy Future except for cost of carbon. This cost varies by $10 increments from $0 to $100. The results can be found in Figure 10.2-5. Points of interest include the level of carbon cost, where base load coal is replaced with base load nuclear, and base load coal is replaced with natural gas fired capacity.

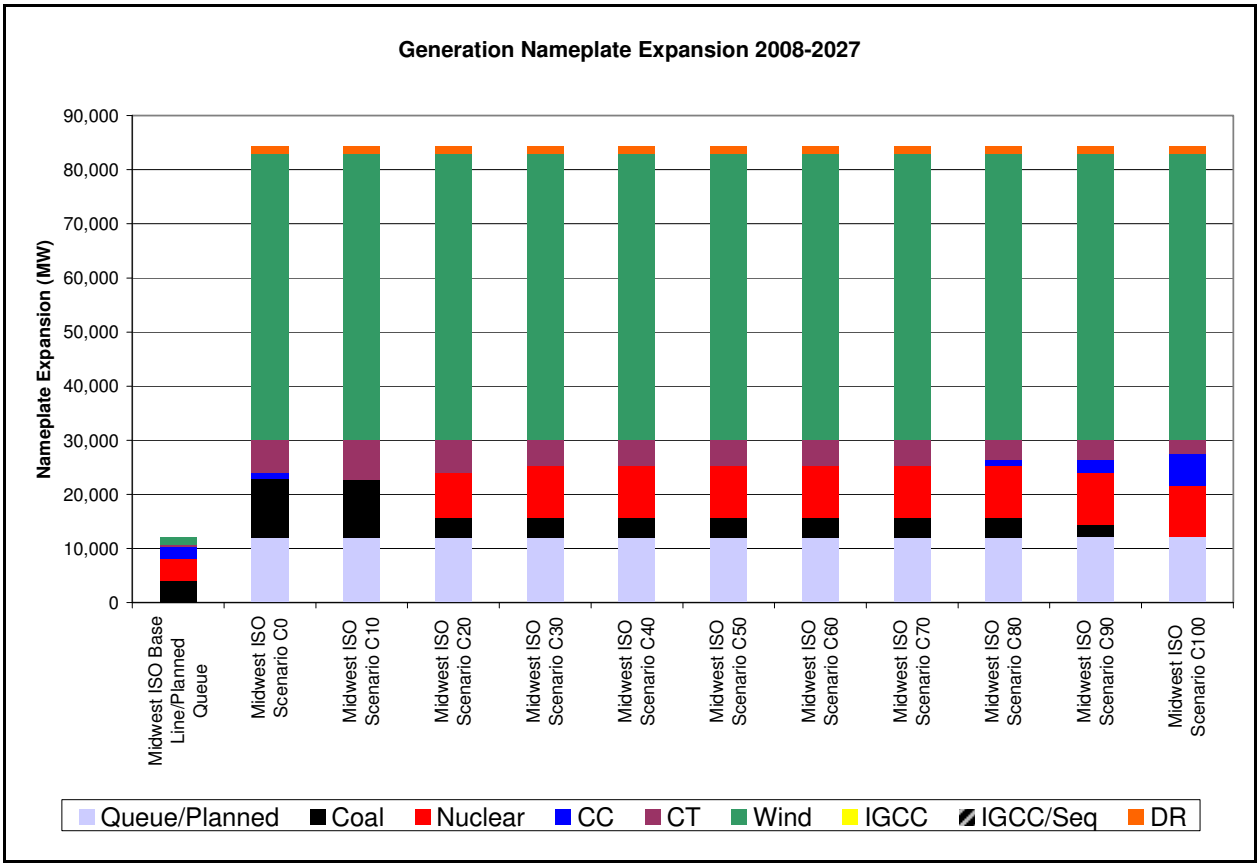

Figure 10.2-5: Capacity Expansion Comparison with Varying levels of Carbon Cost and Natural Gas Costs at $8/Mbtu

The application of a carbon cost not only impacts the resource mix needed for future capacity needs within the Midwest ISO. It also effects the production of carbon by the new and existing fleet. Without including retirements and assuming that the Midwest ISO would ramp up renewable resources to meet 20% of all energy needs, carbon can reduce to up to 20% on an annual basis from a 2008 base, see Figure 10.2-6. If retirements are included, a greater reduction of carbon production can be achieved. However, this does have an implication of increased capital investment on a new fleet that is closer to carbon neutral while potentially retiring capacity that may already be fully depreciated from the existing rates. This scenario is currently being analyzed through the OMS Cost Allocation and Regional Planning effort.

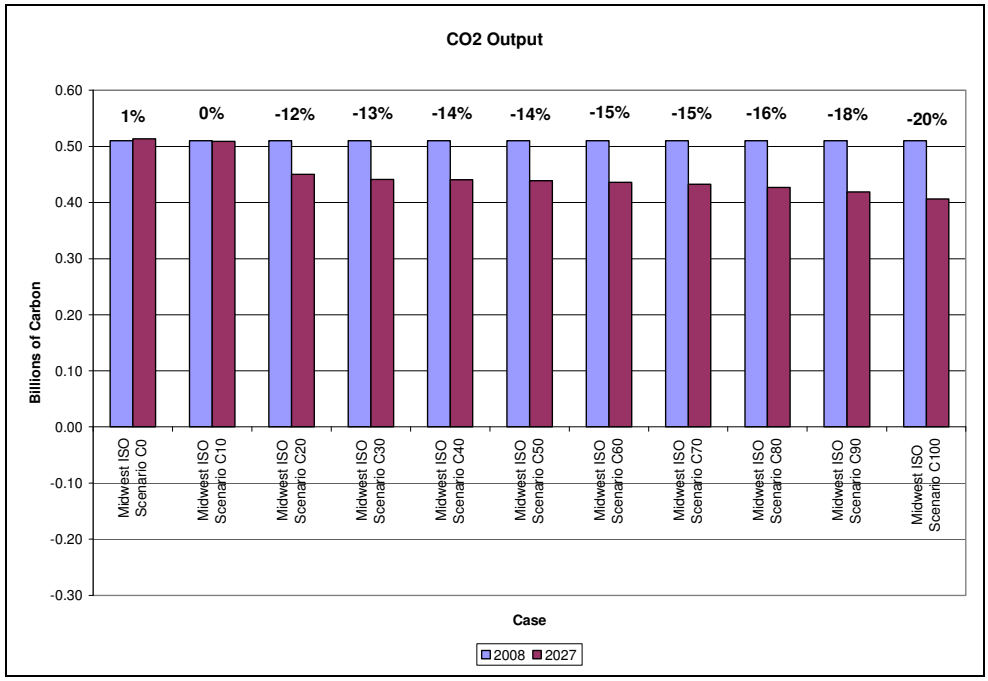

Figure 10.2-6: Carbon Impact by Carbon Cost with 20% wind energy (assumes no retirements)

The second sensitivity holds all assumptions common in the Reference Future except for the cost of natural gas. Also note that a cost of carbon is added to this case at $25/ton. The natural gas cost varies by $1 increments from $2 to $8. The results can be found in Figure 10.2-7. Points of interest include where future combined cycle capacity is no longer competitive with nuclear and where combustion turbine and combined cycle capacity is no longer competitive with coal.

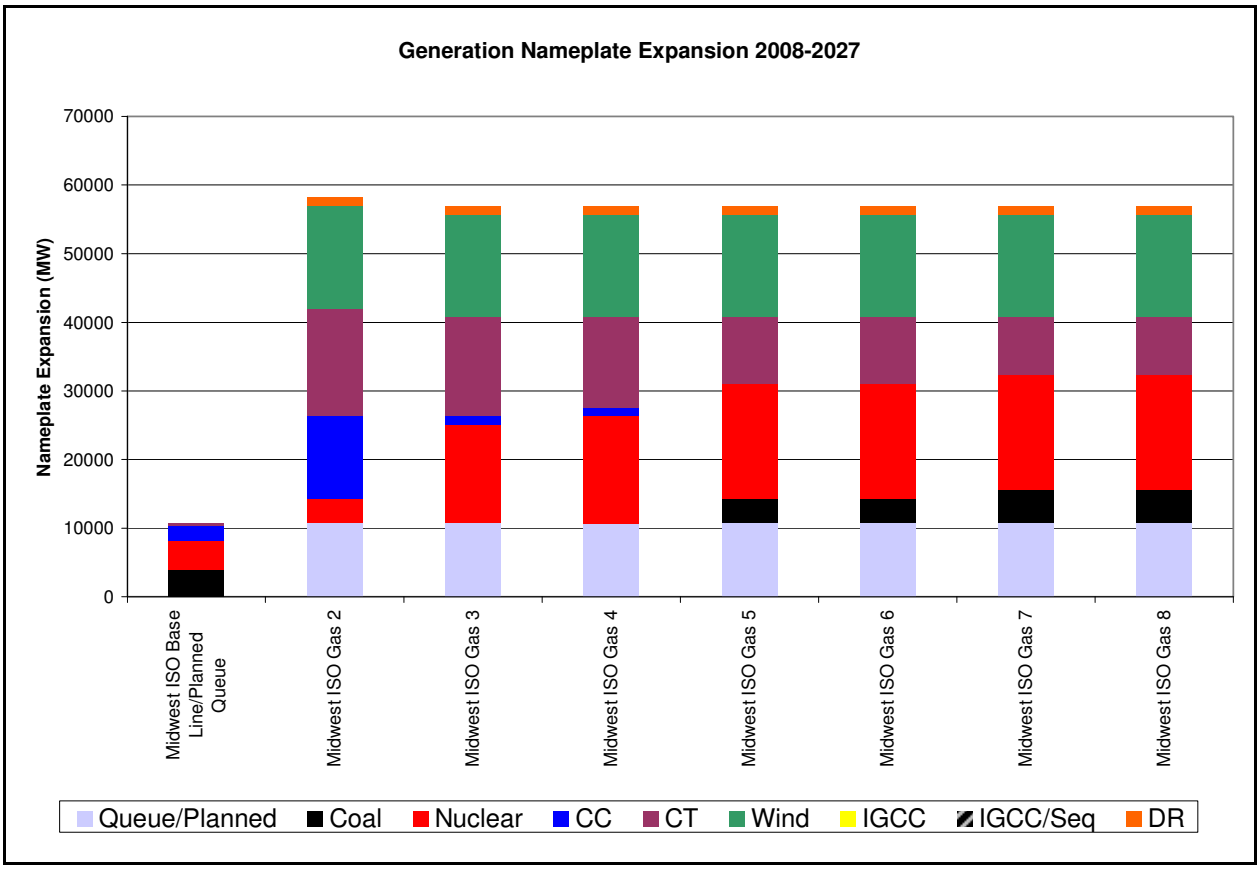

Figure 10.2-7: Capacity Expansion Comparison with Varying Levels of Natural Gas Costs at a Carbon Cost of $25/ton

10.2.4 Siting of the Capacity

The resources that are forecasted from the expansion model, for each of the scenarios, are specified by fuel type and timing; but these resources are not site specific at this point. A siting methodology, to tie each resource to a specific bus in the power flow models, is required to complete the process. A philosophy and rule based methodology, in conjunction with industry expertise, was used to site the forecasted generation. Figures 10.2-8 through 10.2-12 shows the capacity siting associated with the designated Futures. The siting methodology is explained in the Appendix E of this report.

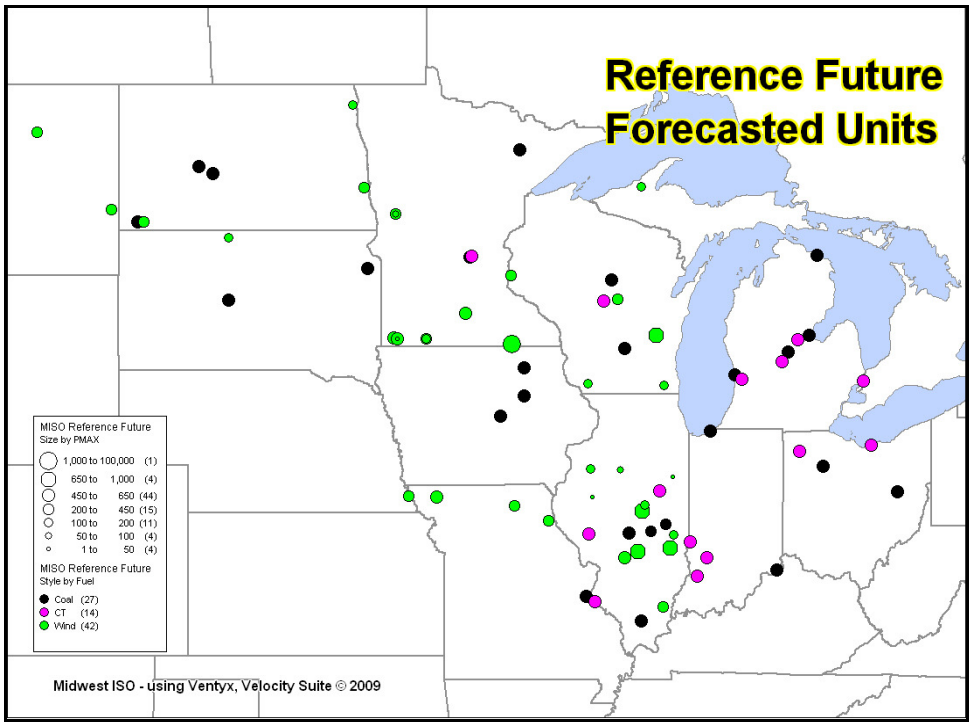

Figure 10.2-8: Midwest ISO Reference Future Capacity Sites

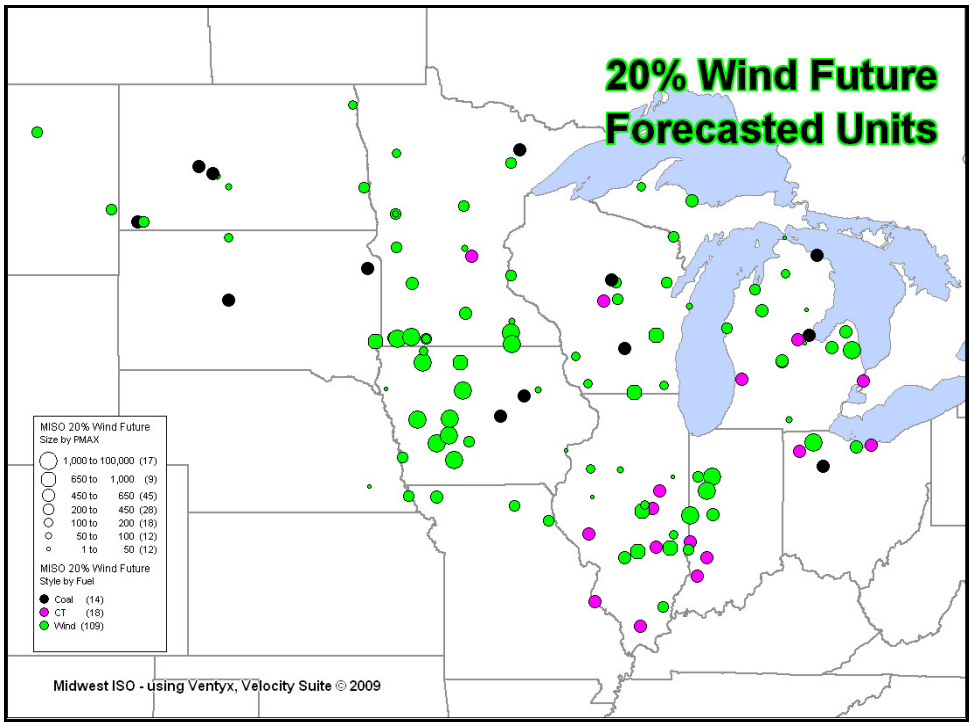

Figure 10.2-9: Midwest ISO 20% Wind Energy Future Capacity Sites

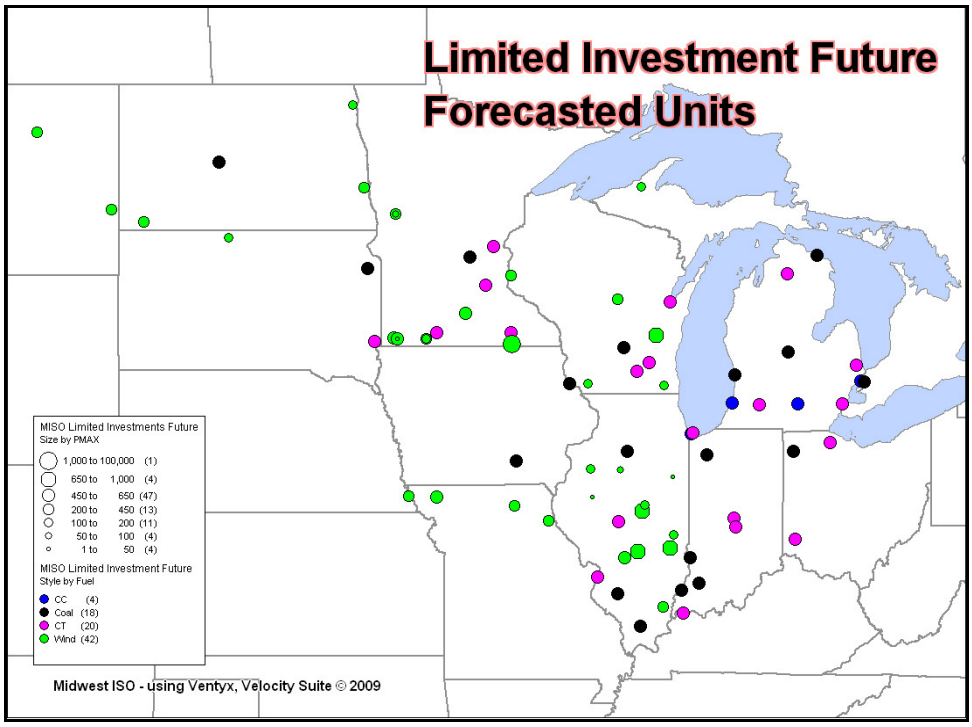

Figure 10.2-10: Midwest ISO Limited Investment Future Capacity Sites

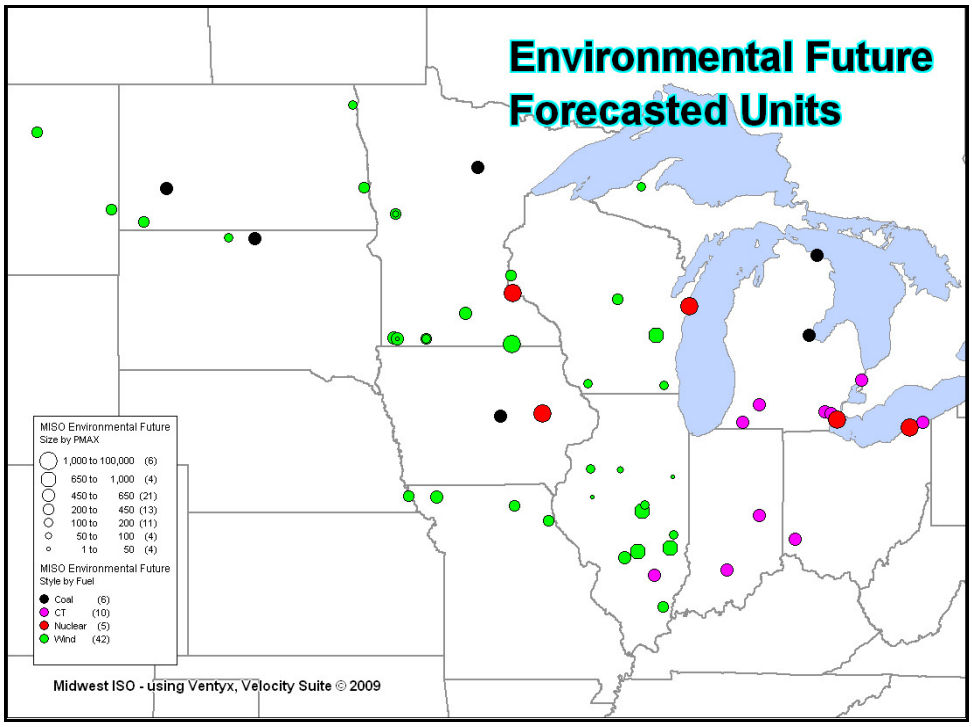

Figure 10.2-11: Midwest ISO Environmental Future Capacity Sites

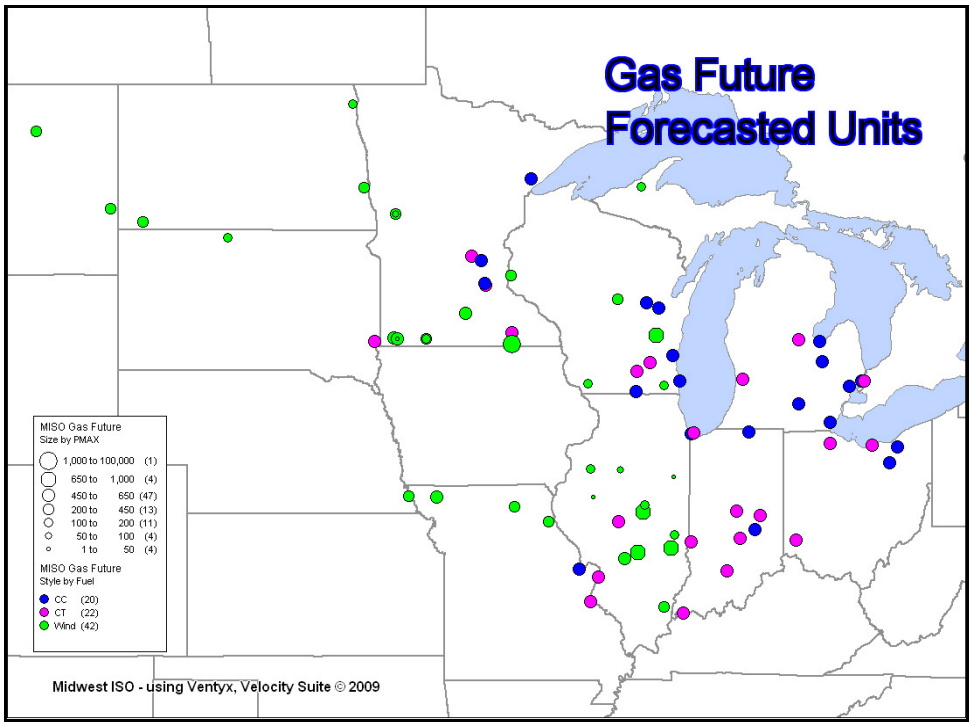

Figure 10.2-12: Midwest ISO Gas Only Future Capacity Sites

10.3 Conceptual Extra High Voltage (EHV) Overlay Transmission

Many of the studies discussed elsewhere in this report are reliability studies that determine a problem and seek the least capital cost alternative to resolve the problem. By contrast, the methodology discussed in Section 10 uses an economic transmission design process, developed by the Midwest ISO, that uses economic information from studies to identify potentially high benefit transmission solutions. The MTEP 09 value-based (economic) planning process, as described in Section 6, is intended to provide information to answer questions and provide insight into possible benefits against various scenarios of the electric system up to twenty years in the future. These future operating states are defined by the four generation portfolios Futures in MTEP 09. Section 10.2 provides more information on how the generation portfolio Futures were developed for MTEP 09.

Two of these Futures were used to develop conceptual economic transmission for MTEP 09:

- **The Reference Future -** mandated wind and the future generation expansion alternative list.
- **The Renewable Future –** national 20% wind energy and future generation expansion from the alternative list. Wind mandates are included in the 20% wind energy model.

This section describes Step 3 of the value-based planning process. Step 3 focuses on development of conceptual Extra High Voltage (EHV) transmission overlays required to deliver generation. This development is based on an evaluation first of energy economics. Evaluating where energy would flow in an unconstrained system provides the basis for the development of conceptual transmission. Next, economic studies are performed to understand how the EHV overlays perform against a specific set of economic metrics.

The conceptual economic transmission development was performed through multiple workshops performed in coordination with the Joint Coordinated System Plan (JCSP) process. This included input from Midwest ISO stakeholders as well as stakeholders of the participating signatories and non-signatories of the JCSP study.

More detailed discussion of the development process and results is located in Appendix E2 of this report.

10.3.1 Summary of Conceptual EHV Transmission Study Results

The general observations result from the MTEP 09 economic studies of conceptual EHV transmission overlays:

- A transmission expansion to the higher priced areas on the East Coast may be economically feasible within the structure of the present energy markets and provide incremental benefit to the Midwest ISO.
- 20% wind energy with remote wind requirements being located within the Midwest ISO and SPP footprints would require some transmission to be added for long distance integration

10.3.2 Conceptual EHV Transmission Overlay Development

The present transmission system was designed to deliver local generation to local load with some transmission for sharing of generation for reliability purposes and some energy sales and purchases. Most of the transmission system that exists today was designed and constructed long before open access and energy markets. Therefore, only the most recent additions to transmission may have been designed to enable the system to operate efficiently in a multiple Regional Transmission Organization (RTO) energy market environment. The development of the conceptual transmission overlays seeks to gain economically possible market efficiencies through the development of transmission, given a specific future outcome.

The following process is used to develop the conceptual transmission overlays in Step 3. First, we use the power flow and PROMOD® models developed in Steps 1 and 2 (Section 10.2) and run PROMOD® using the same assumptions used in the development of the generation portfolio assessment. For example, if we have two Futures from the portfolio assessment process we would develop two corresponding PROMOD® models with the uncertainty variables (e.g. emissions levels and rates, fuel prices and limitation, resource retirements, etc.) for that particular Future being incorporated. The remainder of the discussion in this section will focus on a single Future; however, the same process would need to be performed for each Future being addressed.

Next, a 'Copper Sheet' case assuming no transmission constraints is made to determine where the energy wants to flow. From this information a hypothetical high voltage overlay is simulated such that the identified energy flow requirements are met. From this initial effort the hourly flows and size of the transmission system begin to be refined. Further use of constraint identification tools linked to PROMOD® enable the continued refinement of the conceptual EHV transmission overlays The next sections describe the conceptual EHV transmission overlays developed for each generation portfolio future for Eastern Interconnection benefit area.

10.3.3 Conceptual Transmission Design

Each generation Future has a conceptual EHV transmission overlay that is designed for the specific generation expansion forecast and the economics available from the generation. Figures 10.3-1 and 10.3-2 are the conceptual transmission expansion maps for each Future. Conceptual transmission was modeled for the Eastern Interconnect.

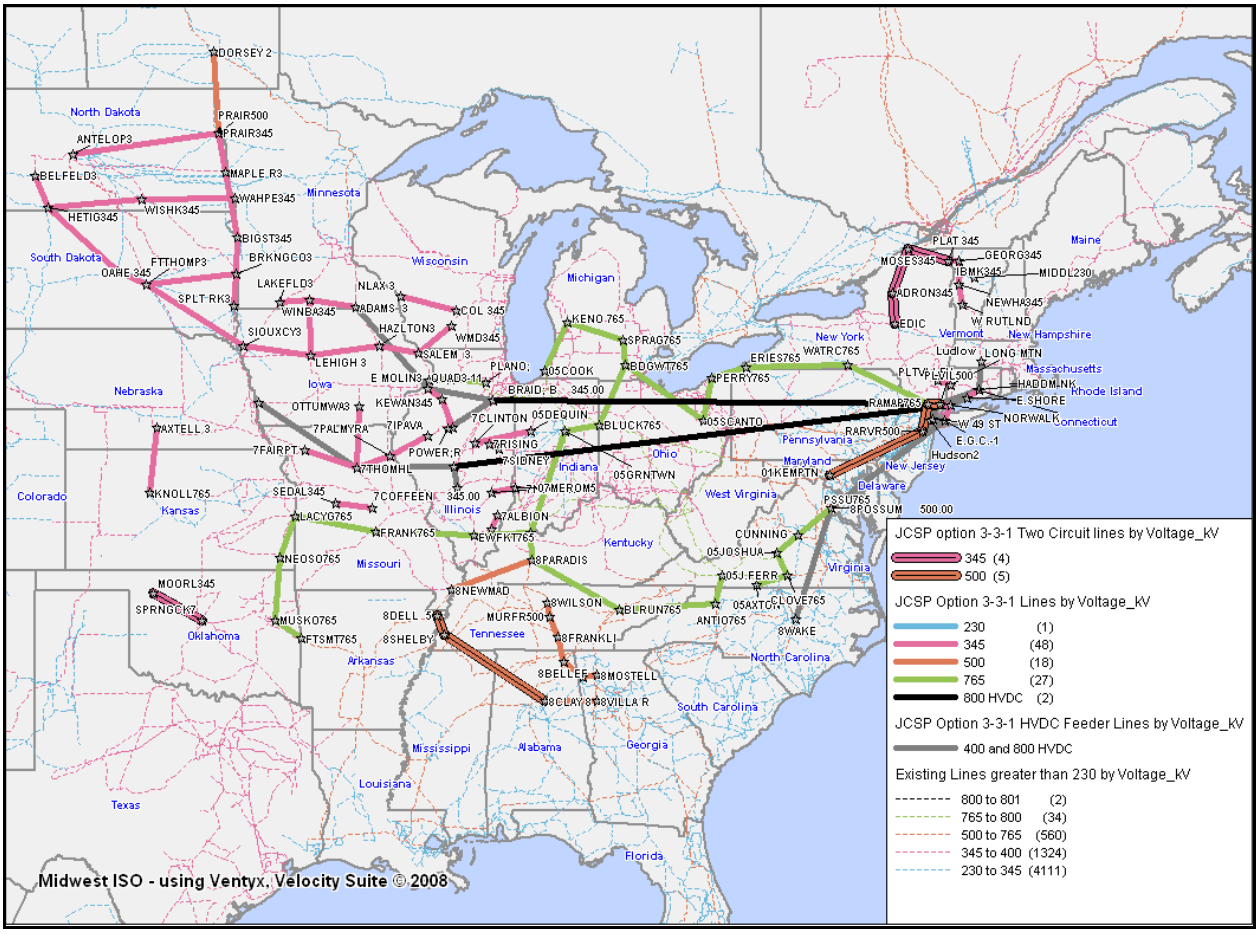

Figure 10.3-1: Conceptual Transmission for Reference Future

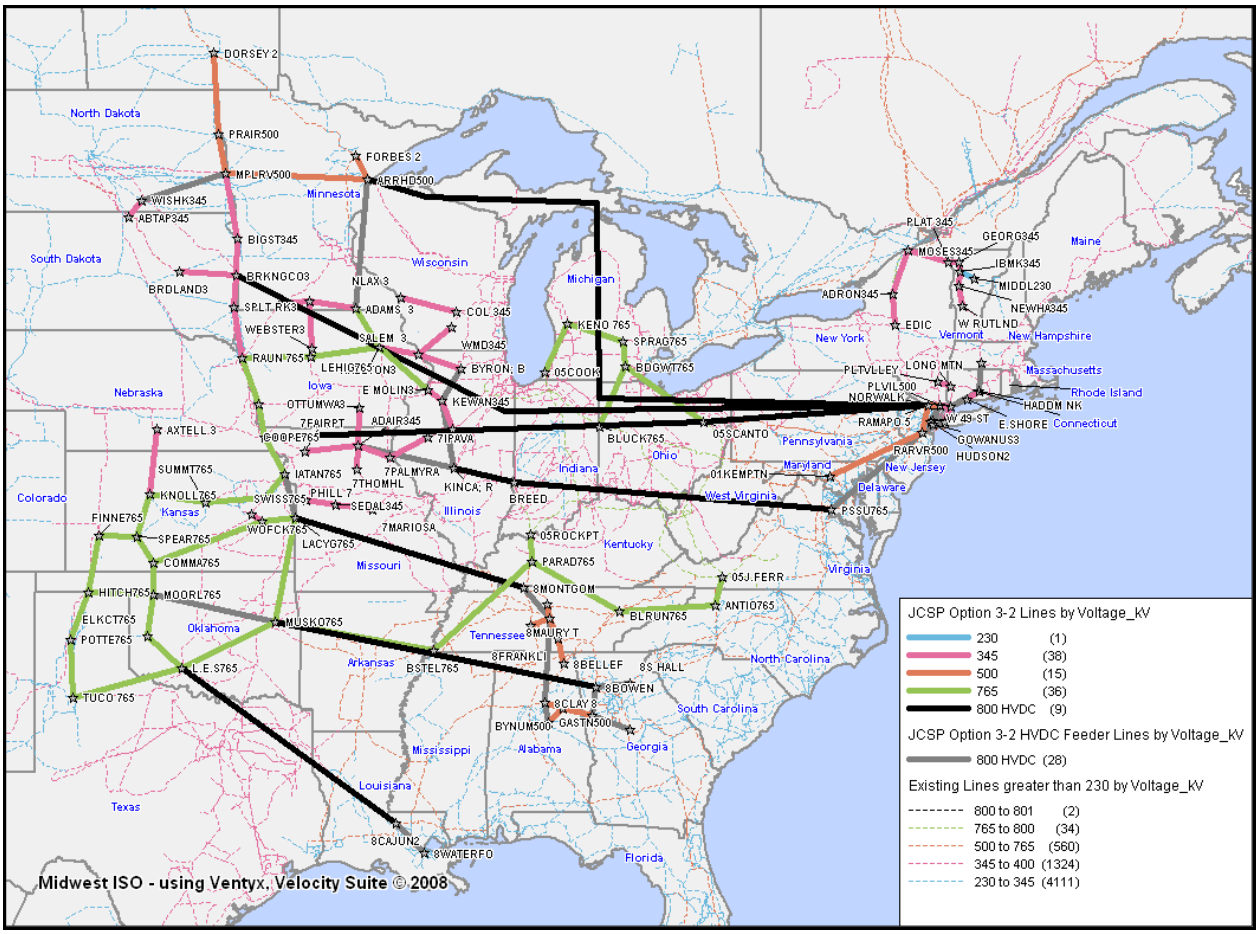

Figure 10.3-2: Conceptual Transmission for Renewable Future

Tables 10.3-1 through 10.3-3 contain the assumptions on the cost per mile for each voltage, the estimated line mileage used in assessing the conceptual overlays and the estimated costs of each overlay.

Table 10.3-1: Cost-per-mile assumptions

Cost-per-mile Assumptions							
	345 kV	(2)-345 kV	500 kV	(2)-500 kV	765 kV	DC-400 kV	DC-800 kV
2024$	2,250,000	3,750,000	2,875,000	4,792,000	5,125,000	3,800,000	6,000,000

Table 10.3-2: Estimated Line Mileage

Estimated Line Mileage Summary-Miles								
	345 kV	**345 kV (2)**	**500 kV**	**500 kV (2)**	**765 kV**	**DC-400 kV**	**DC-800 kV**	**Total**
Reference Future	3,106	292	593	494	2,624	470	2400	9,980
20% Wind Energy Future	2,042	193	864	279	3,977	0	7,582	14,937

Table 10.3-3: Estimated Cost Summary

Estimated Cost Summary Million (2024$)								
	345 kV	**345 kV (2)**	**500 kV**	**500 kV (2)**	**765 kV**	**DC-400 kV**	**DC-800 kV**	**Total**
Reference Future	8,736	1,371	2,130	2,960	16,810	2,155	14,400	48,562
20% Wind Energy Future	5,742	905	3,106	1,671	25,478	0	45,492	82,394

The benefit value metrics considered in the MTEP 09 study is Adjusted Production Cost (APC) saving, which is calculated by taking the APC difference between the overlay case and the constrained case for the study footprint. For each case:

APC = Production Cost + Import * Load Weighted LMP (or)-Export * Generation Weighted LMP

An annual revenue requirement of 15% of the total overlay cost is used to calculate the annual cost of the overlay. The Benefit/Cost ratios for the conceptual overlays are included in Table 10.3-4. A further comprehensive cost benefit analysis of potential alternatives will be required before making any recommendations for need justification.

Table 10.3-4: 2024 B/C Ratios

	2024 B/C ratio
Reference Future	1.46
20% Wind Energy Future	1.00

Only adjusted production costs (production cost, minus sales, plus purchases) were used to calculate the benefits. Difference in the adjusted production cost is used by economists as the measure of the social good provided by the scenario being studied. Three very broad theoretical assumptions are made that may not be true in the short term.

- Net revenues to generators are invested to the benefit of the load customer to produce lower cost generation options in a competitive market. For vertically integrated utilities, the regulators would apply the net revenue of generators to the price of energy for the loads.
- Regulators are efficient in applying the adjusted production cost to the load customer price of energy such as a production cost adder.
- Transmission is paid for by the reliability needs of the local areas and does not enter into the benefit considerations. Economic transmission would be built for constraint relief.

10.3.4 Gas Only PROMOD® Analysis

Table 10.3-5 demonstrates the total energy consumed, and produced, in each modeled region within the PROMOD® model, as well as the costs associated with load, generation and the adjusted production cost. The combination of the LMP contour map and the output data for the Gas Only Future provides additional information when evaluating the economic Futures modeled for conceptual transmission development for the MTEP 09 scenarios.

Table 10.3-5: Gas Only Future Cost and Energy Information

Pool	Pool Adjusted Production Cost ($Millions)	Pool Total Load (GWh)	Pool Total Load Cost ($Millions)	Pool Total Generation (GWh)	Pool Total Gen Revenue ($Millions)
PJM	33,228	936,993	94,109	954,686	90,651
Midwest ISO	24,438	716,185	58,514	698,881	55,668
TVASUB	9,635	304,211	27,807	312,945	27,806
MAPPCOR	2,527	116,843	8,267	120,945	8,297
SPP	9,077	238,152	21,726	237,357	20,760
SERCNI	37,201	835,502	85,914	833,559	82,520
E_CAN	3,763	248,728	19,295	261,214	16,237
IMO	2,593	176,215	13,341	188,114	13,774
ISONE	8,647	177,549	17,952	174,233	16,729
MHEB	(533)	26,540	1,068	46,619	1,902
NYISO	12,292	196,771	21,421	162,492	16,127
Totals:	**142,867**	**3,973,689**	**369,413**	**3,991,046**	**350,470**

The Reference and 20% Wind Energy Futures focused on delivering economic energy through the building of conceptual transmission overlays from low cost energy areas to higher cost energy areas; however, these two futures, as well as previously studied economic futures, do not consider the option that no economic transmission is built. Conceptual economic transmission is dependent on price variations across interfaces that are large enough to potentially justify the costs of conceptual transmission.

The Gas Only Future results in a greater dependence on the natural gas fleet for future energy needs and results in a levelization of the average costs of energy across not only the Midwest ISO footprint, but also the Eastern Interconnect.

The Reference and 20% Wind Energy Futures, which do not limit the type of capacity expansion for future energy needs, show a greater disparity in the costs across the Eastern Interconnect. This provides an opportunity for transmission to be built which provides an economic benefit to both the source region and the sink region.

Tables 10.3-6 and 10.3-7 present the detailed data for each of the Futures with the conceptual transmission added to the models. When compared to the Gas Only Future, costs for the Midwest ISO and the rest of the Eastern Interconnect are less. This is a result of the addition of low cost capacity and additional transmission used to transport the energy over long distances.

Table 10.3-6: Reference Future Cost and Energy Information with Conceptual Transmission Overlay

Pool	Pool Adjusted Production Cost ($Millions)	Pool Total Load (GWh)	Pool Total Load Cost ($Millions)	Pool Total Generation (GWh)	Pool Total Gen Revenue ($Millions)
PJM	25,739	936,993	63,262	967,748	61,121
Midwest ISO	18,940	716,185	40,914	741,018	40,408
TVASUB	7,288	304,211	20,036	329,342	20,911
MAPPCOR	2,443	116,843	6,392	121,617	6,242
SPP	7,885	238,152	18,362	238,382	16,931
SERCNI	28,000	835,502	58,987	834,869	54,064
E_CAN	1,406	248,728	14,395	260,373	13,506
IMO	2,682	176,215	9,790	181,836	9,416
ISONE	6,927	177,549	12,967	134,274	9,385
MHEB	(575)	26,540	984	47,820	1,747
NYISO	8,197	196,771	13,929	134,046	8,743
Totals:	**108,932**	**3,973,689**	**260,016**	**3,991,325**	**242,474**

Table 10.3-7: 20% Wind Energy Future Cost and Energy Information with Conceptual Transmission Overlay

Pool	Pool Adjusted Production Cost ($Millions)	Pool Total Load (GWh)	Pool Total Load Cost ($Millions)	Pool Total Generation (GWh)	Pool Total Gen Revenue ($Millions)
PJM	22,107	936,993	57,990	967,992	56,737
Midwest ISO	16,607	716,185	36,610	723,104	36,955
TVASUB	5,587	304,211	17,135	328,868	18,501
MAPPCOR	2,011	116,843	4,932	116,282	5,418
SPP	6,188	238,152	12,959	224,727	13,142
SERCNI	22,329	835,502	54,305	840,751	50,092
E_CAN	2,131	248,728	9,834	255,513	8,034
IMO	1,764	176,215	6,061	196,869	7,193
ISONE	6,148	177,549	11,424	129,422	8,185
MHEB	(536)	26,540	864	47,665	1,597
NYISO	6,156	196,771	11,489	141,647	7,197
Totals:	**90,491**	**3,973,689**	**223,603**	**3,972,840**	**213,052**

Figures 10.3-4 through 10.3-6 provide the generation weighted LMP contour maps for the Gas Only, Reference and 20% Wind Energy Futures for comparison. The combination of both low cost energy and transmission to deliver that energy over a wide area of demand in the Reference and 20% Wind Energy Futures will level costs down, rather than up, as in the Gas Only Future.

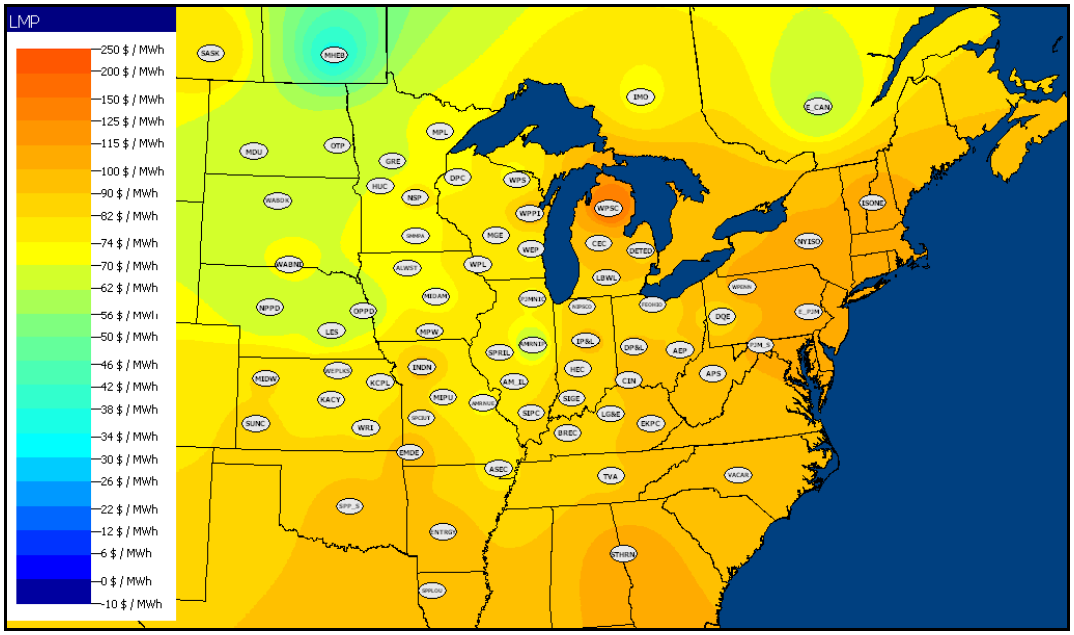

Figure 10.3-3: Gas Only Future Generation LMP Contour Map

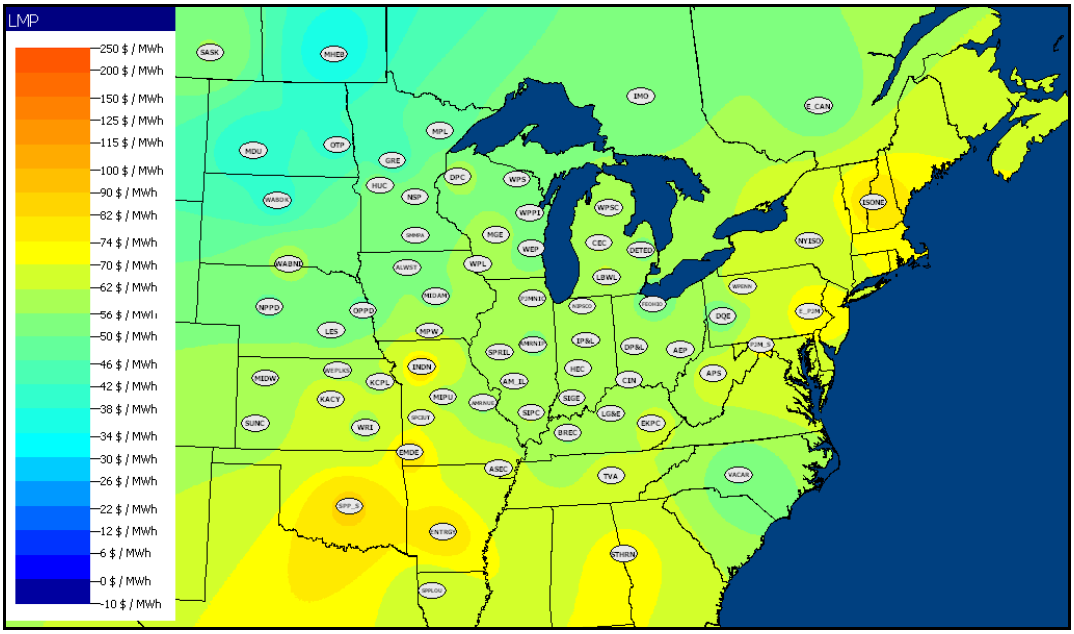

Figure 10.3-4: Reference Future Generation LMP Contour Map with Conceptual Transmission

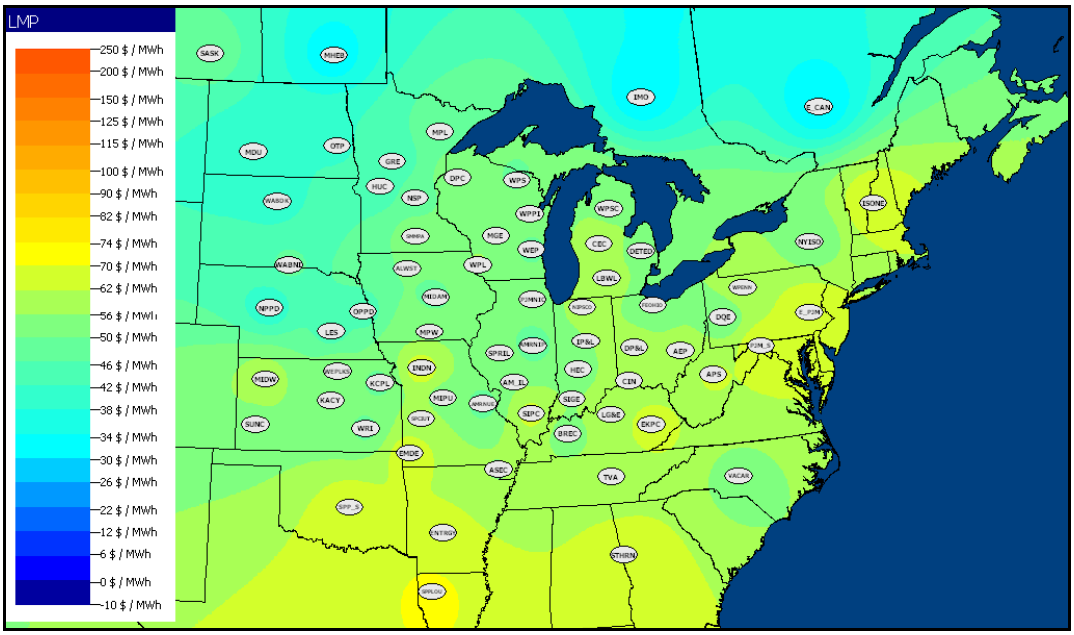

Figure 10.3-5: 20% Wind Energy Future Generation LMP Contour Map with Conceptual Transmission

When comparing future transmission and generation, it is important to compare the entire portfolio of the analysis. Building low cost energy capacity in portions of the Eastern Interconnect without transmission will result in captured capacity within a particular area and artificially suppress the LMP values in the areas. By adding economic transmission to this same case, the low cost energy would then be shared over a larger region, providing additional revenue to generation in some areas, while lowering the costs of energy to load in other areas. Comparisons between the low cost energy additions with conceptual transmission development, with a case that distributes higher cost energy sources for future needs closer to load centers with the intent for not building economic transmission, is the relevant comparison of these results.

Economic analysis of the development of conceptual transmission depends heavily on the assumptions used. Appendix E1 goes into the details of the economic assumptions used within the models. Making changes in the assumptions can result in different comparative results, such as in natural gas prices. Further examination of varying assumptions will provide additional information to the analysis of conceptual transmission and economic energy transfer.

10.4 Robustness Testing

As part of value-based economic transmission planning in the Midwest ISO Transmission Expansion Plan (MTEP) process, Midwest ISO needs to develop transmission plans - ranging from an incremental line addition to an entire system overlay - that are feasible for both economic and reliable energy delivery under a wide range of potential energy policies. To achieve this, the Midwest ISO needs to study hundreds of different project combinations under a wide variety of scenarios to ensure the recommended transmission plan is appropriately robust. Due to the high level of grid expansion required to support a wide variety of energy policy objectives, Midwest ISO is performing an ever-increasing number of studies to ensure economic expansion and reliable operation of the transmission system.

The economic transmission analysis within the planning process is performed with PROMOD IV®, a Security-Constrained Economic Dispatch (SCED) software package used in the power industry. Midwest ISO PROMOD IV® studies are analyzed over a one-year time horizon and can comprise the entire Eastern Interconnection. Because of that scope, typical PROMOD IV® runs can take from 48-72 hours to complete. The labor and time required is prohibitive for analyzing hundreds of individual projects to develop an optimal economic plan. To alleviate this problem, Midwest ISO determined that an economic transmission screening tool was necessary to determine the top ranked projects that warrant further evaluation through a complete PROMOD IV® analysis. By utilizing a subset of representative hours for analysis, the screening tool could analyze and rank the transmission projects in a fraction of the time required to run a PROMOD IV® study, significantly streamlining the time required to execute Step 4, Robustness Testing. Figure 10.2-1, which shows the Economic Planning process, illustrates where Step 4 fits in the MTEP process.

10.4.1 Transmission Portfolio Screening Overview

Midwest ISO performs numerous studies throughout the year. These studies range from economic analysis within the Midwest ISO footprint, such as the Regional Generation Outlet Study (RGOS), to studies that span the entire Eastern Interconnection such as the Midwest Transmission Expansion Plan (MTEP) and the Joint Coordinated System Plan (JCSP). The primary purpose of the transmission screening tool is to screen hundreds of different project combinations, under different scenarios, and rank them by according to benefit measures. The top ranked projects are then further analyzed in PROMOD IV® for detailed economic impacts.

To rank a portfolio of transmission projects, Midwest ISO currently uses Regional Economic Criteria Benefits (RECB) II criteria to determine a Benefit/Cost (B/C) ratio for each project. This methodology identified benefits as a combination of 70% adjusted production cost savings and 30% load cost savings. Savings are determined by comparing a base case to the transmission overlay case; A diagram of this process in shown in Figure 10.4-1.

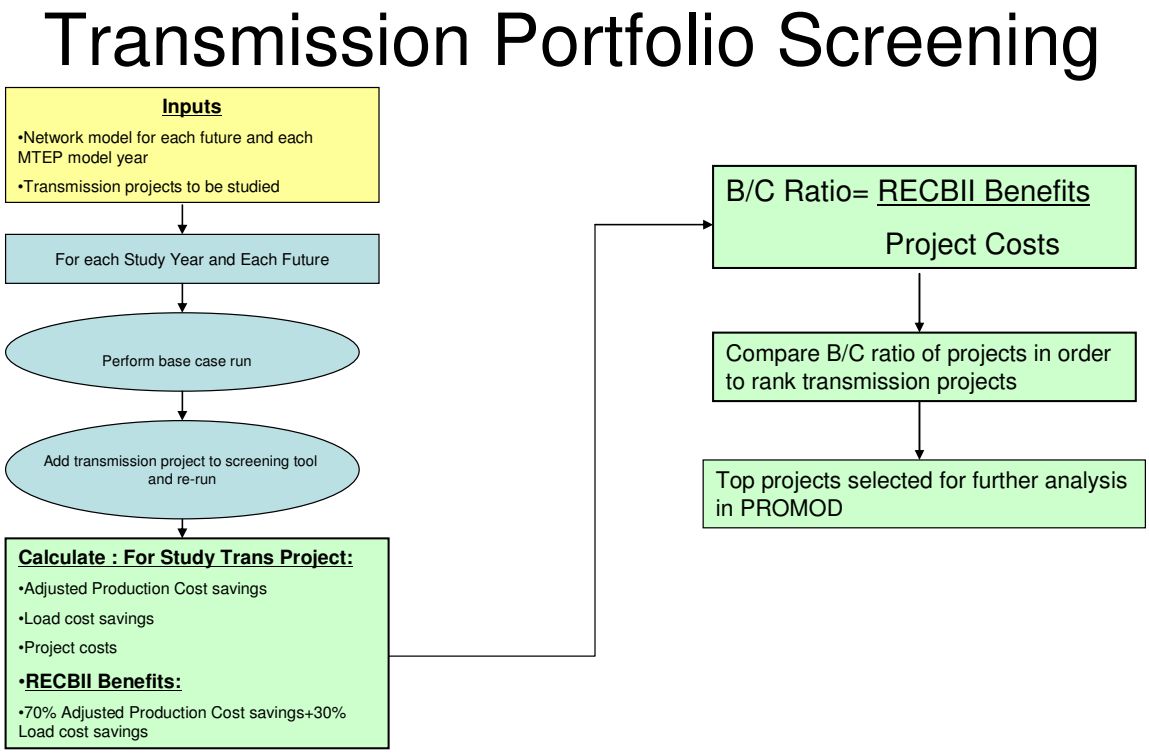

Figure 10.4-1 Transmission Portfolio Screening Process

In order to successfully perform transmission portfolio screening, Midwest ISO identified three principles that must be adhered to for any screening process to add value to the MTEP value-based planning process.

1. The screening process must use a tool that uses algorithms similar to those used in PROMOD IV®
2. The raw data output from the screening tool should be consistent with the raw data output from PROMOD IV®
3. The screening tool should be able to analyze multiple projects faster than PROMOD IV®

These principles are fundamental to the ultimate goal of robustness testing: being able to analyze a number of projects using different scenarios or Futures and determine which projects provide economic benefit across the greatest number of Futures. For example, Midwest ISO may analyze 100 projects in an MTEP study cycle; during the economic analysis, the projects need to be analyzed under four different scenarios: a base case, a 20 % wind penetration case, a low-demand case, and a high-gas penetration case. Individually analyzing 100 different transmission projects across four scenarios would take at least two years in run time using PROMOD IV®. Additionally, the project combinations must be created manually in PROMOD IV®. To simplify this process, Midwest ISO sought to automate the combinatorial process of analyzing different combinations of numerous projects, while reducing the time needed to screen the different project combinations.

10.4.2 Development of Methodology

Once the need for a transmission portfolio screening process was identified, a methodology and tool had to be chosen. While another tool was initially considered (see Appendix E4.2), the PROMOD® Analysis Tool (PAT) was eventually selected as the tool to use in Step 4 of the MTEP process (for a description of PAT, please see Appendix E4.3). In order to reduce the run-time of the transmission portfolio screening, Midwest ISO decided to investigate the possibility of analyzing a small subset of hours in PAT that would be representative of an 8,760 hour analysis in PROMOD IV®. During the investigation, Midwest ISO wanted to answer two questions:

1. What is the smallest number of hours that can be modeled while still producing the same project ranking results as an 8,760 hour run?
2. Does a weighting factor need to be applied based on a given logic (for example a seasonal or on-peak/off-peak weighting)?

Midwest ISO began their investigation with a 50 hour run and continued to increase the number of hours until an adequate benchmarking with PROMOD IV® was reached. The primary weighting method used was an on-peak/off-peak weighting methodology, in combination with a summer/winter seasonal weighting. The steps involved in weighting the hours can be found in Figure 10.4-2:

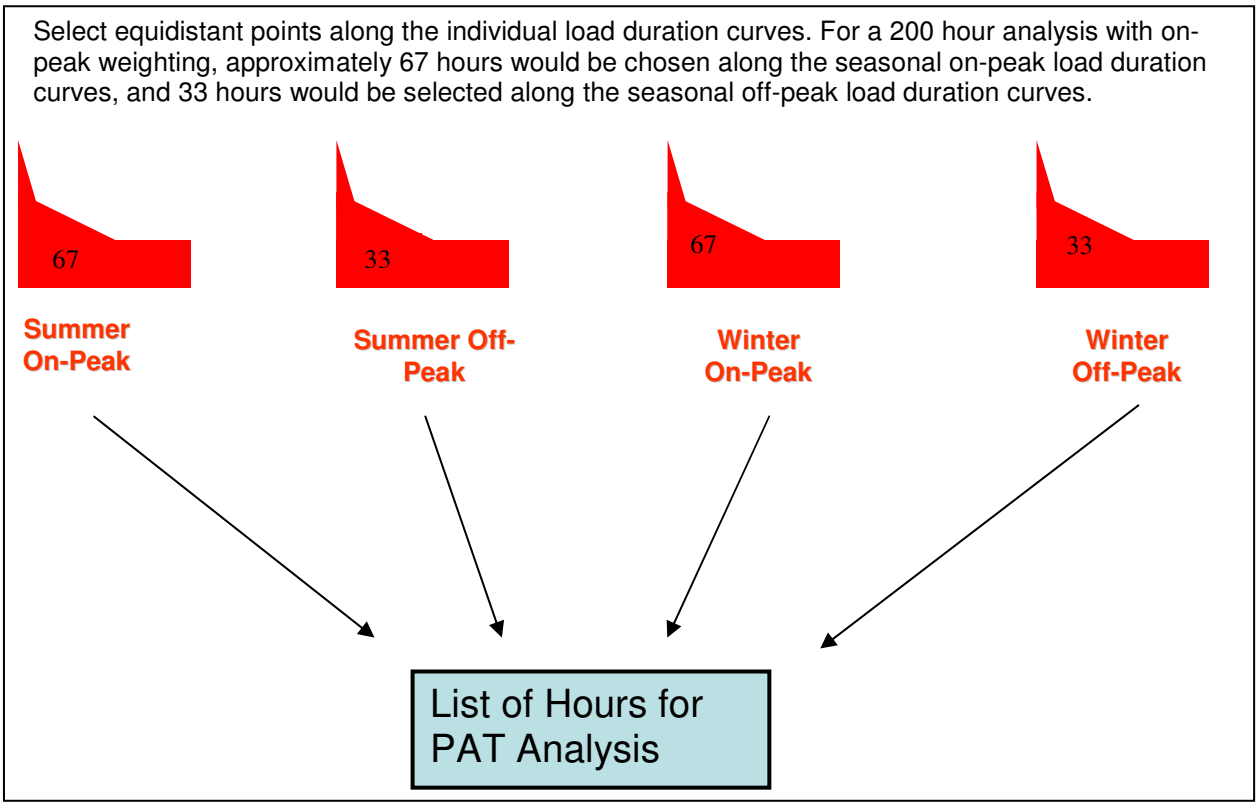

Figure 10.4-2 Hour-Picking Methodology

A new module, the Transmission Expansion Tool, was developed as an extension to PAT to analyze transmission project combinations and calculate economic benefits for each of the project combinations for

a selected number of hours that met the hour-picking methodology criteria. A detailed explanation of the Transmission Expansion Tool can be found in Appendix E4.4

In 2008 and 2009, Midwest ISO focused on execution of a benchmarking process in order to validate the PAT Transmission Expansion Tool. The benchmarking process sought to ensure that:

1. PAT produces the same economic results as PROMOD IV® when comparing the same hours. For an overview of the modifications made to PAT and PROMOD® to ensure the benchmarking was successful, please see Appendix E.5.
2. The ranking of projects in PAT and PROMOD IV® is similar when a reduced-hour PAT run is compared to a full-year PROMOD IV® run.

Detailed information and results from the benchmark can be found in Appendix E4.6

10.4.3 Robustness Testing Utilizing the Promod® Analysis Tool

Robustness testing is the primary purpose of MTEP 09 Step 4. Robustness testing is defined as the analysis of transmission project across all MTEP Futures to determine which projects consistently provide the greatest benefit (figure 10.4-3). Transmission projects from the MTEP 08 2021 Futures Overlay were used with MTEP 09 2024 PROMOD IV® models to perform the robustness testing. Benefit/cost ratios for the new transmission options were calculated with PAT, for all hours selected with the hour-picking methodology, and compared to benefit/cost ratios calculated using PROMOD IV® for a full study year using the same set of transmission projects, and the same network models. The robustness test allowed the Midwest ISO to identify economically beneficial transmission projects against multiple Futures, while at the same time analyzing whether a particular hour-picking methodology compared favorably to full-year PROMOD IV® results. If an hour-picking methodology produced consistent rankings when compared with PROMOD IV® rankings, the top projects identified by PAT could be analyzed in-depth using PROMOD IV®. The list of projects analyzed came from the MTEP 08 2021 Futures Overlay and are identified in Appendix E4.7. Each project is identified with an acronym that was used in the PAT analysis.

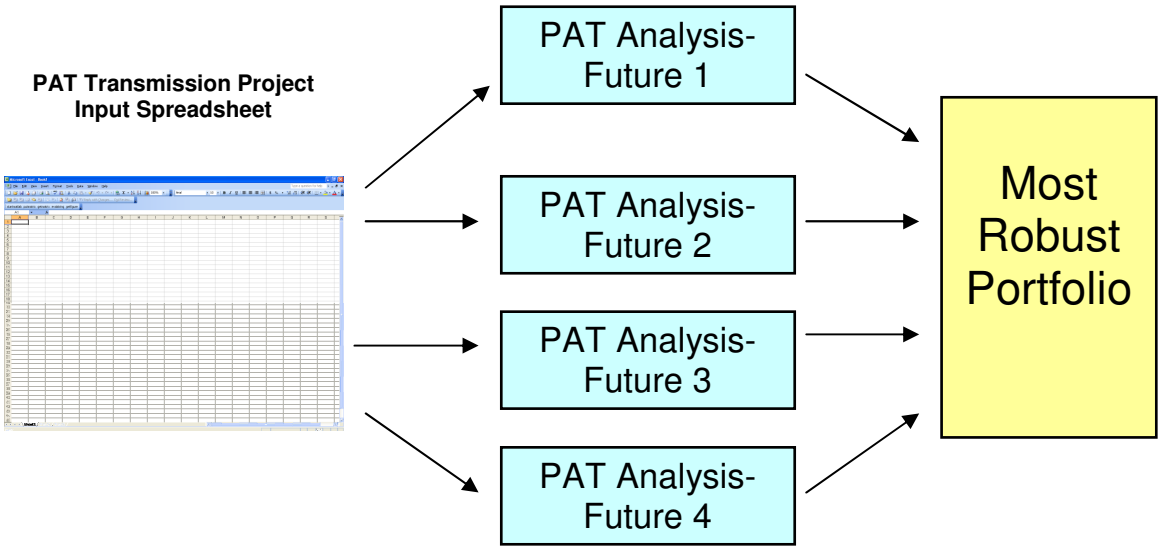

Figure 10.4-3 - Robustness Testing

Midwest ISO selected eleven transmission projects from the MTEP 08 2021 overlay and, using the PAT Transmission Expansion Tool, developed eighteen different transmission project combinations for robustness testing. The projects were selected from the MISO West, Central, and East regions. Because the PAT Transmission Expansion Tool was initially created to only handle two-project combinations, Central projects were grouped with West projects for the robustness testing. Additionally, a number of PJM transmission expansion projects were added to the cases as existing transmission infrastructure. The project combinations spanned from the West region to the East Region within the Midwest ISO footprint. Two different hour-picking methodologies were identified for the robustness testing:

- **Method M1:** Set of 200 hrs (67 summer peak hours, 33 summer off-peak hours, 67 winter peak hours and 33 winter off-peak hours). This combination gives more weight to peak hrs

- **Method M2:** Set of 200 hrs (67 summer off-peak hours, 33 summer peak hours, 67 winter off-peak hours and 33 winter peak hours). This combination gives more weight to off-peak hrs

The purpose for the PAT Transmission Expansion Tool is to screen transmission projects for further PROMOD IV® evaluation, as part of MTEP robustness testing, and to assist with PROMOD IV® studies by creating a transmission plan that performs well in various MTEP futures. The hours selected using the hour-picking methodology need to produce a comparable ranking to a full-year, 8,760 hour PROMOD IV® analysis.

To verify that the selected hours worked for different MTEP futures, Midwest ISO tested the selected hours on two different Futures using MTEP 09 2024 PROMOD IV® models.

- Reference Future
- Wind 20 % Future

The Reference Future was chosen so that Midwest ISO had a base case to compare between PROMOD IV® and PAT. The Wind Future was chosen due to its dissimilarities with the Reference case and the large amount of wind modeled in the case, which has an effect on transmission loading and locational marginal prices. PAT simulations were performed for each of the two Futures and for each of the twenty nine transmission projects (eleven individual projects and eighteen project combinations), using methods M1 and M2. Economic benefits and benefit/cost ratios were calculated for the projects for both Futures and hour-picking methodologies. The ranking comparison between PROMOD IV® and PAT can be seen in Table 10.4-1.

Table 10.4-1: Reference Case and Wind 20% Future Method M1 and M2 PROMOD IV®/PAT Ranking

Project	PROMOD® One-Year Ranking Results 2024	Reference Future		PROMOD® One-Year Ranking Results – Wind 2024	Wind 20% Future	
		M1	M2		M1	M2
E1	1	1	1	3	11	11
E2	2	9	2	2	9	9
W1	11	11	11	11	6	10
W2	8	8	8	7	5	5
W3	9	3	9	9	1	2
W4	10	4	10	10	10	8
W5	7	5	6	8	3	3
W6	6	10	7	6	2	1
W7	4	7	3	1	8	6
W8	5	6	4	4	7	7
W9	3	2	5	5	4	4
W1-E1	18	17	18	17	16	17
W1-E2	17	10	14	15	12	12
W2-E1	14	9	16	10	18	18
W2-E2	12	7	11	9	15	11
W3-E1	15	11	15	14	2	14
W3-E2	8	4	13	18	7	3
W4-E1	16	2	17	16	6	1
W4-E2	11	3	8	13	5	4
W5-E1	13	16	12	12	13	8
W5-E2	9	8	7	11	9	6
W6-E1	10	1	10	7	1	10
W6-E2	7	5	9	8	8	5
W7-E1	3	14	2	1	10	7
W7-E2	1	12	1	2	11	13
W8-E1	6	15	5	6	17	15
W8-E2	5	13	4	3	14	16
W9-E1	4	6	6	5	4	9
W9-E2	2	18	3	4	3	2

MI gives more weight to peak hours (33% summer peak, 17% summer off peak, 33% winter peak, 17% winter off peak)

M2 gives more weight to off peak hours (17% summer peak, 33% summer off peak, 17% winter peak, 33% winter off peak)

Looking at the results, Midwest ISO found that the M2 methodology, which was weighted more towards off-peak hours, benchmarked well with the full-year PROMOD IV® Reference Future rankings for the same set of transmission projects. The results seem to indicate that PAT is consistently able to match the PROMOD IV® ranking for the top 5-10% of projects with lower-ranked projects deviating from the PROMOD IV® rankings by no more than 10-15% on average. Neither methodology M1 or M2 matched with the full-year PROMOD IV® 20% Wind Future rankings. With large amounts of wind modeled in the 20% Wind Future, Midwest ISO believes a variety of hour-picking methodologies needs to be analyzed to determine what works best with a wind-heavy Future. Figure 10.4-4 indicates that the hour-picking

methodology can produce consistent rankings when comparing PROMOD IV® and PAT results, but also indicates that the Wind Future may require a methodology that captures the fluctuations of wind turbine output and its effect on the electricity market.

Because of the inconclusiveness of the Wind future robustness testing, Midwest ISO wanted to verify if the hour-picking methodologies mentioned above would work on any other futures. To test this possibility, Midwest ISO performed a benchmark against the Gas Future from the MTEP 09 2024 PROMOD IV® models. The other MTEP 09 Future, Regulatory Future, was not analyzed due to its similarities with the Gas Future. The Gas Future simulation was performed on the eleven individual projects described above. Method M1, which was weighted more towards peak hours, benchmarked well with PROMOD IV® rankings for the Gas Future as seen in Table 10.4-2. Specific projects, such as East 1 (E1) and East 2 (E2), had a high ranking in both the Reference and Gas Futures, indicating that these projects are robust in providing economic benefit when included in different Futures.

Table 10.4-2: Gas Future Results - Method M1 and M2 PROMOD IV®/PAT Ranking

Project	PROMOD® One-Year Ranking Results - Gas 2024	Gas Future	
		M1	M2
E1	2	2	1
E2	1	1	2
W1	11	11	3
W2	8	3	5
W3	9	9	8
W4	10	8	10
W5	6	10	11
W6	5	5	6
W7	3	4	7
W8	7	7	9
W9	4	6	4

10.4.4 Next Steps and Conclusion

The initial robustness testing results demonstrated the viability of Midwest ISO's use of PAT, in combination with an hour-picking methodology, to produce PROMOD IV®-like results. Midwest ISO has identified a few areas for additional work as they implement Step 4 in future MTEP analyses:

1. **Inclusion of additional transmission overlay data-** there are a number of studies that have been produced within the last year that identify transmission overlays to meet state and regional renewable standards as well as transmission infrastructure expansion goals: Regional Generation Outlet Study (RGOS), Joint Coordinated System Plan (JCSP), Green Power Express, and HVDC overlays. These projects could be studied separately or together to determine optimal transmission paths.

2. **Identification of single hour-picking methodology-** During the initial robustness testing, different hour-picking methodologies worked better for different Futures. For the Wind Future, neither method M1 or M2 benchmarked well against the PROMOD IV® ranking of projects. Identification of a single hour-picking methodology would reduce PAT run-time. Due to the unique nature of each Future, this goal may not be feasible.

Through the benchmarking process, Midwest ISO identified that the PAT Transmission Expansion Tool can be used as an economic transmission screening tool. This will enable Midwest ISO to study numerous transmission combinations by screening them initially in PAT, with more detailed analysis to follow in PROMOD IV® for those projects, or portfolio of projects, that show economic benefit to the system. As indicated in Figure 10.4-4 and Figure 10.4-5, the top projects identified in PAT tend to match the top projects identified in PROMOD IV®. As the number of projects analyzed increases, Midwest ISO hopes to use this trend as a screening tool to identify top projects for further PROMOD IV® evaluation.

Section 11: Joint Coordinated System Plan (JCSP)

11.1 JCSP 08 Executive Summary

The Joint Coordinated System Plan 2008 Report was published in February 2009. The full report is available at: http://www.jcspstudy.org/. The Executive Summary from that report is included here as Section 11.1.1.

11.1.1 Joint Coordinated System Plan 2008 Overview

The Joint Coordinated System Plan 2008 (JCSP 08) analysis offers a conceptual regional transmission and generation system plan for a large portion of the Eastern Interconnection in the United States, developed with the participation of most of the major transmission operators in the Eastern Interconnection. This initial effort looks at two scenarios that expand transmission and generation opportunities between 2008 and 2024 – a Reference Scenario and a 20% Wind Energy Scenario – in support of the U.S. Department of Energy's Eastern Wind Integration and Transmission Study. Future JCSP analyses will examine additional scenarios.

Several features distinguish the JCSP 08 study from prior transmission expansion studies:

- The JCSP 08 is the first inter-regional planning effort to involve most of the major transmission operators in the Eastern Interconnection. The study represents the collaborative efforts of Midwest ISO, SPP, PJM, TVA, MAPP and several key members of SERC. The New England and New York areas are also included in the study analysis. Most other transmission studies address smaller regional footprints.
- The JCSP 08 used a collaborative, transparent, stakeholder process to develop and screen key analytical assumptions and design the transmission expansion options for the two scenarios studied; many other transmission studies have less direct stakeholder involvement.
- The JCSP 08 uses common economic and system condition assumptions to characterize most of the Eastern Interconnection in a single multi-regional analysis, rather than through parallel, region-specific analyses.

This JCSP 08 study is valuable as a demonstration of the value of an inter-regional planning process, as well as for its analytical planning results. From the process standpoint, the JCSP 08 put together a wide-reaching stakeholder involvement process over a near-Interconnection-wide area; this will enhance the Eastern Interconnection's ability to conduct future planning activities pursuant to Federal Energy Regulatory Commission (FERC) Order 890. The JCSP 08 also developed a process to identify, evaluate and screen alternative high-voltage transmission overlays, which has rarely been done in planning to serve smaller regions. From an analytical standpoint, the JCSP 08 establishes that transmission overlays may provide significant economic value by reducing grid congestion and facilitating new renewable resource development (within the context of the scenarios evaluated).

The JCSP 08 offers a valuable foundation for future planning work within the Eastern Interconnection. Future interconnection-wide planning analyses should test additional scenarios to examine the reliability and economic impacts of alternative combinations of supply-and-demand-side resource technologies, densities and locations and transmission infrastructure options, and also conduct sensitivity analysis to determine the implications of varying assumptions such as fuel and technology costs, load projections, plant retirements, and carbon regulation options and costs.

Section 2 of the full report describes the process of developing the JCSP 08.

11.1.2 JCSP 08 Scenario and Transmission Overlay Development

The traditional approach to transmission planning is to evaluate targeted transmission additions to meet specific reliability or economic needs, building individual high voltage transmission lines (mostly 345 kV and below) and adding substation and voltage management equipment to meet identified system needs such as load growth or new generation interconnection. These targeted additions are evaluated using both reliability and economic modeling, often under alternative scenarios stretching out to a specified future horizon year. An alternative to this approach entails using production cost simulation information to identify a portfolio of transmission system expansion options involving multiple, major, simultaneous high voltage additions (that can include High Voltage Direct Current (HVDC) as well as 765kV, 500kV and 345 kV technologies) that together serve and link entire regions and markets across an entire interconnection. Such a transmission expansion is called a "transmission overlay." The targeted method has been the dominant means of transmission expansion in the Eastern Interconnection. But, with the possibility of national Renewable Portfolio Standards (RPS), and the development of large amounts of new generation resources in certain regions of the nation to meet such standards, this JCSP 08 analysis was designed to look at the costs and benefits of transmission overlays that can serve a range of policy goals. As with any transmission expansion plan, evaluation of an overlay requires considering a broad range of reliability, economic, and environmental drivers.

The JCSP 08 Study developed and analyzed the costs and benefits of conceptual transmission overlays for two scenarios. The Reference Scenario assumes that the existing laws and policies governing generation resource choices remain in place and was premised on the assumption that incremental wind development would address existing RPS requirements, which translates to an average 5% wind energy development across the U.S. portion of the Eastern Interconnection. The scenario assumes each state will build as much new on-shore wind generation as its total RPS requires, and on-shore wind generation will be built as closely as possible to the regional load. For example, the JCSP 08 reference scenario assumes that wind needs within New England are met with on-shore wind projects within New England,[1] as opposed to wind imports from the Midwest or Canada. Under the Reference Scenario there will be about 60,000 MW of new wind developed by 2024, along with 75,600 MW of additional base load steam generation. Many possible transmission overlays were developed and one was selected to represent the Reference Scenario.

The second scenario, the 20% Wind Energy Scenario, assumes that the entire Eastern Interconnection will meet 20% of its energy needs using wind generation by 2024. In this scenario, the bulk of the wind production capacity is assumed to be located in those areas with the highest quality (best capacity factor) on-shore wind resources, which are located in the western part of the Eastern Interconnection.[2] The 20% Wind Energy Scenario assumes that 229,000 MW of new wind capacity will be built by the year 2024, with 36,000 MW of new base load steam generation. Here too, a number of possible transmission overlays were examined and one was selected because it provided the best optimal performance based on the assumptions in the study.

[1] It was beyond the scope of this study to examine and model the potential for off-shore wind development along the East Coast due to lack of data availability, but those options should be examined in future transmission development scenarios.

[2] The study authors recognize that beyond the specific 20% Wind Energy Scenario outlined here, there are other options for meeting a 20% wind energy target, as well as more broadly formulated targets for renewable energy, that would involve different renewable resource development patterns and different transmission overlay patterns. This study makes no judgment on the superiority or desirability of this scenario relative to others, which could and should be developed in future analyses of the Eastern Interconnection.

The JCSP 08 used an iterative process to assure that each conceptual overlay delivers economic value as well as system reliability. The planning process starts by performing a capacity expansion analysis for each of the regions under study. These capacity expansion assumptions are then incorporated into transmission and production cost models. These models then allow for the development of conceptual transmission overlays to economically deliver energy to the Eastern Interconnection. Established transmission planning processes evaluate the reliability requirements (under North American Electric Reliability Corp. (NERC) standards) and economic benefits of the expansion options for the planning period; the JCSP 08 did so as well, although the JCSP 08 conducted the production cost analysis for 2024 before conducting the reliability analyses. As the production cost models perform security constrained economic dispatch of the entire Eastern Interconnection for each hour of the year being analyzed (here 2024), the conceptual transmission overlays that result from this process consider reliability only to the extent that they ensure that pre-overlay security constraints are enforced; however, a production cost-based analysis does not contain the level of detail required to satisfy all reliability analysis requirements.[3] More detailed reliability analysis of the conceptual transmission overlays must be conducted for each of the overlays, to make the final conceptual overly both economic and reliable.

The two scenarios are described in detail in the full report in Section 3. The Reference and 20% Wind Energy Scenarios share common load growth and economic assumptions; they differ in terms of how much wind is developed and how the wind penetration levels affect the need for transmission and other types of generation. Although the modeling results indicate that the bulk of new fossil generation under these scenarios could be coal-fired, that result appears to be an artifact of the modeling assumptions and process rather than a prediction regarding the implications of transmission overlay development. Future analyses that incorporate more detail on technology and fuel costs (e.g., carbon sequestration), carbon regulation options, and operational needs relating to intermittency (as it relates to assuring reliable grid operations with high levels of wind resources) will lead to more firmly grounded conclusions regarding future generation technology mixes.

Both transmission overlays incorporate specific transmission projects that will contribute to the system's reliability needs for the ten-year period through the year 2018, and provide economic benefits in the 2024 time frame. The conceptual overlays were developed consistent with assumptions about fuel costs, load levels and resource expansion through 2024 for most of the Eastern Interconnection, with the important assumption that the Eastern Interconnection would be operated as a fully coordinated market. The process of creating the overlay options entailed extensive discussions in workshops with Eastern Interconnection stakeholders. The overlay options were systematically refined, adding and dropping various combinations of transmission facilities to develop the final sets of options that are economic within the context of the study's assumptions.[4] The final overlays for these scenarios have been reviewed using basic reliability screens, but have not been subjected to detailed design and reliability analyses; these transmission overlays should be viewed as conceptual rather than project-specific.

The process of locating new generation and developing and refining the transmission overlays is described in Sections 4 and 5 of the full report.

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[3] Additional reliability analyses needed include stability analysis, voltage and reactive power requirements, and analysis of the lower voltage systems that are necessary to successfully integrate the EHV transmission overlay's elements. Such analyses could be included in future transmission overlay analyses.

[4] Electric system cost-effectiveness analysis requires comparison of a project's economic savings relative to new generation and transmission capital and energy production costs. The JCSP study could not conduct rigorous cost-effectiveness analysis because it examined energy production costs and savings only for the years 2018 and 2024, and assumed that new transmission and generation investment occurred instantly (overnight) at the start of each horizon year. A more thorough cost-effectiveness analysis would incorporate the full stream of costs and benefits (i.e., energy and environmental savings) in every year of the forecast period; such a task was beyond the scope of this initial JCSP study.

To determine the net costs and impacts of each scenario, the JCSP 08 compared each scenario to a common base case, which contains the transmission constraints inherent in the existing system. Each scenario is evaluated by comparing the costs and benefits (production cost savings) of the base or constrained case to those of the scenario to determine the net impact of the transmission and generation assumed in each scenario; however, due to time constraints, the economic impacts have been calculated as point estimates for the year 2024 alone, rather than as a full year-after-year stream of benefits and costs. Although these estimates are offered in future value terms (2024 $), the reader should not assume that the costs and benefits represent cumulative benefits over a number of years; estimated capital costs are represented as if all of the new wind and fossil generation and transmission were built overnight at the start of the examined year. For that reason, this study does not attempt to estimate cost-effectiveness results for the two scenarios studied. Future studies should put more effort into refining the cost and economic assumptions and developing more rigorous cost and benefits calculations that span the full analysis period

11.1.3 Study Results

The JCSP 08 study examined two different resource and transmission paths to serve a total of 745,000 MW of coincident peak load in the Eastern Interconnection, except Florida in 2024. The Reference Scenario, which assumes that present RPS requirements are met with local on-shore wind resources, would add 10,000 miles of new Extra High Voltage (EHV) transmission at an assumed cost of approximately $50 billion. With 5% of the Interconnection's energy coming from wind and 54% from base load steam generation, total energy production costs in 2024 would equal $104 billion and total generation capital costs would equal $674 billion. In contrast, the 20% Wind Energy Scenario, which assumes a 20% national RPS requirement met by U.S. on-shore wind development, would add 15,000 miles of new EHV transmission at an assumed cost of approximately $80 billion. Under this scenario, energy production costs in 2024 would equal $85 billion and the capital cost of new generation would equal $1,050 billion. These results should be viewed as illustrative or "ballpark" costs rather than definitive findings about the costs of new transmission and generation related to either the status quo expansion path or a high-renewables scenario. Even with that caveat, however, the findings suggest that transmission overlays should be strongly considered as a way to improve the future reliability and economics of the nation's bulk power electric system under either policy path.

The transmission and generation additions assumed under each scenario are summarized below and discussed in detail in Section 5 of the full report.

11.1.4 Incremental Capacity Needs By 2024

To maintain electric reliability in 2024, new resources must be added to keep up with assumed future increases in demand. A new resource can be generation and transmission, or demand-side measures such as efficiency and demand response. In this study, a capacity expansion path was developed for each of the nine areas in the study to maintain an approximate 15% reserve margin across the Eastern Interconnection.

The JCSP 08 process handled resource additions for wind, demand response, and remaining supply-side resources as follows. The amount of new wind resource is based on the requirements of meeting either the Reference (5% wind) or 20% Wind Energy Scenario needs. The amount of demand response (DR) for this study is assumed to maintain the same percentage level of demand response as exists in 2008 (e.g., if a region had DR serving approximately 2.5% of peak demand in 2008, then new demand response additions were added out through 2024 to maintain that 2.5% share); energy efficiency was assumed to be embedded within the demand forecast. The type and timing of all of the other new supply-side resource additions is based on the relative life cycle costs of those resources, given stakeholder-accepted forecast assumptions for different technologies' capital costs, fuel and production costs, and environmental costs.

Figure 11-1 shows the capacity additions projected for the Reference and 20% Wind Energy Scenarios. Because the wind capacity figures are essentially fixed in each scenario, the remaining resources were selected by a least cost regional resource forecast model to fill in around the wind capacity. Future analyses should look further at alternative scenarios that rely more heavily on energy efficiency and demand response as resources that modify both supply and demand patterns and capabilities, as well as at alternate supply-side resource fuel and technology mixes.

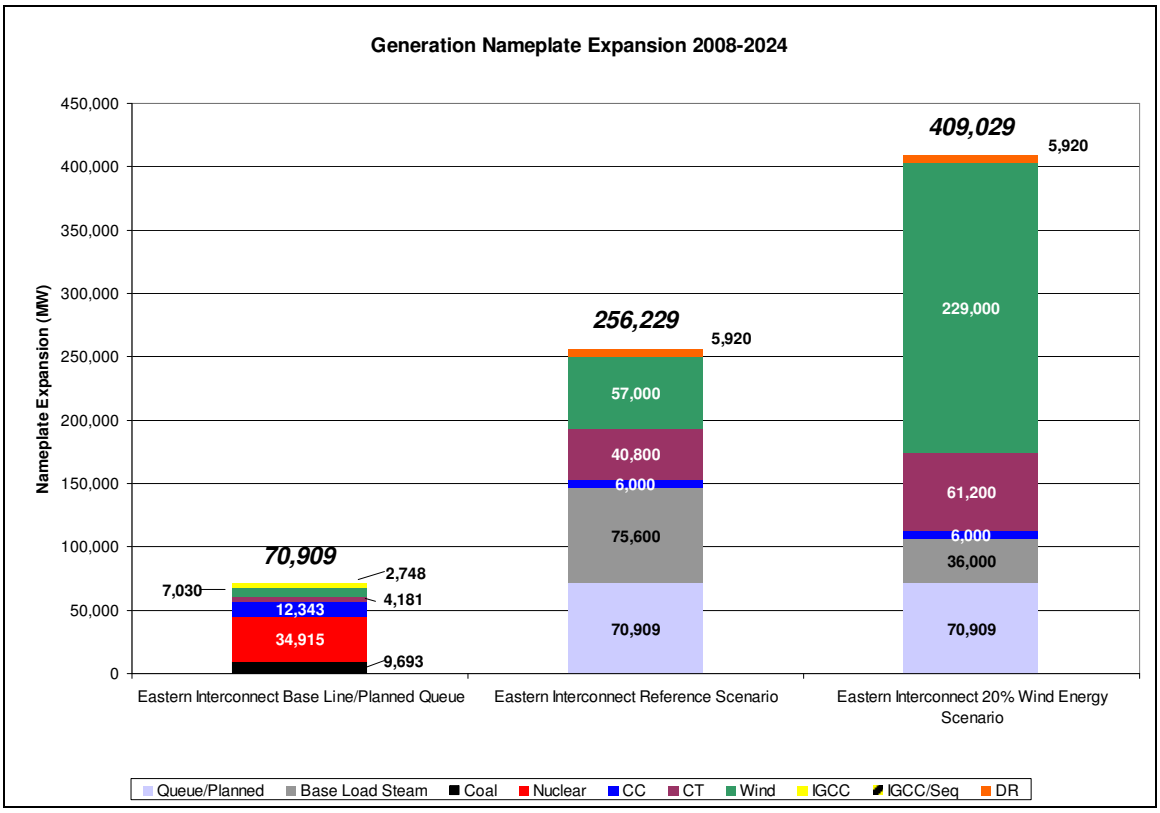

Figure 11-1: Capacity Additions by Resource Type

Table 11-1 provides more details on the transmission and generation investments made under the Reference and 20% Wind Energy Scenarios. While Figure 11-1 highlights the differences in generation types projected for each scenario, Table 11-1 shows that the Wind Scenario assumes significantly more high voltage direct current transmission construction (at a notably higher cost), reflecting the long distances over which wind energy is assumed to be shipped from the western Midwest to the northeast and southeast. There are high levels of base load steam generation assumed in both scenarios (54% under the Reference Scenario and 42% in the Wind Scenario), with the increased wind generation offsetting primarily base load steam production while requiring more production from fast-response, gas-fired combustion turbines. As might be expected, generation investment costs would be significantly higher under the 20% Wind Energy Scenario than under the Reference Scenario, but energy production costs would be lower with greater wind-power use, and those savings would increase over time.

Table 11.1-1: Summary Statistics for the Two Scenarios

		Reference Scenario		Wind Scenario	
			Percentage		Percentage
Transmission Overlay (Miles)	EHV AC (>=345 kV)	7,109	71%	6,898	48%
	HV AC (<345 kV)				
	HV DC	2,870	29%	7,582	52%
	Total	**9,979**	**100%**	**14,480**	**100%**
New Generation Expansion Capacity (MW)	Wind	57,000	31%	229,000	68%
	Base Load Steam	75,600	41%	36,000	11%
	Gas CT	40,800	22%	61,200	18%
	Gas CC	6,000	3%	6,000	2%
	Other	5,920	3%	5,920	2%
	Total	**185,320**	**100%**	**338,120**	**100%**
Energy Production (TWH)	Wind	24 6 % 2		764	18%
	Base Load Steam	2,160	54%	1,741	42%
	Gas	210	5%	301	7%
	Other	1,356	34%	1,371	33%
	Total	**3,968**	**100%**	**4,177**	**100%**
Transmission Capital Cost (2024 million $)	Transmission-overlay	42,159		72,825	
	Transmission-substations	6,401		7,074	
Overnight Construction Costs for Capacity Added through 2024 (2024 million $)	Generation-Wind	176,009	26%	648,813	62%
	Generation-Base Load Steam	250,882	37%	134,401	13%
	Generation-Gas	68,317	10%	87,861	8%
	Generation-Other	179,138	27%	179,138	17%
	Total	**674,346**	**100%**	**1,050,213**	**100%**
2024 Production Cost and Savings (2024 million $)	**Total Energy Production Cost**	**104,294**		**85,167**	
	Total Production Cost Savings from Constrained Case	**10,624**		**20,362**	

Capacity expansion in these scenarios is driven by the underlying need to maintain appropriate reserve margins within each region and across the Eastern Interconnection as a whole. In these scenarios, only 15% of the wind generation is counted as a capacity resource for reserve calculation purposes. This is because wind generation is only available when the wind blows, and is not available and dispatchable by system operators during all time periods. Since system operators can only count on fully dispatchable and predictable resources (such as fossil and nuclear resources and hydro storage units) for reliability purposes, less of the wind resource can be counted toward regional and Interconnection-wide reserve margins. Changes in loads, technologies and costs (including environmental or carbon costs and the capability of dynamic response and smart grid technologies to firm intermittent wind generation) could significantly change the pattern of generation capacity expansion and should be studied through further scenario and sensitivity analyses.

11.1.5 Carbon Emissions

The capacity expansion analysis allows the calculation of the amount of carbon and other emissions produced under each scenario studied. The JCSP 08 analysis found that under the Reference Scenario, the generation mix in the Eastern Interconnection produced a total of 35 billion tons of carbon between 2008 and 2024, with 5% wind energy; under the 20% Wind Energy Scenario, comparable carbon emissions reached 32.1 billion tons, an 8% reduction.

These carbon output findings are highly dependent upon the generation mix developed under each scenario. Any combination of changes to the scenarios and their underlying assumptions could materially change the carbon emissions results, including assumptions about more energy efficiency, more renewable energy generated in Canada and East Coast off-shore wind, a carbon tax or tight carbon emissions regulation, the relative economics between base load steam and gas generation, or transmission capital costs and congestion as they affect the ability to move renewable or base load steam power across the Interconnection.

11.1.6 The Reference Scenario - New Transmission Projects Totaling $50 Billion of Investment

The Reference Scenario assumes that wind generation from relatively local, on-shore sources produces 5% of the U.S. Eastern Interconnection's energy use. These assumptions and the resulting generation and transmission needs drive design of a transmission overlay and underlying expansion that includes 10,000 miles of new Extra High Voltage (EHV) transmission at an estimated cost of $50 billion. The new transmission is comprised of a mix of transmission line sizes ranging from 345 kV to 765 kV for AC lines and up to 800 kV for DC lines. The transmission required under this scenario enables renewable and base load steam energy generated in the western side of the Eastern Interconnection to reach a wider area, and has the potential to reduce energy costs to eastern consumers. For these assumptions, work performed to date indicates the transmission overlay for the Reference Scenario, with 5% wind energy, may have benefits that exceed costs on an aggregate interregional basis.

The types and approximate locations for the new transmission are shown in Figure 11-2.

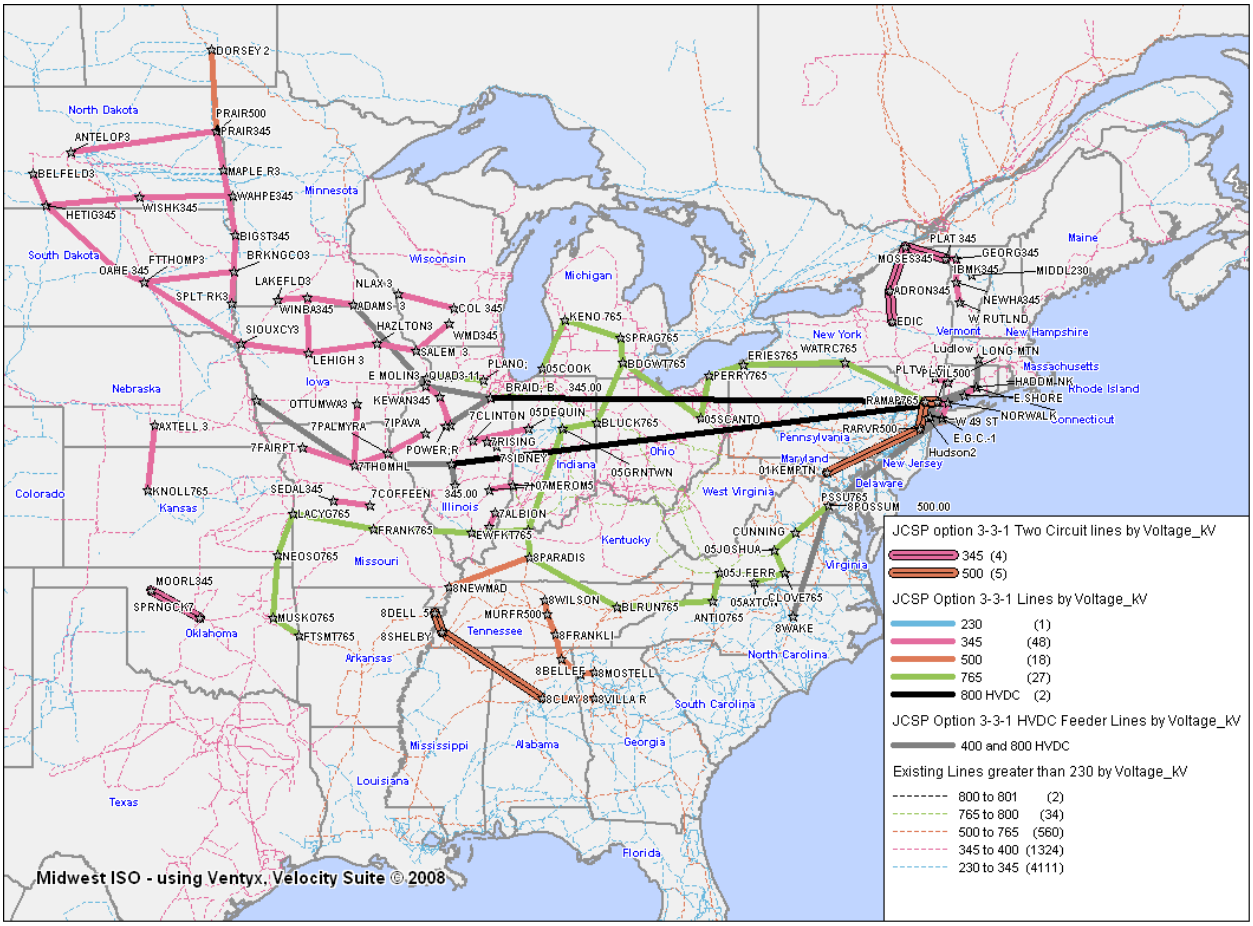

Figure 11-2: Reference Scenario Conceptual Transmission Overlay

11.1.7 The 20% Wind Energy Scenario – New Transmission Projects Totaling $80 Billion of Investment by 2024

The 20% Wind Energy Scenario presumes construction of a transmission overlay with 15,000 miles of new EHV transmission at an estimated cost of $80 billion. The new transmission would be a mix of transmission line sizes ranging from 345 kV to 765 kV for AC lines and up to 800 kV for DC lines. The majority of the conceptual overlay (approximately 75%) would be 765kV AC or 800kV DC. As in the Reference Scenario, the transmission overlay enables renewable and base load steam energy from the Midwest to reach a wider area and also has the potential to reduce energy costs to consumers along the Eastern Seaboard. Again, under the assumptions made in the JCSP 08, preliminary analysis indicates that this illustrative transmission overlay's benefits may exceed its costs.

The types and approximate locations for the new transmission are shown in Figure 11-3.

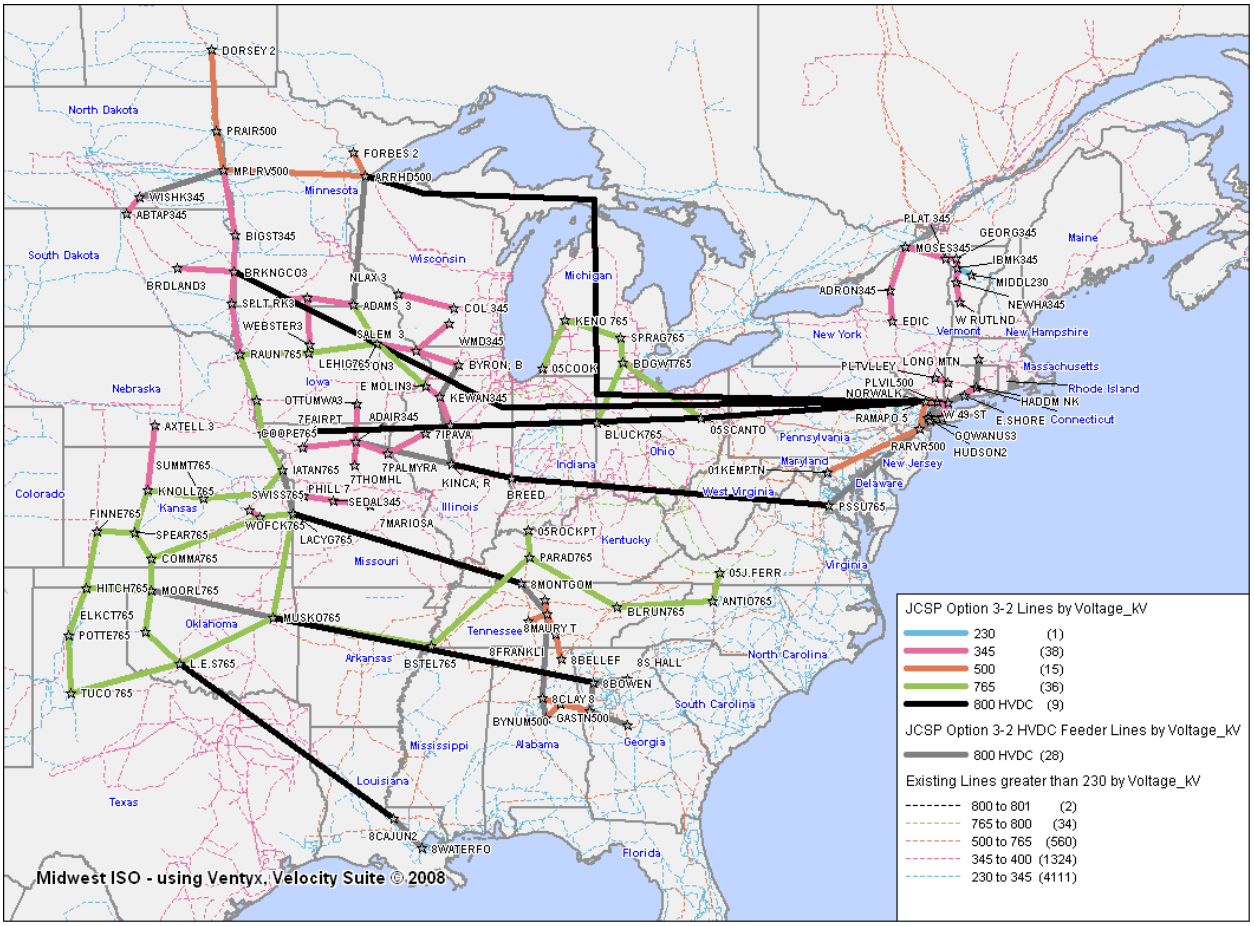

Figure 11-3: 20% Wind Energy Scenario Conceptual Transmission Overlay

Future analyses of high renewable generation scenarios should examine alternate assumptions about the location and density of future renewables development, with more attention to renewable resource development sited off-shore and in Canada, and more local rather than long-distance production and transmission. Each of these resource options would affect the type, location and cost of new transmission infrastructure needed.

11.2 JCSP Results From Midwest ISO's Perspective

The Midwest ISO performs transmission development analysis on a localized as well as on a regional scope. The roll-up of the transmission owner reliability plans focuses on the local requirements to maintain a reliable transmission system. Studies on the regional level focus on certain localized policy objectives in a longer time frame that gives a framework on integrating short-term transmission goals with longer-term economic and policy objectives.

An Eastern Interconnect wide study, such as the JCSP, provides an additional input to offer further guidance and context to internal Midwest ISO transmission development. A JCSP study offers the opportunity for the Midwest ISO and its neighbors to analyze potential policy decisions and technological advancements affecting supply, demand and transmission. This study also offers the chance for analysis to be performed on a common set of assumptions making results consistent for the entire Eastern Interconnect. By providing a long-term analysis platform, as well as reliability and economic analysis, the Midwest ISO region can position its internal transmission development to optimize internal system operation while building for a stronger interconnect.

By no means should transmission concepts developed though JCSP efforts be considered a plan within itself, but instead should be looked at as a supplement to the existing planning methodologies to help guide and interpret what projects meet a wide range of needs - not only short-term reliability requirements, but also long-term reliability, economic and energy transfer needs.

11.3 Looking Forward: JCSP 09 and Beyond

The JCSP 08 process offers an integrated approach to planning transmission and resource expansion for a very large area, considering both economic value and reliability needs. This approach has particular relevance if the nation is considering policies that would develop large amounts of remotely-located renewable and other generation distant from load centers. Although further analysis of reliability requirements is needed, the JCSP 08 study offers planners and policy-makers valuable insights for long-term transmission development.

Building upon the relationships and insights gained from this initial JCSP 08 effort, the stakeholders are looking forward. The Eastern Interconnection Planning Collaborative (EIPC) was formed since the completion of JCSP 08 and is expected to follow up on the JCSP 08 work and develop new scenarios to address analysis gaps. One question the group can address is whether EHV transmission overlays offer superior reliability and economic results to incremental transmission development under alternative policy - and cost-driven scenarios. After examining a wide range of future generation, load and policy scenarios, planners should be able to identify the common transmission elements and principles that surface in all of these scenarios, and use those common elements as the foundation for a robust final transmission plan that serves the Eastern Interconnection economically and reliably as electricity policies and economics evolve. Insights developed by the organization can inform a broad spectrum of groups including policy makers, transmission owners and developers, generation owners and developers and regulators, and help to improve the nation's transmission over the long term.

Although the JCSP 08 and successor efforts can help improve bulk power system planning in the Eastern Interconnection, parallel efforts will be needed to turn those plans into realities. Although many new generation and transmission investments are moving forward, continuing uncertainties about the nation's policies with respect to carbon regulation, renewable development policies, and super-regional cost and benefit allocation for projects that span multiple regions constrain other investments. More clarity about these policy issues will facilitate new bulk power system investments needed to turn infrastructure plans into reality and make inter-regional and interconnection-wide transmission expansion planning effective.

List of Acronyms Commonly Used Throughout MTEP09

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
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
METC	Michigan Electric Transmission Co. (ITC Holding)
MOD	Model on Demand
MP	Minnesota Power (& Light Co.)
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
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
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
PrjID	Project ID
PS	Planning Subcommittee
RA	Reliability Authority
RAR	Resource Adequacy Requirements
RECBII	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

Appendix A: Approved Projects

Appendix A contains projects which are being or have been approved by Midwest ISO Board of Directors. Transmission Owners are obligated to make a good faith effort to construct projects in Appendix A.

Appendix B projects have been reviewed by Midwest ISO staff for need and effectivenes.

Appendix C projects are new to planning process or conceptual

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Project Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Project ID: Midwest ISO project identifier
Project Name	Project name (short name)
Project Description	A description of the project's components
State	State project is located or a majority of project if in multiple states
State 2	If applicable, the second state the project is located
Allocation Type per FF	Project Type per Attachment FF of Tariff. BaseRel is Baseline Reliability, GIP is Generator Interconnection Project, TDSP is Transmission Delivery Service Project, RegBen is Regionally Beneficial Project, Other is non of the above. Preliminary project types may be designated for Appendix B and C projects
Share Status	Projects moving to Appendix A in current planning cycle are eligible for cost allocation per terms in Attachment FF. Projects are Shared, Not Shared or Excluded. Preliminary sharing designations may be input for Appendix B or C projects.
Other Type	Indicates the project driver behind Other type projects.
Estimated Cost	Total estimated project cost from Facility table
Expected ISD	Date when entire project is expected to be inservice. Expected ISD are in Facility table.
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Max kV	Maximum facility voltage in project. Summary information from Facility table
Min kV	Minimum facility voltage in project. Summary information form Facility table
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.

Appendix A: Project Table 10/16/2009 *Project Summary Information from Facility table*

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A in MTEP09	Central	AmerenIL	2269	South Bloomington 138kV Capacitor Bank	Install an 80 MVAR, 138 kV Capacitor Bank at the South Bloomington Substation	IL		BaseRel	Not Shared		$1,224,100	6/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2271	Hennepin-Oglesby Line 1556 Term. Equipment	Upgrade terminal equipment at Hennepin to match line conductor capability (1360 A summer emergency)	IL		BaseRel	Not Shared		$902,000	6/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2277	Steelville Sub. 138 kV Bus-Tie	Rconnect 2-CT's to 1000 A	IL		BaseRel	Not Shared		$50,000	6/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2278	Mt. Vernon, West Bus-Tie	Upgrade bus conductor to 1200 A summer normal capability	IL		BaseRel	Not Shared		$30,000	6/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2272	Hennepin-E. Kewanee 138 kV - Term. Equipment	Replace 600 A CT at Hennepin with 1200 A unit	IL		Other	Not Shared	TO Criteria	$71,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2273	Supply to LaFarge Customer Substation	Provide 161 kV supply to customer substation	IL		Other	Not Shared	Distribution	$570,000	12/1/2009	Planned	161		B>A	Y
A in MTEP09	Central	AmerenIL	2276	Clinton Route 54 Sub. Bus-Tie	Reconnect 600 A CT to 1200 A	IL		BaseRel	Not Shared		$50,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2059	Centerville Breaker Addition	Install a 138 kV PCB at Centerville Substation to replace normally-open 138 kV Switch #1497. Minimum capability 2000 A. New breaker is to be operated normally closed.	IL		BaseRel	Not Shared		$1,139,000	6/1/2010	Proposed	138		B>A	Y
A in MTEP09	Central	AmerenIL	2063	North Coulterville – 230/138kV Transformer Upgrade	Replace existing 140 MVA, 230/138 kV transformer with a 225 MVA unit. Install new 230kV circuit switcher and disconnect switch. Install new potential transformers for station power and upgrade the wave trap on the Coulterville-Tilden 138 kV line	IL		BaseRel	Not Shared		$1,251,000	6/1/2010	Proposed	230	138	B>A	Y
A in MTEP09	Central	AmerenIL	2274	Oglesby Substation 138 kV Breaker Replacements	Replace 5-138kV circuit breakers and CT's, and a wave trap on 138kV Line 1516 with new equipment having a minimum continuous current capability of 1,200 A	IL		BaseRel	Not Shared		$1,057,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2281	Mt. Vernon-Ashley 138 kV	Replace 2-600 A, 138 kV disconnect switches at Ashley terminal with 1200 A switches	IL		BaseRel	Not Shared		$64,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2284	Turkey Hill-S. Belleville 138 kV Line 1532	Replace terminal equipment at both ends to 1600 A continuous capability	IL		BaseRel	Not Shared		$471,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2764	Pana North Transformer Upgrade	Replace existing 400 MVA unit with an existing spare transformer with 560 MVA capacity	IL		Other	Not Shared	Local Econ	$5,300,000	12/31/2010	Planned	345	138	B>A	Y
A in MTEP09	Central	AmerenIL	2829	Coffeen - Coffeen North 345 kV	Install a second 345 kV bus tie between Coffeen and Coffeen N ring busses; add a ring bus position at each station. Replace Coffeen N. wave trap and Ramsey E. switch to increase line rating from 956 MVA to 1195 MVA.	IL		RegBen	Shared		$5,591,000	12/31/2010	Planned	345		B>A	Y
A in MTEP09	Central	AmerenIL	2270	Hennepin-Oglesby Line 1516 Term. Equipment	Replace three 138kV breakers and wave trap in the Hennepin Substation Increase clearances to ground on 14.46 miles of 795 kcmil ACSR from Hennepin to the Ottawa tap Upgrade Hennepin to Oglesby 138kV terminal equipment to 1,200 A	IL		BaseRel	Not Shared		$2,525,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2279	Grand Tower-Steeleville 138 kV Reconductor	Reconductor 6.19 miles of 477 kcmil ACSR to carry 1200 A under summer emergency conditions	IL		BaseRel	Not Shared		$1,866,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2285	South Belleville 138-34.5 kV Substation	Upgrade terminal equipment for South Belleville-17th Street circuit position to 1,600A continuous capability. Reconductor 2.57 miles of 138kV conductor between South Belleville and the Belleville 17th Street tap	IL		Other	Not Shared	Reliability	$2,642,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	Central	AmerenIL	2287	Stallings-E. Collinsville 138 kV Line Upgrades (Line 1426)	Upgrade terminal equipment at Stallings and East Collinsville to a minimum 1,600A capability Increase ground clearance on 8.59 miles of 138 kV line from Stallings to East Collinsville.	IL		BaseRel	Not Shared		$1,395,000	6/1/2011	Proposed	138		B>A	Y

Appendix A: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A in MTEP09	Central	AmerenIL	2472	New 345kV Supply at Fargo Substation	Tap existing 345kV line from Duck Creek to Tazewell and create new Maple Ridge Substation ($6.5M) Build a new supply line to the Fargo Substation by extending 20 miles of 345kV from the new Maple Ridge Substation ($50.1M) Create Fargo Station and install 560 MVA 345/138kV Transformer ($9.4M)	IL		BaseRel	Shared		$66,019,000	12/1/2016	Planned	345	138	B>A	Y
A in MTEP09	Central	AmerenMO	2787	North Park 138-12.47 kV Substation	Construct a new 138/12kV substation with two 33MVA transformers, sourced from 138kV Page-Berkeley Lines 1 and 2	MO		Other	Not Shared	Distribution	$2,650,000	6/1/2009	Planned	138	12.47	B>A	Y
A in MTEP09	Central	AmerenMO	2275	AECI Spalding Substation Connection	Tap Peno Creek-Palmyra 161 kV for Spalding connection	MO		Other	Not Shared	Distribution	$749,100	12/1/2009	Planned	161		B>A	Y
A in MTEP09	Central	AmerenMO	2282	Selma-St. Francois 138 kV Line Reconductor	Reconductor 15.5 miles of paralleled 4/0 Cu conductor to 1200 A summer emergency capability	MO		BaseRel	Not Shared		$4,650,000	12/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	AmerenMO	1240	Reconductor Sioux-Huster-1 and -3 138 kV	Reconductor 9.1 miles of 138kV line on Sioux-Huster 1 and 3 lines	MO		BaseRel	Shared		$12,966,000	6/1/2012	Proposed	138		B>A	Y
A in MTEP09	West	ATC LLC	2161	Uprate Glenview-Shoto 138 kV	Increase line clearance to 200 deg F SN/SE	WI		Other	Not Shared	Clearance	$1,412,755	6/1/2009	Proposed	138		B>A	Y
A in MTEP09	West	ATC LLC	2458	Stoughton Terminal uprates	Uprate Stoughton Terminal Equipment	WI		Other	Not Shared	Reliability	$697,998	6/1/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2776	Spring Green Mobile Cap	Mobile cap bank placed at Spring Green	WI		Other	Not Shared	Reliability	$670,116	7/15/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2022	Uprate Delta-Mead-NorthBluff 69 kV	Increase line clearance to 167 deg F SN/SE	MI		Other	Not Shared	Reliability	$156,000	9/1/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2023	Uprate Masonville-Gladstone 69 kV	Increase line clearance to 167 deg F SN/SE	MI		Other	Not Shared	Reliability	$190,418	9/1/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2024	Uprate North Bluff-Gladstone 69kV	Increase line clearance to 167 deg F SN/SE	MI		Other	Not Shared	Reliability	$178,059	10/1/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2459	Sun Valley T-D	Tap Sun Valley Tap into Oregon-Verona 69-kV & Construct a 3.3 mile Sun Valley Tap-Sun Valley 69-kV line	WI		Other	Not Shared	Distribution	$3,046,857	10/17/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2021	Uprate Chandler-LakeheadTap-Masonville 69 kV	Increase line clearance to 167 deg F SN/SE	MI		Other	Not Shared	Reliability	$535,000	10/30/2009	Planned	69		B>A	Y
A in MTEP09	West	ATC LLC	2453	Rebuild Arpin-Rocky Run 345 kV	Rebuild Arpin-Rocky Run 345 kV	WI		Other	Not Shared	Condition	$23,544,820	6/1/2010	Planned	345		B>A	Y
A in MTEP09	West	ATC LLC	2452	G706 Randolph Energy Center Wind Farm	G706 Randolph Energy Center Wind Farm; taps Friesland-Hamilton 138 kV line	WI		GIP	Shared		$3,867,377	10/1/2010	Planned	138		B>A	Y
A in MTEP09	West	ATC LLC	2455	G611 Ecomet Wind	G-T Interconnection Taps Forest Jct-Elkhart Lk 138 kV	WI		GIP	Shared		$4,464,956	12/31/2010	Planned	138		B>A	Y
A in MTEP09	West	ATC LLC	2796	Ledge Wind G773	G-T Interconnection Taps Forest Jct-Lost Dauphin 138 kV	WI		GIP	Shared		$4,950,990	3/1/2011	Proposed	138		B>A	Y
A in MTEP09	Central	DEM	2152	WVPA Anson North new 69kv dist sub	WVPA Anson N. Jct - DEM to Install two single 1200 amp 69kv line switches with provisions for tap line - in the 69186 line between Whitestown and Brownsburg N. Jct to serve new WVPA sub	IN		Other	Not Shared	Distribution	$86,000	3/1/2009	In Service	69		B>A	NT
A in MTEP09	Central	DEM	2376	Pierce 345/138kV TB B & A Replacement	Replacement of failed Pierce 125 MVA TB "B" plus 125 MVA TB "A" with 400 MVA system spare & reconductor 138kV cir 1889	OH		BaseRel	Not Shared		$1,541,334	5/1/2009	In Service	345	138	B>A	Y
A in MTEP09	Central	DEM	1567	Rockies Express-Install 138 kv Ring Bus	Rockies Express-Inst Ring Bus-Install Four Breaker 138 kV ring bus & associated equipment and 2-138/13.1 distribution Xfmrs; on the 5689 ckt	OH		BaseRel	Not Shared		$500,000	6/1/2009	In Service	138	13.1	B>A	Y
A in MTEP09	Central	DEM	1572	Wards Corner new 138-13.1 KV substation	Loop the F9482 ckt through a new substation with a 138-13.1 KV - 22.4 mva xfmr	OH		Other	Not Shared	Distribution	$656,000	6/1/2009	In Service	138	13.1	B>A	Y
A in MTEP09	Central	DEM	1888	Liberty - new 69/13kV distribution sub	new Liberty 22.4MVA 69-13.09 kV sub and approx. 5.5 mile - 69kv line - 954 kcmil 45/7 ACSR - from Allen sub	OH		Other	Not Shared	Distribution	$3,100,000	6/1/2009	Under Const	69	13.1	B>A	NT
A in MTEP09	Central	DEM	2336	HE Martinsville Park Ave 69kV Switches	HE Martinsville Park Ave (new sub) - Install two one-way 1200amp 69kV line swiches at tap for new HE sub in 6903 line	IN		Other	Not Shared	Distribution	$150,000	6/1/2009	In Service	69	12	B>A	NT
A in MTEP09	Central	DEM	2338	HE Solar Sources Portal #1 - 69kV Switches	HE Solar Sources Portal #1 - install 69kV-1200A line Switches in the 6963 ckt to serve new HE mine load	IN		Other	Not Shared	Distribution	$62,363	6/1/2009	In Service	69		B>A	NT

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A in MTEP09	Central	DEM	2374	Evendale Replace 138kv CB 952	Replace CB 952 and disconnect sws at Evendale Sub with 2000 Amp rated eq, upgrade F4685 metering @ both Sta. (Metering was 1255A limmited - New rating will be 1600A - 382 mva)	OH		BaseRel	Not Shared		$500,000	6/1/2009	In Service	138		B>A	Y
A in MTEP09	Central	DEM	1562	Bloomington Rockport Rd	Build 22.4MVA 138/12kV sub w/ 2 12kV exits in Bloomington, IN near intersection of SR37 & Rockport Road. Tap 13837 line.	IN		Other	Not Shared	Distribution	$513,000	8/1/2009	Under Const	138	12	B>A	Y
A in MTEP09	Central	DEM	2335	HE Gateway Ind Pk 69kV Switches	HE Gateway Industrial Park (new sub) - Install two one-way 1200amp 69kV line swiches at tap for new HE sub in 6918 line	IN		Other	Not Shared	Distribution	$103,000	8/1/2009	Under Const	69	12	B>A	NT
A in MTEP09	Central	DEM	1882	Carmel 69kV to Towne Rd Jct ckt 6989 rebuild	Reconductor 69kV - 6989 line from Carmel 69kV to Towne Rd N. Jct with 954 ACSR @ 100C, Shell Jct. Switch to be upgraded from 600 amp to 1200 amp	IN		Other	Not Shared	Reliability	$834,141	12/1/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	1885	Todhunter to Carlisle 69kV - F5661 line uprate	Todhunter to Carlisle 69kV - Feeder 5661 Uprate to 100C	OH		Other	Not Shared	Reliability	$561,600	12/1/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2138	Greenwood HE Gilmore 69kV Switches	Greenwood HE Gilmore - Upgrade (2) 69kV line switches for 1200 amp capacity (or replace if required) in the 69102 line	IN		Other	Not Shared	Reliability	$183,000	12/1/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	1883	Brown to S. Bethel 69kV - F5863 line uprate	Brown to S. Bethel 69kV line uprate - Modify spans in F5863 as required to provide clearance for 100C operation - 477 kcmil ACSR conductor	OH		Other	Not Shared	Reliability	$97,057	12/31/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	1884	Wilder to Kenton 69kV - F965 line uprate	Wilder to Kenton 69kV line uprate - Modify spans in 69 kV Feeder 965 as required to provide clearance for 100 C operation - 477 kcmil ACSR conductor	KY		Other	Not Shared	Reliability	$128,975	12/31/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2126	Martinsville SE Jct replace line switches	600A switches 1&2 to be replaced with 1200A switches in the 6903 line	IN		Other	Not Shared	Reliability	$146,000	12/31/2009	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2141	Terminal Sub Phase 2 Rehab	Terminal Substation - replace 138kv bank breaker and moving from line terminal 1782 over to main 138kv bus #1; replacing: 345kv(4514) wave trap, 138kv(1782 and 7481) wave traps	OH		Other	Not Shared	Condition	$1,269,000	12/31/2009	Under Const	345	138	B>A	Y
A in MTEP09	Central	DEM	2373	Lafayette Concord Jct to Laf Industry S. - 138kV uprate	Lafayette Concord Jct to Laf Industry S. - 13808 ckt - uprate 397acsr conductor to 100C - one h-frame structure to replace	IN		BaseRel	Not Shared		$11,400	12/31/2009	Planned	138		B>A	Y
A in MTEP09	Central	DEM	1879	KY University 138kV Bus and Dist Bk addition	Reconfigure 138kV bus for and add on a 22.4 MVA (2nd) distribution xfmr	KY		Other	Not Shared	Distribution	$90,513	6/1/2010	Planned	138	13.2	B>A	Y
A in MTEP09	Central	DEM	2149	West End 138kv bus tie and 1389 line bkrs	West End substation - Install a 138kV circuit breaker to tie the east and west 138 kV busses together and a line breaker in the 1389 ckt	OH		BaseRel	Not Shared		$1,040,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	DEM	2150	Plainfield West 69-12kv Distribution Sub	Plainfield West new dist sub; 22.4MVA w/4 12kV exits; loop 69125 ckt through sub	IN		Other	Not Shared	Distribution	$161,000	6/1/2010	Planned	69	12	B>A	NT
A in MTEP09	Central	DEM	2151	Wilder 138kV-5985 reactors & wavetrap	Wilder Sub - Install 138kV, 3.8 Ohm reactors in ckt 5985; replace 138kv - 5985 1200A wavetrap with 1600A	OH		BaseRel	Not Shared		$690,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	DEM	2131	Whiteland Jct to Madison Ave Jct Uprate 69	Whiteland Jct to Madison Ave Jct uprate 1.29 miles 69kV line section for 100C operation	IN		Other	Not Shared	Reliability	$28,000	6/30/2010	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2375	G941 Yankee - 69kV New Sub for SunCoke (Middletown Coke Co. Inc) generator.	Install 69kv substation and 5 brkr ring bus on Yankee Rd. for SunCoke (Middletown Coke Co. Inc) generator, loop F5661 & F5666 through station	OH		GIP	Shared		$4,440,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	Central	DEM	1647	Carmel SE 69/12 KV new distribution substation	Construct Carmel SE Bank 1 22.4MVA bank with 2 exits - extend a new radial 69kv from Carmel 146th St (no new bkr - share dist bk terminal)	IN		Other	Not Shared	Distribution	$2,000,000	6/1/2011	Planned	69	12	B>A	NT
A in MTEP09	Central	DEM	2128	Martinsville to Martinsville SE 69kV Jct Uprate	Martinsville to Martinsville SE 69kV Jct Uprate 6903 line's 336acsr to 100C operation	IN		Other	Not Shared	Reliability	$439,000	6/1/2011	Planned	69		B>A	NT

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A in MTEP09	Central	DEM	2334	Fishers 106th St 69/12kv New Sub	New Fishers 106th St 69/12 kv sub: Construct 69kV line in and out of sub and 69kv bus including 69kv breaker	IN		Other	Not Shared	Distribution	$174,000	6/2/2011	Planned	69	12	B>A	NT
A in MTEP09	Central	DEM	1880	Columbia 138kV-22.4MVA Sub	Columbia 138kV-22.4MVA Sub - New site or purchase and rebuild existing Siemens Sub #537- in F5484 between Warren and Maineville	OH		Other	Not Shared	Distribution	$215,000	12/31/2011	Planned	138	12	B>A	Y
A in MTEP09	Central	DEM	2148	Cadiz to Milner's Corner Jct 69kv reconductor	Cadiz to Markleville to Milner's Corner J - Reconductor 69kv - 69131 ckt - 9.24 mile section with 477ACSR@100C; Replace 69kv three way switch at Milner's Corner Jct with three one way 1200A switches; Upgrade the Markleville 600A switches #1 and #2 to 1200A	IN		Other	Not Shared	Reliability	$3,860,000	5/1/2012	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2133	Franklin to Forsythe new 69kV line	Franklin 230 sub to Forsythe 69 sub - Build new 3.5 mile 69kV line; new line terminal at Forsythe end only	IN		Other	Not Shared	Reliability	$1,030,000	6/1/2012	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2154	Carmel Rohrer Rd 69/12kv New Sub	Carmel Rohrer Rd 69/12-22.4MVA sub to looped through the 6989 ckt. at or near the existing Carmel Shell Oil tap	IN		Other	Not Shared	Distribution	$591,143	6/1/2012	Planned	69	12	B>A	NT
A in MTEP09	Central	DEM	2331	Shelbyville NE to Knauf 69kv - 6946 ckt. Reconductor	Shelbyville NE to Knauf Reconductor 1.75 miles of 397ACSR on 6946 ckt. with 954acsr@100C	IN		Other	Not Shared	Reliability	$777,000	6/1/2012	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2332	Zionsville Turkeyfoot to Zionsville 96th St Jct 69kV - 69155 ckt. Reconductor	Zionsville Turkeyfoot to Zionsville 96th St Jct Reconductor 1.59 mile 69kV - 69155 ckt with 954ACSR@100C	IN		Other	Not Shared	Reliability	$704,000	6/1/2012	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2132	Frances Creek 69kV capacitor	Frances Creek Install 36MVAR 69kV capacitor bank	IN		Other	Not Shared	Reliability	$615,500	6/30/2012	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2153	Mohawk to Lee Hanna 69kV reconductor	Mohawk to Lee Hanna 69kV reconductor 69130 ckt (5.27 mi) with 954acsr@100C	IN		Other	Not Shared	Reliability	$2,317,000	6/1/2013	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2327	Speed to HE Bethany 69kV - 6955 Reconductor Ph1	Speed to HE Bethany 69kV - 6955 Reconductor Ph1 - Replace 5.2 miles of 3/0 ACSR with 477 ACSR (new limiter 4/0acsr)	IN		Other	Not Shared	Reliability	$1,560,000	6/1/2013	Planned	69		B>A	NT
A in MTEP09	Central	DEM	2127	Martinsville 69163-1 switch replacement	69163-1 switch replacement near tap to HE Cope with 1200A switch	IN		Other	Not Shared	Reliability	$40,000	6/1/2019	Planned	69		B>A	NT
A in MTEP09	East	FE	2769	ZincOx - New Customer Tap	New 20 MW to 30 MW customer being tapped to the Vulcan-Wauseon between York and Delta			Other	Not Shared	Distribution	$200,000	11/30/2009	Planned	138		B>A	Y
A in MTEP09	East	FE	2263	Brookside - Cloverdale 138 kV Line - Reconductor	Reconductor 20.38 miles of 336,4 ACSR with 336.4 ACSS/TW.	OH		BaseRel	Not Shared		$1,169,400	6/1/2010	Planned	69		B>A	Y
A in MTEP09	East	FE	2249	Inland Substation - Cleveland Public Power 4th Interconnect	Install a 138 kV exit with breaker and add a breaker to the Q-14-IN-IV at Inland Substation. Replace an overdutied Q-18 breaker at Ivy Substation.	OH		Other	Not Shared	Distribution	$895,500	9/1/2010	Planned	138		B>A	Y
A in MTEP09	East	FE	2788	Hitchcock Reconfigure				Other	Not Shared	Move	$982,000	10/1/2010	Planned	138		B>A	Y
A in MTEP09	East	FE	1920	Shinrock/Johnson area 138-69kV Substation	Build a 138/69 kV substation with a high side ring bus on the Beaver-Brookside 138 kV Line. Install 3 - 69 kV exits and necessary reconductoring on the Johnson 69 kV Line.	OH		Other	Not Shared	Reliability	$6,091,601	6/1/2011	Planned	138	69	B>A	Y
A in MTEP09	East	FE	2791	Toledo 69 kV Line Reconfigurations Associated with BP Oil 138 kV Service Project	Reconfigure the existing 69 kV lines: BP Oil (6896) to Locust (6815) line, BP VRDS (6885) to Ironville (6965) line, BP ISO2 (6899) to Ironville (6967) line tpo create the following 69 kV lines: A new Ironville (6967) to Locust (6815) line and a new Ironville (6965) radial 69 kV line (to CSX-Toledo, Union Oil and N. O. switch 6647). The reconfiguration is necesary due to the project to rpovide 138 kV servie to BP Oil. (RPA WOH-09-080721-152149)			Other	Not Shared	Reconfig	$198,900	6/1/2011	Proposed	69		B>A	Y

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A in MTEP09	East	FE	2790	69kV line to connect 69 kV radials at Hillcrest (Y-194) and Grant St (Y-196)	Build 69kV line section (approx 1.6 mi) from Grant St 69kV Substation to Hillcrest Substation. Replace Y-196 line exit relays at Cedar Street Substation with SEL 321 and SEL 311B relays to replace basic overcurrent relays presently installed for radial circuit. Install SCADA controlled MOAB switches at Grant Street and Hillcrest for line sectionalizing. The switch at Grant Street towards Hillcrest will be equipped with a vacuum interruptor.	OH		Other	Not Shared	Reliability	$610,635	6/1/2011	Planned	69		B>A	Y
A in MTEP09	East	FE	2753	BP Oil - 138kV Service	138 kV service to BP Oil. Loop two existing 138 kV lines into new BP Substation	OH		BaseRel	Not Shared		$800,000	11/1/2011	Planned	138	69	B>A	Y
A in MTEP09	East	FE	1612	Cranberry Substation	Construct a 500/138kV Sub with four exits in the Cranberry/Adams Township area.	PA		BaseRel	Shared		$37,738,043	6/1/2012	Planned	500	138	B>A	Y
A in MTEP09	East	FE	2264	Greenford Substation - Install 69 kV, 14.4 MX Cap Bank	Install a 14.4MVAR, 69 kV cap bank at Canfield.	OH		Other	Not Shared	Reliability	$200,000	6/1/2012	Planned	69		B>A	Y
A in MTEP09	East	FE	2789	Masury-Salt Springs Cap Bank Addition	Install 21.6 MVAR capacitor bank at Vienna 69kV substation. Bank installation will include free standing disconnect switch, cap switcher, CT's, cap bank, plus all associated foundations and pads.			Other	Not Shared	Reliability	$580,000	6/1/2012	Proposed	69		B>A	Y
A in MTEP09	East	FE	1607	Hanna Sub - Loop the Cham - Mansfield 345 kV Line in	Loop the Chamberlin - Mansfield 345 kV Line in and out of Hanna Substation creating a Chamberlin - Hanna and a Hanna - Mansfield 345 kV Line.	OH		Other	Not Shared		$5,597,657	6/1/2013	Proposed	345		B>A	Y
A in MTEP09	East	FE	2814	Midway-Richland-Wauseon 138 kV line-Reconductor	Reconductor the Naomi Jct-Wauseon 138 kV line section (4.98 miles) from 336.4 ACSR to 795 ACSR. Modify setting or replace thermal relay at Wauseon	OH		BaseRel	Not Shared		$650,000	6/1/2013	Planned	138		B>A	Y
A in MTEP09	East	FE	2120	Keystone Substation, New 138-36kV Substation	Construct 2 138kV loops to a new Keystone 138-36kV distribution substation for additional support of the area	OH		Other	Not Shared	Distribution	$4,000,000	12/31/2013	Planned	138	36	B>A	Y
A in MTEP09	East	FE	2266	Pine Substation - Add (1) 100/134 MVA 138/69kV transformer unit	Add one new 100/134 MVA unit with the ability to be switched to either East or West bus at Pine Substation.	PA		Other	Not Shared	Reliability	$4,244,800	6/1/2015	Proposed	138	69	B>A	Y
A in MTEP09	West	GRE	2553	Milroy-Sheridan 69kV line addition	Milroy-Sheridan 69kV line addition	MN		TDSP	Not Shared		$630,000	6/1/2009	Under Const	69		B>A	Y
A in MTEP09	West	GRE	2554	Tamarac Two 115 kV line breakers	Tamarac Two 115 kV line breakers, 115 kV capacitor	MN		BaseRel	Not Shared		$668,000	6/1/2009	Planned	115		B>A	Y
A in MTEP09	West	GRE	2557	Lake Mina (REA) 115 kV	Lake Mina (REA) 115 kV	MN		Other	Not Shared	Distribution	$387,000	6/1/2009	Planned	115		B>A	Y
A in MTEP09	West	GRE	2560	Alexandria-Parkers Prairie Tap Retemp (26.75miles)	Alexandria-Parkers Prairie Tap Retemp (26.75miles)	MN		Other	Not Shared	Reliability	$255,000	6/1/2009	Planned	41.6		B>A	NT
A in MTEP09	West	GRE	2561	Le Sauk 115 kV conversion with Sartell	115 kV conversion	MN		Other	Not Shared	Reliability	$375,000	6/1/2009	Planned	115		B>A	Y
A in MTEP09	West	GRE	2575	Mary Lake-Buffalo 69 kV transmission	Mary Lake-Buffalo 69 kV transmission	MN		Other	Not Shared	Reliability	$718,000	6/1/2009	Under Const	69		B>A	NT
A in MTEP09	West	GRE	2619	Remmele Tap-Big Lake-Waco-Elk River West Temperature Upgrade	Remmele Tap-Big Lake-Waco-Elk River West Temperature Upgrade	MN		Other	Not Shared	Reliability	$268,000	6/1/2009	Planned	69		B>A	NT
A in MTEP09	West	GRE	2556	Ritter Park (DEA) 115 kV Substation	Ritter Park (DEA) 115 kV Substation	MN		Other	Not Shared	Distribution	$1,335,000	11/1/2009	Planned	115		B>A	Y
A in MTEP09	West	GRE	2612	Soderville Bus Replacement	Upgrade Bus capacity	MN		Other	Not Shared	Reliability	$340,000	12/1/2009	Proposed	69		B>A	NT
A in MTEP09	West	GRE	2613	Pilot Knob--Yankee Doodle Projects	Conversion to 115 kV	MN		Other	Not Shared	Reliability	$1,870,000	12/1/2009	Planned	115		B>A	Y
A in MTEP09	West	GRE	2559	Orr (LCP) 13 mile, 69 kV line	Orr (LCP) 13 mile, 69 kV line	MN		Other	Not Shared	Distribution	$5,275,000	12/31/2009	Planned	69		B>A	NT
A in MTEP09	West	GRE	2562	G362 - Pleasant Valley 345/161 KV transformer	G362 Network Upgrades: Pleasant Valley 345/161 kV transformer (GRE part of G362)	MN		GIP	Shared		$8,100,000	2/1/2010	Planned	345	161	B>A	Y
A in MTEP09	West	GRE	2563	Athens to Martin Lake 69kV System Upgrades and Permitting	Athens to Martin Lake 69kV System Upgrades and Permitting	MN		Other	Not Shared	Reliability	$6,000,000	12/1/2010	Planned	69		B>A	NT
A in MTEP09	Central	IPL	2053	Petersburg 345/138kV East and West Autotransformers	Replace and upgrade existing East and West 345/138kV autotransformer at Petersburg Substation	IN		BaseRel	Shared		$15,400,000	6/1/2012	Planned	345	138	B>A	Y
A in MTEP09	East	ITC	2544	Oakwood	New distribution interconnection served from River Rouge-Navarre 120kV circuit	MI		Other	Not Shared	Distribution	$200,000	7/1/2009	Planned	120		B>A	Y
A in MTEP09	East	ITC	2543	MacSteel GOAB	Install 3-way GOAB switch at North Star Tap point on Custer-Monroe 120kV circuit	MI		Other	Not Shared	Distribution	$200,000	7/31/2009	Planned	120		B>A	Y
A in MTEP09	East	ITC	1860	Breaker Replacement Program 2009	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2009	Planned			B>A	Y

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A in MTEP09	East	ITC	1862	Cable Termination Replacement 2009	Replace high pressure gas filled underground cable terminations throughout system.	MI		Other	Not Shared	Condition	$3,000,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	1864	Relay Betterment Program 2009	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2523	Capacitor Replacement 2009	Replace capacitor banks	MI		Other	Not Shared	Condition	$565,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2526	Potential Device Replacement 2009	Replace aging potential devices	MI		Other	Not Shared	Condition	$300,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2529	Power Plant Control Relocation 2009	Relocate substation controls currently located in power plant control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2532	Wood Pole Replacement 2009	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$1,200,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2535	Synchronizing Sites 2009	New 120kV synchronizing sites	MI		Other	Not Shared	Operations	$565,000	12/31/2009	Planned			B>A	Y
A in MTEP09	East	ITC	2518	Bloomfield - Wheeler 120kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$20,000	6/1/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	2540	Genoa - Latson	Replace all line structures and insulators.	MI		Other	Not Shared	Condition	$1,500,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	ITC	2545	Marathon/Navarre	New distribution interconnection served from Navarre substation	MI		Other	Not Shared	Distribution	$640,000	9/1/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	1861	Breaker Replacement Program 2010	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	1863	Cable Termination Replacement 2010	Replace high pressure gas filled underground cable terminations throughout system.	MI		Other	Not Shared	Condition	$3,000,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	1865	Relay Betterment Program 2010	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	1872	Scio	Distribution Interconnection to add new 120/41kV transformer. Loops the Lark-Spruce 120kV circuit into the station.	MI		Other	Not Shared	Distribution	$3,000,000	12/31/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	2524	Capacitor Replacement 2010	Replace capacitor banks	MI		Other	Not Shared	Condition	$565,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	2527	Potential Device Replacement 2010	Replace aging potential devices	MI		Other	Not Shared	Condition	$300,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	2530	Power Plant Control Relocation 2010	Relocate substation controls currently located in power plant control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	2533	Wood Pole Replacement 2010	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$1,200,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	2536	Synchronizing Sites 2010	New 120kV synchronizing sites	MI		Other	Not Shared	Operations	$565,000	12/31/2010	Planned			B>A	Y
A in MTEP09	East	ITC	2538	NERC Relay Loadability Compliance 2010	Upgrade relays throughout system	MI		BaseRel	Not Shared		$2,250,000	12/31/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	2541	Hunters Creek - Robin - Wabash	Install double groundwire peaks and second shield wire.	MI		Other	Not Shared	Condition	$2,400,000	12/31/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	2542	Hunters Creek - Stratford - Pointiac	Install double groundwire peaks and second shield wire.	MI		Other	Not Shared	Condition	$1,100,000	12/31/2010	Planned	120		B>A	Y
A in MTEP09	East	ITC	2546	East Ann Arbor	New distribution interconnection served from Coventry-Superior 120kV circuit	MI		Other	Not Shared	Distribution	$5,650,000	5/1/2011	Planned	120		B>A	Y
A in MTEP09	East	ITC	2519	Breaker Replacement Program 2011	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2520	Cable Termination Replacement 2011	Replace high pressure gas filled underground cable terminations throughout system.	MI		Other	Not Shared	Condition	$3,000,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2521	Relay Betterment Program 2011	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2525	Capacitor Replacement 2011	Replace capacitor banks	MI		Other	Not Shared	Condition	$565,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2528	Potential Device Replacement 2011	Replace aging potential devices	MI		Other	Not Shared	Condition	$300,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2531	Power Plant Control Relocation 2011	Relocate substation controls currently located in power plant control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2534	Wood Pole Replacement 2011	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$1,200,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2537	Synchronizing Sites 2011	New 120kV synchronizing sites	MI		Other	Not Shared	Operations	$565,000	12/31/2011	Planned			B>A	Y
A in MTEP09	East	ITC	2539	NERC Relay Loadability Compliance 2011	Upgrade relays throughout system	MI		BaseRel	Not Shared		$2,250,000	12/31/2011	Planned	120		B>A	Y
A in MTEP09	West	ITCM	2450	New Woodburn Jct. 69kV Switching Station	Construct a new 3-terminal 69kV switching station at the existing Woodburn Jct 69/34kV sub.	IA		Other	Not Shared	Reliability	$1,000,000	3/31/2009	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2349	Savanna 161kV Terminal Upgrades	Upgrade terminal equipment at the Savanna 161kV substation (CTs, jumpers, switches, etc.) so that the Galena-Savanna-York 161kV line is conductor limited.	IL		BaseRel	Not Shared		$205,000	6/1/2009	Planned	161		B>A	Y

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A in MTEP09	West	ITCM	2351	Powesheik 161kV Breaker Upgrades	Upgrade the 3 existing 161kV Powesheik breakers to 2000 amp and add a 4th breaker to separate the Powesheik-Beacon 161kV line and the Powesheik 161/69kV TRF.	IA		BaseRel	Not Shared		$965,000	6/1/2009	Planned	161		B>A	Y
A in MTEP09	West	ITCM	2372	G573,574,575 Nuthatch	G573,574,575 Nuthatch	IA		GIP	Shared		$4,360,113	9/15/2009	Planned	161	115	B>A	Y
A in MTEP09	West	ITCM	1775	Triboji-CBPC Milford 69kV	Rebuild the Triboji-Milford 69kV line.	IA		GIP	Shared		$2,023,508	12/31/2009	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2340	Grand Junction-Paton REC tap 34kV Rebuild	Rebuild the 34kV line from Grand Jct-Paton REC tap to 69kV. Retire Dana 34kV/dist sub and construct in & out taps for new Grand Jct North 69kV/dist. Sub. (still operate at 34kV)	IA		Other	Not Shared	Condition	$3,260,000	12/31/2009	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2342	Boone-Jewell 34kV Rebuild	Rebuild 25.3 miles of 34kV line from Jewell to approximately 6 miles south of the Ridgeport dist. substation to 69kV standards. This line will continue to be operated at 34kV.	IA		Other	Not Shared	Condition	$6,685,000	12/31/2009	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2346	Welton 3.6 mile 34kV line Retire	Retire 3.6 miles of 34kV near Welton.	IA		Other	Not Shared	Retire	$90,000	12/31/2009	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2347	Bonaparte-Farmington Retirements	Retire the Bonaparte 69kV sub and the Bonaparte-Farmington (7.4 mile) 34kV line	IA		Other	Not Shared	Retire	$225,000	12/31/2009	Planned	69	34	B>A	NT
A in MTEP09	West	ITCM	2352	Old Settlers 115kV Substation	Construct 115kV taps, 115kV bus, and breakers for new 2 TRF 115kV/dist. Substation.	IA		Other	Not Shared	Distribution	$2,815,000	12/31/2009	Planned	115		B>A	Y
A in MTEP09	West	ITCM	2354	Saints Run 115kV Substation	Construct 115kV taps, 115kV bus, and breakers for new 2 TRF 115kV/dist. Substation.	IA		Other	Not Shared	Distribution	$1,495,000	12/31/2009	Planned	115		B>A	Y
A in MTEP09	West	ITCM	2355	Barilla 69kV/dist. Sub & 69kV Caps	Construct 2 new 69kV 4.8 MVAR Cap banks, associated Bkrs, bus, switches, reactors, and line taps at a new Consumers Energy sub near Barilla.	IA		Other	Not Shared	Reliability	$750,000	12/31/2009	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2359	Bridgeport 161kV Area Upgrades	Upgrade the Bridgeport 161kV sub & the EIC sub. These upgrades combined with the Tri-County upgrades will allow for the Bridgeport 69kV sub to be retired. The Bridgeport 69kV sub needs to be retired to allow for the plant to expand.	IA		Other	Not Shared	Distribution	$6,900,000	12/31/2009	Planned	161		B>A	Y
A in MTEP09	West	ITCM	2360	Burlington 69kV/13kV Sub Rebuild	Replace the existing Burlington distribution sub with a new substation on land adjacent to existing sub. (Line taps, Breakers, bus, etc.)	IA		Other	Not Shared	Condition	$588,000	12/31/2009	Planned	69	13	B>A	NT
A in MTEP09	West	ITCM	2343	West Branch-West Liberty 34kV Rebuild	Rebuild 15.1 miles of 34kV line from West Branch-West Liberty to 69kV standards. This line will continue to be operated at 34kV.	IA		Other	Not Shared	Condition	$4,146,850	3/31/2010	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2348	Beaver Rock 69kV Switching Station	Construct a new 3-terminal 69kV switching station along the Beaver Channel-Rock Creek 69kV line.	IA		Other	Not Shared	Reliability	$1,390,000	3/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2353	Big River 69kV 3-terminal Switching Station	Construct a new 3-terminal 69kV switching station where the Big River REC line taps the Agency-Sawyer 69kV line.	IA		Other	Not Shared	Reliability	$1,200,000	3/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2341	Monticello-Amber Conversion & Lovell REC Rebuild	Rebuild 8.5 miles Monticello-Amber 34kV to 69kV, add 69kV bkr at Sand Springs, Monticello Industrial, & Amber. Operate Sand Springs-Amber at 69kV. Also rebuild 2.21 miles of 34kV to 69kV east of Lovell REC but continue operation of this portion at 34kV in 2009.	IA		Other	Not Shared	Condition	$3,775,000	6/1/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2356	Oran-Oelwein 69kV Rebuild	Rebuild 8 miles of 69kV line Oran-Oelwein.	IA		Other	Not Shared	Distribution	$2,000,000	6/1/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2345	Eldora Area Rebuild & Breaker Station	Rebuild approx 20 miles of 34kV to 69kV from the Hubbard Rural sub to a new 4-terminal Eldora North 69kV switching station and operate at 69kV. The new switching station will tap the CBPC Pleaseant-CBPC Eldora 69kV line. The 4th terminal will be needed in the near future to feed the Eldora North-Union-Conrad 69kV line after substaitons are ready for conversion. This line will be rebuilt to 69kV standard in 2009.	IA		Other	Not Shared	Condition	$14,560,000	6/30/2010	Planned	69		B>A	NT

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A in MTEP09	West	ITCM	2344	Wyoming-Massillon 34kV Rebuild	Rebuild 12 miles of 34kV line from Wyoming-Massilon to 69kV standards. This line will continue to be operated at 34kV.	IA		Other	Not Shared	Condition	$3,000,000	12/31/2010	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2361	Dyersville West Rebuild	Rebuild the Liberty-Dyersville 69kV west line.	IA		Other	Not Shared	Condition	$920,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2362	Dover 69kV Switching Station	Construct a new 3-terminal 69kV switching station.	MN		Other	Not Shared	Reliability	$1,275,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2363	Glenville 161/69kV	Construct a new 161/69kV 75 MVA substation	MN		Other	Not Shared	Reliability	$2,970,000	12/31/2010	Planned	161	69	B>A	Y
A in MTEP09	West	ITCM	2364	Thompson 2 mile 69kV dbl ckt	Rebuild 69kV double circuit line near Thompson, IA	IA		Other	Not Shared	Reliability	$460,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2365	Lansing-Genoa 161kV upgrades & relay	Upgrade the terminal limits & relaying on the Lansing-Genoa 161kV.	IA		BaseRel	Not Shared		$100,000	12/31/2010	Planned	161		B>A	Y
A in MTEP09	West	ITCM	2366	Adams-Harmony 161kV upgrades & relay	Upgrade the terminal limits & relaying on the Adams-Harmony 161kV.	MN		BaseRel	Not Shared		$100,000	12/31/2010	Planned	161		B>A	Y
A in MTEP09	West	ITCM	2368	Montgomery- LE Center 69kV Rd Move	Retire & rebuild 3.4 mile Montgomery-LE Center 69kV line.	IA		Other	Not Shared	Move	$765,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2369	Fairfax-Williamsburg 34kV to 69kV Rebuilds	Rebuild 26.6 miles of 34kV line from the Fairfax sub to the Williamsburg115kV sub to 69kV. These lines will continue to opeate at 34kV.	IA		Other	Not Shared	Condition	$6,903,000	12/31/2010	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2370	Andrew Tap & Monmouth Rebuilds	Rebuild the 5.75 mile Andrew Tap & 2 miles of line in the Monmouth area. These lines will continue to opeate at 34kV.	IA		Other	Not Shared	Condition	$1,869,250	12/31/2010	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2371	New Marengo 69kV Switching Station	Construct a new 3-terminal 69kV switching station at the existing Marengo 34kV sub.	IA		Other	Not Shared	Condition	$1,000,000	12/31/2010	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2786	G595 Network upgrades	G595 Network upgrades	IA		GIP	Shared		$25,531,831	12/31/2010	Planned	161		B>A	Y
A in MTEP09	West	ITCM	2357	Hazleton-Fairbank REC 69kV line & breaker station	Construt a 69kV Hazleton-Fairbank line and a new 3-terminal 69kV switching station.	IA		Other	Not Shared	Distribution	$2,150,000	6/1/2011	Planned	69		B>A	NT
A in MTEP09	West	ITCM	2367	Anita Area 34kV to 69kV Rebuilds	Rebuild 5 miles from the Anita-Exira REC to 69kV. Also rebuild 4.7 miles of the Anita to th e Anita-Wiota Joint sub. Rebuild 21.9 miles from Thompson- Redfield. These lines will continue to opeate at 34kV.	IA		Other	Not Shared	Condition	$7,895,000	6/30/2011	Planned	34		B>A	NT
A in MTEP09	West	ITCM	2358	Hazleton-Blackhawk 161kV Rebuild	Rebuild 12 miles of the Hazleton-Blackhawk 161kV line (ITC owned portion)	IA		BaseRel	Shared		$5,400,000	12/31/2012	Proposed	161		B>A	Y
A in MTEP09	West	ITCM	2339	G612-Marshalltown-Boone 115kV to 161kV	Construct a new Story Co 161kV switching station and rebuild the Marshalltown-Boone 115kV to 161kV.	IA		GIP	Shared		$22,100,799	12/31/2013	Planned	161	34	B>A	Y
A in MTEP09	West	MDU	2471	Tioga area upgrades	Project upgrades to accommodate load growth in the area	ND		BaseRel	Not Shared		$2,200,000	12/1/2009	Planned	230	115	B>A	Y
A in MTEP09	West	MDU	1355	Heskett - Additional 230/115 kV Switchyard and 115 kV Capacitor	Heskett - Additional 230/115 kV Switchyard 230 115 Switchyard in parallel w/ existing Heskett switchyard and Cap Bank	ND		BaseRel	Shared		$11,000,000	11/1/2012	Planned	230	115	B>A	Y
A in MTEP09	East	METC	2474	Harvard Lake	New distribution interconnection served from Four Mile - North Belding 138kV.	MI		Other	Not Shared	Distribution	$200,000	6/1/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2491	Tallmadge - Wealthy 138kV ckt. #1	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$60,000	7/1/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	240	Garfield-Hemphill 138kV	Terminal equipment upgrade	MI		Other	Excluded	Reliability	$60,000	8/1/2009	Proposed	138		B>A	Y
A in MTEP09	East	METC	2476	Hubbardston Road	New distribution interconnection served from Marquette - Bingham 138kV.	MI		Other	Not Shared	Distribution	$170,000	8/1/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2477	Cochran Junction	Install a switch pole and line switch at Cochran junction towards Island Road.	MI		Other	Not Shared	Distribution	$175,000	10/15/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	1839	Acme	New 138/46kV Bulk Power station served from Keystone-Stover 138kV circuit. Requires a new 138kV ring bus at Plum station located at the Clearwater Junction point.	MI		Other	Not Shared	Distribution	$4,060,000	11/15/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2473	LaBarge	New distribution interconnection served from Gaines - Thompson Rd. 138kV.	MI		Other	Not Shared	Distribution	$12,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2479	Chase	CE 138/46kV transformer upgrade at Chase substation	MI		Other	Not Shared	Distribution	$12,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2480	Hazelwood	CE to install circuit switcher as high-side protective device for 138/46kV transformer	MI		Other	Not Shared	Distribution	$12,000	12/1/2009	Planned	138		B>A	Y

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A in MTEP09	East	METC	1821	Breaker Replacement Program 2009	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2009	Proposed			B>A	Y
A in MTEP09	East	METC	1823	Relay Betterment Program 2009	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2009	Proposed			B>A	Y
A in MTEP09	East	METC	1826	Sag clearance 2009	Identify and remediate inherent sag limitations on heavily loaded METC trasmission lines throughout the system.	MI		Other	Not Shared	Clearance	$3,400,000	12/31/2009	Proposed			B>A	Y
A in MTEP09	East	METC	2508	Wood Pole Replacement 2009	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$4,500,000	12/31/2009	Planned	138		B>A	Y
A in MTEP09	East	METC	2511	Power Plant Control Relocation 2009	Relocate substation controls currently located in power plant control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2009	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2512	Battery Replacement 2009	Replace batteries and chargers	MI		Other	Not Shared	Condition	$300,000	12/31/2009	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2513	Potential Device Replacement 2009	Replace aging potential devices	MI		Other	Not Shared	Condition	$300,000	12/31/2009	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2514	Transformer Monitoring 2009	Install tempurature and bushing monitors on EHV transformers	MI		Other	Not Shared	Operations	$1,200,000	12/31/2009	Planned	345	138	B>A	Y
A in MTEP09	East	METC	1828	Argenta-Palisades 345kV ckt. 1 & 2	Remove the SAG limit on Argenta-Palisades 345kV ckt 1& 2. Upgrade terminal equipment at both substations.	MI		BaseRel	Shared		$10,880,000	6/1/2010	Planned	345		B>A	Y
A in MTEP09	East	METC	2475	Titus Lake	Distribution interconnection to add a second transformer at Titus Lake.	MI		Other	Not Shared	Distribution	$4,200,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2478	Captial Ave	New distribution interconnection served from Battle Creek - Verona #2 138kV (Line connection change to Battle Creek to Island Road)	MI		Other	Not Shared	Distribution	$170,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2481	Forrest Grove	New distribution interconnection served from Campbell-Ransom 138kV circuit.	MI		Other	Not Shared	Distribution	$170,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2483	Maines Road	New distribution interconnection served from Marshall - Blackstone 138kV circuit	MI		Other	Not Shared	Distribution	$170,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2484	Scenic Lake	New distribution interconnection served from Cornell-Tihart 138kV circuit	MI		Other	Not Shared	Distribution	$170,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2493	Bullock - Summerton 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$100,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2495	Bullock - Warren 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$200,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2496	Bullock - Tittabawassee 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$420,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2497	RTU / SCADA Re-direction Program	Install and/or upgrade RTU's and SCADA points throughout system	MI		Other	Not Shared	SCADA	$12,500,000	6/1/2010	Planned	345	138	B>A	Y
A in MTEP09	East	METC	1822	Breaker Replacement Program 2010	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2010	Proposed			B>A	Y
A in MTEP09	East	METC	1824	Relay Betterment Program 2010	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2010	Proposed			B>A	Y
A in MTEP09	East	METC	1827	Sag clearance 2010	Identify and remediate inherent sag limitations on heavily loaded METC trasmission lines throughout the system.	MI		Other	Not Shared	Clearance	$3,400,000	12/31/2010	Proposed			B>A	Y
A in MTEP09	East	METC	2503	Battery Replacement 2010	Replace batteries and chargers	MI		Other	Not Shared	Condition	$300,000	12/31/2010	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2504	Potential Device Replacement 2010	Replace aging potential devices	MI		Other	Not Shared	Condition	$300,000	12/31/2010	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2505	Power Plant Control Relocation 2010	Relocate substation controls currently located in power plant control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2010	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2506	Transformer Monitoring 2010	Install tempurature and bushing monitors on EHV transformers	MI		Other	Not Shared	Operations	$1,200,000	12/31/2010	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2509	Wood Pole Replacement 2010	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$3,400,000	12/31/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2516	NERC Relay Loadability Compliance 2010	Upgrade relays throughout system	MI		BaseRel	Not Shared		$2,250,000	12/31/2010	Planned	138		B>A	Y
A in MTEP09	East	METC	2501	Northern Reactive	Install 3 capacitors in the northern part of Michigan	MI		BaseRel	Not Shared		$2,700,001	4/1/2011	Planned			B>A	Y
A in MTEP09	East	METC	1806	Canal Jct - Island Rd 138kV	Rebuild 11 miles of 138kV line to 954 ACSR	MI		Other	Not Shared	Condition	$9,000,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	East	METC	2485	Ironwood	New distribution interconnection served from CE's 138kV spur on the Ransom-Buck Creek 138kV.	MI		Other	Not Shared	Distribution	$12,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	East	METC	2489	Terminal Equipment upgrade at Tippy	Terminal Equipment upgrade at Tippy	MI		BaseRel	Not Shared		$60,000	6/1/2011	Planned	138		B>A	Y
A in MTEP09	East	METC	2500	Murphy Second 345/138kV Transformer	Install a second 345/138kV transformer at Murphy substation	MI		BaseRel	Not Shared		$18,446,000	6/1/2011	Planned	345	138	B>A	Y
A in MTEP09	East	METC	2515	Tihart - Oakland (Genoa) 138kV	Replace all line structures and insulators.	MI		Other	Not Shared	Condition	$23,500,000	6/1/2011	Planned	138		B>A	Y

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A in MTEP09	East	METC	1833	Sag clearance 2011	Identify and remediate inherent sag limitations on heavily loaded METC trasmission lines throughout the system.	MI		Other	Not Shared	Clearance	$3,400,000	12/31/2011	Proposed			B>A	Y
A in MTEP09	East	METC	2498	Breaker Replacement Program 2011	Replace defective, damaged, or over dutied breakers throughout system.	MI		Other	Not Shared	Condition	$5,650,000	12/31/2011	Proposed			B>A	Y
A in MTEP09	East	METC	2499	Relay Betterment Program 2011	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.	MI		Other	Not Shared	Condition	$1,200,000	12/31/2011	Proposed			B>A	Y
A in MTEP09	East	METC	2510	Wood Pole Replacement 2011	Replace deteriorating wood pole	MI		Other	Not Shared	Condition	$3,400,000	12/31/2011	Planned	138		B>A	Y
A in MTEP09	East	METC	2517	NERC Relay Loadability Compliance 2011	Upgrade relay throught system	MI		BaseRel	Not Shared		$2,250,000	12/31/2011	Planned	138		B>A	Y
A in MTEP09	East	METC	2522	'Power Plant Control Relocation 2011	Relocate substation controls currently located in power plants control rooms	MI		Other	Not Shared	Condition	$1,200,000	12/31/2011	Proposed			B>A	Y
A in MTEP09	East	METC	2486	Haakwood	New distribution interconnection served from Riggsville-Livingston 138kV (on the Rondo-Vanderbilt section)	MI		Other	Not Shared	Distribution	$170,000	1/1/2012	Planned	138		B>A	Y
A in MTEP09	East	METC	1810	Iosco - East Tawas 138kV	Rebuild 12 miles of 138kV to 954 ACSR.	MI		Other	Not Shared	Condition	$10,000,000	6/1/2012	Planned	138		B>A	Y
A in MTEP09	East	METC	2482	Hawthorne	New distribution interconnection served from Four Mile - Blendon 138kV circuit.	MI		Other	Not Shared	Distribution	$170,000	6/1/2012	Planned	138		B>A	Y
A in MTEP09	East	METC	2487	Birchwood	New distribution interconnection served from Spaulding-Plaster Creek 138kV (on the Spaulding-Kraft section)	MI		Other	Not Shared	Distribution	$170,000	6/30/2012	Planned	138		B>A	Y
A in MTEP09	East	METC	646	Edenville Jct. - Warren 138kV	Replace poles on the Edenville-Warren 138kV line	MI		Other	Not Shared	Reliability	$12,500,000	12/1/2012	Planned	138		B>A	Y
A in MTEP09	East	METC	662	Weeds Lake	Loop the 345kV Argenta - Robinson Park 345kV circuit into a new 345/138kV EHV substation called Weeds Lake. Build 4 new (approximately 6 miles) 138kV circuits to loop the two Argenta-Milham 138kV lines into the substation.	MI		BaseRel	Shared		$39,800,002	6/1/2013	Proposed	345	138	B>A	Y
A in MTEP09	East	METC	2488	Stronach - Tippy 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$240,000	6/1/2013	In Service	138		B>A	Y
A in MTEP09	East	METC	2492	Battle Creek - Verona 138kV ckt. #2	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$200,000	6/1/2013	Planned	138		B>A	Y
A in MTEP09	East	METC	2494	Bullock - Dow Corning 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$400,000	6/1/2013	Planned	138		B>A	Y
A in MTEP09	East	METC	2507	Alcona - Mio 138kV	Rebuild the line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI		Other	Not Shared	Condition	$24,500,000	6/1/2013	Planned	138		B>A	Y
A in MTEP09	East	MISO-NIPS	2797	Dune Acres - Michigan City CT upgrade	Replace a circuit breaker at Michigan City and upgrade the CT's to 1000/5 amps to increase the SE rating up to the conductor capacity limit which is 222 MVA	IN		Other	Not Shared	Local Econ	$345,000	10/1/2009	Proposed	138		B>A	Y
A in MTEP09	East	MISO-NIPS	2798	State Line - Wolf Lake - Sheffield 138 kV line reconductoring with ACSS conductor	Replace the existing bundled '300 kcm CU - 397.5 kcm ACSR' with bundled (2) 336.4 kcm ACSS (1089 A @ 200 C each side) and the 900 kcm ACSR with 954 kcm ACSS (2131 A @ 200 C). Total length is 4.2 miles (State Line - Wolf Lake 1.2 miles and Wolf Lake - Sheffield 3 miles).	IN		Other	Not Shared	Local Econ	$2,700,000	4/1/2010	Proposed	138		B>A	Y
A in MTEP09	West	MP	2763	LSPI 34.5	Add 115/34.5 kV Transformer and line exit to LSPI 115/14 kV Sub	MN		Other	Not Shared	Distribution	$500,000	9/1/2009	Planned	115	34.5	B>A	Y
A in MTEP09	West	MP	2758	Taft	New 115/34.5 Substation	MN		Other	Not Shared	Distribution	$992,500	10/1/2009	Planned	115	34	B>A	Y
A in MTEP09	West	MP	2757	Grand Rapids	Add new 115/23 kV Lind-Greenway Substaion off MP Line #29	MN		Other	Not Shared	Reliability	$2,741,100	12/1/2009	Planned	115	23	B>A	Y
A in MTEP09	West	MP	2760	Virginia	add 115/46 kV 39 MVA LTC transformer	MN		Other	Not Shared	Reliability	$1,284,100	12/1/2009	Planned	115	46	B>A	Y
A in MTEP09	West	MP	2756	Essar Phase 1	MP's 115 kV Line #28 (28L) must be moved as it crosses the area that Essar will be mining.	MN		Other	Not Shared	Distribution	$2,900,000	6/30/2010	Planned	115	14	B>A	Y
A in MTEP09	West	MP	2552	Skibo	Skibo-Hoyt Lakes 138 ckt 1, Sum rate 202	MN		BaseRel	Not Shared		$2,540,000	12/30/2010	Proposed	138		B>A	Y
A in MTEP09	West	MP	2759	Laskin	Move Virginia 115/46 kV Transformer to Laskin	MN		Other	Not Shared	Distribution	$500,000	6/1/2011	Planned	115	46	B>A	Y
A in MTEP09	East	NIPS	2326	Gary Airport Expansion	Relocate Chicago Ave 345kV to new Gary Avenue substation including Chicago Ave 345/138kV 336 MVA transformer and rebuild section underground of circuit 13825 Roxana to Mitchell	IN		Other	Not Shared	Move	$15,000,000	12/1/2008	In Service	345	138	B>A	Y
A in MTEP09	East	NIPS	2313	Aetna Sub - Replace Circuit 138-102S Breaker	Aetna Sub - Replace Circuit 138-102S Breaker	IN		BaseRel	Not Shared		$108,491	6/1/2009	Proposed	138		B>A	Y
A in MTEP09	East	NIPS	2314	RMSGS - Add 345kv N. Bus Tie Breaker	RMSGS - Add 345 kV N. Bus Tie Breaker	IN		BaseRel	Not Shared		$720,814	6/1/2009	Proposed	345		B>A	Y

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A in MTEP09	East	NIPS	2310	New Praxair 138kV substation @ Whiting	Customer Expansion	IN		Other	Not Shared	Distribution	$2,780,453	12/1/2009	Proposed	138	69	B>A	Y
A in MTEP09	East	NIPS	2316	Highland Sub - 69 kV Switched Capacitors	Replace Existing capacitors with 2-9.6 mVAR steps. Upgrade Controllers. Work in 2007 for engineering only.	IN		Other	Not Shared	Reliability	$729,007	12/1/2009	Proposed	69		B>A	Y
A in MTEP09	East	NIPS	2317	Circuit 13823 - Hartsdale to Munster - Capacity Upgrade	Rebuild section of Hartsdale to Munster 138 kV line.	IN		BaseRel	Not Shared		$90,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	East	NIPS	2325	Liberty Park bus Upgrades	Replace 500KCM Copper and 397.5 KCM acsr with 1272 KCM Al.	IN		BaseRel	Not Shared		$234,000	12/1/2009	Planned	138		B>A	Y
A in MTEP09	East	NIPS	2775	Hartsdale Capacitors	Add (3) steps of 10.8MVAR capacitors to the Hartsdale 69kV bus	IN		BaseRel	Not Shared		$950,000	12/1/2009	Planned	69		B>A	Y
A in MTEP09	West	OTP	2750	G645 Spiritwood 115 kV ring bus	Build New 115 kV Ring Bus	ND		GIP	Shared		$1,400,000	7/1/2009	Planned	115		B>A	Y
A in MTEP09	West	OTP	2749	Fertile-Fertile Jct. 41.6 kV Line	Build New 1.5 Mile 41.6 kV Line to Eliminate Critical Contingency	MN		Other	Not Shared	Reliability	$165,000	6/1/2010	Planned	41.6		B>A	NT
A in MTEP09	West	OTP	2751	New Perham 115/12.5 kV Substation	Build New 115/12.5 kV Substation at Perham to Serve as a Back-up Source for Outage of Primary Source	MN		Other	Not Shared	Distribution	$400,000	12/31/2012	Proposed	115	12.5	B>A	Y
A in MTEP09	West	OTP, GRE, MP(	2738	Ramsey 230/115kV Transformer Upgrade	Increase Transformer Capacity & Improve Category C Contingency Performance to Devils Lake Area	ND		BaseRel	Not Shared		$5,000,000	11/1/2010	Planned	230	115	B>A	Y
A in MTEP09	Central	Vectren (SIGE)	2461	Dubois Sub Z84 terminals	Add 1 new 138kV terminal to existing sub to avoid 3 term line, breaking up Duff - Dubois - Culley 138kV line	IN		BaseRel	Not Shared		$1,000,000	6/1/2010	Planned	138		B>A	Y
A in MTEP09	Central	Vectren (SIGE)	2465	Leibert Rd 138/12kV Substation	New 138/12kV Substation for load growth	IN		Other	Not Shared	Distribution	$3,000,000	6/1/2011	Planned	138	12.47	B>A	NT
A in MTEP09	Central	Vectren (SIGE)	2466	Roesner Rd 138/12kV Substation	New 138/12kV Substation for load growth	IN		Other	Not Shared	Distribution	$3,000,000	6/1/2013	Planned	138	12.47	B>A	NT
A in MTEP09	East	WPSC	2770	Gilmore	New distribution interconnection served from Hersey to Vestaburg circuit.	MI		Other	Not Shared	Distribution	$200,000	6/1/2010	Planned	69		B>A	Y
A in MTEP09	East	WPSC	2771	Monterey	New distribution interconnection served from Hersey to Vestaburg circuit.	MI		Other	Not Shared	Distribution	$200,000	7/2/2010	Planned	69		B>A	Y
A in MTEP09	East	WPSC	2735	Alba-Westwood Line Rebuild	Alba - Mancelona - Westwood 69 kV line rebuild (11 miles) to 143 MVA	MI		Other	Not Shared	Reliability	$5,605,000	12/31/2013	Proposed	69		B>A	Y
A in MTEP09	East	WPSC	2736	East Bay-South Boardman Line Rebuild	East Bay - South Boardman Dist - South Boardman 69 kV line rebuild (16 miles) to 143 MVA	MI		Other	Not Shared	Reliability	$8,015,000	12/31/2013	Proposed	69		B>A	Y
A in MTEP09	East	WPSC	2737	South Boardman-Kalkaska Generation Line rebuild	South Boardman - Kalkaska gen 69 kV line rebuild (3.4 miles) to 143 MVA	MI		Other	Not Shared	Reliability	$1,710,000	12/31/2013	Proposed	69		B>A	Y
A in MTEP09	West	XEL	2765	Uilk Wind farm (G185)	This is a new 4.5 MW interconnection at Chanarambie	MN		GIP	Shared		$118,100	12/1/2008	Planned	34.5		B>A	Y
A in MTEP09	West	XEL	2159	Nelson Cap Bank	Add 18 MVAR cap at Nelson substation	WI		Other	Not Shared	Reliability	$721,000	6/1/2010	Planned	69		B>A	NT
A in MTEP09	West	XEL	2772	South Minneapolis	1 new 115 kV distribution substation with four terminations tapping the Elliot Park - Southtown line, 1.25 new miles of double circuit 795 SAC to a new 115 kV distribution sustation	MN		Other	Not Shared	Distribution	$28,390,000	10/1/2010	Planned	115	13.8	B>A	Y
A in MTEP09	West	XEL	2156	North Mankato 115 kV project	1) New 345/115 kV TR at the proposed Helena 345 kV switching station. 2) New 115 kV line from Helena - St. Thomas. 3) New 115/69 kV substation near St. Thomas. 4) New 69 kV switchig station at Lesueur Tap.	MN		Other	Not Shared	Reliability	$17,450,000	6/1/2011	Planned	345	69	B>A	Y
A in MTEP09	West	XEL	2157	Douglas Co 2nd TR	2nd Douglas Co 115/69 kV transfromer	MN		Other	Not Shared	Reliability	$4,435,000	6/1/2011	Planned	115	69	B>A	NT
A in MTEP09	West	XEL	2158	Upgrade Sauk Center - Osakis 69 kV line	Upgrade Sauk Center - Osakis 69 kV line to a lower impedance.	MN		Other	Not Shared	Reliability	$4,514,000	6/1/2011	Planned	69		B>A	NT
A in MTEP09	West	XEL	2308	Grove Lake - Glenwood line rebuild	This project is to rebuild 13 miles of 69 kV line from Grove Lake switching station to Glenwood to 477 ACSR	MN		Other	Not Shared	Reliability	$16,350,812	6/1/2011	Proposed	69		B>A	NT
A in MTEP09	West	XEL	1952	Plato capacitor bank	'This project is to add a 10 MVAR cap bank at Plato. This project is required to convert the existing 69 kv line from Young America - Glencoe to 115 kV (part of Glencoe - West Waconia 115 kV line project).	MN		Other	Not Shared	Reliability	$700,000	12/1/2011	Planned	69		B>A	NT
A in MTEP09	West	XEL	2160	Park Falls TR upgrade	Upgrade the Park Falls 115/34.5 kV TR to 47 MVA	WI		Other	Not Shared	Reliability	$3,355,800	6/1/2012	Planned	115	34.5	B>A	NT
A in MTEP09	West	XEL	2176	Cannon Falls transmission improvements	(1) Change breaker configuration at Colville Substation (2) Add 115 kV Ring bus at Cannon Falls (3) Install new 115/69 kV transformer at Colville substation (4) New 2 mile 69 kV line from Cannon Falls to Byllesby.	MN		Other	Not Shared	Reliability	$6,235,000	6/1/2012	Proposed	115	69	B>A	Y

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A in MTEP09	West	XEL	2178	G362 Pleasant Valley XEL	G362 Network upgrades: New 161 kV line from Pleasant Valley - Byron 161 kV line	MN		GIP	Shared		$10,007,181	6/1/2012	Planned	161		B>A	Y
A in MTEP09	West	XEL	2307	St. Cloud Loop	(1) New 4 mile 115 kV line from St. Cloud tap tap to Mayhew Lake substation.(2) Convert Benton Co - St. Cloud double circuit to bifurcated line and reterminarte into Mayhew Lake substation (3) Convert St. Cloud tap to Granite City into bifurcated line (this results in single 115 kV circuit from St. Cloud to Granite City).	MN		BaseRel	Shared		$6,100,000	6/1/2012	Proposed	115		B>A	Y
A in MTEP09	West	XEL	2309	Maple Lake - Watkins line rebuild	This project is to rebuild 20 miles of 69 kV line from Maple Lake to Watkins in west Central Minnesota	MN		Other	Not Shared	Reliability	$2,487,000	6/1/2012	Proposed	69		B>A	NT
A in MTEP08	Central	AmerenIL	2113	San Jose Rail 138kV Substation (G515)	Construct a new 138 kV, three breaker substation, tapping existing 138kV line from Tazewell to East Springfield in Tazewell County, IL Upgrade relaying at the Tazewell and East Springfield Substations to accommodate line configuration changes	IL		GIP	Shared		$3,407,000	7/2/2009	Under Const	138		A	Y
A in MTEP08	Central	AmerenIL	2058	Conoco Phillips 138 kV Supply	Tap wood River - Roxford - 1502 138 kV line and extend appraoximately 2.7 miles, and extend Roxford - BOC 138 kV line approximately 3.3 mi to supply new Conoco Phillips 138 - 34 kV substation. The new line capacity would be 1600 A (summer Emergency)	IL		Other	Not Shared		$13,000,000	9/30/2009	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	2071	East Springfield - Interstate 138 kV line and Interstate - Holland 138 kV line	Cut the East Sprigfield - Holland 138 kV line and create in and out lines ; East Springfield - Interstate 138 kV line and Interstate - Holland 138 kV line. For CWLP project P1552.	IL		BaseRel	Not Shared		$553,000	11/1/2009	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	2116	IP04	Network upgrades for tariff service request	IL		GIP	Shared		$2,027,957	12/1/2009	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	1529	Brokaw-State Farm Line 1596 - Reconductor	Reconductor 3.3 miles of 138 kV line to 2000 A Summer Emergency capability	IL		BaseRel	Not Shared		$2,566,900	6/1/2010	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	2060	East Peoria - Flint : Increase Clerances to ground	Increase ground clearance on existing line conductor (at least 3 spans of 477 kcmil ACSR) between East Peoria and flint to permit full utilization of line capacity	IL		BaseRel	Not Shared		$2,113,000	6/1/2010	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	1532	Stallings-E. Collinsville - Upgrade Terminal Equipment, Increase Ground Clearance	Replace terminal equipment at Stallings, increase ground clearance between Stallings, Maryville REA	IL		BaseRel	Not Shared		$744,800	6/1/2011	Planned	138		A	Y
A in MTEP08	Central	AmerenIL	2068	Latham - Oreana 345 kV line	Convert Oreana 345 kV Bus to 6-Position Ring Bus with 3000 A Capability; Construct 8.5 miles of 345 kV line (2-954 kcmil ACSR conductor or equivalent capability) from Oreana Substation to 345 kV Line 4571 tap to Latham Substation. 3-345 kV PCB's at Oreana Substation.	IL		BaseRel	Shared		$15,039,400	6/1/2012	Planned	345		A	Y
A in MTEP08	Central	AmerenIL	2069	South Bloomington - Install new 560 MVA 345 /138 Xfmr	South Bloomington Area 345/138 kV Substation - Install 345/138 kV, 560 MVA Transformer. Extend new 345 kV line approximately 5 miles from Brokaw Substation to South Bloomington Substation. Install 1-138 kV PCB at South Bloomington Substation, and 2-345 kV PCB's at Brokaw Substation	IL		BaseRel	Shared		$17,600,000	12/1/2012	Planned	345	138	A	Y
A in MTEP08	Central	AmerenMO	717	Conway-Tyson-3 138 kV	Conway-Orchard Gardens section of Conway-Tyson-3 138 kV - Increase ground clearance	MO		Other	Excluded	Reliability	$125,350	6/1/2010	Proposed	138		A	Y
A in MTEP08	Central	AmerenMO	718	Conway-Tyson-4 138 kV	Conway-Orchard Gardens section of Conway-Tyson-4 138 kV - Increase ground clearance	MO		Other	Excluded	Reliability	$125,350	6/1/2010	Proposed	138		A	Y
A in MTEP08	Central	AmerenMO	2061	Gray Summit : Second 560 MVA 345/138 kV Transformer	Install a 345 kV six position ring bus making Labadie - Tyson 1 & 2 345 kV lines and add a second 560 MVA 345/138 kV transformer.	MO		BaseRel	Shared		$19,000,000	12/1/2010	Planned	345	138	A	Y
A in MTEP08	Central	AmerenMO	1238	GM-Point Prairie 161 kV to AECI Enon Sub.	Extend 1 mile of 161 kV to AECI Enon Substation	MO		BaseRel	Not Shared		$1,279,700	6/1/2011	Planned	161		A	Y
A in MTEP08	Central	AmerenMO	1235	Fredericktown-AECI Fredericktown	Increase ground clearance on 12 miles	MO		Other	Not Shared		$970,500	6/1/2012	Proposed	161		A	Y

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A in MTEP08	West	ATC LLC	1679	Richland Center Olson sub and Brewer Sub Capacitor banks	Expand the existing 69 kV capacitor bank from 5.4 to 8.1 MVAR at Richland Center Olson substation and install one 7.8 MVAR 12.4 kV capacitor bank at Brewer substation	WI		Other	Not Shared	Reliability		6/30/2009	Under Const	12.4		A	Y
A in MTEP08	West	ATC LLC	1279	North Beaver Dam 49 MVAR cap bank	install two 24.5 MVAR cap bank at North Beaver Dam	WI		BaseRel	Not Shared		$2,500,000	9/15/2009	Under Const	138		A	Y
A in MTEP08	West	ATC LLC	1555	Perkins Capacitor Banks	Install two 16.33 MVAR 138kV capacitor banks at Perkins substation	MI		BaseRel	Not Shared		$1,395,185	10/31/2009	Under Const	138		A	Y
A in MTEP08	West	ATC LLC	1667	Pine River substation Upgrades	Construct a ring bus at Pine River 69 kV sub and upgrade existing 1-5.4 Mvar cap bank to 2-4.08 Mvar banks	MI		Other	Not Shared		$10,500,000	11/14/2009	Planned	69		A	Y
A in MTEP08	West	ATC LLC	1553	Hiawatha 138kV Capacitor Bank	Install one 16.33 MVAR 138kV capacitor bank at Hiawatha substation	MI		BaseRel	Not Shared		$615,283	12/1/2009	Planned	138		A	Y
A in MTEP08	West	ATC LLC	1268	Cap banks at Artesian and Kilbourn	Install 2-24.5 MVAR 69 kV capacitor banks at Kilbourn and install 2-24.5 MVAR 138-kV capacitor banks at Artesian	WI		BaseRel	Not Shared		$630,000	1/15/2010	Planned			A	Y
A in MTEP08	West	ATC LLC	1680	Uprate Walworth-North Lake Geneva 69 kV line	Uprate Walworth-North Lake Geneva 69 kV line to 69 MVA	WI		Other	Not Shared		$370,000	3/17/2010	Planned	69		A	Y
A in MTEP08	West	ATC LLC	2057	Warrens T-D	Construct a 5 mi 69 kV line to a new Warrens distribution substation from a tap of the Ocean Spray Tap-Tunnel City line	WI		Other	Not Shared		$3,185,000	3/31/2010	Planned	69		A	Y
A in MTEP08	West	ATC LLC	1676	L'Anse Capicitor Bank	Install one 4.08 MVAR 69 kV capacitor bank at L'Anse substation	MI		Other	Not Shared		$600,000	4/1/2010	Planned	69		A	Y
A in MTEP08	West	ATC LLC	1945	Upgrade Sheekskin Capacitor 69-kV Bank	Upgrade Sheekskin Capacitor 69-kV Bank from 10.8 Mvar to 16.2 Mvar	WI		Other	Not Shared		$272,268	4/12/2010	Planned	69		A	Y
A in MTEP08	West	ATC LLC	1684	Pleasant Valley 138 kV bus	Construct a 138 kV bus at Pleasant Valley substation to permit second distribution transformer interconnection	WI		Other	Not Shared		$2,160,000	12/1/2010	Proposed	138		A	Y
A in MTEP08	West	ATC LLC	1683	Rebuild Sunset Point-Pearl Ave 69 kV line	Rebuild 2.37 miles of 69 kV from Sunset Point-Pearl Ave with 477 ACSR	WI		Other	Not Shared	Reliability	$1,759,714	6/1/2011	Planned	69		A	Y
A in MTEP08	West	ATC LLC	356	Rockdale-West Middleton 345 kV	Construct a new 345/138 kV substation at Cardinal (next to the existing West Middleton sub), install a 345/138 kV 500 MVA transformer at Cardinal, construct 47.9 miles overhead 345 kV line from Albion to Cardinal/West Middleton, modifications to the existing West Middleton substation, construct a new Albion 345 kV switching station. Facility costs listed in the facility table are for the southern route.	WI		BaseRel	Shared		$230,056,311	6/1/2013	Planned	345	138	A	Y
A in MTEP08	West	ATC LLC	574	Monroe County - Council Creek 161 kV line projects	Monroe County - Council Creek 161 kV line, Council Creek 161/138 kV transformer; Council Creek-Petenwell uprate 138 kV	WI		Other	Not Shared		$21,900,000	6/1/2013	Proposed	161	138	A	Y
A in MTEP08	Central	DEM	1515	Speed to LGEE Trimble 345kV tie	Replace Speed relays for the LGEE Trimble addition. Also add breakers and disconnect switches at Speed to complete 345kV ring	IN		Other	Not Shared	Non-MISO (	$0	10/1/2009	Under Const	345		A	Y
A in MTEP08	Central	DEM	1266	Hortonville 69kV Cap	Install 69kV 36MVAR cap bank at Hortonville	IN		Other	Not Shared		$500,000	12/31/2009	Planned	69		A	NT
A in MTEP08	Central	DEM	1878	Speed Bk 1 replacement	Replace 138/69/12 kV BK 1 with a 138/69kV 150 MVA transformer w/LTC	IN		Other	Not Shared		$2,000,000	12/31/2009	Under Const	138	69	A	Y
A in MTEP08	Central	DEM	1890	Geist to new Fishers N. Jct. 69kV line	Build new 69kV line - 69181 - 4 miles with 954ACSR along 126th St. (completes approx 5.9 mile line section)	IN		Other	Not Shared	Reliability	$1,181,223	5/1/2010	Planned	69		A	NT
A in MTEP08	Central	DEM	1513	Metea 69kV Cap	Install 14.4MVAR 69kV capacitor at Metea.	IN		Other	Not Shared		$568,653	6/1/2010	Planned	69		A	NT
A in MTEP08	Central	DEM	1889	Danville to Danville Jct 69kV reconductor	Danville to Preswick Jct to Danville Jct - recond. 5.2 mi of the 6945 ckt. with 954acsr OVAL @100C and replace the 600 amp, two way switches at Danville Jct with two 1200 amp one way switches and replace the 600 amp switch at Prestwick Jct with a 1200 amp	IN		Other	Not Shared	Reliability	$2,235,000	6/1/2010	Planned	69		A	NT
A in MTEP08	Central	DEM	1194	Prescott	Add 43.2 MVAR capacitor.	IN		Other	Not Shared		$439,845	12/31/2010	Planned	69		A	NT
A in MTEP08	Central	DEM	1265	Geist 69kV Cap 2	Add a second 69kV 36MVAR cap bank at Geist	IN		Other	Not Shared		$500,000	12/31/2010	Planned	69		A	NT

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A in MTEP08	Central	DEM	1514	Wabash River to Staunton 230 100C Uprate	Uprate Wabash River to Staunton 23002 to 100C summer operating temperature and 80C winter (559MVA).	IN		Other	Not Shared		$2,195,000	6/1/2011	Planned	230		A	Y
A in MTEP08	Central	DEM	1560	Edwardsport 138kV cap	Install a 138kV 57.6MVAR capacitor at Edwardsport.	IN		BaseRel	Not Shared		$500,000	6/1/2011	Planned	138		A	Y
A in MTEP08	Central	DEM	1561	Kokomo Webster St 230kv Ring bus	Retire existing 1600A circuit switcher and complete the Webster St ring in order to utilize the full capacity of the bundled 477 ACSS wire on the 23016 line.	IN		Other	Not Shared		$399,580	6/1/2011	Planned	230		A	Y
A in MTEP08	Central	DEM	1564	Roseburg Switching Station cap	Install 69kV 21.6MVAR std capacitor	IN		Other	Not Shared		$518,503	6/1/2011	Planned	69		A	NT
A in MTEP08	Central	DEM	1887	Plainfield S. to Plainfield 69kV rebuild	Plainfield S. to Plainfield - Rebuild and reconductor 4.3 miles of 69kV line in the 69126 ckt. with 954acsr@100C; terminal: replace 3-600A switches with 1200A and reconductor buswork with 954 conductor at Plainfield S. end	IN		Other	Not Shared	Reliability	$2,418,000	6/1/2011	Planned	69		A	NT
A in MTEP08	Central	DEM	1512	Ashland to Rochelle 138	Install underground 138 kV circuit from Ashland to Ridgeway (New Dist Sub) to Rochelle.	OH		BaseRel	Not Shared		$9,634,051	12/31/2011	Planned	138	13.1	A	Y
A in MTEP08	Central	DEM	1881	Bloomington Rogers St - replace 13836 breaker	Bloomington Rogers St - replace 13836 breaker and WT; replace 13871 breaker, WT, and disc sw's - All 2000Amp rated; Replace relays for 13836, 13837, 13871	IN		Other	Not Shared		$1,252,764	12/31/2011	Planned	138		A	Y
A in MTEP08	Central	DEM	1245	Frankfort Jefferson to Potato Creek new 69kV Line	Construct new 69kV line from Frankfort Jefferson to new Potato Creek switching station.	IN		Other	Not Shared		$2,094,115	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	1519	Noblesville NE to Geist 69	Build a new 69kV line from Noblesville NE sub to tap the Fishers North - Geist 69kV line	IN		Other	Not Shared	Reliability	$2,640,107	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	1893	Mitchell Lehigh Portland to Bedford 25th St 6995 rebuild	Reconductor 10.3 miles of 69kV - 6995 line with 477 ACSR@100C	IN		Other	Not Shared	Reliability	$3,620,481	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	1896	Connersville 138 sub to Connersville 30th St 69kV uprate	Connersville 138 sub to Connersville 30th St 69kV Uprate to 100C - 4/0 acsr sections – 1.2 miles - 6981 ckt	IN		Other	Not Shared		$16,493	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	1897	Deedsville to Macy 69kV Reconductor	Reconductor Deedsville to Macy section of 6957 circuit with 477ACSR approx 2.5 miles; and replace Macy #1 and #2 - 600A line switches (1955 vintage) with 1200A	IN		Other	Not Shared		$921,919	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	1651	Madison Michigan Rd to HE Fairview 13854 Uprate	Madison Michigan Rd to HE Fairview 13854 Uprate 397ACSR conductor to 100C operation	IN		BaseRel	Not Shared		$278,000	6/30/2012	Planned	138		A	Y
A in MTEP08	Central	DEM	1899	Macy to Rochester Metals Jct 69kV reconductor	Reconductor Macy to Rochester Metals Jct section of 6957 circuit with 477ACSR - approx 9.1 miles	IN		Other	Not Shared	Reliability	$3,102,711	12/31/2012	Planned	69		A	NT
A in MTEP08	Central	DEM	835	Pittsboro 69kV Cap	Add 14.4 MVAR 69kV capacitor at Pittsboro.	IN		Other	Not Shared		$422,362	6/1/2013	Planned	69		A	NT
A in MTEP08	Central	DEM	1568	Qualitech 345/138KV Transformer and breakers	Qualitech Sub- Install one 345/138kv, 300Mva Xtr and 2-345kv Bkrs and 1-138kv Bkr to provide second 138kv source to proposed Hendricks Co 138kv system	IN		Other	Not Shared	Reliability	$4,561,674	6/1/2013	Planned	345	138	A	Y
A in MTEP08	Central	DEM	1901	Noblesville Station to Noblesville Jct 69kV line rebuild	Reconductor 69kV - 6984 & 6916 ckt. Noblesville Plant to Noblesville 8th St. to Noblesville Jct with 954ACSS @ 200C (5.47 miles)	IN		Other	Not Shared	Reliability	$1,510,946	6/1/2013	Planned	69		A	NT
A in MTEP08	Central	DEM	1569	Qualitech to Pittsboro new 138kv line	Construct new 138kv line, Qualitech to Pittsboro, and connect to the Pittsboro-Brownsbg line to provide new 954ACSR outlet line from Qualitech 345/138kV Bank	IN		Other	Not Shared	Reliability	$1,507,856	6/2/2013	Planned	138		A	Y
A in MTEP08	Central	DEM	1570	Plainfield South to Pittsboro 69KV to 138KV Conversion	Convert the existing 69KV (69144) line from Plainfield S. to Pittsboro (and 4 distribution subs) over to 138KV operation and connect to the new Qualitech to Pittsboro 138KV line	IN		Other	Not Shared	Reliability	$4,139,000	6/3/2013	Planned	138		A	Y
A in MTEP08	Central	DEM	1895	Brownsburg to Avon East 138kV Reconductor	Brownsburg to Avon East 138kV Reconductor 4.2 miles of 138kV line with 954 ACSR - AFTER 138KV CONVERSION	IN		BaseRel	Not Shared		$1,433,227	6/4/2013	Planned	138		A	Y
A in MTEP08	Central	DEM	834	Kingman 69kV Cap	Add 7.2 MVAR 69kV capacitor at Kingman.	IN		Other	Not Shared		$500,000	6/1/2014	Planned	69		A	NT
A in MTEP08	Central	DEM	1501	Carmel 146th St 69kV Cap 2	Added second 36 MVAR 69kV capacitor at Carmel 146th St	IN		Other	Not Shared		$624,145	6/1/2014	Planned	69		A	NT

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A in MTEP08	Central	DEM	1902	Zionsville 69 to Zionsville 96th Jct 69kV reconductor	Reconductor .32 miles of the 69kV - 69155 line from Zionsville 69 sub to Zionsville 96th Jct with 954ACSR conductor; replace/upgrade 69kV switches, jumpers and bus at Zionsville 69 sub for a min. capacity of 152MVA (502G6709)	IN		Other	Not Shared		$309,475	6/1/2014	Planned	69		A	NT
A in MTEP08	Central	DEM	1650	Fairview to HE Fairview 13854 Reconductor	Fairview to HE Fairview 13854 Reconductor with 954ACSR @ 100C	IN		BaseRel	Not Shared		$1,236,384	6/30/2014	Planned	138		A	Y
A in MTEP08	Central	DEM	841	Westwood Bk1 Limiting Equipment	Replace 1600A 138kV breaker with 3000A to allow full xfr rating.	IN		BaseRel	Not Shared		$141,623	6/1/2015	Planned	345	138	A	Y
A in MTEP08	East	FE	1596	Lakeview Sub - Install 34.5kV Cap Bank for 138kV system	Install 1 - 18.9 MVAR Capacitor bank	OH		Other	Not Shared	Reliability	$577,214	12/31/2009	Planned	34.5		A	Y
A in MTEP08	East	FE	1912	Cardington-Tangy: R/C 69kV line	Reconductor The entire Cardington-Tangy 69kV line to 336.4 ACSR conductor.	OH		Other	Not Shared	Reliability	$2,400,000	12/31/2009	Planned	69		A	Y
A in MTEP08	East	FE	1599	Bayshore-Maclean-Lemoyne 138kV 3-terminal lines elimination (Includes P1324: Reconductor Walbridge Jct.-MacLean Project as part of P1599)	Bayshore-Maclean-Lemoyne 138kV eliminate 3-terminal line, reconductor the Walbridge Jct.-Maclean 13202 line segment and upgrade replace wave trap at Lemoyne.	OH		BaseRel	Not Shared		$1,267,900	6/1/2010	Planned	138		A	Y
A in MTEP08	East	FE	1911	Fayette 138-69kV Substation & 69kV line addition	Add a 138/69kV transformer and 3 breaker 138kV ring-bus at the Fayette Substation area and construct a 69kV line from Fayette to a point on the Bryan-Stryker No. 1 69kV line near Holiday City. The new line will be tapped to provide primary supplies to Pioneer and Holiday City substations	OH		Other	Not Shared	Reliability	$12,678,421	11/1/2010	Planned	138	69	A	Y
A in MTEP08	East	FE	2096	Stacy 138-36kV distribution sub	Construct a 138kV loop to a new Stacy 138/36kV substation for 138kV support in the area, with possible networking to other substations based on future growth.	OH		Other	Not Shared	Reliability	$12,000,000	11/4/2010	Planned	138	36	A	Y
A in MTEP08	East	FE	1909	Davis Besse 345kV sub reconfiguration	Reconfigure the Davis Besse switch yard by extending J and K buses and adding 345kV breakers	OH		BaseRel	Not Shared		$2,501,000	12/17/2010	Planned	345		A	Y
A in MTEP08	East	FE	1601	Chamberlin - Shalersville New 138 kV Line	Build a new Chamberlin - Shalersville 138 kV Line to complete loop between Chamberlin, Shalersville and Hanna.	OH		Other	Not Shared	Reliability	$3,669,000	6/1/2012	Planned	138		A	Y
A in MTEP08	East	FE	1921	Chittenden - Darrow New 69 kV Line and Install (4) 69kV Bkrs at Chittenden	Build a new 3.87 mile 336 Chittenden - Darrow 69 kV Line and addition of 69 kV breakers at Chittenden Substation.	OH		Other	Not Shared	Reliability	$3,448,047	6/1/2013	Planned	69		A	Y
A in MTEP08	East	FE	1589	West Medina Sub - Install a 138/69 kV Transformer & Reconductor Medina-W Medina 69kV Line	Establish 138/69 kV transformation at West Medina Substation, and connect to the existing Abbe - Medina 69 kV Line for area support.	OH		Other	Not Shared	Reliability	$4,131,000	6/1/2014	Planned	138	69	A	Y
A in MTEP08	East	FE	1918	Dale - Jackson New 69 kV Line	Build a new Dale - Jackson 69 kV Line. Install 3.9 miles of 605 ACSR and 2.9 miles of 605 ACSR double circuiting on existing poles.	OH		Other	Not Shared	Reliability	$2,243,200	6/1/2014	Planned	69		A	Y
A in MTEP08	East	FE	1591	Newton Falls Substation - R/P No.3 TR 138/69 kV	Replace No. 3 Newton Falls TR 138/69 kV with a larger MVA unit	OH		Other	Not Shared	Reliability	$2,034,365	6/1/2016	Planned	138	69	A	Y
A in MTEP08	West	GRE, XEL, OTP	286	Fargo, ND - St Cloud/Monticello, MN area 345 kV project	Maple River- AlexandriaSS - Waite Park - Monticello 345 ckt 1, Sum rate 2085	MN		BaseRel	Shared		$494,500,000	7/1/2015	Planned	345	115	A	Y
A in MTEP08	West	GRE/OTP	1033	Silver Lake 230/41.6 kV transformer	Silver Lake 230/41.6 kV transformer	MN		Other	Not Shared	Reliability	$3,804,000	12/30/2011	Planned	230	41.6	A	Y
A in MTEP08	Central	HE	1323	Sandborn Primary Substation	161/69kV Primary Station at Sandborn	IN		Other	Not Shared	Reliability	$6,000,000	9/1/2008	Planned	161	69	A	Y
A in MTEP08	Central	HE	1926	Gywnneville to Pioneer tie	69kV Tie from DE Gwynneville to HE Pioneer	IN		Other	Not Shared		$1,000,000	9/1/2008	Planned	69		A	NT
A in MTEP08	Central	HE	2095	Sandborn Primary	Sandborn Primary to Freelandville Switch 69 kV line and Sandborn Primary to Carlisle Switch 69 kV line	IN		Other	Not Shared		$4,000,000	9/1/2008	Planned	69		A	NT
A in MTEP08	Central	HE	1923	Spring Valley 69kV Switch Station	69kV Switching station w/ 69kV Ring Bus	IN		Other	Not Shared	Reliability	$2,600,000	9/1/2009	Planned	69		A	NT
A in MTEP08	Central	HE	2082	Shelbyville Intel Park	138kV Substation and Tapline	IN		Other	Not Shared	Reliability	$1,000,000	9/1/2009	Planned	138	12.5	A	Y
A in MTEP08	Central	HE	2083	Wayne County Industrial Park	69kV Substation and Tapline	IN		Other	Not Shared		$750,000	9/1/2009	Planned	69	12.5	A	NT
A in MTEP08	Central	HE	2084	Worthington 161/138kV Transformer	Worthington 161/138kV Transformer replacement	IN		Other	Not Shared		$4,500,000	9/1/2009	Planned	161	138	A	Y
A in MTEP08	Central	HE	1635	Ramsey Primary Substation Ringbus	345kV Ringbus Addition/Modification to Ramsey Primary	IN		Other	Not Shared	Reliability	$7,000,000	12/1/2009	Planned	345		A	Y

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A in MTEP08	Central	HE	1927	Hubbell Primary Ring Bus	138kV Ring Bus addition / Modification to Hubbell Primary	IN		Other	Not Shared	Reliability	$3,000,000	9/1/2010	Planned	138		A	Y
A in MTEP08	Central	HE	1928	Fairview Primary Ring Bus	138kV Ring Bus addition / Modification to Fairview Primary	IN		Other	Not Shared	Reliability	$1,500,000	9/1/2011	Planned	138		A	Y
A in MTEP08	Central	HE	1929	Georgetown Primary Ring Bus	138kV Ring Bus addition / Modification to Georgetown Primary	IN		Other	Not Shared	Reliability	$1,250,000	9/1/2012	Planned	138		A	Y
A in MTEP08	Central	IPL	1639	General IPL Capacitor Additions	Add capacitors to the IPL General Distribution System	IN		Other	Not Shared		$50,000	6/1/2013	Planned			A	Y
A in MTEP08	East	ITC	1664	Relay Betterment	replace relays that do not meet up to date standards	MI		Other	Not Shared		$1,130,000	12/31/2008	Planned			A	Y
A in MTEP08	East	ITC	1875	G503 Noble Wind Farm	Generation interconnection project to install 157 MW of wind turbines that will connect to the existing Sandusky - Wyatt 120 kV circuit	MI		GIP	Shared		$5,894,687	9/30/2009	Planned	120		A	Y
A in MTEP08	East	ITC	1661	Axle	Chrysler Axle Sub	MI		Other	Not Shared		$800,000	10/31/2009	Under Const	120		A	Y
A in MTEP08	East	ITC	1871	Hurst	Distribution Interconnection to add a new 120/41kV transformer at Hurst. Breaks up the Genoa-Durant 120kV circuit	MI		Other	Not Shared		$2,100,000	11/1/2009	Planned	120		A	Y
A in MTEP08	East	ITC	1866	Anti-galloping project 2009	Installation of air flow spoilers on problematic lines.	MI		Other	Not Shared		$1,500,000	12/31/2009	Under Construction			A	Y
A in MTEP08	East	ITC	1663	Cable Termination	replace cable terminations that have reached end of life or lack spare parts	MI		Other	Not Shared		$4,000,000	4/1/2010	Planned			A	Y
A in MTEP08	East	ITC	1857	Adams - Spokane 120 kV and Jewell - St. Clair 2 120 kV	Reconfigure the Jewell - Spokane - St. Clair 120 kV line in to the Adams - Spokane 120 kV and the Jewell - St. Clair 2 120 kV lines to eliminate relaying issues associated with the 3-ended line. This project frees up the assets from Structure 1199 to Structure 1182 so they can be utilized in the Belle River - Greenwood - Pontiac 345kV cut into Jewell project.	MI		Other	Not Shared		$1,400,000	5/31/2010	Proposed	120		A	Y
A in MTEP08	East	ITC	1873	Tahoe	Distribution Interconnection to add a new 120/13.2kV transformer at Tahoe.	MI		Other	Not Shared		$2,800,000	3/1/2011	Planned	120		A	Y
A in MTEP08	East	ITC	1870	Clyde	Distribution Interconnection to add a new 120/41kV transformer at Clyde. Taps the Placid-Durant 120kV circuit	MI		Other	Not Shared		$2,750,000	6/1/2011	Planned	120		A	Y
A in MTEP08	West	ITCM	1757	Cambridge REC-Maxwell 69kV Rebuild	Rebuild 6.35 miles of 69kV line from Cambridge REC to the Maxwell North Sub.	IA		Other	Not Shared	Reliability	$2,100,000	12/31/2008	Planned	69		A	NT
A in MTEP08	West	ITCM	1758	Beaver Channel-2nd Ave 69kV	Rebuild 2.5 miles of 69kV line from Beaver Channel-2nd Ave (dbl ckt with BC-Mill creek) . This line will be rebilt to 161kV standards operated 69kV.	IA		Other	Not Shared		$1,906,000	12/31/2008	Under Const	69		A	NT
A in MTEP08	West	ITCM	1341	Replace two Hazleton 161/69 kV transformers	Replace two Hazleton 161/69 kV transformers with 74.7 MVA	IA		Other	Not Shared	Reliability	$900,000	6/1/2009	Under Const	161	69	A	Y
A in MTEP08	West	ITCM	1345	Replace the limiting facility of CTs and conductor inside the substations for Quad Cities-Rock Creek-Salem 345 kV line	Replace the limiting facility of CTs and conductor inside the substations for 345 kV line Quad Cities-Rock Creek-Salem so the line rating can be raised to the same as conductor rating between substations	IA		BaseRel	Not Shared		$50,000	6/1/2009	Planned	345		A	Y
A in MTEP08	West	ITCM	1346	Upgrade conductor inside the substation so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer	Upgrade conductor inside the substation so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer	IA		BaseRel	Not Shared		$13,400	6/1/2009	Planned	345	161	A	Y
A in MTEP08	West	ITCM	1641	OGS 50 MVAR Cap Bank	Install a 161kV 50 MVAR cap bank at the Ottumwa Generating Station.	IA		BaseRel	Not Shared		$1,400,000	6/1/2009	Planned	161		A	Y
A in MTEP08	West	ITCM	1755	Washington-Hills 69kV Rebuild	Rebuild the 69kV line from Washington-Kalona T-N Crane T-Hills (MEC).	IA		Other	Not Shared	Reliability	$4,350,000	6/1/2009	Under Const	69		A	NT
A in MTEP08	West	ITCM	1756	Dyersville-Peoasta 69kV Rebuild	Rebuild the 69kV line from Dyersville-Farley-Epworth-Peosta.	IA		Other	Not Shared		$1,990,326	6/1/2009	Under Const	69		A	NT
A in MTEP08	West	ITCM	1753	Winnebago Jct south 161/69kV	Replace the Winnebago Jct 161/69kV 30 MVA transformer with a new 75 MVA unit	IA		Other	Not Shared	Reliability	$1,400,000	6/30/2009	Planned	161	69	A	Y
A in MTEP08	West	ITCM	1337	Rose Hollow Substation	New 161/69 kV substation will tap the Hills - Bertram 161kV Line	IA		Other	Not Shared	Reliability	$4,160,000	12/31/2009	Planned	161	69	A	Y

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A in MTEP08	West	ITCM	1522	6th Street - Beverly	New line to serve new industrial customer load.	IA		BaseRel	Shared		$7,200,000	12/31/2009	Planned	161		A	Y
A in MTEP08	West	ITCM	1619	Grnd Mnd 161-69kV 2nd Xfmr & 161kV loop	Install a 2nd Grand Mound 161-69kV Xfmr (75 MVA) & build a 2.0 miles of new line from the Grand Mound sub to tap the E. Calamus-Maquoketa line (approx. 87% from Maq-E.Cal). The E. Calamus-new tap portion of line will be retired. Existing E.Cal-Maq bkr will feed to GMnd and a new GMnd bkr will feed to Maq. The three terminal line at E.Calamus will be eliminated.	IA		Other	Not Shared	Reliability	$2,407,708	12/31/2009	Planned	161	69	A	Y
A in MTEP08	West	ITCM	1636	Waterbury breaker station	Waterbury breaker station	MN		Other	Not Shared	Reliability	$1,000,000	12/31/2009	Planned	69		A	NT
A in MTEP08	West	ITCM	1739	Arnold-Vinton-Dysart-Washburn 161kV Reconductor	Reconductor the 161kV from Arnold-Vinton-Dysart-Washburn, sum rate 446 MVA	IA		Other	Not Shared		$14,100,000	12/31/2009	Planned	161		A	Y
A in MTEP08	West	ITCM	1754	Emery-Lime Creek 161kV Road move	Rebuild a portion of the Emery-Lime Creek 161kV line (about 1 mile)	IA		Other	Not Shared		$365,000	12/31/2009	Planned	161		A	Y
A in MTEP08	West	ITCM	1769	Belle Plaine - Hwy 30 1.4 mi Rebuild	Rebuild 1.4 miles	IA		Other	Not Shared		$110,000	12/31/2009	Planned	69		A	Y
A in MTEP08	West	ITCM	1972	Decorah Mill St-Cresco dbl ckt Rebuild	Rebuild 0.65 miles of 69kV line on the Mill St-Cresco 69kV dble ckt line	IA		Other	Not Shared		$203,000	12/31/2009	Planned	69		A	NT
A in MTEP08	West	ITCM	2108	G358-Fairbault County	Network upgrades for tariff service request	MN		GIP	Shared		$2,119,692	12/31/2009	Planned	161	34.5	A	Y
A in MTEP08	West	ITCM	1747	Elk 161/69kV upgrades	Upgrade both Elk 161/69kV transformers and add a 161kV BKR between the new units.	IA		Other	Not Shared	Reliability	$4,000,000	6/1/2010	Planned	161	69	A	Y
A in MTEP08	West	ITCM	1618	Hrn Lk-Lkfld 161kV Ckt 1 Rbld	Rebuild Heron Lake-Lakefield 161kV line, sum rate 446 MVA	MN		BaseRel	Shared		$6,940,000	12/31/2010	Planned	161		A	Y
A in MTEP08	West	ITCM	1643	Anita 24 MVAR Cap Bank	Install a 161kV 24 MVAR cap bank at the Anita substation.	IA		BaseRel	Not Shared		$650,000	12/31/2010	Proposed	161		A	Y
A in MTEP08	West	ITCM	1644	Grand Junction 24 MVAR Cap Bank	Install a 161kV 24 MVAR cap bank at the Grand Junction substation.	IA		BaseRel	Not Shared		$650,000	12/31/2010	Proposed	161		A	Y
A in MTEP08	West	ITCM	1645	Leon 7.2 MVAR Cap Bank	Install a 69kV 7.2 MVAR cap bank at the Leon substation.	IA		Other	Not Shared	Reliability	$150,000	12/31/2010	Proposed	69		A	NT
A in MTEP08	West	ITCM	1750	Goose Pond 161kV Switching Station	Build a new Goose Pond 3 terminal 161kV switching station along the Palmyra-Twin Rivers 161kV line.	IA		Other	Not Shared		$1,800,000	12/31/2010	Proposed	161		A	Y
A in MTEP08	West	ITCM	1772	North Centerville 7 MVAR Cap bank	Install a new 69kV North Centerville 7 MVAR Cap bank & 69kV Bkr	IA		Other	Not Shared	Reliability	$1,200,000	12/31/2010	Planned	69		A	NT
A in MTEP08	West	ITCM	1340	Hazleton - Salem 345 kV line with a 2nd Salem 345/161 kV 448 MVA transformer.	Build a new Hazleton - Salem 345 kV line. Expand the Hazleton 345kV bus to a 5 position ring and expand the Salem 345kV ring to allow for a 2nd Salem 345/161 kV 448 MVA transformer. (option 1)	IA		Other	Not Shared		$119,010,000	12/31/2011	Planned	345	161	A	Y
A in MTEP08	West	ITCM	1744	Maquoketa-Grand Mound 161kV Reconductor	Reconductor 161kV from Maquoketa to Grand Mound (old East Calamus-Maquoketa 161kV line)	IA		BaseRel	Not Shared		$6,900,000	12/31/2011	Planned	161		A	Y
A in MTEP08	West	ITCM	1640	Marshalltown-Franklin 115kV conversion to 161kV.	Rebuild Marshalltown-Wellsburg-Eldora-Iowa Falls Industrial-Iowa Falls-Franklin 115kV to 161kV. This will also convert the Wellsburg, Eldora, Iowa Falls Industrial, and Iowa Falls substations to 161kV operation on the high side. The 161-115kV source at Franklin will be eliminated.	IA		Other	Not Shared		$25,080,000	12/31/2013	Planned	161	34	A	Y
A in MTEP08	East	METC	1820	METC Communication and Relaying Upgrade	Throughout system	MI		Other	Not Shared		$10,000,000	12/31/2008	Proposed			A	Y
A in MTEP08	East	METC	1443	Milham	Install a second distribuiton transformer served from Milham-Upjohn 138kV	MI		Other	Not Shared		$100,000	6/1/2009	Planned	138	12.5	A	Y
A in MTEP08	East	METC	1829	Leoni-Beecher 138 kV	Increase capacity of Leoni-Beecher 138 kV ckt.	MI		BaseRel	Not Shared		$450,000	6/1/2009	Planned	138		A	Y
A in MTEP08	East	METC	1838	College (formerly Meridian)	New Distrbution Interconnection served from Delhi-Tihart 138kV circuit	MI		Other	Not Shared		$2,200,000	11/1/2009	Planned	138		A	Y
A in MTEP08	East	METC	480	Brickyard Jct. - Felch Road 138 kV	Rebuild 13 miles of 3/0 ACSR to 954 ACSR	MI		BaseRel	Shared		$10,000,000	12/31/2009	Planned	138		A	Y
A in MTEP08	East	METC	1656	Relay NERC/8A Compliance	Upgrade relays throughout system	MI		Other	Not Shared		$3,055,555	12/31/2009	Planned	345		A	Y

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A in MTEP08	East	METC	1793	Argenta Breaker Additions	Add a breaker each at the 345kV and 138kV stations in the rows where transformer #3 ties into the stations. This will prevent a stuck breaker scenario on either the 345kV or 138kV stations from taking out two Argenta transformers.	MI		BaseRel	Not Shared		$2,200,000	12/31/2009	Planned	345		A	Y
A in MTEP08	East	METC	1819	Felch Road - Croton	Rebuild 138 kV Line. Prebuild to 230 kV construction.	MI		BaseRel	Shared		$7,750,000	12/31/2009	Planned	138		A	Y
A in MTEP08	East	METC	1797	Almeda - Saginaw River 138kV	Rebuild 25 miles of 138kV of various conductor size (110, 115 and 1/0 CU; 3/0 ACSR) to 954 ACSR. Prebuild to 230kV construction.	MI		BaseRel	Shared		$21,000,000	5/31/2010	Planned	138		A	Y
A in MTEP08	East	METC	1798	Campbell - Black River 138kV	Construct a 138kV switching station next to Campbell, loop an existing Campbell 138kV line into this new substation, and build a new 138kV line (15 miles, 954 ACSR) from this sub. to Black River.	MI		BaseRel	Shared		$23,327,551	6/1/2010	Planned	138		A	Y
A in MTEP08	East	METC	1841	Eagles Landing	New Distrbution Interconnection served from Iosco - Karn 138kV circuit	MI		Other	Not Shared		$175,000	6/1/2010	Planned	138		A	Y
A in MTEP08	East	METC	1655	Breaker Repair or Replace Program	throughout system	MI		Other	Not Shared		$2,060,000	12/31/2010	Planned	345		A	Y
A in MTEP08	East	METC	1813	Cobb Swamp Rebuild	Rebuild the segments [each segment is approximately 4 miles] of the Cobb to Brickyard, Cobb to Tallmadge Ckt # 1, Cobb to Tallmadge Ckt # 2, Cobb to Four Mile and Cobb to Sternberg 138 kV lines that are located within the floodplain swamp of the Muskegon	MI		Other	Not Shared		$14,000,000	12/31/2010	Planned	138		A	Y
A in MTEP08	East	METC	1818	Algoma - Croton	Rebuild 138 kV Line. Prebuild to 230 kV construction.	MI		BaseRel	Shared		$17,150,000	5/31/2011	Planned	138		A	Y
A in MTEP08	East	METC	1796	Twining - Almeda 138kV	Rebuild 22 miles of 138kV of 110 Cu to 954 ACSR. Prebuild to 230kV construction.	MI		BaseRel	Shared		$19,500,000	6/1/2011	Planned	138		A	Y
A in MTEP08	East	METC	1799	Grand Rapids SAG limits	Remove the SAG limit on: Roosevelt - Tallmadge	MI		BaseRel	Not Shared		$1,000,000	6/1/2011	Planned	345		A	Y
A in MTEP08	East	METC	1834	Tirrell Road	New Distrbution Interconnection served from Battle Creek - Island Rd. 138kV circuit	MI		Other	Not Shared		$200,000	12/15/2011	Planned	138		A	Y
A in MTEP08	East	METC	1814	Tippy - Chase 138kV	Rebuild 30 miles of 138kV 110 CU to 954 ACSR. Prebuild to 230kV construction.	MI		BaseRel	Shared		$30,000,000	12/31/2011	Planned	138		A	Y
A in MTEP08	East	METC	1448	Simpson	Project to connect a distribution transformer at Simpson	MI		Other	Not Shared		$2,200,000	6/1/2014	Proposed	138	12.5	A	Y
A in MTEP08	West	MP	1482	Pepin Lake 115/34.5 - Transformer 115/34.5 kV 39 MVA	Pepin Lake 115/34.5 - Transformer 115/34.5 kV 39 MVA	MN		Other	Not Shared		$2,836,500	4/1/2009	Under Const	115	34.5	A	Y
A in MTEP08	East	NIPS	1992	Upgrade 138/69 kV Transformer Capacity at Starke substation	Add additional cooling pumps to increase existing 138/69 KV transformers capacity at Starke Substation. Capacity to be increased from 56 MVA to 70 MVA.	IN		Other	Not Shared	Reliability	$126,000	4/1/2009	Planned	138	69	A	Y
A in MTEP08	East	NIPS	1977	Leesburg Sub - New 138/69 Substation	Install 138/69 kV Transformer and 2 69 kV Circuits at Leesburg Substation	IN		Other	Not Shared	Reliability	$5,407,000	6/1/2009	Proposed	138	69	A	Y
A in MTEP08	East	NIPS	1978	Goshen Jct. Cir 6976 - Recond 2.1 Miles	Upgrade (reconductor) 2.1 miles of 69 KV line 2/0 ACSR line to 336.4 KCM ACSR in the northern Goshen area just north of Rock Run Substation.	IN		Other	Not Shared		$190,000	12/1/2009	Planned	69		A	Y
A in MTEP08	East	NIPS	1996	Circuit 6980 - Angola Sub to Sw #644 - Rebuild w 336 KCM ACSR	Rebuild and upgrade 12 miles of Circuit 6980's existing 2/0 Cu to 336.4 kCM ACSR.	IN		Other	Not Shared		$1,780,000	12/1/2009	Planned	69		A	Y
A in MTEP08	East	NIPS	1986	Green Acres Sub - Add 3rd 138/69 kV Transformer	Install a 3rd 138/69 KV 112 MVA transformer, associated breakers and bus at Green Acres Substation.	IN		Other	Not Shared	Reliability	$755,000	12/1/2011	Planned	138	69	A	Y
A in MTEP08	East	NIPS	1997	Circuit 6977 - Goshen Jct to Model Sub Tap - Recond. 1.5 Miles	Upgrade (reconductor) 1.5 miles of 69 KV line to 336.4 KCM ACSR.	IN		Other	Not Shared		$357,000	12/1/2012	Planned	69		A	Y
A in MTEP08	West	NWE	2008	Milltown-Luck NSP 34.5KV Rebuild	Rebuild the 34.5Kv system between Milltown and Luck NSP sub at 69KV with 477ASCR and horizontal post construction.	WI		Other	Not Shared		$165,000	6/8/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2009	Milltown Tap-Eureka Tap 34.5KV Rebuild	Rebuild the 34.5KV system between Milltown Tap and Eureka Tap at 69KV by replacing poles and using same conductor.	WI		Other	Not Shared		$125,000	6/9/2008	Planned	69		A	Y

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A in MTEP08	West	NWE	2010	Eureka Tap-Balsam Lake 34.5KV Rebuild	Rebuild the 34.5KV system between Eureka Tap and Balsam Lake at 69KV by replacing poles and using same conductor.	WI		Other	Not Shared		$265,000	6/9/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2012	Falun-Penta 34.5KV Rebuild	Rebuild the 34.5Kv system between Falun and Penta sub at 69KV with 477ASCR and horizontal post construction.	WI		Other	Not Shared		$538,000	6/10/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2013	Penta-Siren Tap 34.5KV Rebuild	Rebuild the 34.5Kv system between Penta sub and Siren Tap at 69KV with 477ASCR and horizontal post construction.	WI		Other	Not Shared		$175,000	6/10/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2014	Garfield-Balsam Lake 69KV Rebuild	Rebuild the 69KV line with 477 ASCR and horizontal post construction.	WI		Other	Not Shared		$500,000	6/11/2008	Proposed	69		A	Y
A in MTEP08	West	NWE	2015	Balsam Lake Substation	Build new Balsam Lake transmission substation	WI		Other	Not Shared		$500,000	6/11/2008	Proposed	69		A	Y
A in MTEP08	West	NWE	2016	Frederic-Coffee Cup 69KV reconductor	Reconductor 69KV line with 477ACSR	WI		Other	Not Shared		$100,000	6/12/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2017	Milltown Tap-Balsam Lake 69KV Reconductor	Reconductor 69KV line with 477ACSR	WI		Other	Not Shared		$250,000	6/12/2008	Planned	69		A	Y
A in MTEP08	West	NWE	2018	Balsam Lake-Centuria 69KV line	Build new 69KV line to Centuria and build Distribution Sub	WI		Other	Not Shared		$750,000	6/12/2008	Proposed	69	12.47	A	Y
A in MTEP08	West	NWE	2011	Frederic-Lewis 34.5KV Rebuild	Rebuild the 34.5Kv system between Frederic and Lewis sub at 69KV with 477ASCR and horizontal post construction.	WI		Other	Not Shared		$350,000	12/9/2008	Planned	69		A	Y
A in MTEP08	West	OTP	2090	Cass Lake 115 kV capacitor	Cass Lake 115 kV capacitor (2x15 Mvar)	MN		Other	Not Shared		$630,000	12/31/2009	Planned	115		A	Y
A in MTEP08	West	OTP	1792	Mapleton - Buffalo 115 kV line addition	This project will be completed in two phases. Phase 1 involves construction of a 115 kV line from Mapleton 115 to a new substation located west of Casselton. Phase 2 will construct a 115 kV line from the Ethanol plant to the Buffalo 115 kV bus. Phase 1 is expected to be in service by 9/1/2008 with phase 2 expected to in service by the middle of 2010.	ND		Other	Not Shared		$6,980,000	6/30/2010	Planned	115		A	Y
A in MTEP08	West	OTP	2092	South Cascade 115 kV Addition	This project proposes to tap the Hoot Lake to Grant County 115 kv line approximately 1.6 miles south of the Hoot Lake substation. A new 115 kV line approximately 2 miles in length will be constructed from this tap point the existing South Cascade 41.6/12.5 kV substation. A new 115/12.5 kV transformer will be added to the South Cascade substation.	MN		Other	Not Shared		$2,000,000	12/31/2010	Proposed	115		A	Y
A in MTEP08	West	OTP/MPC	2091	Cass Lake 115/69/41.6 kV sub	Cass Lake 115/69/41 kV substation	MN		Other	Not Shared		$1,000,000	12/31/2009	Planned	115	69	A	Y
A in MTEP08	West	OTP/MPC	971	Winger 230/115 kV Transformer Upgrade	Winger 230/115 kV Transformer upgrade	MN		BaseRel	Not Shared		$3,715,351	12/31/2011	Proposed	230	115	A	Y
A in MTEP08	Central	SIPC	1778	Hamilton 138KV Interconnect	Construct a 138KV line connecting SIPC Hamilton Substation to Ameren Norris City Substation. This project includes the construction of 18 miles of 138KV line.	IL		Other	Not Shared		$5,000,000	7/1/2008	Planned	138		A	Y
A in MTEP08	Central	Vectren (SIGE)	1001	Add 138 kV bus at Oak Grove. Install 150 MVA 138/69 kV transformer	Add 138 kV bus at Oak Grove. Install 150 MVA 138/69 kV transformer	IN		Other	Not Shared		$8,950,000	7/15/2009	Under Const	138	69	A	Y
A in MTEP08	Central	Vectren (SIGE)	1783	Princeton Area Load Addition	Expansion of Substation	IN		Other	Not Shared		$400,000	10/1/2009	Under Const	69	12.47	A	NT
A in MTEP08	Central	Vectren (SIGE)	1002	New Northeast to Oak Grove to Culley Line 138 kV	New Northeast to Oak Grove to Culley Line 138 kV	IN		Other	Not Shared	Reliability	$8,500,000	12/31/2009	Planned	138		A	Y
A in MTEP08	Central	Vectren (SIGE)	1782	NorthEast Sub Bus re-config	Rebuild existing straight bus with more reliable breaker and half scheme	IN		Other	Not Shared	Reliability	$3,300,000	12/31/2009	Planned	138		A	Y
A in MTEP08	Central	Vectren (SIGE)	1785	Z83 Upgrade	Upgrade terminal equipment at NE and NW.	IN		Other	Not Shared		$100,000	12/31/2009	Planned	138		A	Y
A in MTEP08	Central	Vectren (SIGE)	1786	Z98 Upgrade	Upgrade terminal equipment at AB Brown and Point	IN		Other	Not Shared		$100,000	12/31/2009	Planned	138		A	Y
A in MTEP08	Central	Vectren (SIGE)	1780	Aventine Phase II	Expansion of Substation	IN		Other	Not Shared	Reliability	$1,325,000	6/1/2010	Planned	69	12.47	A	NT
A in MTEP08	Central	Vectren (SIGE)	1970	New 345/138kV Substation at AB Brown	New 448MVA 345/138kV transformer in addition to the Gibson-AB Brown-Reid 345kV line.	IN		BaseRel	Shared		$7,680,032	5/31/2011	Planned	345	138	A	Y
A in MTEP08	Central	Vectren (SIGE)	1784	Jasper#3 Sub Exp-Victory Line	Extend existing Victory line to new term at existing sub	IN		Other	Not Shared		$1,250,000	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	Vectren (SIGE)	1787	Y75 - Dale to Santa Clause	New 69kV line from Dale Sub to Santa Clause Sub	IN		Other	Not Shared	Reliability	$3,300,000	6/1/2012	Planned	69		A	NT

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A in MTEP08	Central	Vectren (SIGE)	1788	Y34 - St. Wendel to Mohr Rd	New 69kV line from St. Wendel Sub to Mohr Rd Sub	IN		Other	Not Shared	Reliability	$2,600,000	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	Vectren (SIGE)	1789	Y56 - City of Boonville Loop	New 69kV line from Boonville Sub to Boonville Pioneer Sub	IN		Other	Not Shared	Reliability	$1,400,000	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	Vectren (SIGE)	1790	Y52 rebuild and Sunbeam loop	Rebuild/Reconductor existing Y52 and loop into Sunbeam	IN		Other	Not Shared	Reliability	$1,500,000	6/1/2012	Planned	69		A	NT
A in MTEP08	Central	Vectren (SIGE)	1791	Y66-2 Angel Mounds to Eastside uprate	Uprate Y66-2 from Angel Mounds to East Side to increase transfer capacity	IN		Other	Not Shared		$300,000	6/1/2012	Planned	69		A	NT
A in MTEP08	East	WPSC	1968	Westwood Substation	Construct new substation at the Westwood location	MI		Other	Not Shared		$2,000,000	7/3/2009	Under Const	69		A	Y
A in MTEP08	East	WPSC	1214	Garfield X to Grawn	Rebuild Overloaded Line to 795 ACSS	MI		Other	Not Shared	Reliability	$3,400,000	12/31/2009	Planned	69		A	Y
A in MTEP08	East	WPSC	1219	Lake County - Plains Junction Line Rebuild	Rebuild line to 795ACSS	MI		Other	Not Shared	Reliability	$6,200,000	12/31/2009	Planned	69		A	Y
A in MTEP08	East	WPSC	1964	Chester Tie	Add 138/69kV Transformer to Copemish substation	MI		Other	Not Shared	Reliability	$11,200,000	5/31/2010	Planned	138	69	A	Y
A in MTEP08	East	WPSC	1965	Gray Tie	Add 138/69kV Transformer to WPSC's Garfield junction	MI		Other	Not Shared	Reliability	$6,600,000	5/31/2010	Planned	138	69	A	Y
A in MTEP08	East	WPSC	1209	Hersey 69KV Breaker and a half bus and new 138/69kV tie	Convert 6 breaker bus at Hersey to breaker and a half configuration and add 138/69kV stepdown transformer	MI		Other	Not Shared	Reliability	$8,000,000	12/31/2010	Planned	138	69	A	Y
A in MTEP08	East	WPSC	1313	Plains X to Hersey	Plains X to Hersey line rebuild	MI		Other	Not Shared	Reliability	$10,000,000	12/31/2010	Planned	69		A	Y
A in MTEP08	East	WPSC	1967	Wayland to Portland	Rebuild Outdated line	MI		Other	Not Shared	Reliability	$15,000,000	12/31/2010	Planned	69		A	Y
A in MTEP08	East	WPSC	1222	Lake County 69kV Ring Bus and Transformer	Convert 4 breaker bus at Lake County to Ring Bus and add 168MVA transformer	MI		Other	Not Shared	Reliability	$6,050,000	12/31/2011	Planned	138	69	A	Y
A in MTEP08	East	WPSC	1274	Blendon to Osipoff	Blendon to Osipoff line rebuild	MI		Other	Not Shared	Reliability	$6,000,000	12/31/2011	Planned	69		A	Y
A in MTEP08	East	WPSC	1276	Burnips to Wayland	Burnips to Wayland line rebuild	MI		Other	Not Shared	Reliability	$7,000,000	12/31/2011	Planned	69		A	Y
A in MTEP08	East	WPSC	1581	Alba to Advance 69 rebuild	Alba to Advance 69 kV line rebuild	MI		Other	Not Shared	Reliability	$8,000,000	12/31/2011	Planned	69		A	Y
A in MTEP08	East	WPSC	1311	Copemish to Grawn	Copemish to Grawn line rebuild	MI		Other	Not Shared	Reliability	$7,200,000	12/31/2012	Planned	69		A	Y
A in MTEP08	East	WPSC	1577	Copemish - Bass Lake Line Rebuild	Rebuild line to 795ACSS	MI		Other	Not Shared		$10,300,000	12/31/2012	Planned	69		A	Y
A in MTEP08	East	WPSC	1586	Gaylord to Advance 69 kV line rebuild, Advance to Petoskey 69 kV line rebuild, Petoskey to Oden 69 kV line rebuild	Rebuild Overloaded line	MI		Other	Not Shared	Reliability	$15,700,000	12/31/2014	Planned	69		A	Y
A in MTEP08	West	XEL	1486	Mary Lake - City of Buffalo 69 kV line 116 MVA	Mary Lake - City of Buffalo 69 kV line 116 MVA	MN		Other	Not Shared	Reliability	$2,190,000	2/1/2010	Planned	69		A	NT
A in MTEP08	West	XEL	1368	Three Lakes 115/69 kV substation	Three Lakes 115/69 kV substation on existing Kinnickinnic - Roberts 69 kV line and Pine Lake - Willow River 115 kV line	WI		Other	Not Shared	Reliability	$10,123,000	6/1/2010	Planned	115	69	A	Y
A in MTEP08	West	XEL	1373	Ft. Ridgeley - Searles Jct 115 new line and Searles Jct - New Ulm 69 Reconductor	Ft. Ridgeley - Searles Jct 115 new line and Searles Jct - New Ulm 69 Reconductor	MN		TDSP	Direct Assigned		$1,500,000	6/1/2010	Planned	115		A	Y
A in MTEP08	West	XEL	1375	BRIGO - Buffalo Ridge Incremental Generation Outlet	BRIGO (non-GIA): Hazle Creek - Minnesota Valley 115 kV line (new), Lake Yankton - SE Marshall 115 kV line, Winnebago Jct 161 capacitor, McLeod 115 capacitor	MN		TDSP	Direct Assigned		$10,000,000	6/1/2010	Planned	115		A	Y
A in MTEP08	West	XEL	1548	La Crosse Area Capacitor banks	Install one 60 MVAR capacitor bank on 161 kV Bus 1 at La Crosse Substation and 2x30 Mvar capacitor banks on the 161 kV bus at Monroe County Substation.	WI		BaseRel	Not Shared		$2,300,000	6/1/2010	Planned	161		A	Y
A in MTEP08	West	XEL	1959	Yankee Doodle interconnection	New 115 kV line from Yankee Doodle - Pilot Knob. Convert line 0703 to 115 kV operation and build a 115 kV line to Pilot Knob Substation from near the intersection of line 0703 and Diffley Road.	MN		Other	Not Shared		$3,765,200	6/1/2010	Planned	115		A	Y
A in MTEP08	West	XEL	1370	Convert/Relocate the 69 kV Rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	Convert/Relocate the 69 kV Rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI		Other	Not Shared	Reliability	$11,672,000	7/1/2010	Planned	161	23.9	A	Y
A in MTEP08	West	XEL	1369	Osceola - Sand Lake 69 Reconductor	Osceola - Sand Lake 1 69 Reconductor	WI		Other	Not Shared		$400,000	9/1/2010	Planned	69		A	NT
A in MTEP08	West	XEL	1953	St. Cloud - Sauk River 115 kV line upgrade	This project is to upgrade the 115kV line between St. Cloud and Sauk River to a higher capacity. Upgrade the 115 kV line # 0868 between Sauk River and St. Cloud substations to 795 ACSS. This project does not require upgrading the 1200 Amp breaker at St. Cloud substation as 239 MVA capacity will suffice.	MN		BaseRel	Shared		$5,264,000	12/1/2010	Planned	115		A	Y

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A in MTEP08	West	XEL	1956	Blue Lake - Wilmarth 345 kV line capacity upgrade	This project is to increase the capacity of the 345 kV line between Wilmarth and Blue Lake. Phase raise the line to allow for a normal 100 degree C operation. Allow for a 10% emergency loading using the new 4 ft/sec wind speed rating.	MN		TDSP	Direct Assigned		$1,904,600	12/1/2010	Planned	345		A	Y
A in MTEP08	West	XEL	1961	Lake Emily Capacitor bank	This project is to add 10 MVAR cap bank at Lake Emiky	MN		Other	Not Shared		$507,200	12/1/2010	Planned			A	Y
A in MTEP08	West	XEL	1549	Eau Claire - Hydro Lane 161 kV Conversion	1.)Eau Claire 161 kV circuit breaker. 2.Bring Wheaton-Presto Tap 161 kV line into Eau Claire substation. 3.) Reconductor Wheaton to Eau Claire 161 kV line to 795 ACS. 4.) Construct second circuit from Wheaton Tap to Wheaton substation. 5.New 50th Avenue substation near where Red Cedar to Wissota 161 kV line intersects 69 kV corridor from Eau Claire to Chippewa Falls. Construct a 4 breaker 161 kV ring bus, add two 161-69 kV transformers with at least 60 MVA capacity. Construct a strait bus 69 kV with a bus tie breaker between the transformers. 6.) Where the 161 kV line from Eau Claire to Presto crosses the double-circuit 69 kV line to Hallie, tap the 161 kV line and convert the 69 kV lines to one 161 kV line with 795 ASCC conductor up to the new 50th Ave substation. 7.)Convert Hallie Substation from 69 kV to 161 kV operation.	WI		Other	Not Shared	Reliability	$20,602,000	2/1/2011	Planned	161	69	A	Y
A in MTEP08	West	XEL	1960	Traverse - St. Peter upgrade	This project is to upgrade 2.3 miles of the 69 kV line between Traverse and St. Peter to 84 MVA.	MN		Other	Not Shared		$720,000	4/1/2011	Planned	69		A	NT
A in MTEP08	West	XEL	675	Rebuild Westgate to Scott County 69 kV to 115 kV	Upgrade 20.1 miles Westgate-Deephaven-Excelsior-Scott County 69kV to 115 kV using 795 ACSS conductor, Upgrade 2 miles Westgate-Eden Prairie 115kV #1 and #2 to 400MVA (PrjID 606), Substation work at Deephaven, Excelsior and Scott County.	MN		Other	Not Shared		$14,000,000	6/1/2011	Planned	115		A	Y
A in MTEP08	West	XEL	1285	Build 18 miles 115 kV line from Glencoe - West Waconia	Build 18 miles 115 kV line from Glencoe - West Waconia	MN		BaseRel	Shared		$18,800,000	6/1/2011	Planned	115		A	Y
A in MTEP08	West	XEL	1954	Cherry Creek - Split Rock 115 kV line saperation	This project is saperate the double circuit 115 kV line between Split Rock and Cherry Creek in to two single circuits.	SD		BaseRel	Not Shared		$1,189,200	12/1/2011	Planned	115		A	Y
A in MTEP08	West	XEL	1487	Somerset - Stanton 69 kV line 84 MVA	Construct 7 miles of 69 kV line using 477 SSAC conductor traveling north along 210th Avenue, interconnecting with a new stanton 69 kV substion on the Clear Lake - New Richmond 69 kV line and the New Summerset substation on the DPC Roberts - St. Criox Falls 69 kV line	WI		Other	Not Shared	Reliability	$9,247,500	12/31/2011	Planned	69		A	NT
A in MTEP08	West	XEL	1957	New 161/69 kV Sub SW of Eau Claire where Alma – Elk Mound 161 kV intersects Shawtown – Naples 69 kV line. Rebuild 69 kV London/Madison to new substation. New 69 kV from new substation - DPC Union Sub. New 69 kV to DPC Brunswick Sub	New 161/69 kV Substation southwest of Eau Claire where Alma – Elk Mound 161 kV line intersects with Shawtown – Naples 69 kV line. Rebuild 69 kV line from London/Madison Tap to new substation. Construct 69 kV line from new substation to DPC Union Substation. Construct 69 kV line from new substation to DPC Brunswick Substation	WI		Other	Not Shared	Reliability	$7,080,000	6/1/2012	Planned	161	69	A	Y

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A in MTEP08	West	XEL	1958	Stone Lake-Edgewater 161 kV line. A new radial 161 kV line and substation in Sawyer County, Wisconsin	Expand 161 kV ring bus at Stone Lake to accept new line termination. Construct 161 kV line from Stone Lake to Couderay Substation. Install 161/69 kV transformer at Couderay Substation. Install the following substation equipment at Couderay: -161 kV MOD -69 kV low-side transformer breaker -69 kV line breaker	WI		Other	Not Shared	Reliability	$26,185,641	12/1/2012	Planned	161		A	Y
A in MTEP08	West	XEL, SMP, Non	1024	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	Construct Hampton Corner-North Rochester-Chester-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer	MN	WI	BaseRel	Shared		$360,000,000	9/30/2015	Planned	345	161	A	Y
A in MTEP08	West	XEL/GRE	1955	Grove Lake switching station	This project is to build a new three breaker switching station at the existing Bangor tap.	MN		Other	Not Shared	Reliability	$900,000	7/1/2009	Planned	69		A	NT
A in MTEP08	West	XEL/GRE	1545	Mankato 115 kV loop	(1) New South Bend 161/115/69 kV susstation. (2) Operate 161 kV line from Wilmarth - South Bend at 115 kV. (3) Convert the 69 kV line from South Bend - Hungry Hollow to 115 kV. (4) Convert the existng line from Hungry Hollow - Pohl tap - Pohl - Eastwood to 115 kV. (5) Convert Pohl Substation to 115 kV. (6) Add 115/69 kV Transformer at Hungry Hollow Substation.	MN		Other	Not Shared	Reliability	$17,735,000	4/1/2010	Planned	161	69	A	Y
A in MTEP07	Central	AmerenMO	152	Big River-Rockwood 138 kV	Big River-Rockwood 138 kV - Construct new line	MO		BaseRel	Shared		$13,381,100	12/1/2010	Planned	138		A	Y
A in MTEP07	West	ATC LLC	1267	New Oak Ridge-Verona 138-kV line and a 138/69-kV transformer at Verona	Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona	WI		Other	Not Shared		$20,800,000	2/19/2010	Planned	138	69	A	Y
A in MTEP07	West	ATC LLC	1256	Paddock - Rockdale 345kV	Paddock - Rockdale 345kV circuit #2 and supporting projects of lower voltage levels	WI		Other	Not Shared		$126,500,000	4/1/2010	Planned	345		A	Y
A in MTEP07	Central	DEM	1263	G431 - Edwardsport	Edwardsport 420 MW: The Generating Facility will be located near the Interconnection Customer's existing Edwardsport Generating Station site which has three existing units 6, 7 and 8 that shall be retired before the Generating Facility provided by this LGIA commences Commercial Operation. The new Generating Facility will have 420 MW net summer peak NR Interconnection Service	IN		GIP	Shared		$9,367,000	3/1/2010	Under Const	345		A	Y
A in MTEP07	Central	DEM	852	Crawfordsville to Tipmont Concord to Lafayette SE 138 Reconductor	Reconductor 13819 circuit with 954ACSR 100C.	IN		BaseRel	Shared		$8,919,730	6/1/2013	Planned	138		A	Y
A in MTEP07	West	GRE	1361	Badoura - Birch Lake 115 lines	Badoura - Birch Lake 115 lines	MN		Other	Not Shared		$11,275,000	9/28/2010	Planned	115		A	Y
A in MTEP07	East	METC	1817	Midland	Construct a new Richland 345/138 kV substation, Loop the Nelson Road to Tittabawassee 345 kV Line into the new Richland station, construct a new Orr Road 138 kV switching station, construct a new 3-5 mile 138 kV line between Orr Road and Richland, loop he existing Lawndale to HSC 138 kV line into Richland and Orr Road stations, loop the Tittabawassee to HSC #2 line into Richland and Orr Road stations, remove the reactors at Tittabawassee station, replace nine 138 kV breakers at Tittabawassee station, correct all NESC code issues to allow the HSC to Tittabawassee #1 line to operate to its full conductor limit, and install a new 138 kV capacitor at Orr Road station.	MI		BaseRel	Shared		$21,818,852	12/31/2009	Planned	345	138	A	Y
A in MTEP07	West	MP	1286	'Add a 25 Mvar capacitor bank & Switching station at Two Harbors	'Add a 25 Mvar capacitor bank & Switching station at Two Harbors	MN		BaseRel	Not Shared		$2,970,500	12/31/2009	Under Const	115		A	Y

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A in MTEP07	West	MP	277	Badoura Project: Pine River - Pequot Lakes 115 kV line	Pine River - Pequot Lakes 115 ckt 1, Sum rate 182	MN		BaseRel	Shared		$23,156,500	5/1/2010	Planned	115	34.5	A	Y
A in MTEP07	West	MP	1025	G519 - Mesaba	Network Upgrades associated with 600 MW coal gasification generating facility at the propsoed Mesaba generating station. There is a G477 alternate site which is not described here.	MN		GIP	Shared		$76,319,541	7/1/2012	Planned	230	115	A	Y
A in MTEP07	West	MP/GRE	1022	Badoura-Long Lake 115 kV line	115 kV line from MP Badoura to GRE Long Lake	MN		BaseRel	Shared		$8,621,000	9/1/2009	Under Const	115		A	Y
A in MTEP07	West	MP/GRE	1021	Embarass to Tower 115 kV Line	115 kV line from 34L tap to Tower 46 kV	MN		Other	Not Shared		$6,190,400	11/1/2009	Under Const	115		A	Y
A in MTEP07	West	XEL	1613	G386 - Trimont Wind	Network Upgrades for Project G386, a 100 MW (gross Summer output rating) wind Generating Facility interconnecting at the 345kV Trimont Wind Substation in Martin County, Minnesota. The Trimont Wind Substation is connected to Transmission Owner's Lakefield Generation Substation by a 345kV line with a length of approximately 500 feet. The Trimont Wind Substation and the 345kV line were constructed in 2005 for Project 263, another 100 MW wind Generating Facility, pursuant to the Project G263 LGIA and are owned by the Project G263 Interconnection Customer, its successors or assigns ("the G263 IC"). The Trimont Wind Substation and the 345kV line were designed to accommodate three wind generation projects of approximately 100 MW each, Projects G263 and G386 being the first two.	MN		GIP	Shared		$4,779,000	5/30/2012	Planned	115		A	Y
A in MTEP07	West	XEL	1614	G426	G426 Network Upgrades under the FCA filed in Feb 2007. 30 MVAr SVC at Hazel Creek Substation (including associated switches, etc.). GI project is a 100 MW wind farm to be located in Osceola and Dickinson County, Iowa (ALTW system)	MN		GIP	Shared		$4,803,000	5/30/2012	Planned	115		A	Y
A in MTEP06	Central	AmerenIL	1241	Mattoon, West Wind Farm Connection	Install 138 kV Breaker at Mattoon, West Substation to connect Wind Farm	IL		Other	Not Shared		$1,010,000	12/1/2009	Planned	138		A	Y
A in MTEP06	Central	AmerenIL	739	Franklin County Power Plant Connection	Franklin County Power Plant Connection - Tap 345 kV Line 4561 Tap, and Install new 345 kV ring bus	IL		Other	Not Shared (Pre-RECB 1)		$6,410,900	11/1/2012	Proposed	345		A	Y
A in MTEP06	West	ATC LLC	352	Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV	Construct Cranberry-Lakota Rd 115 kV line, Rebuild/convert Conover-Plains 69 kV line to 138 kV, Construct 138 kV bus and install 138/115 kV 150 MVA and 138/69 kV 60 MVA transformers at Conover, Construct 138 kV bus and install 60 MVA transformer at Aspen, Relocate Iron River substation (Iron Grove), Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove	WI	MI	BaseRel	Shared		$5,850,000	10/1/2009	Under Const	138	69	A	Y
A in MTEP06	West	ATC LLC	345	Morgan - Werner West 345 kV line (includes Clintonville-Werner West 138)	Morgan - Werner West 345 kV line, Clintonville - Werner West 138 kV line primarily on 345 kV line structures, and terminate the existing Werner - White Lake 138 kV line at the Werner West switching station	WI		BaseRel	Shared		$128,132,800	10/30/2009	Under Const	345		A	Y

Appendix A: Project Table 10/16/2009 *Project Summary Information from Facility table*

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A in MTEP06	West	ATC LLC	877	Elm Road (Oak Creek) Generation Related Additions	Reconductor Oak Creek-Ramsey 138 kV line (2009), Reconductor Oak Creek-Allerton 138 kV line (2009), Replace relaying on 230 kV circuits at Oak Creek (2009), Replace two 345 kV circuit breakers at Pleasant Prairie on the Racine and Zion lines with IPO breakers and upgrade relaying (2009), Expand Oak Creek 345 kV switchyard to interconnect one new generator (2009), Loop Ramsey5-Harbor 138 kV line into Norwich and Kansas to form a new line from Ramsey-Norwich and Harbor-Kansas 138 kV lines (2009), Uprate Kansas-Ramsey6 138 kV line (2009), Install second 500 MVA 345/138 kV transformer at Oak Creek (2010), Expand 345 kV switchyard at Oak Creek to interconnect one new generator (2010), Uprate Oak Creek-Root River 138 kV line (2010), Uprate Oak Creek-Nicholson 138 kV line (2010).	WI		Other	Not Shared (Pre-RECB 1)		$17,472,014	6/1/2010	Planned	345	138	A	Y
A in MTEP06	West	ATC LLC	1461	G376, 37395-03, Green Lake Energy	Net: loop into existing substation, install 138 kV equipment at Green Lake Sub, replace 69 kV circuit breaker at Wautoma sub.	WI		Other	Not Shared (Pre-RECB 1)		$2,314,698	9/1/2010	Planned	138	1	A	Y
A in MTEP06	West	ATC LLC	1470	G483	50 MW wind farm at Whistling Wind 69 kV substation	WI		GIP	Shared		$7,538,732	12/1/2011	Planned	69	1	A	Y
A in MTEP06	Central	DEM	1193	Nickel	Extend 5680 through new Nickel 138/12 sub to be built on development property.	OH		Other	Not Shared		$150,377	6/1/2009	Under Const	138		A	Y
A in MTEP06	Central	DEM	1254	Indiana Arsenal Jct to CMC new 138kV line	Construct 8.5 mi. of 138kV - 13857 line from Indiana Arsenal Jct (in the Charlestown area) to CMC. This line section will be owned by IMPA.	IN		Other	Not Shared		$5,497,000	12/31/2009	Planned	138		A	Y
A in MTEP06	Central	DEM	42	Bedford to Seymour 13829 Reconductor	Reconductor 13829 line from Bedford - Shawswick - Pleasant Grove - Airport Road Jct - Seymour. 'Seymour 13829 Bus & Disconnect Switches - Reconductor 2 sections of ring bus and upgrade 13829-51 and 13880-29 breaker disconnects (Reconductor 250CU ring bus for 2000A capacity from the 13829 common point to the 13851 and 13880 common points. Replace the 13851 and 13880 600A breaker disconnects with 2000A disconnects)	IN		Other	Excluded		$4,631,271	6/1/2010	Planned	138		A	Y
A in MTEP06	Central	DEM	632	Gallagher to HE Georgetown 138kV Reconductor	Reconductor section of the 13885 circuit from Gallagher to HE Georgetown.	IN		Other	Excluded		$1,065,110	6/1/2010	Planned	138		A	Y
A in MTEP06	Central	DEM	1199	Dresser to Water St 100C Urate	Uprate 13868 conductor to 100C operating temperature from Dresser to S 1st St to Water St. New limit 1200A terminal equipment.	IN		BaseRel	Not Shared		$20,000	6/1/2010	Planned	138		A	Y
A in MTEP06	Central	DEM	1246	Five Points 23030 Wave Trap	Replace 800A wave trap with a 2000A wave trap. Increase line rating for Five Points to Geist 230kV line.	IN		BaseRel	Not Shared		$24,038	6/1/2011	Planned	230		A	Y
A in MTEP06	Central	DEM	1247	Greentown to Peru SE 23021 uprate to 100C	Upgrade Greentown to Peru SE 230kV line to 100C operating temperature.	IN		BaseRel	Not Shared		$28,403	6/1/2011	Planned	230		A	Y
A in MTEP06	Central	DEM	1251	Kokomo Highland Park to Noblesville 23008 Wave Trap Upgrade	Replace 800A wave traps with 2000A wave traps at Kok HP and Noblesville. Increase 230kV line rating from Kok HP to Carmel 146th St Jct to Noblesville.	IN		BaseRel	Not Shared		$24,038	6/1/2011	Planned	230		A	Y
A in MTEP06	Central	DEM	1253	Noblesville 23007 Wave Trap	Replace 800A wave trap with a 2000A wave trap. Increase line rating for Noblesville to Geist 230kV line.	IN		BaseRel	Not Shared		$24,038	6/1/2011	Planned	230		A	Y
A in MTEP06	Central	DEM	851	Laf Cumberland to Laf AE Staley 138 Reconductor	Reconductor section of 13806 circuit with 954ACSR 100C.	IN		BaseRel	Not Shared		$349,357	6/1/2013	Planned	138		A	Y
A in MTEP06	Central	DEM	1244	Cayuga to Frankfort 23013 Wave Trap Upgrade	Upgrade wave traps at Cayuga and Frankfort to increase line rating to 797 MVA.	IN		BaseRel	Not Shared		$167,560	6/1/2013	Planned	230		A	Y
A in MTEP06	Central	DEM	853	West Lafayette to Cumberland 138 Reconductor	Reconductor section of 13806 circuit with 954ACSR 100C.	IN		Other	Not Shared		$706,921	6/1/2015	Planned	138		A	Y

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Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A in MTEP06	West	GRE	1459	G351, 37804-01, G352, 37804-02	Net: new Dakota County substation will be located between NSP Blue Lake and Prairie Island Substations on the 345 kV line 0976	MN		GIP	Shared		$8,935,288	1/1/2011	Planned	345	1	A	Y
A in MTEP06	Central	HE	1322	Owensville Primary Substaton	138/69kV Primary Station at Owensville	IN		Other	Not Shared		$8,000,000	6/1/2008	Planned	138	69	A	Y
A in MTEP06	Central	HE	1321	Napoleon to DCSS Transmission Project	161kV Transmission from Napoloen to DCSS, 30 MVAR Cap	IN		Other	Not Shared		$8,000,000	12/1/2008	Planned	161		A	Y
A in MTEP06	Central	IPL	40	Cumberland-Julietta-Indian Crk 138kV Line	Add new 138kV Line from Cumberland to Julietta to Indian Creek	IN		Other	Excluded		$5,000,000	12/31/2009	Planned	138		A	Y
A in MTEP06	East	ITC	1011	Durant-Genoa 120 kV	Builds a new 120 kV Durant sub-station with a new circuit from Genoa to Durant	MI		Other	Not Shared		$15,000,000	7/31/2009	Under Const	120		A	Y
A in MTEP06	East	ITC	1308	B3N Interconnection	Returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the Phase Angle Regulator with 2 new phase angle regulating transformers in series	MI		Other	Not Shared		$25,000,000	12/31/2009	Planned	220		A	Y
A in MTEP06	East	ITC	1309	Breaker Replacement Program	Targets the replacement of breakers nearing their end of life where maintenance costs will be just as high as new breakers	MI		Other	Not Shared		$1,250,000	12/31/2009	Planned	345		A	Y
A in MTEP06	East	ITC	1310	Breaker Replacement Program	Targets the replacement of breakers nearing their end of life where maintenance costs will be just as high as new breakers	MI		Other	Not Shared		$1,350,000	12/31/2009	Planned	345		A	Y
A in MTEP06	East	ITC	1488	Break up 3-ended Prizm-Proud-Placid 120 kV line	Results in Placid to Durant and Placid to Proud (Durant substation replaces Prizm sub).	MI		Other	Not Shared		$5,650,000	12/31/2009	Planned	120		A	Y
A in MTEP06	East	ITC	907	Goodison Station (Oakland)	Build Goodison Station, with a Belle River-Goodison 345 kV, Pontiac-Goodison 345 kV, new 345/120 kV Xfmr, new Pontiac-Goodison 120 kV line, Goodison-Tienken 120 kV, Sunbird-Goodison 120 kV, and Tienken-Spokane 120 kV.	MI		BaseRel	Shared		$50,000,000	12/31/2011	Planned	345	120	A	Y
A in MTEP06	East	ITC	692	Bismark-Troy 345 kV line	Creates a Bismarck-Troy 345 kV line with a Troy 345/120 kV transformer.	MI		BaseRel	Shared		$150,000,000	6/30/2012	Planned	345	120	A	Y
A in MTEP06	West	ITCM	1287	Replace Salem 345/161 kV transformer with 448 MVA unit	Replace Salem 345/161 kV transformer with 450 MVA unit	IA		BaseRel	Shared		$5,650,000	6/1/2009	Planned	345	161	A	Y
A in MTEP06	West	ITCM	1473	Mason City Armor - Emery North 69 kV line	Mason City Armor - Emery North 69 kV line	IA		TDSP	Direct Assigned		$1,060,000	12/31/2009	Planned	69		A	NT
A in MTEP06	West	ITCM	1342	Lewis Fields 161 kV substation which taps the SwampFX - Coggon 115 kV line	Build a new 161 kV substation Lewis Fields to be tapped to the 115 kV line Swamp Fox - Coggon at 5% distance via a new 161/115 kV transformer. Also build a new 161 kV line from Hiawatha to Lewis Fields	IA		BaseRel	Not Shared		$14,851,600	6/30/2010	Planned	161	115	A	Y
A in MTEP06	West	ITCM	1288	Replace Hazleton 345/161 kV transformer #1 with 335 MVA unit	Replace Hazleton 345/161 kV transformer #1 with 335 MVA unit	IA		BaseRel	Shared		$5,650,000	12/31/2010	Planned	345	161	A	Y
A in MTEP06	West	ITCM	1289	Marshalltown - Toledo - Belle Plaine - Stoney Point 115 kV line rebuild	Marshalltown - Toledo - Belle Plaine - Stoney Point 115 kV line will be rebuilt/upgraded between 2008 and 2011	IA		Other	Not Shared		$19,000,000	6/1/2011	Planned	115		A	Y
A in MTEP06	West	ITCM	1344	Build a new 345 kV Morgan Valley (Beverly) substation which taps the Arnold -Tiffin 345 kV line	Build a new 345 kV Morgan Valley (Beverly) Tap substation and tapped to 345 kV line Arnold -Tiffin at 40% distance away from Arnold. Add a new 335 MVA 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus	IA		Other	Not Shared		$12,750,000	6/1/2012	Proposed	345	161	A	Y
A in MTEP06	East	METC	1465	G418, 38068-02	Construction Suspended on 5/15/2006, can be suspended for 3 years. Net:	MI		GIP	Shared		$5,192,616	10/1/2008	Planned	138	1	A	Y
A in MTEP06	East	METC	1408	RTU / SCADA Re-direction Program	Install and/or upgrade RTU's and SCADA points throughout system	MI		Other	Not Shared		$801,000	12/31/2008	Under Const	345	138	A	Y
A in MTEP06	East	METC	1425	Gray Road	Install a tap pole and two switches on Keystone-Elmwood 138kV Line plus some relay upgrades	MI		Other	Not Shared		$4,136,000	12/1/2009	Planned	138		A	Y
A in MTEP06	East	METC	1434	Five Mile	Install bulk substation served from the Spaulding 138kV ring bus	MI		Other	Not Shared		$750,000	6/1/2010	Planned	138		A	Y

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A in MTEP06	East	METC	1437	N Ave	Install a tap pole and two switches on Argenta-Milham 138kV Line	MI		Other	Not Shared		$160,000	6/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	1438	Potvin	Install a tap pole and one switch on Wexford-Tippy 138kV Line	MI		Other	Not Shared		$80,000	6/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	1440	Huckleberry	Install a tap pole and two switches on Beals Rd-Wayland-Hazelwood 138kV Line	MI		Other	Not Shared		$80,000	6/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	1445	Emmet	Install a second distribution transformer at Emmet	MI		Other	Not Shared		$2,750,000	6/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	1446	Gaines	Install bulk substation at Gaines	MI		Other	Not Shared		$50,000	6/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	988	Simpson - Batavia 138 kV line	Simpson - Batavia 138 kV line - Build 30 miles new 138 kV line, 795 ACSS	MI		BaseRel	Shared		$13,000,000	12/1/2010	Planned	138		A	Y
A in MTEP06	East	METC	1433	Buskirk	Install bulk substation served from the Beals-Hazelwood 138kV Line	MI		Other	Not Shared		$2,200,000	6/1/2011	Planned	138		A	Y
A in MTEP06	East	METC	1444	Dublin	Install a tap pole and two switches on Bullock-Edenville 138kV Line	MI		Other	Not Shared		$160,000	6/1/2011	Planned	138		A	Y
A in MTEP06	East	METC	1447	Horseshoe Creek (Deja)	Install bulk substation served from the Eureka-Deja-Vestaburg 138kV Line	MI		Other	Not Shared		$2,200,000	6/1/2012	Planned	138		A	Y
A in MTEP06	East	METC	1449	Juniper	Install bulk substation served from the Cobb-Tallmadge #2 138kV Line	MI		Other	Not Shared		$160,000	6/1/2012	Planned	138		A	Y
A in MTEP06	East	METC	981	Wabasis	Install a tap pole and two switches on N. Belding - Vergennes 138kV Line	MI		Other	Not Shared		$160,000	6/1/2013	Planned	138		A	Y
A in MTEP06	West	MPC/XEL/OTP/	279	Bemidji-Grand Rapids 230 kV Line	Boswell - Wilton 230 ckt 1, Sum rate 495, Addition of a 187 MVA 230/115 kV transformer at Cass Lake	MN		BaseRel	Shared		$101,027,080	12/31/2011	Proposed	230	115	A	Y
A in MTEP06	East	NIPS	1298	Inland #5 to Marktown - Upgrade Capacity	Upgrade Cir. 13830 capacity on existing 2.2 miles of 400 KCM Cu line by upgrading conductor to 954 KCM ACSR between Marktown and Inland #5 Substation.	IN		BaseRel	Not Shared		$750,000	1/1/2009	Planned	138		A	Y
A in MTEP06	West	OTP / GRE	1462	G380, 37946-02	Net: Transmission Owner will upgrade the Rugby Substation to accomdate the interconnection of the IC's 230 kV radial transmission line into Rugby, will need to add additional 230 kV bus, new 230 kV breaker and associated equipment.	ND		GIP	Shared		$898,740	11/30/2009	Planned	230	1	A	Y
A in MTEP06	Central	Vectren (SIGE)	1257	New Transmission Line Gibson (Cinergy) to AB Brown (Vectren) to Reid (BREC)	New 345 kV transmission line Gibson (Cinergy) to AB Brown (Vectren) to Reid (BREC)	IN	KY	BaseRel	Shared		$66,000,000	5/31/2011	Planned	345		A	Y
A in MTEP06	East	WPSC	1227	Gaylord Gen - Gaylord OCB	Gaylord Generation to Gaylord OCB line rebuild	MI		Other	Not Shared	Reliability	$1,400,000	12/31/2009	Planned	69		A	Y
A in MTEP06	East	WPSC	1272	Redwood 75MVA Transformer	Add 75MVA Transformer at Redwood Substation a separate line from Redwood Junction will be ran to energize the transformer.	MI		Other	Not Shared	Reliability	$3,000,000	12/31/2012	Planned	138	69	A	Y
A in MTEP06	West	XEL	1457	G287, 37642-03. Upgrades for G287	G287 Upgrades: Nobles County sub upgrades, Hazel Creek substation, Nobles County - Fenton 115 kV line, Hazel Creek capacitor and SVC	MN		GIP	Shared		$25,175,000	12/31/2010	Planned	345	1	A	Y
A in MTEP06	West	XEL	1458	G349, 37774-01. Upgrades for G349	G349 Upgrades: Yankee substation, Brookings Co 345/115 substation, Hazel Run 53 Mvar capacitor, Brookings-Yankee 115 kV line	MN		GIP	Shared		$31,982,000	11/30/2011	Planned	345	115	A	Y

Appendix A: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A in MTEP05	Central	AmerenIL	150	Prairie State Power Plant transmission outlet	Establish a new Prairie State 345 kV switchyard including a 6-position breaker and ½ bus arrangement to accommodate 2 generating units and 4-345 kV outlet lines with 9-345 kV circuit breakers. Tap the existing Baldwin-Stallings 345 kV line 4531 "in and out" and build 7.5 miles of double-circuit line to the switchyard. Tap the existing Baldwin-Mt. Vernon 345 kV line 4541 "in and out" and build 1.5 miles of double-circuit line to the switchyard. At the Baldwin 345 kV switchyard, replace 9-345 kV circuit breakers that would be overstressed as a result of the Prairie State development. Also install 3-345 kV circuit breakers for a new Baldwin-Rush Island 345 kV line and a new connection for the Baldwin 345/138 kV transformer. Build a new 26 mile 345 kV line from Baldwin to Rush Island.	IL		Other	Not Shared (Pre-RECB 1)		$77,987,700	6/1/2010	Planned	345		A	Y
A in MTEP05	Central	AmerenIL	725	LaSalle Area Development	N. LaSalle-Wedron Fox River 138 kV - 20 miles new line, 2-138 kV breakers at N. LaSalle, 1 138 kV Breaker at Wedron Fox River	IL		Other	Excluded		$21,357,530	3/12/2012	Planned	138		A	Y
A in MTEP05	Central	AmerenIL	726	LaSalle Area Development	Ottawa-Wedron Fox River 138 kV - Construct 14 miles new 138 kV line, 1 new 138 kV breaker at Ottawa	IL		Other	Excluded		$8,962,967	3/12/2012	Planned	138		A	Y
A in MTEP05	Central	AmerenMO	719	Labadie Plant	Labadie Plant - Replace 4-345 kV Breakers	MO		Other	Not Shared		$2,511,700	11/8/2010	Under Const	345		A	Y
A in MTEP05	West	ATC LLC	339	Lake Mills Transmission-Distribution interconnection	Construct a Jefferson-Lake Mills-Stony Brook 138 kV line Uprate Rockdale to Jefferson 138 kV line Uprate Rockdale to Boxelder 138 kV line Uprate Boxelder to Stonybrook 138 kV line	WI		Other	Excluded		$19,700,000	11/30/2009	Planned	138		A	Y
A in MTEP05	West	ATC LLC	568	North Lake Geneva - White River 138 kV line	North Lake Geneva - White River 138 kV line	WI		Other	Excluded		$1,250,000	12/31/2013	Proposed	138		A	Y
A in MTEP05	Central	DEM	624	Cloverdale to Plainfield 138 Lightning Protection	Upgrade static and grounding on the Cloverdale to Plainfield South 138kV circuit.	IN		Other	Excluded		$1,816,905	12/31/2010	Planned	138		A	Y
A in MTEP05	West	GRE	599	Crooked Lake - Enterprise Park 115 kV line	Crooked Lake - Enterprise Park 115 kV line	MN		Other	Excluded		$6,900,000	2/8/2012	Planned	115	69	A	Y
A in MTEP05	West	MP/GRE	600	Baxter - Southdale 115 kV line	Baxter - Southdale 115 kV line	MN		Other	Excluded		$10,023,000	3/25/2011	Planned	115		A	Y
A in MTEP03	Central	SIPC	81	Marion Power Plant - Carrier Mills 161 kV line	Construct a 161 kV line connecting the Marion 161 kV Plant to a new Carrier Mills 161/69 kV Substation. The project includes the construction of nearly 27 miles of 161 kV transmission line and converting a 69 kV switching station into a 161/69 kV substation.	IL		Other	Excluded		$7,083,000	7/1/2009	Planned	161		A	Y
A in MTEP03	West	XEL	385	Xcel Energy Wind 425-825 MW project	Buffalo Ridge (SW MN) 825 MW of Generation Outlet: White-Brookings 345 kV #2	MN		TDSP	Not Shared			12/31/2009	Planned	345		A	Y
A in MTEP03	West	XEL	56	Chisago - Apple River	Chisago - Lindstrom - Shafer- Lawrence Creek 69 kV rebuild to 115 kV, Lawrence Creek - St Croix Falls - Apple River 69 kV rebuild to 161 kV. New Lawrence Creek 161/115/69 kV substation	MN		Other	Excluded		$36,389,357	12/31/2010	Planned	161	69	A	Y

Facility Table Field Legend

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Facilty Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Indicates the Project the Facility belongs to. Projects may have multiple facilities.
Facility ID	Facility ID: Midwest ISO facility identifier
Expected ISD	Expected In Service Date for this facility
From Sub	From substation for transmission line or location of transformer or other equipment
To Sub	To substation for transmission line or transformer designation
Ckt	Circuit identifier
Max kV	Maximum voltage of this facility
Min kV	Minumum voltage of this facility (transformer low-side voltage)
Summer Rate	Rating of the facility in applicable units
Upgrade Description	Brief description of transmission upgrade involving this facility
State	State the facility is located in
Miles Upg.	Transmission line miles on existing rights of way (ROW)
Miles New	Transmission line miles on new rights of way (ROW)
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Estimated Cost	Total estimated facility cost
Cost Shared	Y if facility is cost shared per Attachment FF
Postage Stamp	Y if facility has postage stamp cost allocation per Attachment FF
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.

Appendix A: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	Ameren	1240	1940	6/1/2012	Sioux	Huster	3	138		370	Reconductor 13 miles	MO	13		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	AmerenCILCO	2472	4444	12/1/2016	Fargo 345/138 kV	New Substation		345	138	560	Install 560 MVA, 345/138 kV Transformer	IL			Planned	$9,370,000	Y		Y	B>A
A in MTEP09	Central	AmerenCILCO	2472	4445	12/1/2016	Fargo	Maple Ridge	1	345		1793	Install approximately 20 miles of new line to supply Fargo Substation	IL		20	Planned	$50,126,000	Y	Y	Y	B>A
A in MTEP09	Central	AmerenCILCO	2472	4446	12/1/2016	Maple Ridge 345 kV Switching Station	New Substation		345			Install switching station in Duck Creek-Tazewell 345 kV line	IL			Planned	$6,523,000	Y	Y	Y	B>A
A in MTEP09	Central	AmerenCIPS	2273	4187	12/1/2009	LaFarge	161 kV Supply to Customer Substation		161			Provide 161 kV supply to customer substation	IL			Planned	$570,000			Y	B>A
A in MTEP09	Central	AmerenIL	2059	3967	6/1/2010	Centerville	South Belleville	1	138		160	Install 138 kV breaker at Centerville Substaion	IL			Proposed	$1,139,000			Y	B>A
A in MTEP09	Central	AmerenIL	2063	3965	6/1/2010	Noth Coulterville	North Coulterville Xfmr	1	230	138	225	Replace 140 MVA 230/138 kV transformer with 225 Mva one	IL			Proposed	$1,251,000			Y	B>A
A in MTEP09	Central	AmerenIL	2063	3966	6/1/2010	North Coulterville	Tilden Tap	1	138		160	Replace terminal equipment at North Coulterville	IL			Proposed				Y	B>A
A in MTEP09	Central	AmerenIL	2764	4791	12/31/2010	Pana North	345/138 kV transformer	1	345	138	560 MVA	replace existing transformer	IL			Planned	$5,300,000			Y	B>A
A in MTEP09	Central	AmerenIL	2829	4968	12/31/2010	Coffeen	Coffeen N		345			Install a second 345 kV bus tie between Coffeen and Coffeen N ring busses; add a ring bus position at each station	IL			Planned	$5,456,000	Y	Y	Y	B>A
A in MTEP09	Central	AmerenIL	2829	4969	12/31/2010	Coffeen North wave trap	Ramsey switch		345		1195 MVA	Replace Coffeen N. wave trap and Ramsey E. switch to increase rating from 956 to 1195 MVA	IL			Planned	$135,000	Y	Y	Y	B>A
A in MTEP09	Central	AmerenIP	2269	4183	6/1/2009	S. Bloomington Substation	80 Mvar, 138 kV Capacitor Bank		138		80	Install 48 Mvar, 138 kV Capacitor Bank	IL			Planned	$1,224,100			Y	B>A
A in MTEP09	Central	AmerenIP	2270	4184	6/1/2011	Hennepin	Oglesby Line 1516	1	138		214	Upgrade terminal equipment at Hennepin and Oglesby to 1200 A	IL			Planned	$2,525,000			Y	B>A
A in MTEP09	Central	AmerenIP	2271	4185	6/1/2009	Hennepin	Oglesby Line 1556	1	138		255	Upgrade terminal equipment at Hennepin to match line conductor	IL			Planned	$902,000			Y	B>A
A in MTEP09	Central	AmerenIP	2272	4186	12/1/2009	Hennepin	E. Kewanee	1	138		160	Reconnect or replace 600 A CT with CT with 1200 A capability	IL			Planned	$71,000			Y	B>A
A in MTEP09	Central	AmerenIP	2274	4188	6/1/2010	Oglesby	Raab Rd.	1	138		160	Reconnect or replace 600 A CTs and associated PCB's with PCB's with CT's with 1200 A capability at Oglesby	IL			Planned	$211,400			Y	B>A
A in MTEP09	Central	AmerenIP	2274	4189	6/1/2010	Oglesby	LaSalle	1	138		160	Reconnect or replace 600 A CTs and associated PCB's with PCB's with CT's with 1200 A capability at Oglesby	IL			Planned	$211,400			Y	B>A
A in MTEP09	Central	AmerenIP	2274	4190	6/1/2010	Oglesby	Bus Tie 1302	1	138		256	Reconnect or replace 600 A CTs and associated PCB's with PCB's with CT's with 1200 A capability at Oglesby	IL			Planned	$211,400			Y	B>A
A in MTEP09	Central	AmerenIP	2274	4447	6/1/2010	Oglesby	Crescent Ridge	1	138		256	Reconnect or replace 600 A CTs and associated PCB's with PCB's with CT's with 1200 A capability at Oglesby	IL			Planned	$211,400			Y	B>A
A in MTEP09	Central	AmerenIP	2274	4448	6/1/2010	Oglesby	Hennepin	1	138		214	Reconnect or replace 600 A CTs and associated PCB's with PCB's with CT's with 1200 A capability at Oglesby	IL			Planned	$211,400			Y	B>A
A in MTEP09	Central	AmerenIP	2276	4192	12/1/2009	Clinton Route 54 Substation	Bus-Tie Position 1372		138		287	Reconnect 600 A CT to 1200 A	IL			Planned	$50,000			Y	B>A
A in MTEP09	Central	AmerenIP	2277	4193	6/1/2009	Steelville Substation	138 kV Bus-Tie Position 1636		138		239	Reconnect 2-CT's to 1000 A	IL			Planned	$50,000			Y	B>A
A in MTEP09	Central	AmerenIP	2278	4194	6/1/2009	Mt. Vernon, West	Bus-Tie Position 1402		138		287	Upgrade bus conductor to 1200 A summer normal capability	IL			Planned	$30,000			Y	B>A
A in MTEP09	Central	AmerenIP	2279	4195	6/1/2011	Campbell	Steelville	1	138		220	Reconductor 477 kcmil ACSR to carry 1200 A summer emergency	IL	6.19		Planned	$1,866,000			Y	B>A
A in MTEP09	Central	AmerenIP	2281	4197	6/1/2010	Ashley	Mt. Vernon-Ashley 138 kV position	1	138		160	Replace 2-600 A, 138 kV disconnect switches with 1200 A switches	IL			Planned	$64,000			Y	B>A
A in MTEP09	Central	AmerenIP	2284	4200	6/1/2010	Turkey Hill	S. Belleville	1	138		280	Replace terminal equipment at both terminals with minimum 1600 A capability	IL			Planned	$471,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	AmerenIP	2285	4201	6/1/2011	S. Belleville	17th Street	1	138		160	Upgrade terminal equipment at S. Belleville to 1200 A, reconductor 2.57 miles of line between S.Belleville and 17th Street. Install 138 kV PCB at Centerville Substation to replace N.O. Disc. Switch	IL	2.57		Planned	$2,642,000			Y	B>A
A in MTEP09	Central	AmerenIP	2287	4203	6/1/2011	Stallings	E. Collinsville Line 1426	1	138		280	Upgrade E. Collinsville terminal to 2000 A, increase ground clearance between Maryville, E. Collinsville	IL	3.69		Proposed	$1,395,000			Y	B>A
A in MTEP09	Central	AmerenMO	2275	4191	12/1/2009	Spalding Sub.	Tap Peno Creek-Palmyra	2	161			Associated Electric Substation connection	MO			Planned	$749,100			Y	B>A
A in MTEP09	Central	AmerenMO	2282	4198	12/1/2010	Selma	Rivermines	2	138		269	Reconductor 15.5 miles of parallel 4/0 Copper conductor	MO	15.5		Planned	$4,650,000	Y		Y	B>A
A in MTEP09	Central	AmerenMO	2787	4907	6/1/2009	North Park	Tap Page-Berk-1 and -2		138	12.5	66 MVA	Connect new substation to Page-Berkeley-1 and -2 138 kV lines	MO			Planned	$2,650,000			Y	B>A
A in MTEP09	West	ATC LLC	2021	3889	10/30/2009	Chandler	Lakehead Tap	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		8.65		Planned				Y	B>A
A in MTEP09	West	ATC LLC	2021	3890	10/30/2009	Lakehead Tap	Masonville	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		2.96		Planned	$535,000			Y	B>A
A in MTEP09	West	ATC LLC	2022	3891	9/1/2009	Delta	Mead	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		4.65		Planned				Y	B>A
A in MTEP09	West	ATC LLC	2022	3892	9/1/2009	Mead	Bayview Tap	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		1.37		Planned				Y	B>A
A in MTEP09	West	ATC LLC	2022	3893	9/1/2009	Bayview Tap	North Bluff	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		4.15		Planned	$156,000			Y	B>A
A in MTEP09	West	ATC LLC	2023	2895	9/1/2009	Masonville	Gladstone	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		3.56		Planned	$190,418			Y	B>A
A in MTEP09	West	ATC LLC	2024	3895	10/1/2009	North Bluff	Gladstone	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		2.06		Planned	$178,059			Y	B>A
A in MTEP09	West	ATC LLC	2161	4000	6/1/2009	Glenview	Shoto	1	138		128/173 SN/SE	Increase line clearance to 200 deg F SE	WI	23		Proposed	$1,412,755			Y	B>A
A in MTEP09	West	ATC LLC	2452	4393	10/1/2010	Randolph EC	substation	1	138			G-T Interconnection taps Friesland-Hamilton 138 kV line	WI			Planned	$3,867,377	Y		Y	B>A
A in MTEP09	West	ATC LLC	2453	4828	6/1/2010	Arpin	Rocky Run	1	345		1219 MVA	Rebuild Arpin-Rocky Run 345 kV	WI	20.6		Planned	$23,544,820			Y	B>A
A in MTEP09	West	ATC LLC	2455	4407	12/31/2010	Lau Road	substation	1	138			G-T Interconnection Taps Forest Jct-Elkhart Lk 138 kV	WI			Planned	$4,026,060	Y		Y	B>A
A in MTEP09	West	ATC LLC	2455	4409	12/31/2010	Forest Jct	Elkhart Lk	1	138		112 MVA	Increase line clearance to achieve a 114 MVA SE rating	WI	28.9		Planned	$438,896	Y		Y	B>A
A in MTEP09	West	ATC LLC	2458	4417	6/1/2009	Stoughton	Stoughton Muni East Tap	1	69		143 MVA	uprate terminal Equip @ Stoughton to 143 MVA	WI			Planned	$232,666			Y	B>A
A in MTEP09	West	ATC LLC	2458	4418	6/1/2009	Stoughton Muni East Tap	Stoughton Muni North Tap	1	69		146 MVA	uprate terminal Equip @ Stoughton to 143 MVA	WI			Planned	$0			Y	B>A
A in MTEP09	West	ATC LLC	2458	4419	6/1/2009	Stoughton	Sheepskin	1	69		57 MVA	uprate terminal Equip @ Stoughton to 143 MVA	WI			Planned	$232,666			Y	B>A
A in MTEP09	West	ATC LLC	2458	4420	6/1/2009	Stoughton	Stoughton Muni South Tap(Aaker Rd)	1	69		61 MVA	uprate terminal Equip @ Stoughton to 143 MVA	WI			Planned	$232,666			Y	B>A
A in MTEP09	West	ATC LLC	2459	4421	10/17/2009	Sun Valley Tap	Oregon	1	69		36 MVA	Tap Sun Valley Tap into Oregon-Verona 69-kV	WI			Planned				Y	B>A
A in MTEP09	West	ATC LLC	2459	4422	10/17/2009	Sun Valley Tap	Verona	1	69		36 MVA	Tap Sun Valley Tap into Oregon-Verona 69-kV	WI			Planned				Y	B>A
A in MTEP09	West	ATC LLC	2459	4423	10/17/2009	Sun Valley Tap	Sun Valley	1	69		95 MVA	Construct 3.3 mile Sun Valley Tap-Sun Valley 69-kV line	WI		3.3	Planned	$3,046,857			Y	B>A
A in MTEP09	West	ATC LLC	2776	4870	7/15/2009	Spring Green	substation	1	69		12.24 MVAR	Mobile cap bank placed at Spring Green	WI		0	Planned	$670,116			Y	B>A
A in MTEP09	West	ATC LLC	2796	4921	3/1/2011	Ledge Wind	substation	1	138			G-T Interconnection Taps Forest Jct-Lost Dauphin 138 kV	WI		0	Proposed	$4,950,990	Y		Y	B>A
A in MTEP09	Central	DEM	1562	3113	8/1/2009	Bloomington Rockport Road			138	12		Build 22.4MVA 138/12kV sub w/ 2 12kV exits in Bloomington, IN near intersection of SR37 & Rockport Road. Tap 13837 line.	IN			Under Construction	$513,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	DEM	1567	3119	5/31/2009	Rockies Express (REX)	substation		138	13.1		Rockies Express-Inst Ring Bus-Install Four Breaker 138 kV ring bus & associated equipment and 2-138/13.1 distribution Xfmrs; in the 5689 line - only 5689 line is 50% DEM cost responsibility - the rest is customer reimbursable	OH			In Service	$500,000			Y	B>A
A in MTEP09	Central	DEM	1567	4258	6/1/2009	Carlisle	relocate line	1	138		306	Phase 2 of REX project - Move 5689 ckt tap to Carlisle over to 5381 ckt immediately outside REX ring bus	OH		1.5	Under Construction	$0			Y	B>A
A in MTEP09	Central	DEM	1572	3124	6/1/2009	Wards Corner	transformer	1	138	13.1		Loop the F9482 ckt through a new substation with a 138-13.1 KV - 22.4 mva xfmr (site purchased)	OH			In Service	$656,000			Y	B>A
A in MTEP09	Central	DEM	1647	3378	6/1/2011	Carmel SE	69/12 substation		69	12	245	Construct Carmel SE Bank 1 22.4MVA bank with 2 exits - extend a new radial 69kv - 954ACSS@200C from Carmel 146th St (no new bkr - share dist bk terminal)	IN		4	Planned	$2,000,000			NT	B>A
A in MTEP09	Central	DEM	1879	3773	6/1/2010	KY University	transformer		138	13.2		Reconfigure 138kV bus for and add on a 22.4 MVA (2nd) distribution xfmr	KY			Planned	$90,513			Y	B>A
A in MTEP09	Central	DEM	1880	3774	12/31/2011	Columbia	distribution sub		138	12		Columbia 138kV-22.4MVA Sub - New site or purchase and rebuild existing Siemens Sub #537- in F5484 between Warren and Maineville	OH			Planned	$215,000			Y	B>A
A in MTEP09	Central	DEM	1882	3777	12/1/2009	Carmel 69	Carmel Towne Rd N Jct	1	69		153	Reconductor 69kV - 6989 line from Carmel 69kV to Towne Rd N. Jct with 954 ACSR @ 100C, Shell Jct. Switch to be upgraded from 600 amp to 1200 amp	IN	2.5		Planned	$834,141			NT	B>A
A in MTEP09	Central	DEM	1883	3779	12/31/2009	Brown	South Bethel		69		100	Brown to S. Bethel 69kV line uprate - Modify spans in F5863 as required to provide clearance for 100C operation - 477 kcmil ACSR conductor	OH	1		Planned	$97,057			NT	B>A
A in MTEP09	Central	DEM	1884	3780	12/31/2009	Wilder	Kenton	1	69		100	Modify spans in 69 kV Feeder 965 as required to provide clearance for 100 C operation - 477 kcmil ACSR conductor	KY	1		Planned	$128,975			NT	B>A
A in MTEP09	Central	DEM	1885	3781	12/1/2009	Todhunter	Carlisle	1	69			Modify spans in 69 kV feeder 5661 Uprate to 100C	OH	1		Planned	$561,600			NT	B>A
A in MTEP09	Central	DEM	1888	3784	6/1/2009	Liberty	distribution sub		69	13.1	153	new Liberty 22.4MVA 69-13.09 kV sub and approx. 5.5 mile - 69kv line - 954 kcmil 45/7 ACSR - from Allen sub	OH		5.5	Under Construction	$3,100,000			NT	B>A
A in MTEP09	Central	DEM	2126	2911	12/31/2009	Martinsville SE Jct	switches		69		143	600A switches 1&2 to be replaced with 1200A switches	IN			Planned	$146,000			NT	B>A
A in MTEP09	Central	DEM	2127	2912	6/1/2019	Martinsville 69	69163-1 switch		69		143	69163-1 switch replacement near tap to HE Cope with 1200A switch	IN			Planned	$40,000			NT	B>A
A in MTEP09	Central	DEM	2128	2913	6/1/2011	Martinsville 69	Martinsville SE Jct	1	69		80	Uprate 6903 line's 336acsr to 100C operation	IN	4		Planned	$439,000			NT	B>A
A in MTEP09	Central	DEM	2131	2916	6/30/2010	Whiteland Jct	Madison Ave Jct	1	69		80	Whiteland Jct to Madison Ave Jct uprate 1.29 miles 69kV line section for 100C operation - 6997 ckt.	IN	1.29		Planned	$28,000			NT	B>A
A in MTEP09	Central	DEM	2132	2917	6/30/2012	Frances Creek	capacitor		69		36 MVAR	Frances Creek Install 36MVAR 69kV capacitor bank	IN			Planned	$615,500			NT	B>A
A in MTEP09	Central	DEM	2133	2918	6/1/2012	Franklin 230	Franklin Forsythe	2	69		143	Franklin 230 sub to Forsythe 69 sub - Build new 3.5 mile 69kV - 69159 line; new line terminal at Forsythe; use existing terminal at Franklin 230	IN		3.5	Planned	$1,030,000			NT	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	DEM	2138	2923	12/1/2009	Greenwood HE Gilmore	switches		69		100	Greenwood HE Gilmore - Relocate 69kv - 69102 ckt line switching (and add 1 additional switch) to HE sub property - all 3-1200Amp	IN			Planned	$183,000			NT	B>A
A in MTEP09	Central	DEM	2141	2927	12/31/2009	Terminal	Wave traps & breaker		345	138		replace 138kv bank #1 breaker and move from line terminal 1782 over to main 138kv bus #1; replacing: 345kv (4514) wave trap, 138kv (7481) wave traps with no resulting branch ratings changes	OH			Under Construction	$1,269,000			Y	B>A
A in MTEP09	Central	DEM	2148	2935	5/1/2012	Cadiz	Milner's Corner Jct	1	69		143	Cadiz-Markleville-Milner's Corner J - Reconductor 69kv - 69131 ckt - 9.24 mile section with 477ACSR@100C; Replace 69kv three way switch at Milner's Corner Jct with three one way 1200A switches; Upgrade the Markleville 600A switches #1 and #2 to 1200A	IN	9.24		Planned	$3,860,000			NT	B>A
A in MTEP09	Central	DEM	2149	2936	6/1/2010	West End	bus tie bkr & line bkr	1	138		478	West End substation - Install a 138kV circuit breaker to tie the east and west 138 kV busses together and a line breaker in the 1389 ckt	OH			Planned	$1,040,000			Y	B>A
A in MTEP09	Central	DEM	2150	2937	6/1/2010	Plainfield West	distribution sub	1	69	12		Plainfield West new dist sub; 22.4MVA w/4 12kV exits; loop 69125 ckt through sub	IN			Planned	$161,000			NT	B>A
A in MTEP09	Central	DEM	2151	2938	6/1/2010	Wilder	reactor & wave trap	1	138		300	Wilder Sub - Install 138kV, 3.8 Ohm reactors in ckt 5985; replace 138kv - 5985 1200A wavetrap with 1600A	OH			Planned	$690,000			Y	B>A
A in MTEP09	Central	DEM	2152	2940	3/1/2009	WVPA Anson North	distribution sub	1	69			WVPA Anson N. Jct - DEM to Install two single 1200 amp 69kv line switches with provisions for tap line - in the 69186 line between Whitestown and Brownsburg N. Jct to serve new WVPA sub	IN			In Service	$86,000			NT	B>A
A in MTEP09	Central	DEM	2153	2941	6/1/2013	Mohawk	Lee Hanna	1	69		71.7	Mohawk to Lee Hanna 69kV reconductor 69130 ckt (5.27 mi) with 954acsr@100C	IN			Planned	$2,317,000			NT	B>A
A in MTEP09	Central	DEM	2154	2942	6/1/2012	Carmel Rohrer Rd.	distribution sub		69	12		Carmel Rohrer Rd 69/12-22.4MVA sub to looped through the 6989 ckt. at or near the existing Carmel Shell Oil tap	IN	0.4	0.4	Planned	$591,143			NT	B>A
A in MTEP09	Central	DEM	2327	4259	6/1/2013	Speed	HE Bethany	1	69		53	Speed to HE Bethany 69kV - 6955 Reconductor Ph1 - Replace 5.2 miles of 3/0 ACSR with 477 ACSR (new limiter 4/0acsr @ 80C)	IN	5.2		Planned	$1,560,000			NT	B>A
A in MTEP09	Central	DEM	2331	4263	6/1/2012	Shelbyville NE	Knauf	1	69		153	Shelbyville NE to Knauf Reconductor 1.75 miles of 397ACSR on 6946 ckt. with 954acsr@100C	IN	1.75		Planned	$777,000			NT	B>A
A in MTEP09	Central	DEM	2332	4264	6/1/2012	Zionsville Turkeyfoot	Zionsville 96th St Jct	1	69		153	Zionsville Turkeyfoot to Zionsville 96th St Jct Reconductor 1.59 mile 69kV - 69155 ckt with 954ACSR@100C	IN	1.59		Planned	$704,000			NT	B>A
A in MTEP09	Central	DEM	2334	4266	6/2/2011	Fishers 106th St	distribution sub		69	12		New Fishers 106th St 69/12 kv sub: Construct 69kV line in and out of sub and 69kv bus; located in the proposed loop between Carmel SE 69 sub and Fishers 69145	IN			Planned	$174,000			NT	B>A
A in MTEP09	Central	DEM	2335	4267	8/1/2009	HE Gateway Ind Pk	distribution sub		69	12		HE Gateway Industrial Park (new sub) - Install two one-way 1200amp 69kV line swiches at tap for new HE sub in 6918 line	IN			Under Construction	$103,000			NT	B>A
A in MTEP09	Central	DEM	2336	4268	6/1/2009	HE Martinsville Park Ave	distribution sub		69	12		HE Martinsville Park Ave (new sub) - Install two one-way 1200amp 69kV line swiches at tap for new HE sub in 6903 line	IN			In Service	$150,000			NT	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	Central	DEM	2338	4271	6/1/2009	HE Solar Sources Portal #1	distribution sub	1	69			HE Solar Sources Portal #1 - install 69kV-1200A line Switches in the 6963 ckt to serve new HE mine load	IN			In Service	$62,363			NT	B>A
A in MTEP09	Central	DEM	2373	4399	12/31/2009	Lafayette Concord Jct	Lafayette Industry S.	1	138		179	Lafayette Concord Jct to Laf Industry S. - 13808 ckt - uprate 397acsr conductor to 100C - one h-frame structure to replace	IN	0.37		Planned	$11,400			Y	B>A
A in MTEP09	Central	DEM	2374	4400	6/1/2009	Evendale	Terminal	1	138		382	Replace CB 952 and disconnect sws at Evendale Sub with 2000 Amp rated eq, upgrade F4685 metering @ both Sta. (Metering was 1255A limmited - New rating will be 1600A - 382 mva)	OH			In Service	$500,000			Y	B>A
A in MTEP09	Central	DEM	2375	4401	12/31/2010	Yankee - 69kV	new sub	1	69			Install 69kv substation and 5 brkr ring bus on Yankee Rd. for SunCoke (Middletown Coke Co. Inc) 67MW generator, loop F5661 & F5666 through station	OH			Planned	$4,440,000			NT	B>A
A in MTEP09	Central	DEM	2376	4402	5/1/2009	Pierce	Transformer	A	345	138	139	Retire Pierce TB A - 125 MVA	OH			In Service	$0			Y	B>A
A in MTEP09	Central	DEM	2376	4403	5/1/2009	Pierce	Transformer	17	345	138	433	Add new 400 MVA TB 17 - System Spare - 345/138kv	OH			In Service	$1,239,067			Y	B>A
A in MTEP09	Central	DEM	2376	4404	5/1/2009	Pierce	WCBeckjord Sta# 18	1	138		611	Reconductor 138KV - Cir 1889	OH	0.2		In Service	$302,267			Y	B>A
A in MTEP09	East	FE	1607	2699	6/1/2013	Existing Chamberlin-Mansfield Line	Hanna	1	345		1504/1793 MV	New Line looping from existing line	OH	2		Proposed	$5,597,657			Y	B>A
A in MTEP09	East	FE	1612	2705	6/1/2012	Cranberry Transformer #1		1	500	138	600	New # 1 500-138kV TR Bank, 2-500kV Breakers and 1/2 500kV Buswork	PA			Planned	$14,834,041	Y		Y	B>A
A in MTEP09	East	FE	1612	2898	6/1/2012	Cranberry Transformer #2	Cranberry	2	500	138		New # 2 500-138kV TR Bank, 2-500kV Breakers and 1/2 500kV Buswork	PA	0.1		Planned	$14,834,041	Y		Y	B>A
A in MTEP09	East	FE	1612	2899	6/1/2012	Cranberry 138	Cranberry Transformer 1 & 2	1	500			Connection of the two transformers to the 138 kv Bus (4 - 138 kv Breakers & 138 kV Buswork & Line extensions) / 3	PA	0.1		Planned	$2,689,987	Y		Y	B>A
A in MTEP09	East	FE	1612	3881	6/1/2012	Cranberry-Pine, Cranberry Hoytdale 138kV Lines	(2) New 138kV lines	2	138			New line extensions from current 138kV Line and connection to Transformer # 2 (4 - 138 kv Breakers & 138 kV Buswork & Line extensions) / 3	PA	0.2		Planned	$2,689,987	Y		Y	B>A
A in MTEP09	East	FE	1612	3882	6/1/2012	Cranberry-Maple, Cranberry-Pine 138kV lines	(2) New 138kV lines	2	138			New line extensions from current 138kV Line & connection to Transformer #1 (4 - 138 kv Breakers & 138 kV Buswork & Line extensions) / 3	PA	3		Planned	$2,689,987	Y		Y	B>A
A in MTEP09	East	FE	1920	3880	6/1/2011	New Shinrock/Johnson area	Substation	1	138	69		New Substation	OH			Planned	$6,091,601			Y	B>A
A in MTEP09	East	FE	2120	2900	12/31/2013	Q-12-Eastlake/Lloyd	Keystone	1	138			New line extension from current 138kV Line	OH	0.01		Planned				Y	B>A
A in MTEP09	East	FE	2120	2901	12/31/2013	Q-13-Eastlake/Lloyd	Keystone	1	138			New line extension from current 138kV Line	OH	0.01		Planned				Y	B>A
A in MTEP09	East	FE	2120	2902	12/31/2013	Q3-Mayfield	Keystone	1	138			Loop in the exsting Q-3-Mayfield/Northfield circuit	OH	0.01		Planned				Y	B>A
A in MTEP09	East	FE	2120	2903	12/31/2013	Q3-Northfield	Keystone	1	138			Loop in the exsting Q-3-Mayfield/Northfield circuit	OH	0.01		Planned				Y	B>A
A in MTEP09	East	FE	2120	2904	12/31/2013	Keystone		1	138			New 138kV substation	OH			Planned	$4,000,000			Y	B>A
A in MTEP09	East	FE	2120	2905	12/31/2013	Keystone		1	138	36		New 138-36kV Distribution transformer	OH			Planned				NT	B>A
A in MTEP09	East	FE	2249	4161	9/1/2010	Inland	CPP	1	138			New Line	OH		1	Planned	$895,500			Y	B>A
A in MTEP09	East	FE	2263	4177	6/1/2010	Brookside	Cloverdale	1	69			reconductor line	OH			Planned	$1,169,400			Y	B>A
A in MTEP09	East	FE	2264	4178	6/1/2012	Greenford	capacitor bank	1	69			Capacitor Bank Addition	OH			Planned	$200,000			Y	B>A
A in MTEP09	East	FE	2266	4180	6/1/2015	Pine	Substation	3	138	69		New 138/69 kV Transformer	PA			Proposed	$4,244,800			Y	B>A
A in MTEP09	East	FE	2753	4449	11/1/2011	BP Oil	Substation	4	138	69		New 138/69kV substation	OH			Planned	$800,000			Y	B>A
A in MTEP09	East	FE	2769	4829	11/30/2009	New customer connection	tap connection	1	138			Tap connection to new customer substation	OH			Planned	$200,000			Y	B>A
A in MTEP09	East	FE	2788	4908	10/1/2010	Hitchcock Road	relocation	138	138			Move from North line to South line			1.8	Planned	$982,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	FE	2789	4910	6/1/2012	Vienna	capacitor		69		21.6 Mvar	new capacitor				Proposed	$580,000			Y	B>A
A in MTEP09	East	FE	2790	4911	6/1/2011	Hilcrest	Grant	1	69			New Line	PA		1.6	Planned	$610,635			Y	B>A
A in MTEP09	East	FE	2791	4912	6/1/2011	Toledo	line reconfig		69			see project description				Proposed	$198,900			Y	B>A
A in MTEP09	East	FE	2814	4950	6/1/2013	Naomi Jct	Wauseon	1	138			Reconductor	OH		4.98	Planned	$650,000			Y	B>A
A in MTEP09	West	GRE	2553	4753	6/1/2009	Lyon County	Milroy Tap	1	69		144	new line	MN		2	Under Construction	$630,000			NT	B>A
A in MTEP09	West	GRE	2554	4568	6/1/2009	Tamarac	Substation	1	115			Breakers and Capacitor	MN		0	Planned	$668,000			Y	B>A
A in MTEP09	West	GRE	2556	4570	11/1/2009	Ritter Park	Ritter Park Tap	1	115			New Distribution	MN		0	Planned	$1,335,000			Y	B>A
A in MTEP09	West	GRE	2557	4571	6/1/2009	Lake Mina	Lake Mina Tap	1	115			New distribution	MN		0.6	Planned	$387,000			Y	B>A
A in MTEP09	West	GRE	2559	4574	12/31/2009	Orr	Cook	1	69			New Distribution	MN		13	Planned	$5,275,000			NT	B>A
A in MTEP09	West	GRE	2560	4575	6/1/2009	Alexandria	Parkers Prairie	1	41.6		27.4		MN	26.75		Planned	$255,000			NT	B>A
A in MTEP09	West	GRE	2561	4632	6/1/2009	Le Sauk	Le Sauk Tap	1	115		141.6		MN	0.5		Planned	$375,000			Y	B>A
A in MTEP09	West	GRE	2562	4024	2/1/2010	Pleasant Valley	345/161 kV transformer	2	345	161	500	add transformer	MN			Planned	$8,100,000	Y		Y	B>A
A in MTEP09	West	GRE	2563	4579	12/1/2010	Martin Lake	Athens	1	69		135.9	System upgrades and permitting	MN		10	Planned	$6,000,000			NT	B>A
A in MTEP09	West	GRE	2575	4754	6/1/2009	Goose Lake Tap	Liberty	1	69		58.8	upgrade	MN	16.77		Under Construction	$568,600			NT	B>A
A in MTEP09	West	GRE	2575	4755	6/1/2009	Dickinson	Mary Lake	1	69		75.8	upgrade	MN	2.4		Under Construction	$149,400			NT	B>A
A in MTEP09	West	GRE	2612	4807	12/1/2009	Soderville Bus Replacement			69			Upgrade Bus capacity	Mn			Proposed	$340,000			NT	B>A
A in MTEP09	West	GRE	2613	4623	12/1/2009	Lemay Lake	Wescott	1	115			Lemay Lake Tap-Wescott 477 ACSR 115 kV line	MN		0.5	Planned	$1,870,000			Y	B>A
A in MTEP09	West	GRE	2619	4576	6/1/2009	Remmele Tap	Elk River West	1	69			temperature upgrade (multiple line sections in model)	MN	6.7		Planned	$268,000			NT	B>A
A in MTEP09	Central	IPL	2053	3939	6/1/2012	Petersburg	East Autotransformer	E	345	138	300 MVA	New transformer & share of 345 breaker	IN			Planned	$6,700,000	Y		Y	B>A
A in MTEP09	Central	IPL	2053	3940	6/1/2012	Petersburg	West Autotransformer	W	345	138	300 MVA	New transformer & share of 345 breaker	IN			Planned	$6,700,000	Y		Y	B>A
A in MTEP09	Central	IPL	2053	5341	6/1/2012	Petersburg	breakers & switches		138			six 138 kV breakers and disconnect switches	IN			Planned	$2,000,000	N		Y	B>A
A in MTEP09	East	ITC	1860	2881	12/31/2009	Breaker Replacement Program 2009	Throughout System						MI			Planned	$5,650,000			Y	B>A
A in MTEP09	East	ITC	1861	2882	12/31/2010	Breaker Replacement Program 2010	Throughout System						MI			Planned	$5,650,000			Y	B>A
A in MTEP09	East	ITC	1862	2883	12/31/2009	Cable Termination Replacement 2009	Throughout System						MI			Planned	$3,000,000			Y	B>A
A in MTEP09	East	ITC	1863	2884	12/31/2010	Cable Termination Replacement 2010	Throughout System						MI			Planned	$3,000,000			Y	B>A
A in MTEP09	East	ITC	1864	2885	12/31/2009	Relay Betterment Program 2009	Throughout System						MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	1865	2886	12/31/2010	Relay Betterment Program 2010	Throughout System						MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	1872	3762	12/31/2010	ScioTP	Lark	1	120		249 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI			Planned				Y	B>A
A in MTEP09	East	ITC	1872	3763	12/31/2010	ScioTP	Spruce	1	120		313 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI			Planned				Y	B>A
A in MTEP09	East	ITC	1872	3764	12/31/2010	ScioTP	Scio	1	120		343 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI			Planned	$3,000,000			Y	B>A
A in MTEP09	East	ITC	2518	4525	6/1/2010	Bloomfield			120			Terminal equipment upgrade	MI			Planned	$20,000			Y	B>A
A in MTEP09	East	ITC	2519	4526	12/31/2011	Breaker Replacement Program 2011	Throughout System						MI			Planned	$5,650,000			Y	B>A
A in MTEP09	East	ITC	2520	4527	12/31/2011	Cable Termination Replacement 2011	Throughout System						MI			Planned	$3,000,000			Y	B>A
A in MTEP09	East	ITC	2521	4528	12/31/2011	Relay Betterment Program 2011	Throughout System						MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	2523	4529	12/31/2009	Capacitor Replacement 2009	Throughout System					Replace capacitor banks	MI			Planned	$565,000			Y	B>A
A in MTEP09	East	ITC	2524	4530	12/31/2010	Capacitor Replacement 2010	Throughout System					Replace capacitor banks	MI			Planned	$565,000			Y	B>A
A in MTEP09	East	ITC	2525	4531	12/31/2011	Capacitor Replacement 2011	Throughout System					Replace capacitor banks	MI			Planned	$565,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	ITC	2526	4532	12/31/2009	Potential Device Replacement 2009	Throughout System					Replace aging potential devices	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	ITC	2527	4533	12/31/2010	Potential Device Replacement 2010	Throughout System					Replace aging potential devices	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	ITC	2528	4534	12/31/2011	Potential Device Replacement 2011	Throughout System					Replace aging potential devices	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	ITC	2532	4538	12/31/2009	Wood Pole Replacement 2009	Throughout System					Replace deteriorating wood pole	MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	2533	4539	12/31/2010	Wood Pole Replacement 2010	Throughout System					Replace deteriorating wood pole	MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	2534	4540	12/31/2011	Wood Pole Replacement 2011	Throughout System					Replace deteriorating wood pole	MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	ITC	2538	4544	12/31/2010	NERC Relay Loadability Compliance 2010	Throughout system		120			Upgrade relay throught system	MI			Planned	$2,250,000			Y	B>A
A in MTEP09	East	ITC	2539	4545	12/31/2011	NERC Relay Loadability Compliance 2011	Throughout system		120			Upgrade relay throught system	MI			Planned	$2,250,000			Y	B>A
A in MTEP09	East	ITC	2540	4546	6/1/2010	Genoa	Latson (ITC side)	1	138			Replace wood structures	MI			Planned	$1,500,000			Y	B>A
A in MTEP09	East	ITC	2543	4549	7/31/2009	MacSteel GOAB		1	120			Install 3-way GOAB switch at North Star Tap point on Custer-Monroe 120kV circuit	MI			Planned	$200,000			Y	B>A
A in MTEP09	East	ITC	2544	4550	7/1/2009	Oakwood	River Rouge	1	120			Oakwood taps the River Rouge-Navarre 120kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	ITC	2544	4551	7/1/2009	Oakwood	Navarre	1	120			Oakwood taps the River Rouge-Navarre 120kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	ITC	2545	4552	9/1/2010	Navarre			120			Relay modifications	MI			Planned	$640,000			Y	B>A
A in MTEP09	East	ITC	2546	4553	5/1/2011	East Ann Arbor (Earhart)			120			New 120kV switching station	MI			Planned	$5,650,000			Y	B>A
A in MTEP09	West	ITCM	1775	2868	12/31/2009	Triboji	Milford (CBPC)		69		140 MVA	Rebuild the Triboji-Milford 69kV line.	IA	7		Planned	$2,023,508	Y		Y	B>A
A in MTEP09	West	ITCM	2339	4279	31-Dec-09	Fernald	Story County	1	161			Rebuild 115kV to 161kV line includes Fernal	IA	7		Planned	3,454,391.00	Y		Y	B>A
A in MTEP09	West	ITCM	2339	4280	30-Jun-10	Story County	Highland Acres	1	161			Rebuild 115kV to 161kV line includes Highla	IA	16	4.5	Planned	8,686,060.00	Y		Y	B>A
A in MTEP09	West	ITCM	2339	4284	31-Dec-13	Boone	Boone Junction	1	161			Rebuild 115kV to 161kV line includes Boone	IA	5.2		Planned	5,236,391.00	Y		Y	B>A
A in MTEP09	West	ITCM	2339	4285	31-Dec-13	Boone Junction	Ames	1	161			Rebuild 115kV to 161kV line includes 50% A	IA	8.4		Planned	2,726,927.00	Y		Y	B>A
A in MTEP09	West	ITCM	2339	4286	31-Dec-10	Ames	Fernald	1	161			Rebuild 115kV to 161kV line includes 50% A	IA	6		Planned	1,997,031.00	Y		Y	B>A
A in MTEP09	West	ITCM	2340	4296	9/1/2009	Grand Junction	Grand Junction City	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2.75		Planned	$639,200			NT	B>A
A in MTEP09	West	ITCM	2340	4297	9/1/2009	Grand Junction City	Grand Junction North	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2		Planned	$464,327			NT	B>A
A in MTEP09	West	ITCM	2340	4298	9/1/2009	Grand Junction North	Paton REC	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	9		Planned	$2,096,473			NT	B>A
A in MTEP09	West	ITCM	2340	4299	12/31/2009	Grand Junction North	substation		69			Construct taps in & out of a new Allaint Energy 69kV/dist. Grand Junction North substation. The Dana 34kV/dist. sub will also be retired.	IA			Planned	$60,000			NT	B>A
A in MTEP09	West	ITCM	2341	4331	6/1/2010	Amber	Monticello Industrial	1	69		77/77 MVA	Rebuild 34kV to 69kV	IA	8.51		Planned	$2,291,032			NT	B>A
A in MTEP09	West	ITCM	2341	4332	6/1/2010	Amber	breakers		69			Add two 69kV breakers at the Amber Creamery sub.	IA			Planned	$185,000			NT	B>A
A in MTEP09	West	ITCM	2341	4333	6/1/2010	Sand Springs	breaker		69			Add a Sand Springs 69kV breaker and operate the Sand Springs-Monticello Industrial-Amber line at 69kV.	IA			Planned	$340,000			NT	B>A
A in MTEP09	West	ITCM	2341	4334	6/1/2010	Monticello Industrial	breaker		69			Add a Monticello Industrial 69kV bus tie breaker and 69kV line breakers on the Sand Springs and Amber Creamery 69kV lines.	IA			Planned	$364,000			NT	B>A
A in MTEP09	West	ITCM	2341	4335	6/1/2010	Lovell REC Tap	Lovell REC Junction	1	34		39/39 MVA	Rebuild the remaning 2.21 miles of the 4.14 mile Lovell REC Tap-Lovell Junction 34kV line to 69kV standards. This line section will continue operation at 34kV. Monticello Industrial-Lovell REC 34kV line N.O.	IA	2.21		Planned	$594,968			NT	B>A
A in MTEP09	West	ITCM	2342	4300	12/31/2009	Jewell	Stanhope	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	9.25		Planned	$2,448,961			NT	B>A
A in MTEP09	West	ITCM	2342	4301	12/31/2009	Stanhope	Stratford REC Tap	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	5		Planned	$1,323,762			NT	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	West	ITCM	2342	4302	12/31/2009	Stratford REC Tap	Ridgeport REC	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	5		Planned	$1,323,762			NT	B>A
A in MTEP09	West	ITCM	2342	4303	12/31/2009	Ridgeport REC	Boone Junction	1	34		39/39 MVA	Rebuild 6 miles of 34kV to 69kV (operated 34kV) from the Ridgeport REC sub south towards Boone Jct.	IA	6		Planned	$1,588,515			NT	B>A
A in MTEP09	West	ITCM	2343	4304	3/31/2010	West Branch	Mid-America Storage	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2		Planned	$550,710			NT	B>A
A in MTEP09	West	ITCM	2343	4305	3/31/2010	Mid-America Storage	Mid-America Pump Tap	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2		Planned	$550,710			NT	B>A
A in MTEP09	West	ITCM	2343	4306	3/31/2010	Mid-America Pump Tap	Mid-America Pump Station	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	1.25		Planned	$344,194			NT	B>A
A in MTEP09	West	ITCM	2343	4307	3/31/2010	Mid-America Pump Tap	IA Valley Milling Tap	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	0.5		Planned	$302,891			NT	B>A
A in MTEP09	West	ITCM	2343	4308	3/31/2010	IA Valley Milling Tap	IA Valley Milling Sub	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	1.1		Planned	$137,678			NT	B>A
A in MTEP09	West	ITCM	2343	4309	3/31/2010	IA Valley Milling Tap	West Liberty	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	8.21		Planned	$2,260,667			NT	B>A
A in MTEP09	West	ITCM	2344	4310	12/31/2010	Wyoming	Dome Pipeline	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2.3		Planned	$575,000			NT	B>A
A in MTEP09	West	ITCM	2344	4311	12/31/2010	Dome Pipeline	Oxford Mills	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	5		Planned	$1,250,000			NT	B>A
A in MTEP09	West	ITCM	2344	4312	12/31/2010	Oxford Mills	Massilon	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	4.7		Planned	$1,175,000			NT	B>A
A in MTEP09	West	ITCM	2345	4313	6/30/2010	Eldora North	new switching station		69			Construct a new 4-terminal 69kV switching station along the Corn Belt 69kV line.	IA			Planned	$1,500,000			NT	B>A
A in MTEP09	West	ITCM	2345	4314	6/30/2010	CBPC Radcliffe Switch Station	Hubbard Rural	1	69		77/77 MVA	Operate at 69kV (already built to 69kV standards)	IA			Planned	$0			NT	B>A
A in MTEP09	West	ITCM	2345	4315	6/30/2010	Hubbard Rural	Enron Tap	1	69		77/77 MVA	Rebuild 34kV to 69kV	IA	3.6		Planned	$900,000			NT	B>A
A in MTEP09	West	ITCM	2345	4316	6/30/2010	Enron Tap	Eldora City Sub	1	69		77/77 MVA	Rebuild 34kV to 69kV	IA	14.5		Planned	$3,625,000			NT	B>A
A in MTEP09	West	ITCM	2345	4317	6/30/2010	Eldora City Sub	New Eldora North Switching	1	69		77/77 MVA	Rebuild 34kV to 69kV	IA	2		Planned	$500,000			NT	B>A
A in MTEP09	West	ITCM	2345	4318	6/30/2010	IPL Hubard Rural 69kV/dist Sub	substation		34			IPL Hubbard Rural Sub 34 to 69kV converion	IA			Planned	$100,000			NT	B>A
A in MTEP09	West	ITCM	2345	4319	6/30/2010	CBPC Enron	substation		34			CBPC Enron Sub 34 to 69kV converion	IA			Planned	$0			NT	B>A
A in MTEP09	West	ITCM	2345	4320	6/30/2010	IPL Radcliffe 34kV/dist Sub	substation		34			Retire IPL Radcliffe Sub	IA			Planned	$50,000			NT	B>A
A in MTEP09	West	ITCM	2345	4321	6/30/2010	IPL Hubbard 34kV/dist. Sub	substation		34			Retire IPL Hubbard Sub	IA			Planned	$50,000			NT	B>A
A in MTEP09	West	ITCM	2345	4322	6/30/2010	IPL Radcliffe Sub	substation		34			Retire IPL Garden City Sub	IA			Planned	$50,000			NT	B>A
A in MTEP09	West	ITCM	2345	4323	6/30/2010	New Eldora North Switching	Airport East Tap	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	4.5		Planned	$1,125,000			NT	B>A
A in MTEP09	West	ITCM	2345	4324	6/30/2010	Airport East Tap	CBPC Union	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	4.29		Planned	$1,072,500			NT	B>A
A in MTEP09	West	ITCM	2345	4325	6/30/2010	CBPC Union	Union	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	1.5		Planned	$375,000			NT	B>A
A in MTEP09	West	ITCM	2345	4326	6/30/2010	Union	Whitten	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	5.25		Planned	$1,312,500			NT	B>A
A in MTEP09	West	ITCM	2345	4327	6/30/2010	Whitten	Conrad 69/34kV	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	4.8		Planned	$1,200,000			NT	B>A
A in MTEP09	West	ITCM	2345	4328	6/30/2010	Conrad 69/34kV	Conrad distribution	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	5.05		Planned	$1,262,500			NT	B>A
A in MTEP09	West	ITCM	2345	4329	6/30/2010	Conrad distribution	Beaman	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	2.25		Planned	$562,500			NT	B>A
A in MTEP09	West	ITCM	2345	4330	6/30/2010	Beaman	Gladbrook T	1	34		39/39 MVA	Rebuild 34kV to 69kV (operated 34kV)	IA	3.5		Planned	$875,000			NT	B>A
A in MTEP09	West	ITCM	2346	4348	12/31/2009	North of Welton	near Petersville sub	1	34			Retire de-energized 34kV line north of Welton to near Petersville sub.	IA			Planned	$90,000			NT	B>A
A in MTEP09	West	ITCM	2347	4346	12/31/2009	Bonaparte 69/34kV	substation		69	34		Retire Bonaparte 69/34kV Sub	IA			Planned	$40,000			NT	B>A
A in MTEP09	West	ITCM	2347	4347	12/31/2009	Bonaparte 69/34kV	Farmington	1	34			Retire Bonaparte 69/34kV-Farmington 34kV line	IA			Planned	$185,000			NT	B>A
A in MTEP09	West	ITCM	2348	4338	3/31/2010	Beaver Rock	Comanche Tap	1	69		77/77 MVA	Tie new CIPCO 69kV line from Comanche REC to Beaver Rock.	IA		0.75	Planned	$0			NT	B>A
A in MTEP09	West	ITCM	2348	4339	3/31/2010	Beaver Rock	Rock Creek	1	69		130/130 MVA	Tap Beaver Channel-Rock Creek 69kV for new switching station. The Rock Creek-Beaver Rock 69kV line will be N.O.	IA			Planned	$20,000			NT	B>A
A in MTEP09	West	ITCM	2348	4340	3/31/2010	Beaver Rock	Beaver Channel	1	69		103/103 MVA	Tap Beaver Channel-Rock Creek 69kV for new switching station.	IA			Planned	$20,000			NT	B>A
A in MTEP09	West	ITCM	2348	4341	3/31/2010	Beaver Rock	new switching station	1	69			Construct a new 3-terminal 69kV switching station along the Beaver Channel-Rock Creek 69kV line.	IA			Planned	$1,350,000			NT	B>A
A in MTEP09	West	ITCM	2349	4336	6/1/2009	Savanna	York	1	161		200/200 MVA	upgrade limiting equipment	IL			Planned	$105,000			Y	B>A
A in MTEP09	West	ITCM	2349	4337	6/1/2009	Savanna	Galena	1	161		200/200 MVA	upgrade limiting equipment	IL			Planned	$100,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	West	ITCM	2351	4358	6/1/2009	Powesheik 161kV	substation	1	161			Upgrade the 3 existing 161kV Powesheik breakers to 2000 amp and add a 4th breaker to separate the Powesheik-Beacon 161kV line and the Powesheik 161/69kV TRF.	IA			Planned	$965,000			Y	B>A
A in MTEP09	West	ITCM	2352	4351	12/31/2009	Old Settlers 115kV/dist	substation	1	115			Construct 115kV taps, 115kV bus, and breakers for new 2 TRF 115kV/dist. Substation. The new sub will tap the Marion Dry Creek 115kV line.	IA			Planned	$2,815,000			Y	B>A
A in MTEP09	West	ITCM	2353	4344	3/31/2010	Big River Breaker Station	new switching station		69			Construct a new 3-terminal 69kV switching station where the Big River REC line taps the Agency-Sawyer 69kV line.	IA			Planned	$1,200,000			NT	B>A
A in MTEP09	West	ITCM	2354	4349	12/31/2009	Saints Run 115kV/dist	substation	1	115			Construct 115kV taps, 115kV bus, and breakers for new 2 TRF 115kV/dist. Substation. The new sub will tap the Hiawatha-6th Street 115kV line.	IA			Planned	$1,450,000			Y	B>A
A in MTEP09	West	ITCM	2354	4350	12/31/2009	Hiawatha	relay	1	115			A new relay panel will be installed at Hiawatha on the Saints Run 115kV line.	IA			Planned	$45,000			Y	B>A
A in MTEP09	West	ITCM	2355	4342	12/31/2009	Barilla	substation	1	69			Construct a new 69kV/dist. Consumers Energy sub near Barilla (bkrs, bus, switches, reactors, and line taps at a new Consumers Energy sub near Barilla.	IA			Planned	$400,000			NT	B>A
A in MTEP09	West	ITCM	2355	4343	12/31/2009	Barilla	capacitor		69			Add 2-4.8 MVAR Cap Banks at a new Consumers Energy sub near Barilla.	IA			Planned	$350,000			NT	B>A
A in MTEP09	West	ITCM	2356	4398	6/1/2010	Oran	Oelwein		69			Rebuild 69 kV line	IA	8		Planned	$2,000,000			Y	B>A
A in MTEP09	West	ITCM	2357	4389	6/1/2011	Fairbank	new switching station	1	69			Construct a new 3-terminal 69kV switching station.	IA			Planned	$1,200,000			NT	B>A
A in MTEP09	West	ITCM	2357	4390	6/1/2011	Fairbank REC	Fairbank Switching station	1	69		77/77 MVA	Rebuild 9.4 miles of the Fairbank REC-Dundee line from 34kV to 69kV.	IA	9.4		Planned				NT	B>A
A in MTEP09	West	ITCM	2357	4391	6/1/2011	Fairbank REC	Fairbank dist.	1	69		77/77 MVA	Build new 69kV line from the Fairbank REC sub to the Fairbank dist substation..	IA	4		Planned	$950,000			NT	B>A
A in MTEP09	West	ITCM	2358	4352	12/31/2012	Hazleton	Blackhawk	1	161		326/326 MVA	Rebuild existing line	IA	12		Proposed	$5,400,000	Y		Y	B>A
A in MTEP09	West	ITCM	2359	4353	12/31/2009	Bridgeport 161kV Expansion	substation	1	161			Replace the 161kV circuit switcher and add a 161kV breaker on the Bridgeport-OGS 161kV line. Expand the 69kV ring bus for 2 69kV/dist TRFs & an additional position to tie the Centerville 69kV line to the ring.	IA			Planned	$4,400,000			Y	B>A
A in MTEP09	West	ITCM	2359	4354	12/31/2009	EIC 69kV Sub Modifications	substation		69			Retire the EIC 69/13kV 22.4 MVA TRF and reconfigure 69kV ring bus to tie to the Bridgeport 69kV line and the Oskaloosa 69kV line. Install bus, and breaker for capacitor.	IA			Planned	$2,350,000			NT	B>A
A in MTEP09	West	ITCM	2359	4355	12/31/2009	EIC 69kV Capacitor	capacitor		69			Retire the Bridgeport 69kV/dist sub and relocate the Bridgeport 69kV 19.8 MVAR capacitor bank to EIC	IA			Planned	$150,000			NT	B>A
A in MTEP09	West	ITCM	2360	4356	12/31/2009	Burlington 69kV/dist	substation	1	69	13		Replace the existing Burlington distribution sub with a new substation on land adjacent to existing sub. (Line taps, Breakers, bus, etc.)	IA			Planned	$588,000			NT	B>A
A in MTEP09	West	ITCM	2361	4357	12/31/2010	Liberty	Dyersville	1	69		77/77 MVA	Rebuild the Liberty-Dyersville west 69kV line.	IA	3.24		Planned	$920,000			NT	B>A
A in MTEP09	West	ITCM	2362	4384	12/31/2010	Dover	new switching station	1	69			Construct a new 3-terminal 69kV Dover switching station.	MN			Planned	$1,275,000			NT	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	West	ITCM	2363	4385	12/31/2010	Glenville 161/69kV	new substation	1	161	69		Construct a new Glenville 161/69kV 75 MVA substation near the junction of the Hayward-Worth County 161kV line and the DPC Hayward-Twin Lakes 69kV line.	MN			Planned	$2,970,000			Y	B>A
A in MTEP09	West	ITCM	2364	4386	12/31/2010	Bricelyn	Thompson	1	69		77/77 MVA	Rebuild 2 miles of the N.O. 69kV Bricelyn tap-Thompson tap to double circuit 69kV line to allow for 2 separate circuits.	IA	2		Planned	$230,000			NT	B>A
A in MTEP09	West	ITCM	2364	4904	12/31/2010	Lincoln REC Tap (DPC)	Golden Oval (DPC)	1	69		18 MVA	Rebuild 2 miles of the N.O. 69kV Bricelyn tap-Thompson tap to double circuit 69kV line to allow for 2 separate circuits.	IA		2	Planned	$230,000			NT	B>A
A in MTEP09	West	ITCM	2365	4387	12/31/2010	Lansing	terminal equipment	1	161		240 MVA	Upgrade terminal equipment to min. of winter conductor rating on the Lansing-Genoa 161kV line .	IA			Planned	$100,000			Y	B>A
A in MTEP09	West	ITCM	2366	4388	12/31/2010	Adams	Harmony	1	161			Upgrade terminal equipment to min. of winter conductor rating on the Adams-Harmony 161kV line.	IA			Planned	$100,000			Y	B>A
A in MTEP09	West	ITCM	2367	4360	6/30/2011	Anita 161kV	Exira REC	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	5		Planned	$1,250,000			NT	B>A
A in MTEP09	West	ITCM	2367	4361	6/30/2011	Anita 161kV	Anita-Wiota	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	3.5		Planned	$875,000			NT	B>A
A in MTEP09	West	ITCM	2367	4362	6/30/2011	Anita-Wiota	Adair	1	34		39/39 MVA	Rebuild 1.2 miles of the Anita-Wiota-Adair line.	IA	1.2		Planned	$300,000			NT	B>A
A in MTEP09	West	ITCM	2367	4363	6/30/2011	Thompson	Menlo	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	5.5		Planned	$1,375,000			NT	B>A
A in MTEP09	West	ITCM	2367	4364	6/30/2011	Menlo	Stuart REC Tap	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	4.28		Planned	$1,070,000			NT	B>A
A in MTEP09	West	ITCM	2367	4365	6/30/2011	Stuart REC Tap	Stuart Muni Tap	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	1.6		Planned	$400,000			NT	B>A
A in MTEP09	West	ITCM	2367	4366	6/30/2011	Stuart Muni Tap	Dexter	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	4.75		Planned	$1,187,500			NT	B>A
A in MTEP09	West	ITCM	2367	4367	6/30/2011	Dexter	Diamondhead REC	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	3.2		Planned	$800,000			NT	B>A
A in MTEP09	West	ITCM	2367	4368	6/30/2011	Diamondhead REC	Redfield	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	2.55		Planned	$637,500			NT	B>A
A in MTEP09	West	ITCM	2368	4359	12/31/2010	Montgomery	LE Center	1	69			Retire & rebuild 3.4 mile Montgomery-LE Center 69kV line.	IA	3.4		Planned	$765,000			NT	B>A
A in MTEP09	West	ITCM	2369	4369	12/31/2010	Fairfax 161kV	Fairfax dist.	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.5		Planned	$129,560			NT	B>A
A in MTEP09	West	ITCM	2369	4370	12/31/2010	Fairfax dist.	Fairfax REC	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.5		Planned	$129,560			NT	B>A
A in MTEP09	West	ITCM	2369	4371	12/31/2010	Fairfax REC	Walford	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	4.5		Planned	$1,166,047			NT	B>A
A in MTEP09	West	ITCM	2369	4372	12/31/2010	Walford	Norway Tap	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	3.3		Planned	$855,100			NT	B>A
A in MTEP09	West	ITCM	2369	4373	12/31/2010	Walford	Marengo North Tap	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	8.22		Planned	$2,129,980			NT	B>A
A in MTEP09	West	ITCM	2369	4374	12/31/2010	Marengo North Tap	Marengo East	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.57		Planned	$147,700			NT	B>A
A in MTEP09	West	ITCM	2369	4375	12/31/2010	Marengo East	Pioneer Tap	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.3		Planned	$77,735			NT	B>A
A in MTEP09	West	ITCM	2369	4376	12/31/2010	Pioneer Tap	Marengo South	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.25		Planned	$64,780			NT	B>A
A in MTEP09	West	ITCM	2369	4377	12/31/2010	Marengo South	Marengo REC	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	1		Planned	$259,125			NT	B>A
A in MTEP09	West	ITCM	2369	4378	12/31/2010	Marengo REC	Conroy Junction	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	5		Planned	$1,295,608			NT	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	West	ITCM	2369	4379	12/31/2010	Conroy Junction	Williamsburg 115kV	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	2.5		Planned	$647,805			NT	B>A
A in MTEP09	West	ITCM	2370	4380	12/31/2010	Andrew Tap	Andrew dist	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	5.75		Planned	$1,386,865			NT	B>A
A in MTEP09	West	ITCM	2370	4381	12/31/2010	Monmouth Tap	Monmouth dist	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	0.4		Planned	$96,475			NT	B>A
A in MTEP09	West	ITCM	2370	4382	12/31/2010	Monmouth Tap	Monmouth REC	1	34		39/39 MVA	Rebuild the 34kV line to 69kV (operate at 34kV).	IA	1.6		Planned	$385,910			NT	B>A
A in MTEP09	West	ITCM	2371	4383	12/31/2010	Marengo	new switching station	1	69			Construct a new 3-terminal 69kV switching station at the existing Marengo 34kV sub. This work needs to be completed for 69kV operation.	IA			Planned	$1,000,000			NT	B>A
A in MTEP09	West	ITCM	2372	2744	9/15/2009	Franklin	transformer	1	161	115	112/112 MVA	MOVE transformer to new Nuthatch Station	IA			Planned	$0	Y		Y	B>A
A in MTEP09	West	ITCM	2372	4275	9/15/2009	Franklin MEC	Nuthatch	1	161		446 MVA	Rebuild 1.5 miles of the Franklin-Iowa Falls 115kV line to 161kV.	IA	1.5		Planned	$1,000,000	Y		Y	B>A
A in MTEP09	West	ITCM	2372	4276	9/15/2009	Nuthatch	New 161kV Switching Station		161		558 MVA	Construct a new 3-terminal 161kV Nuthatch Switching Station.	IA			Planned	$3,110,113	Y		Y	B>A
A in MTEP09	West	ITCM	2372	4277	9/15/2009	Nuthatch 161/115kV TRF	transformer	1	161	115	112/112 MVA	Temorarily install the Franklin 161/115kV TRF and retire all 115kV equipment at Franklin. Terminate the 161kV into Franklin making that sub a 4-terminal 161kV Breaker Station.	IA			Planned	$250,000	Y		Y	B>A
A in MTEP09	West	ITCM	2450	4345	3/31/2009	Woodburn Junction	new switching station		69			Construct a new 3-terminal 69kV switching station at the existing Woodburn Jct 69/34kV sub.	IA			Planned	$1,000,000			NT	B>A
A in MTEP09	West	ITCM	2786	4896	12/31/2010	Adams	substation upgrades	1	161		558 MVA	Replace 161 kV switches at the Adams sub	MN			Planned	$106,075	Y		Y	B>A
A in MTEP09	West	ITCM	2786	4897	12/31/2010	Lime Creek	substation upgrades	1	161		558 MVA	Add 161 kV line terminal & 161 kV bus tie bkr at the Lime Creek sub	IA			Planned	$485,568	Y		Y	B>A
A in MTEP09	West	ITCM	2786	4898	12/31/2010	Adams	Barton		161		446 MVA	Rebuild 27.2 miles of the Adams-Barton-Lime Creek 161 kV line.	IA	27.2		Planned	$13,911,918	Y		Y	B>A
A in MTEP09	West	ITCM	2786	4899	12/31/2010	Hayward	Worth Co	1	161		446 MVA	Rebuild 21.2 miles of the Harmony-(future Glenworth)-Worth Co. 161 kV line.	IA	21.18		Planned	$11,028,270	Y		Y	B>A
A in MTEP09	West	MDU	1355	2241	11/1/2012	Heskett	Capacitor		115		30 MVAr		ND			Planned	$1,500,000	Y		Y	B>A
A in MTEP09	West	MDU	1355	2242	11/1/2012	Heskett	Additional 230/115 kV Switchyard		230	115	200 MVA	Switchyard in parallel w/ existing Heskett switchyard	ND			Planned	$9,500,000	Y		Y	B>A
A in MTEP09	West	MDU	2471	4443	12/1/2009	Tioga 230	Transformer	1	230	115	125 MVA	upgrade transformer to 125 MVA	ND			Planned	$2,200,000			Y	B>A
A in MTEP09	East	METC	240	4452	8/1/2009	Garfiled			138			Terminal equipment upgrade	MI			Proposed	$60,000			Y	B>A
A in MTEP09	East	METC	646	1329	12/1/2011	Edenville J.	Warren	1	138			Replace poles on half of the Edenville Jct.-Warren 138kV line	MI	7.8		Planned	$6,000,000			Y	B>A
A in MTEP09	East	METC	646	4967	12/1/2012	Edenville J.	Warren	1	138			Replace poles on half of the Edenville Jct.-Warren 138kV line	MI	7		Planned	$6,500,000			Y	B>A
A in MTEP09	East	METC	662	1350	6/1/2013	Weeds Lake 138 kV	BRONCO to 12th ST		138			tapping BRONCO to 12TST circuit into Weeds Lake	MI			Proposed	$732,374	Y		Y	B>A
A in MTEP09	East	METC	662	3592	6/1/2013	Weeds lake 345/138 kV	Transformer		345	138		transformer	MI			Proposed	$20,993,986	Y		Y	B>A
A in MTEP09	East	METC	662	3593	6/1/2013	Weeds Lake	BRONCO		138			line extention on BRONCO 12th ST circuit BRONCO side	MI			Proposed	$4,335,317	Y		Y	B>A
A in MTEP09	East	METC	662	3594	6/1/2013	Weeds Lake	MILHAM		138			line extention on MILHAM to N_AVE circuit MILHAM side	MI			Proposed	$4,335,317	Y		Y	B>A
A in MTEP09	East	METC	662	3595	6/1/2013	Weeds Lake	12th ST		138			line extention on BRONCO to 12th ST circuit 12TST side	MI			Proposed	$4,335,317	Y		Y	B>A
A in MTEP09	East	METC	662	3596	6/1/2013	Weeds Lake	N_AVE		138			line extention on MILHAM to N_AVE circuit N_AVE side	MI			Proposed	$4,335,317	Y		Y	B>A
A in MTEP09	East	METC	662	3597	6/1/2013	Weeds Lake Jct	MILHAM to N_AVE		345			tapping MILHAM to N_AVE circuit into weeds lake	MI			Proposed	$732,374	Y		Y	B>A
A in MTEP09	East	METC	1806	3625	6/1/2011	Canal Jct	Island	1	138			Rebuild 11 miles of 138kV line to 954 ACSR	MI	18.7		Planned	$9,000,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	METC	1810	3634	6/1/2012	East Tawas	Iosco	1	138			Rebuild 12 miles of 138kV to 954 ACSR.	MI	80		Planned	$10,000,000			Y	B>A
A in MTEP09	East	METC	1821	2873	12/31/2009	Breaker Replacement Program 2009	Throughout system						MI			Proposed	$5,650,000			Y	B>A
A in MTEP09	East	METC	1822	2874	12/31/2010	Breaker Replacement Program 2010	Throughout system						MI			Proposed	$5,650,000			Y	B>A
A in MTEP09	East	METC	1823	2875	12/31/2009	Relay Betterment Program 2009	Throughout system						MI			Proposed	$1,200,000			Y	B>A
A in MTEP09	East	METC	1824	2876	12/31/2010	Relay Betterment Program 2010	Throughout system						MI			Proposed	$1,200,000			Y	B>A
A in MTEP09	East	METC	1826	2878	12/31/2009	Sag clearance 2009	Throughout system						MI			Proposed	$3,400,000			Y	B>A
A in MTEP09	East	METC	1827	2879	12/31/2010	Sag clearance 2010	Throughout system						MI			Proposed	$3,400,000			Y	B>A
A in MTEP09	East	METC	1828	3601	6/1/2010	Argenta	Palisades	1	345			Remove sag limits	MI			Planned	$5,200,000	Y	Y	Y	B>A
A in MTEP09	East	METC	1828	3602	6/1/2010	Argenta	Palisades	2	345			Remove sag limits	MI			Planned	$5,200,000	Y	Y	Y	B>A
A in MTEP09	East	METC	1828	4454	6/1/2010	Argenta		1	345			Terminal equipment upgrade	MI			Planned	$240,000	Y	Y	Y	B>A
A in MTEP09	East	METC	1828	4455	6/1/2010	Palisades		1	345			Terminal equipment upgrade	MI			Planned	$240,000	Y	Y	Y	B>A
A in MTEP09	East	METC	1833	2880	12/31/2011	Sag clearance 2011	Throughout system						MI			Proposed	$3,400,000			Y	B>A
A in MTEP09	East	METC	1839	3704	11/15/2009	Acme	Keystone	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned	$230,000			Y	B>A
A in MTEP09	East	METC	1839	3705	11/15/2009	Acme	Plum	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned	$200,000			Y	B>A
A in MTEP09	East	METC	1839	4456	11/15/2009	Plum	Stover	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned	$230,000			Y	B>A
A in MTEP09	East	METC	1839	4457	11/15/2009	Plum	138kV switching station	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned	$3,400,000			Y	B>A
A in MTEP09	East	METC	2473	4458	12/1/2009	Gaines			138			Relay work at Gaines	MI			Planned	$12,000			Y	B>A
A in MTEP09	East	METC	2474	4459	6/1/2009	Harvard Lake	Four Mile	1	138			Havard Lake taps the Four Mile-North Belding 138kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	METC	2474	4460	6/1/2009	Harvard Lake	North Belding	1	138			Havard Lake taps the Four Mile-North Belding 138kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	METC	2475	4461	6/1/2010	Doans	Beals	1	138			New 138kV switching station at Titus Lake junction.	MI			Planned	$2,100,000			Y	B>A
A in MTEP09	East	METC	2475	4462	6/1/2010	Doans	Hazelwood	1	138			New 138kV switching station at Titus Lake junction.	MI			Planned	$2,100,000			Y	B>A
A in MTEP09	East	METC	2476	4463	8/1/2009	Hubbardston Road	Marquette	1	138			Hubbardston Road taps the Marquette-Bingham 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2476	4464	8/1/2009	Hubbardston Road	Bingham	1	138			Hubbardston Road taps the Marquette-Bingham 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2477	4465	10/15/2009	Cochran Junction			138			Install a switch pole and line switch at Cochran towards Island Road.	MI			Planned	$175,000			Y	B>A
A in MTEP09	East	METC	2478	4466	6/1/2010	Capital Ave	Battle Creek	1	138			Capital Ave taps the Battle Creek-Verona 138kV circuit #2.	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2478	4467	6/1/2010	Capital Ave	Battle Creek	1	138			Capital Ave taps the Battle Creek-Verona 138kV circuit #2.	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2479	4468	12/1/2009	Tippy			138			Relay modifications	MI			Planned	$12,000			Y	B>A
A in MTEP09	East	METC	2480	4469	12/1/2009	Argenta			138			Relay modifications	MI			Planned	$12,000			Y	B>A
A in MTEP09	East	METC	2481	4470	6/1/2010	Forest Grove	Campbell	1	138			Forest Grove taps the Campbell-Hudsonville (toward Ransom) 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2481	4471	6/1/2010	Forest Grove	Hudsonville	1	138			Forest Grove taps the Campbell-Hudsonville (toward Ransom) 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2482	4472	6/1/2012	Hawthorne	Four Mile	1	138			Hawthorne taps the Four Mile-Pingree (toward Blendon) 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2482	4473	6/1/2012	Hawthorne	Pingree	1	138			Hawthorne taps the Four Mile-Pingree (toward Blendon) 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2483	4474	6/1/2010	Maines Road	Marshall	1	138			Maines Road taps the Marshall-Blackstone 138kV circuit	MI			Planned	$85,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	METC	2483	4475	6/1/2010	Maines Road	Blackstone	1	138			Maines Road taps the Marshall-Blackstone 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2484	4476	6/1/2010	Scenic Lake	Cornell	1	138			Scenic Lake taps the Cornell-Tihart 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2484	4477	6/1/2010	Scenic Lake	Tihart	1	138			Scenic Lake taps the Cornell-Tihart 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2485	4478	6/1/2011	Ransom	Buck Creek	1	138			Relay modifications	MI			Planned	$12,000			Y	B>A
A in MTEP09	East	METC	2486	4479	1/1/2012	Haakwood	Rondo	1	138			Haakwood taps the Rondo-Vanderbilt section of the Riggsville-Livingston 138kV line.	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2486	4480	1/1/2012	Haakwood	Vanderbilt	1	138			Haakwood taps the Rondo-Vanderbilt section of the Riggsville-Livingston 138kV line.	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2487	4481	6/30/2012	Birchwood	Spaulding	1	138			Birchwood taps the Spaulding-Kraft section of the Spaulding-Plaster Creek 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2487	4482	6/30/2012	Birchwood	Kraft	1	138			Birchwood taps the Spaulding-Kraft section of the Spaulding-Plaster Creek 138kV circuit	MI			Planned	$85,000			Y	B>A
A in MTEP09	East	METC	2488	4483	6/1/2013	Stronach			138			Terminal equipment upgrade	MI			Planned	$190,000			Y	B>A
A in MTEP09	East	METC	2488	4484	6/5/2009	Tippy			138			Terminal equipment upgrade	MI			In Service	$50,000			Y	B>A
A in MTEP09	East	METC	2489	4485	6/1/2011	Tippy	terminal equipment		138			Terminal equipment upgrade	MI			Planned	$60,000			Y	B>A
A in MTEP09	East	METC	2491	4488	7/1/2009	Tallmadge			138			Terminal equipment upgrade	MI			Planned	$0			Y	B>A
A in MTEP09	East	METC	2491	4489	7/1/2009	Wealthy			138			Terminal equipment upgrade	MI			Planned	$60,000			Y	B>A
A in MTEP09	East	METC	2492	4490	6/1/2013	Battle Creek			138			Terminal equipment upgrade	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	METC	2492	4491	6/1/2013	Verona			138			Terminal equipment upgrade	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	METC	2493	4492	6/1/2010	Bullock	Summerton		138			Terminal equipment upgrade at Bullock	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	METC	2494	4493	6/1/2013	Bullock	Dow Corning		138			Terminal equipment upgrade at Bullock	MI			Planned	$400,000			Y	B>A
A in MTEP09	East	METC	2495	4494	6/1/2010	Bullock	Warren		138			Terminal equipment upgrade at Bullock	MI			Planned	$200,000			Y	B>A
A in MTEP09	East	METC	2496	4495	9/1/2009	Bullock	Tittabawassee		138			Terminal equipment upgrade at Bullock	MI			Planned	$60,000			Y	B>A
A in MTEP09	East	METC	2496	4496	6/1/2010	Tittabawassee			138			Terminal equipment upgrade	MI			Planned	$140,000			Y	B>A
A in MTEP09	East	METC	2496	4943	6/1/2010	Bullock	Tittabawassee		138			Terminal equipment upgrade at Bullock	MI			Planned	$220,000			Y	B>A
A in MTEP09	East	METC	2498	4800	12/31/2011	Breaker replacement program	2011						MI			Proposed	$5,650,000			Y	B>A
A in MTEP09	East	METC	2499	4827	12/31/2011	Relay Betterment Program 2011	Throughout system						MI			Proposed	$1,200,000			Y	B>A
A in MTEP09	East	METC	2500	4498	6/1/2011	Murphy	Transformer	2	345	138		Install 2nd transformer	MI			Planned	$8,308,980			Y	B>A
A in MTEP09	East	METC	2500	4960	6/1/2011	Murphy	Thetford-Tittabawassee		345			345 kV substation work	MI			Planned	$10,137,020			Y	B>A
A in MTEP09	East	METC	2501	4499	4/1/2011	New site (Wexford prime)						Install 25.2 MVAR capacitor	MI			Planned	$1,524,194			Y	B>A
A in MTEP09	East	METC	2501	4500	4/1/2011	Keystone						Install 50.4 MVAR capacitor	MI			Planned	$740,323			Y	B>A
A in MTEP09	East	METC	2501	4501	4/1/2011	Plum						Install 25.2 MVAR capacitor	MI			Planned	$435,484			Y	B>A
A in MTEP09	East	METC	2503	4503	12/31/2010	Battery Replacement 2010	Throughout system		345	138		Replace battery chargers	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	METC	2504	4504	12/31/2010	Potential Device Replacement 2010	Throughout system		345	138		Replace aging potential devices	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	METC	2506	4506	12/31/2010	Transformer Monitoring 2010			345	138		Install tempurature and bushing monitors on EHV transformers	MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	METC	2507	4510	6/1/2013	Alcona	Mio	1	138			Rebuild the Twining-Mio 138kV line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI	20		Planned	$24,500,000			Y	B>A
A in MTEP09	East	METC	2508	4511	12/31/2009	Wood Pole Replacement 2009	Throughout system		138			Replace deteriorating wood pole	MI			Planned	$4,500,000			Y	B>A
A in MTEP09	East	METC	2509	4512	12/31/2010	Wood Pole Replacement 2010	Throughout system		138			Replace deteriorating wood pole	MI			Planned	$3,400,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	METC	2510	4513	12/31/2011	Wood Pole Replacement 2011	Throughout system		138			Replace deteriorating wood pole	MI			Planned	$3,400,000			Y	B>A
A in MTEP09	East	METC	2512	4515	12/31/2009	Battery Replacement 2009	Throughout system		345	138		Replace battery chargers	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	METC	2513	4516	12/31/2009	Potential Device Replacement 2009	Throughout system		345	138		Replace aging potential devices	MI			Planned	$300,000			Y	B>A
A in MTEP09	East	METC	2514	4517	12/31/2009	Transformer Monitoring 2009	Throughout system		345	138		Install tempurature and bushing monitors on EHV transformers	MI			Planned	$1,200,000			Y	B>A
A in MTEP09	East	METC	2515	4518	6/1/2011	Oakland	Dean	1	138			Replace wood structures	MI			Planned	$4,700,000			Y	B>A
A in MTEP09	East	METC	2515	4520	6/1/2011	Dean	Latson	1	138			Replace wood structures	MI			Planned	$2,700,000			Y	B>A
A in MTEP09	East	METC	2515	4521	6/1/2011	Latson	Tihart	1	138			Replace wood structures	MI			Planned	$14,700,000			Y	B>A
A in MTEP09	East	METC	2515	4522	6/1/2011	Genoa	Latson (METC side)	1	138			Replace wood structures	MI			Planned	$1,400,000			Y	B>A
A in MTEP09	East	METC	2516	4523	12/31/2010	NERC Relay Loadability Compliance 2010	Throughout system		138			Upgrade relay throught system	MI			Planned	$2,250,000			Y	B>A
A in MTEP09	East	METC	2517	4524	12/31/2011	NERC Relay Loadability Compliance 2011	Throughout system		138			Upgrade relay throught system	MI			Planned	$2,250,000			Y	B>A
A in MTEP09	West	MP	2552	4554	12/30/2010	Skibo	Hoyt Lakes	1	138		202	new line	MN		3	Proposed	$2,540,000			Y	B>A
A in MTEP09	West	MP	2756	4785	6/30/2010	Boswell	Essar site 1	1	115		144	Essar Line reroute	MN		0.25	Planned	$2,900,000			Y	B>A
A in MTEP09	West	MP	2756	4786	6/30/2010	Essar Site 1	Essar site 2	1	115		144	Essar Line reroute	MN		2.5	Planned				Y	B>A
A in MTEP09	West	MP	2756	4787	6/30/2010	Essar Site 2	Nashwaulk	1	115		144	Essar Line Reroute	MN		2	Planned				Y	B>A
A in MTEP09	West	MP	2756	4788	6/30/2010	Essar Site 1	Substation Equipment		115	14	166	Essar Substation Equipment & 2 Transformers	MN			Planned				Y	B>A
A in MTEP09	West	MP	2756	4789	6/30/2010	Blackberry	Substation Terminal Equipment		115		182	Essar Upgrade MP Line #20 Terminal Equipment	MN			Planned				Y	B>A
A in MTEP09	West	MP	2756	4790	6/30/2010	Essar Site 2	Substation Equipment		115	14	83	Essar Substation Equipment & Transformers	MN			Planned				Y	B>A
A in MTEP09	West	MP	2757	4781	12/1/2009	Lind Greenway	Substation Equipment		115	23	39	Substation Equipment & Transformer	MN			Planned	$2,741,100			Y	B>A
A in MTEP09	West	MP	2758	4784	10/1/2009	Bergen Lake	Substation Equipment		115	34	39	Substation Equipment & Transformer	MN			Planned	$992,500			Y	B>A
A in MTEP09	West	MP	2759	4782	6/1/2011	Laskin	Substation Equipment		115	46	28	Substation Transformer	MN			Planned	$500,000			Y	B>A
A in MTEP09	West	MP	2760	4783	12/1/2009	Virginia	Substation Equipment		115	46	39	Substation Transformer	MN			Planned	$1,284,100			Y	B>A
A in MTEP09	West	MP	2763	4779	9/1/2009	LSPI	Substation Equipment		115	34.5	30	Substation Equipment & Transformer	MN			Planned	$500,000			Y	B>A
A in MTEP09	East	NIPS	2310	4237	12/1/2009	Praxair	Substation		138	69		Customer Expansion	IN			Proposed	$2,780,453			Y	B>A
A in MTEP09	East	NIPS	2313	4240	6/1/2009	Aetna	Breaker		138			Aetna Sub - Replace Circuit 138-102S Breaker	IN			Proposed	$108,491			Y	B>A
A in MTEP09	East	NIPS	2314	4241	6/1/2009	RMSGS	Breaker		345			RMSGS - Add 345 kV N. Bus Tie Breaker	IN			Proposed	$720,814			Y	B>A
A in MTEP09	East	NIPS	2316	4243	12/1/2009	Highland	Capacitor		69			Replace Existing capacitors with 2-9.6 MVAR steps. Upgrade Controllers. Work in 2007 for engineering only.	IN			Proposed	$729,007			Y	B>A
A in MTEP09	East	NIPS	2317	4254	12/1/2009	Munster	Hartsdale	1	138			Circuit 13823 - Hartsdale to Munster - Raise Poles at 2 locations to allow for Operating line at higher Temperatures	IN			Planned	$90,000			Y	B>A
A in MTEP09	East	NIPS	2325	4253	12/1/2009	Liberty Park	Bus		138			Replace 500KCM Copper and 397.5 KCM acsr with 1272 KCM Al.	IN			Planned	$234,000			Y	B>A
A in MTEP09	East	NIPS	2326	4255	12/1/2008	Gary Avenue 345/138 kV			345	138		Gary Ave. - New 345-138 Substation, move 1-336 MVA transformer and (2) 345kV lines from Chicago Ave.	IN			In Service	$4,500,000			Y	B>A
A in MTEP09	East	NIPS	2326	4256	12/1/2008	Gary Avenue	Chicago Avenue	1	138		305	Circuit 138-104 - New 138kV circuit from Gary Ave to Chicago Ave.	IN		0.5	In Service	$5,500,000			Y	B>A
A in MTEP09	East	NIPS	2326	4257	12/1/2008	Roxana	Mitchell	1	138		243	Circuit 13825 - Rebuild section underground	IN			In Service	$5,000,000			Y	B>A
A in MTEP09	East	NIPS	2775	4878	12/1/2009	Hartsdale	Capacitor		69			Add three(3) steps of 10.8 MVAR capacitors on Hartsdale 69kV bus	IN			Planned	$950,000			Y	B>A
A in MTEP09	East	NIPS	2797	4922	10/1/2009	Michigan City	Breaker		138			Replace a circuit breaker at Michigan City and upgrade the CT's to 1000/5 amps to increase the SE rating up to the conductor capacity limit which is 222 MVA	IN			Proposed	$345,000			Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	East	NIPS	2798	4923	4/1/2010	State Line	Sheffield		138			Replace existing bundled '300 kcm CU-397.5 kcm ACSR' with bundled (2) 336.4 kcm ACSS (1089 A @ 200 C each side) and the 900 kcm ACSR with 954 kcm ACSS (2131 A @ 200 C). State Line - Wolf Lake 1.2 miles and Wolf Lake - Sheffield 3 miles	IN			Proposed	$2,700,000			Y	B>A
A in MTEP09	West	OTP	2749	4772	6/1/2010	Fertile 41.6 kV	Fertile Jct. 41.6 kV		41.6		30 MVA	Build New 1.5 Mile 41.6 kV Line to Eliminate Critical Contingency	MN			Planned	$165,000			NT	B>A
A in MTEP09	West	OTP	2750	4773	7/1/2009	Spiritwood 115 kV	ring bus		115		30 MVA	Build New 115 kV ring bus	ND			Planned	$1,400,000	Y		Y	B>A
A in MTEP09	West	OTP	2751	4774	12/31/2012	New Perham	distribution sub		115	12.5	14 MVA	Build New 115/12.5 kV Substation at Perham to Serve as a Back-up Source for Outage of Primary Source	MN			Proposed	$400,000			Y	B>A
A in MTEP09	West	OTP/GRE/MPC	2738	4761	11/1/2010	Ramsey 230 kV	Ramsey 115 kV	1	230	115	To Be Determi	Increase Transformer Capacity & Improve Category C Contingency Performance to Devils Lake Area	ND			Planned	$5,000,000			Y	B>A
A in MTEP09	West	SMP	2178	4970	6/1/2012	Byron	line termination		161			Byron - Pleasant Valley161 kV Line Terminal Improvements	MN			Planned	$715,181	Y		Y	B>A
A in MTEP09	Central	Vectren	2461	4425	6/1/2010	Dubois Sub Z84 terminals		84	138			Add 1 new 138kV terminal to existing sub to avoid 3 term line	IN			Planned	$1,000,000			Y	B>A
A in MTEP09	Central	Vectren	2465	4429	6/1/2011	Leibert Rd 138/12kV Substation		1	138	12.5	16/20	New 138/12kV Substation for load growth	IN			Planned	$3,000,000			NT	B>A
A in MTEP09	Central	Vectren	2466	4430	6/1/2013	Roesner Rd 138/12kV Substation		1	138	12.5	16/20	New 138/12kV Substation for load growth	IN			Planned	$3,000,000			NT	B>A
A in MTEP09	East	WPSC	2735	4756	12/31/2013	Alba	Mancelona	1	69		143.4MVA	Rebuild Overloaded Line	MI	4.51		Proposed	$2,255,000			Y	B>A
A in MTEP09	East	WPSC	2735	4757	12/31/2013	Mancelona	Westwood	1	69		143.4MVA	Rebuild Overloaded Line	MI	6.7		Proposed	$3,350,000			Y	B>A
A in MTEP09	East	WPSC	2736	4758	12/31/2013	East Bay	South Boardman Distribution	1	69		143.4MVA	Rebuild Overloaded Line	MI	15.93		Proposed	$7,965,000			Y	B>A
A in MTEP09	East	WPSC	2736	4759	12/31/2013	South Boardman Distribution	South Boardman	1	69		143.4MVA	Rebuild Overloaded Line	MI	0		Proposed	$50,000			Y	B>A
A in MTEP09	East	WPSC	2737	4760	12/31/2013	South Boadman	Kalkaska Generation	1	69		143.4MVA	Rebuild Overloaded Line	MI	3.42		Proposed	$1,710,000			Y	B>A
A in MTEP09	East	WPSC	2770	4832	6/1/2010	Hersey	Gilmore	1	69			Gilmore Taps the Hersey to Vestaburg 69kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	WPSC	2770	4833	6/1/2010	Gilmore	Vestaburg	1	69			Gilmore Taps the Hersey to Vestaburg 69kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	WPSC	2771	4834	7/1/2010	Burnips	Monterey	1	69			Monterey Taps the Hersey to Vestaburg 69kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	East	WPSC	2771	4835	7/2/2010	Monterey	Wayland	1	69			Monterey Taps the Hersey to Vestaburg 69kV circuit	MI			Planned	$100,000			Y	B>A
A in MTEP09	West	XEL	1952	3833	12/1/2011	Plato Cap Bank	Cap Bank		69		10 MVAR	New 10 MVAR cap bank at Lester Prairie	MN			Planned	$700,000			NT	B>A
A in MTEP09	West	XEL	2157	2966	6/1/2011	Douglas Co	Transformer	2	115	69	70	2nd 115/69 kV transformer at	MN			Planned	$4,435,000			NT	B>A
A in MTEP09	West	XEL	2158	2967	6/1/2011	Sauk Center	West Union	1	69		84	upgrade using lower impedance line	MN		9	Planned	$2,774,000			NT	B>A
A in MTEP09	West	XEL	2158	2968	6/1/2011	West Union	Osakis	1	69		84	upgrade using lower impedance line	MN		5.8	Planned	$1,740,000			NT	B>A
A in MTEP09	West	XEL	2159	2969	6/1/2010	Nelson	capacitor bank		69		18MVAR	New 18 MVAR cap at Nelson	WI			Planned	$721,000			NT	B>A
A in MTEP09	West	XEL	2160	2970	6/1/2012	Park Falls	Transformer	1	115	34.5	47	Upgrade the transformer to higher rating	WI			Planned	$1,677,900			NT	B>A
A in MTEP09	West	XEL	2160	2971	6/1/2012	Park Falls	Transformer	2	115	34.5	47	Upgrade the transformer to higher rating	WI			Planned	$1,677,900			NT	B>A
A in MTEP09	West	XEL	2176	4012	6/1/2012	Colville substation	Transfromer	1	115	69	112 MVA	New 115/69 kV transfromer at Colville	MN			Proposed	$4,645,000			Y	B>A
A in MTEP09	West	XEL	2176	4013	6/1/2012	Colville substation	Byllesby	1	69		84 MVA	2 mile 69 kV line	MN			Proposed	$440,000			NT	B>A
A in MTEP09	West	XEL	2176	4014	6/1/2012	Colville substation	Breaker reconfiguration		115			Reconfigure the 115 kV breakers at Colville substation (could be replaced with breaker failure auto sectionalization).	MN			Proposed	$1,150,000			Y	B>A
A in MTEP09	West	XEL	2178	4021	6/1/2012	Pleasant Valley	Byron	1	161		447 MVA	new 161 kV line from PV to Byron	MN		25	Planned	$9,292,000	Y		Y	B>A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP09	West	XEL	2307	4225	6/1/2012	Benton Co	Mayhew Lake	1	115		361 MVA	Convert double circuit 115 kV line from Benton Co to St. Cloud tap to bifurcated single circuit, build additional 4 miles of 115 kV line from St. Cloud tap to Mayhew Lake substation.	MN		4	Proposed	$3,000,000	Y		Y	B>A
A in MTEP09	West	XEL	2307	4226	6/1/2012	St. Cloud	Granite City	1	115		194 MVA	Convert 1 mile of double circuit from St. Cloud tap to Granite City to bifurcated single circuit.	MN			Proposed	$100,000	Y		Y	B>A
A in MTEP09	West	XEL	2307	4227	6/1/2012	Sauk River	W St. Cloud	1	115		361 MVA	Upgrade line to 361 MVA	MN	1.4		Proposed	$1,000,000	Y		Y	B>A
A in MTEP09	West	XEL	2307	4228	6/1/2012	Mayhew Lake substation	Breakers		115			Upgrade to 115 kV ring bus	MN			Proposed	$2,000,000	Y		Y	B>A
A in MTEP09	West	XEL	2308	4233	6/1/2011	Grove Lake	Sedan	1	69		100 MVA	Upgrade to 477 ACSR	MN	5.3		Proposed	$2,260,284			NT	B>A
A in MTEP09	West	XEL	2308	4234	6/1/2011	Sedan	Glenwood (GRE)	1	69		100 MVA	Upgrade to 477 ACSR	MN	5		Proposed	$2,132,344			NT	B>A
A in MTEP09	West	XEL	2308	4235	6/1/2011	Glenwood (GRE)	Lowry tap	1	69		100 MVA	Upgrade to 477 ACSR	MN	2.8		Proposed	$11,941,126			NT	B>A
A in MTEP09	West	XEL	2308	4236	6/1/2011	Lowry tap	Glenwood (XCEL)	1	69		100 MVA	Upgrade to 477 ACSR	MN	0.04		Proposed	$17,058			NT	B>A
A in MTEP09	West	XEL	2309	4229	6/1/2012	Maple Lake	Annandale	1	69		100 MVA	Upgrade to 477 ACSR	MN	6		Proposed	$2,487,000			NT	B>A
A in MTEP09	West	XEL	2765	4792	12/1/2008	Chanarambie	Uilk wind farm		34.5			New 4.5 MW wind interconnection	MN			Planned	$118,100			Y	B>A
A in MTEP09	West	XEL	2772	4836	10/1/2010	Hiawatha	Distribution Substation		115	13.8		New distribution substation Between Elliot Park and Southtown	MN			Planned	$14,270,000			Y	B>A
A in MTEP09	West	XEL	2772	4837	10/1/2010	Hiawatha	Midtown	1	115		~360	Double Circuit 1.25 Mile line	MN		1.25	Proposed	$1,500,000			Y	B>A
A in MTEP09	West	XEL	2772	4838	10/1/2010	Midtown	Sidtribution Substation		115	13.8		New distribution substation	MN			Proposed	$11,120,000			Y	B>A
A in MTEP09	West	XEL	2772	4839	10/1/2008	Hiawatha	Midtown	2	115		~360	Double Circuit 1.25 Mile lin	MN		1.25	Proposed	$1,500,000			Y	B>A
A in MTEP09	West	XEL/GRE	2156	2962	6/1/2011	Helena	Transformer	1	345	115	448	New 345/115 kV transformer at Helena substation	MN			Planned	$7,250,000			Y	B>A
A in MTEP09	West	XEL/GRE	2156	2963	6/1/2011	Helena	St. Thomas	1	115	115	318	New 6 mile 115 kV line	MN		6	Planned	$2,750,000			Y	B>A
A in MTEP09	West	XEL/GRE	2156	2964	6/1/2011	St. Thomas	substation	1	115	69	112	New 115/69 kV substation	MN			Planned	$5,000,000			NT	B>A
A in MTEP09	West	XEL/GRE	2156	2965	6/1/2011	Lesueur Tap	substation		69			69 kV switching station at LeSueur	MN			Planned	$2,450,000			NT	B>A
A in MTEP08	Central	Ameren	1235	1934	6/1/2012	Fredericktown	AECI Fredericktown Tap	1	161		250	Increase ground clearance	MO	12		Proposed	$970,500			Y	A
A in MTEP08	Central	Ameren	1238	1937	6/1/2011	GM-Point Prairie 161 kV Line	AECI Enon Substation	1	161		280	Extend 1 mile of line to AECI Enon Substation	MO		1	Planned	$1,279,700			Y	A
A in MTEP07	Central	Ameren	152	399	12/1/2010	Big River	Rockwood	1	138		339	new line	MO		10	Planned	$13,381,100	Y		Y	A
A in MTEP08	Central	AmerenIL	2058	3955	9/30/2009	Roxford	BOC Tap	1	138		382	Reconductor one span of Roxford - BOC 138 kV line	IL	0.1		Planned	$13,000,000			Y	A
A in MTEP08	Central	AmerenIL	2058	3956	9/30/2009	BOC Tap	Conoco Substation	1	138		382	Build new 138 kV line from BOC Tap to Conoco Substation	IL	2		Planned				Y	A
A in MTEP08	Central	AmerenIL	2058	3957	9/30/2009	1502 Tap	Conoco Substation	1	138		339	Build new 138 kV line from 1502 Tap to Conoco Substation	IL	2		Planned				Y	A
A in MTEP08	Central	AmerenIL	2060	3958	6/1/2010	East Peoria	Flint	1	138		159	Increase Clearances to ground for 120 degrees C operation of 477 ACSR	IL	4.54		Planned	$2,113,000			Y	A
A in MTEP08	Central	AmerenIL	2068	3964	6/1/2012	Latham	Oreana	1	345		1195	Build 8.5 miles of 345 kV line and remove the Latham - Maroa W connection	IL	8.5		Planned	$15,039,400	Y	Y	Y	A
A in MTEP08	Central	AmerenIL	2069	3962	12/1/2012	Brokaw	South Bloomington	1	345		1793	Build approximately 5 miles of 345 kV line from Brokaw - South Bloomington substation	IL	5		Planned	$11,000,000	Y	Y	Y	A
A in MTEP08	Central	AmerenIL	2069	3963	12/1/2012	South Bloomington	South Bloomington XFMR	1	345	138	560	Install 560 MVA 345/138 kV transformer at South Bloomington substation	IL			Planned	$6,600,000	Y		Y	A
A in MTEP08	Central	AmerenIL	2071	3971	11/1/2009	East Springfied	Interstate	1	138		255	Cut East Springfield - Holland 138 kV line and make in - and - out connections	IL			Planned	$553,000			Y	A
A in MTEP08	Central	AmerenIL	2071	3972	11/1/2009	Interstate	Holland	1	138		269	Cut East Springfield - Holland 138 kV line and make in - and - out connections	IL			Planned				Y	A
A in MTEP06	Central	AmerenIL	1241	1942	12/1/2009	Mattoon, West	Install 138 kV Breaker at Mattoon, West	1	138			Install 138 kV Breaker to connect Wind Farm	IL			Planned	$1,010,000			Y	A
A in MTEP08	Central	AmerenIP	1529	2605	6/1/2010	Brokaw	State Farm Line 1596	1	138		337	Reconductor to 2000 A Summer Emergency	IL	3.2		Planned	$2,566,900			Y	A
A in MTEP08	Central	AmerenIP	1532	2609	6/1/2011	Stallings	E. Collinsville	1	138		280	Replace terminal equipment at Stallings, increase ground clearance	IL	4.9		Planned	$744,800			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	Central	AmerenIP	2116	2842	12/1/2009	Project IP04 Substation	substation	1	138			New 138 kV Straight Bus Interconnection Substation, located south of the tap point to the Transmission Owner's El Paso substation and north of the tap point to the Transmission Owner's Raab Road substation on line #1382.	IL			Planned	$1,642,627	Y		Y	A
A in MTEP08	Central	AmerenIP	2116	2843	12/1/2009	El Paso	Raab Road	1	138			Tapping structures installed inline with line #1382: 138 XX Line Extension 556.5 MCM 26/7 ACSS conductor and 7#8 Alumoweld shield wire, 138 YYLine Extension 556.5 MCM 26/7 ACSS conductor and 7#8 Alumoweld shield wire	IL			Planned	$230,000	Y		Y	A
A in MTEP08	Central	AmerenIP	2116	2844	12/1/2009	South Bloomington Substation	substation upgrades	1	138			Replace 138 kV breaker at the South Bloomington Substation. Not necessary if ZVRT package is installed by Interconnection Customer	IL			Planned	$155,330	Y		Y	A
A in MTEP06	Central	AmerenIP	739	1432	11/1/2012	Line 4561 Tap	Franklin County Power Plant	1	345			345 kV connection (new ring bus) to new generation	IL			Proposed	$6,410,900			Y	A
A in MTEP05	Central	AmerenIP	150	1422	6/1/2010	Baldwin	Rush Island	1	345		1793	26 miles of new 345 kV line	IL		26	Planned	$46,149,200			Y	A
A in MTEP05	Central	AmerenIP	150	1423	6/1/2010	Line 4531 tap	Prairie State Power Plant	2	345		1297	345 kV connection to new generation	IL		7.5	Planned	$12,178,600			Y	A
A in MTEP05	Central	AmerenIP	150	1424	6/1/2010	Line 4541 tap	Prairie State Power Plant	2	345		1297	345 kV connection to new generation	IL		1.5	Planned	$2,172,100			Y	A
A in MTEP05	Central	AmerenIP	150	1667	6/1/2010	Prairie State	substation	1	345		1793	new switchyard (6 position, 4 lines, 2 units)	IL			Planned	$15,872,700			Y	A
A in MTEP05	Central	AmerenIP	725	1418	3/12/2012	N. LaSalle	Wedron Fox River	1	138		266	2 CB at N LaSalle, 1 CB at Wedron Fox River Substation	IL		25	Planned	$21,357,530			Y	A
A in MTEP05	Central	AmerenIP	726	1419	3/12/2012	Ottawa	Wedron Fox River	1	138		266	1 CB at Ottawa, new 138 kV line to Wedron Fox River Substation	IL		8	Planned	$8,962,967			Y	A
A in MTEP08	Central	AmerenMO	717	1408	6/1/2010	Conway	Orchard Gardens	1	138		240	increase ground clearance	MO			Proposed	$125,350			Y	A
A in MTEP08	Central	AmerenMO	718	1409	6/1/2010	Conway	Orchard Gardens	2	138		240	increase ground clearance	MO			Proposed	$125,350			Y	A
A in MTEP08	Central	AmerenMO	2061	3968	12/1/2010	Gray Summit	Gray Summit Xfmr	1	345	138	560	Install second Gray Summit 560 MVA transformer	MO			Planned	$19,000,000	Y		Y	A
A in MTEP08	Central	AmerenMO	2061	3969	12/1/2010	Gray Summit	Tyson	1	345		1200	Replace Terminal Equipment at Tyson	MO			Planned	$0	Y		Y	A
A in MTEP08	Central	AmerenMO	2061	3970	12/1/2010	Gray Summit	Tyson	2	345		1200	Replace Terminal Equipment at Tyson	MO			Planned	$0	Y		Y	A
A in MTEP05	Central	AmerenMO	150	398	6/1/2010	Rush Island	Baldwin	1	345		1793	terminal at Rush Island & river crossing only	IL		2	Planned	$1,615,100			Y	A
A in MTEP05	Central	AmerenMO	719	1410	11/8/2010	Labadie Plant	Replace 4-345 kV Breakers		345			replace existing 345 kV breakers	MO			Under Construction	$2,511,700			Y	A
A in MTEP08	Central	AMRN	2113	2836	7/2/2009	G515 Substation	substation	1	138			New (G515) 138 kV Straight Bus Interconnection Substation, tap existing line #1384 Tazewell to East Springfield to Kickapoo. Upgrade 138 kV relaying at East Springfield, Tazewell and Kickpoo Substations				Under Construction	$2,628,000	Y		Y	A
A in MTEP08	Central	AMRN	2113	2837	7/2/2009	Tazewell	East Springfield	1	138			Tapping structures installed inline with line #1384: 138 XX Line Extension 556.5 MCM 26/7 ACSS, 138 YY Line Extension 556.5 MCM 26/7 ACSS	IL			Under Construction	$779,000	Y		Y	A
A in MTEP08	West	ATC LLC	356	486	6/1/2013	Cardinal (formerly West Middleton)	Rockdale/Albion	1	345		1195 MVA SE		WI		35	Planned	$174,094,863	Y	Y	Y	A
A in MTEP08	West	ATC LLC	356	488	6/1/2013	Cardinal (formerly West Middleton) 345/138	transformer	1	345	138	625 MVA SE		WI			Planned	$4,986,995	Y		Y	A
A in MTEP08	West	ATC LLC	356	897	6/1/2013	Rockdale/Albion	345 kV bus modification at Rockdale/new 345 kV switching station at Albion		345			345 kV bus modification at Rockdale/new 345 kV switching station at Albion	WI			Planned	$15,020,590	Y	Y	Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	ATC LLC	356	3383	6/1/2013	Cardinal (formerly West Middleton) 345/138	transformer, backup	2	345	138	625 MVA SE		WI			Planned	$4,986,995	Y		Y	A
A in MTEP08	West	ATC LLC	356	3384	6/1/2013	Cardinal (formerly West Middleton)	substation		345			new 345 substation	WI			Planned	$30,966,868	Y	Y	Y	A
A in MTEP08	West	ATC LLC	574	858	6/1/2013	Council Creek	Petenwell	1	138		293 MVA SE	uprate	WI	32		Proposed	$200,000			Y	A
A in MTEP08	West	ATC LLC	574	1269	6/1/2013	Monroe County (XEL)	Council Creek (ATC)	1	161		577 MVA SE		WI	20		Proposed	$19,200,000			Y	A
A in MTEP08	West	ATC LLC	574	1370	6/1/2013	Council Creek 161-138 kV	transformer	1	161	138	280 MVA SE		WI			Proposed	$2,500,000			Y	A
A in MTEP08	West	ATC LLC	1268	1987	1/15/2010	Kilbourn	Capacitor bank				49	install 2x 24.5 Mvar capacitor banks	WI			Planned	$630,000			Y	A
A in MTEP08	West	ATC LLC	1279	2105	9/15/2009	North Beaver Dam 138			138		49		WI			Under Construction	$2,500,000			Y	A
A in MTEP08	West	ATC LLC	1553	3101	12/1/2009	Hiawatha	Capacitor bank		138		8.1		MI			Planned	$615,283			Y	A
A in MTEP08	West	ATC LLC	1555	3103	10/31/2009	Perkins	Capacitor banks		138		2x16.33 MVAR		MI			Under Construction	$1,395,185			Y	A
A in MTEP08	West	ATC LLC	1667	3438	11/14/2009	Pine River 69 kV ring bus			69			Construct 69 kV ring bus at Pine River	MI			Under Construction	$10,500,000			Y	A
A in MTEP08	West	ATC LLC	1667	3439	11/14/2009	Pine River	Capacitor Bank		69		2x4.08 MVAR	Increase bank size from 5.4 to 8.16 MVAR	MI			Planned				Y	A
A in MTEP08	West	ATC LLC	1676	3448	4/1/2010	L'Anse			69		4.08	Install one 4.08 MVAR 69 kV capacitor bank at L'Anse substation	MI			Planned	$600,000			Y	A
A in MTEP08	West	ATC LLC	1679	3452	6/30/2009	Brewer			12.4		1x7.8 MVAR	Install one 7.8 MVAR capacitor bank at Brewer substation	WI			Under Construction				Y	A
A in MTEP08	West	ATC LLC	1680	3453	3/17/2010	Walworth	North Lake Geneva	1	69		69	Uprate Walworth-North Lake Geneva 69 kV line to 69 MVA	WI	2.25		Planned	$370,000			Y	A
A in MTEP08	West	ATC LLC	1683	3458	6/1/2011	Sunset Point	Pearl Ave	1	69			Rebuild 2.37 miles of 69 kV from Sunset Point-Pearl Ave with 477 ACSR	WI	2.37		Planned	$1,759,714			Y	A
A in MTEP08	West	ATC LLC	1684	3460	12/1/2010	Pleasant Valley			138			Construct a 138 kV bus at Pleasant Valley substation to permit second distribution transformer interconnection	WI			Proposed	$2,160,000			Y	A
A in MTEP08	West	ATC LLC	1945	3824	4/12/2010	Sheepskin	Capacitor Bank		69		+5.4 Mvar	Upgrade Sheekskin Capacitor 69-kV Bank from 10.8 Mvar to 16.2 Mvar	WI			Planned	$272,268			Y	A
A in MTEP08	West	ATC LLC	2057	3944	3/31/2010	Warrens (formerly Mill Creek)			69		56	Construct a new Mill Ck distribution substation	WI			Planned	$3,185,000			Y	A
A in MTEP08	West	ATC LLC	2057	3945	3/31/2010	Warrens (formerly Mill Creek)	Warrens Tap (formerly Mill Creek Tap)	1	69		56	Construct a 5 mi 69 kV line to a new Mill Ck substation from a tap of the Ocean Spray Tap-Tunnel City line	WI		5	Planned				Y	A
A in MTEP07	West	ATC LLC	1256	1964	4/1/2010	Paddock	Rockdale	2	345		1430	add a second circuit (new line) between the existing 345 kV substations Paddock and Rockdale.	WI	22.7	7.6	Planned	$112,800,000			Y	A
A in MTEP07	West	ATC LLC	1256	2461	4/1/2010	Rockdale			345			convert to a modifed breaker and a half configuration, replace 5 overdutied 138 kV breakers and replace existing transformer with 500MVA	WI			Planned	$12,300,000			Y	A
A in MTEP07	West	ATC LLC	1256	2462	4/1/2010	Christiana			138			replace five overdutied 138 kV breakers	WI			Planned	$1,100,000			Y	A
A in MTEP07	West	ATC LLC	1256	2463	4/1/2010	Paddock			345			upgrade protection system	WI			Planned	$300,000			Y	A
A in MTEP07	West	ATC LLC	1267	1984	2/19/2010	Verona 138/69	transformer	1	138	69	100		WI			Planned	$1,700,000			Y	A
A in MTEP07	West	ATC LLC	1267	1985	2/19/2010	Verona	Oak Ridge	1	138			line to new T-D substation	WI			Planned	$17,900,000			Y	A
A in MTEP07	West	ATC LLC	1267	3234	2/19/2010	Verona			138	69		Expand from existing 69 kV sub; cost estimate exclude the transformer cost	WI			Planned	$1,200,000			Y	A
A in MTEP06	West	ATC LLC	345	480	10/30/2009	Morgan	Werner West		345		1882 MVA SE	new line	WI		47	Under Construction	$128,132,800	Y	Y	Y	A
A in MTEP06	West	ATC LLC	352	2460	10/1/2009	Iron Grove	Aspen	1	138		400 MVA SE		MI/WI			Under Construction	$5,850,000	Y		Y	A
A in MTEP06	West	ATC LLC	352	3465	10/1/2009	Aspen		1	138	69	60	Install 60 MVA 138/69 kV transformer at Aspen substation	WI			Under Construction				Y	A
A in MTEP06	West	ATC LLC	877	482	9/1/2009	Oak Creek 345/138 #2	transformer	2	345	138	500		WI			Under Construction	$6,600,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP06	West	ATC LLC	877	870	6/1/2010	Oak Creek	Expand 345 kV switchyard to interconnect second new generator		345			expand switchyard to interconnect second new generator	WI			Under Construction	$10,600,000			Y	A
A in MTEP06	West	ATC LLC	877	872	6/1/2010	Oak Creek	Root River		138		293	uprate	WI			Planned	$136,007			Y	A
A in MTEP06	West	ATC LLC	877	873	6/1/2010	Oak Creek	Nicholson		138		332	uprate	WI	6.8		Planned	$136,007			Y	A
A in MTEP06	West	ATC LLC	877	3459	6/12/2009	Racine			345			Replace CT's at Racine 345 kV substation	WI			Under Construction				Y	A
A in MTEP06	West	ATC LLC	1461	2509	9/1/2010	Green Lake Sub			138	34.5		a collection bus at a voltage level of 34.5kV, 34.5kV facilities, 138/34.5 kV transformer and 138 kV circuit breaker.	WI			Planned	$170,146			Y	A
A in MTEP06	West	ATC LLC	1461	2511	9/1/2010	Green Lake Sub	transformer		138	34.5	178	new two-breaker, 138 kV substation in a configuration allowing future expansion to a six position ring bus. Two line positions will allow for looping line X-4 into the substation. The location of these facilities is	WI			Planned	$2,049,696			Y	A
A in MTEP06	West	ATC LLC	1461	2512	9/1/2010	Green Lake Sub			138			a loop into New Substation, including two (2) steel pole dead-ends to facilitate entry of Line X-4 into the substation. Transmission Owner will perform 138kV Line X-4 relay settings updates at the Green Lake, North Fo	WI			Planned	$94,856			Y	A
A in MTEP06	West	ATC LLC	1470	2479	12/1/2010	Generating Facility Sub			69			New two-breaker 69 kV substation in a configuration allowing future expansion to a six-position ring bus	WI			Planned	$1,765,957	Y		Y	A
A in MTEP06	West	ATC LLC	1470	2480	12/1/2010	Y-33 line			69		63	existing line Y-33 will be re-built completely to increase the line capacity to a minimum of 63 MVA. The new line will have T2-4/0 ACSR conductors and OPGW for fiber communication	WI			Planned	$5,268,974	Y		Y	A
A in MTEP06	West	ATC LLC	1470	2481	12/1/2010	Y-33 line	S. Monroe		69			replacing the existing line protection relays and panels with a new panel containing relays for a permissive under-reaching transfer trip (POTT) system	WI			Planned	$193,240	Y		Y	A
A in MTEP06	West	ATC LLC	1470	2482	12/1/2010	Y-33 line	Brodhead		69			replacing the existing line protection relays and panels with a new panel containing relays for a permissive under-reaching transfer trip (POTT) system	WI			Planned	$184,941	Y		Y	A
A in MTEP06	West	ATC LLC	1470	2483	12/1/2010	Generating Facility Sub			69			extension of the 69 kV bus to a disconnect switch, the addition of an H-frame dead-end structure, and connection to the generation substation with 2156 MCM ACSR	WI			Planned	$125,620	?		Y	A
A in MTEP05	West	ATC LLC	339	449	8/1/2009	Jefferson	Tyranena (formerly Lake Mills)		138		290	construct new	WI		6	Under Construction	$9,850,000			Y	A
A in MTEP05	West	ATC LLC	339	450	11/30/2009	Tyranena (formerly Lake Mills)	Stonybrook		138		290	construct new	WI		6	Planned	$9,850,000			Y	A
A in MTEP05	West	ATC LLC	568	1249	12/31/2013	North Lake Geneva	White River	1	138		237	line to new T-D substation	WI		1.4	Proposed	$1,250,000			Y	A
A in MTEP08	Central	DEM	834	3071	6/1/2014	Kingman	Capacitor		69		7.2 MVAR	Add capacitor	IN			Planned	$500,000			NT	A
A in MTEP08	Central	DEM	835	3072	6/1/2013	Pittsboro	Capacitor		69		14.4 MVAR	Add capacitor	IN			Planned	$422,362			NT	A
A in MTEP08	Central	DEM	841	820	6/1/2015	Westwood Bk1	transformer	1	345	138	369.4	Replace 1600A 138kV breaker with 3000A to allow full xfr rating.	IN			Planned	$141,623			Y	A
A in MTEP08	Central	DEM	1194	1844	12/31/2010	Prescott	Capacitor		69		43.2 MVAR	Add capacitor on 6976 line terminal	IN			Planned	$439,845			NT	A
A in MTEP08	Central	DEM	1245	1958	6/1/2012	Frankfort Jefferson	Potato Creek		69		153	69178 Build 2.7 miles of 954 ACSR 69kV	IN		2.7	Planned	$1,087,115			NT	A
A in MTEP08	Central	DEM	1245	1959	6/1/2012	Potato Creek Switching Station			69			Construct 69kV switching station	IN			Planned	$1,007,000			NT	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	Central	DEM	1265	1982	12/31/2010	Geist 2	Capacitor		69		36 MVAR	Add a second 69kV 36MVAR cap bank at Geist	IN			Planned	$500,000			NT	A
A in MTEP08	Central	DEM	1266	1983	12/31/2009	Hortonville	Capacitor		69		36 MVAR	Install 69kV 36MVAR cap bank at Hortonville	IN			Planned	$500,000			NT	A
A in MTEP08	Central	DEM	1501	2574	6/1/2014	Carmel 146th St	Capacitor 2		69		36 MVAR	Install a 2nd 69kV 36MVAR cap bank	IN			Planned	$624,145			NT	A
A in MTEP08	Central	DEM	1512	2588	12/31/2010	Rochelle	Ridgeway	1	138	13.1	282	Install underground 138 kV circuit from Rochelle - Ridgeway - expand Rochelle sub to complete 138kv ring bus. Build new Ridgeway sub - 138kv-13.1kv	OH		1.04	Planned	$7,802,000			Y	A
A in MTEP08	Central	DEM	1512	2939	12/31/2011	Red Bank	Ashland	1	138			Install 3.8 ohm-1410Amp-138kV reactors in Feeder 7484 at Oakley sub (line runs through Oakley with no connections to other ckts - transitions to UG here)	OH			Planned	$832,051			Y	A
A in MTEP08	Central	DEM	1512	4270	12/31/2011	Ridgeway	Ashland	1	138		282	Install underground 138 kV circuit from Ridgeway to Ashland - expand Ashland sub to complete 138kv ring bus..	OH		1.31	Planned	$1,000,000			Y	A
A in MTEP08	Central	DEM	1513	2589	6/1/2010	Metea	Capacitor		69		14.4 MVAR	Install 14.4MVAR 69kV unit	IN			Planned	$568,653			NT	A
A in MTEP08	Central	DEM	1514	2590	6/1/2011	Wabash River Station	Staunton		230		478	Uprate Wabash River to Staunton 23002 to 100C summer operating temperature and 80C winter (559MVA). 478mva/1200A equipment limited - also, have to modify the 13847 underbuild from 6-wired to 954 3-wire	IN	18.03		Planned	$0			Y	A
A in MTEP08	Central	DEM	1514	3776	6/1/2011	Wabash River Station	Burnett Jct	1	138			Reconductor the 6-wire 13847 477ACSR underbuild from 976-1005 to 976-1035 (34,000 ft), with 3-wire 954ACSSTW conductor to allow uprating of 23002 line overbuild. Wab Riv to Spelterville to Burnett Jct.	IN	6.44		Planned	$2,195,000			Y	A
A in MTEP08	Central	DEM	1515	4272	10/1/2009	Speed (DEM)	Trimble (LGEE)	1	345		1001	Trimble line terminal and line addition required to insert Trimble into the Speed - Ghent 34530 line	IN			Under Construction	$0			Y	A
A in MTEP08	Central	DEM	1515	4273	10/1/2009	Trimble (DEM)	Ghent (LGEE)	1	345		717	Trimble line terminal and line addition required to insert Trimble into the Speed - Ghent 34530 line. DEM Trimble bus and 'dummy' tie-line will be added to show ownership by DEM of a substantial portion of the existing line section.	IN			Under Construction	$0			Y	A
A in MTEP08	Central	DEM	1519	2595	6/1/2012	Noblesville NE	Geist		69			Build a new 69kV line from Noblesville NE sub to tap the Fishers North - Geist 69kV line	IN			Planned	$2,640,107			NT	A
A in MTEP08	Central	DEM	1560	3111	6/1/2011	Edwardsport	capacitor		138		57.6 MVAR	Install a 138kV 57.6MVAR capacitor at Edwardsport.	IN			Planned	$500,000			Y	A
A in MTEP08	Central	DEM	1561	3112	6/1/2011	Kokomo Webster St (terminal equipment)	New London	1	230		797	Retire existing 1600A circuit switcher and complete the Webster St ring in order to utilize the full capacity of the bundled 477 ACSS wire on the 23016 line.	IN			Planned	$399,580			Y	A
A in MTEP08	Central	DEM	1564	3116	6/1/2011	Roseburg Switching Station	Capacitor		69		21.6 MVAR	Install 69kV 21.6MVAR std capacitor	IN			Planned	$518,503			NT	A
A in MTEP08	Central	DEM	1568	3120	6/1/2013	Qualitech	transformer	1	345	138	300	Qualitech Sub- Install one 345/138kv, 300Mva Xtr and 2-345kv Bkrs and 1-138kv Bkr to provide second 138kv source to proposed Hendricks Co 138kv system	IN			Planned	$4,561,674			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	Central	DEM	1569	3121	6/2/2013	Qualitech	Pittsboro Jct	1	138		306	Construct new 138kv line, Qualitech to Pittsboro Jct, and connect to the Pittsboro-Brownsbg line to provide new 954ACSR outlet line from Qualitech 345/138kV Bank	IN		3.3	Planned	$1,507,856			Y	A
A in MTEP08	Central	DEM	1570	3122	6/3/2013	Plainfield South	Pittsboro Jct	1	138		306	Convert the existing 69KV (69144) line from Plainfield S. to Pittsboro Jct(and 4 distribution subs) over to 138KV operation and connect to the new Qualitech to Pittsboro 138KV line	IN	17.6		Planned	$4,139,000			Y	A
A in MTEP08	Central	DEM	1650	3381	6/30/2014	Fairview	HE Fairview	1	138		306	Fairview to HE Fairview 13854 Reconductor with 954ACSR @ 100C	IN	3.3		Planned	$1,236,384			Y	A
A in MTEP08	Central	DEM	1651	3382	6/30/2012	Madison Michigan Rd	HE Fairview	1	138		179	Madison Michigan Rd to HE Fairview 13854 Uprate 397ACSR conductor to 100C operation	IN	13.9		Planned	$278,000			Y	A
A in MTEP08	Central	DEM	1878	3772	12/31/2009	Speed Bk 1	transformer	1	138	69	150	Replace 138/69/12 kV BK 1 with a 138/69kV 150 MVA transformer w/LTC - also retiring the 6969 bus tie bkr	IN			Under Construction	$2,000,000			Y	A
A in MTEP08	Central	DEM	1881	3775	12/31/2011	Bloomington Rogers St	Whitehall Pike	1	138		201	Bloomington Rogers St - replace 13836 breaker and WT; replace 13871 breaker, WT, and disc sw's - All 2000Amp rated; Replace relays for 13836, 13837, 13871	IN			Planned	$1,252,764			Y	A
A in MTEP08	Central	DEM	1887	3783	6/1/2011	Plainfield South	Plainfield 69 sub	1	69		153	Rebuild and reconductor 4.3 miles of 69kV line in the 69126 ckt. with 954acsr@100C; terminal: replace 3-600A switches with 1200A and reconductor buswork with 954 conductor at Plainfield S. end	IN	4.3		Planned	$2,418,000			NT	A
A in MTEP08	Central	DEM	1889	3785	6/1/2010	Danville	Danville Jct	1	69		153	Danville to Preswick Jct to Danville Jct - recond. 5.2 mi of the 6945 ckt. with 954acsr OVAL @100C and replace the 600 amp, two way switches at Danville Jct with two 1200 amp one way switches and replace the 600 amp switch at Prestwick Jct with a 1200 amp	IN	5.2		Planned	$2,235,000			NT	A
A in MTEP08	Central	DEM	1890	3786	5/1/2010	Geist	69181 Fishers N. Jct (new)	1	69		153	Build new 69kV line - 69181 - 4 miles with 954ACSR along 126th St. (completes approx 5.9 mile line section)	IN		4	Planned	$1,181,223			NT	A
A in MTEP08	Central	DEM	1893	3789	6/1/2012	Mitchell Lehigh Portland	Bedford 25th St	1	69		100	Reconductor 10.3 miles of 69kV - 6995 line with 477 ACSR	IN	10.3		Planned	$3,620,481			NT	A
A in MTEP08	Central	DEM	1895	3791	6/4/2013	Brownsburg	Avon East	1	138		306	Brownsburg to Avon East 138kV Reconductor 4.2 miles of 138kV line with 954 ACSR - AFTER 138KV CONVERSION	IN	3.7		Planned	$1,433,227			Y	A
A in MTEP08	Central	DEM	1896	3792	6/1/2012	Connersville 138 sub	Connersville 30th St	1	69		53	Uprate to 100C 4/0 acsr sections – 1.2 miles - 6981 ckt	IN	1.2		Planned	$16,493			NT	A
A in MTEP08	Central	DEM	1897	3793	6/1/2012	Deedsville	Macy	1	69		100	Reconductor Deedsville to Macy section of 6957 circuit with 477ACSR approx 2.5 miles; and replace Macy #1 and #2 - 600A line switches (1955 vintage) with 1200A	IN	2.5		Planned	$921,919			NT	A
A in MTEP08	Central	DEM	1899	3795	12/31/2012	Macy	Rochester Metals Jct	1	69		100	Reconductor Macy to Rochester Metals Jct section of 6957 circuit with 477ACSR - approx 9.1 miles	IN	9.1		Planned	$3,102,711			NT	A
A in MTEP08	Central	DEM	1901	3797	6/1/2013	Noblesville Gen Sta	Noblesville Jct	1	69		245	Reconductor 69kV - 6984 & 6916 ckt. Noblesville Plant to Noblesville 8th St. to Noblesville Jct with 954ACSS @ 200C (5.47 miles)	IN	5.47		Planned	$1,510,946			NT	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	Central	DEM	1902	3799	6/1/2014	Zionsville	Zionsville 96th St	1	69		153	Reconductor .32 miles of the 69kV - 69155 line from Zionsville 69 sub to Zionsville 96th Jct with 954ACSR conductor; replace/upgrade 69kV switches, jumpers and bus at Zionsvile 69 sub for a min. capacity of 152MVA (502G6709)	IN	0.32		Planned	$309,475			NT	A
A in MTEP07	Central	DEM	852	1979	6/1/2013	Crawfordsville	Linden Ethanol Jct		138		306	13819 reconductor with 954ACSR 100C	IN	10.28		Planned	$5,351,838	Y		Y	A
A in MTEP07	Central	DEM	852	2995	6/1/2013	Linden Ethanol Jct	Tipmont Concord Jct		138		306	13819 reconductor with 954ACSR 100C	IN	7.15		Planned	$3,567,892	Y		Y	A
A in MTEP07	Central	DEM	1263	1980	3/1/2010	Edwardsport 345 kV Sub			345			New 345 kV breaker and one half switching station, This LGIA to include eight (8) 345 kV, 3000A, 50 kA circuit breakers, 345 kV interconnection metering, foundations, steel structures, grounding, relaying, control cables, and associated equipment.	IN			Under Construction	$9,198,424	Y	Y	Y	A
A in MTEP07	Central	DEM	1263	2570	3/1/2010	Edwardsport 345 kV sub			345			345 kV Extension – Loop the Wheatland-Amo 345 kV circuit into the New 345 kV switching station. Utilize Bundled 954 kcm ACSR 45X7 phase conductors and 3/8ST7 static wires.	IN			Under Construction	$168,576	Y	Y	Y	A
A in MTEP06	Central	DEM	42	181	6/1/2010	Airport Road Jct	Seymour	1	138		306	Reconductor 13829 ckt between Airport Rd Jct and Seymour	IN	2.2		Planned	$752,906			Y	A
A in MTEP06	Central	DEM	42	183	6/1/2010	Pleasant Grove	Airport Road Jct	1	138		306	Reconductor 13829 ckt between Pleasant Grove Airport Rd Jct	IN	9.3		Planned	$3,388,077			Y	A
A in MTEP06	Central	DEM	42	2926	12/31/2009	Seymour	Bus & Disc. sw's		138			Seymour 13829 Bus & Disconnect Switches - Reconductor 2 sections of ring bus and upgrade 13829-51 and 13880-29 breaker disconnects and replace breakers 13880-29 and 13829-51	IN			Planned	$490,288			Y	A
A in MTEP06	Central	DEM	632	1309	6/1/2010	Gallagher	HE Georgetown	1	138		201	reconductor 250CU, 477ACSR already 100C (no cost)	IN	2.8		Planned	$1,065,110			Y	A
A in MTEP06	Central	DEM	851	826	6/1/2013	Lafayette Cumberland Ave	Laf AE Staley	1	138		306	13806 reconductor with 954ACSR 100C 604F6347	IN	1.3		Planned	$349,357			Y	A
A in MTEP06	Central	DEM	853	828	6/1/2015	West Lafayette	Cumberland Ave	1	138		306	13806 reconductor with 954ACSR 100C 604F6352	IN	2		Planned	$706,921			Y	A
A in MTEP06	Central	DEM	1193	1843	6/1/2009	Nickel			138			Build new Nickel 138/13.09 kv sub to be built on development property - tap the 5680 line	OH			Under Construction	$150,377			Y	A
A in MTEP06	Central	DEM	1199	1850	6/1/2010	Dresser	Terre Haute South 1st St	1	138		287	Uprate 13868 conductor to 100C operating temperature from Dresser to South 1st St. New limit 1200A terminal equipment.	IN			Planned	$10,000			Y	A
A in MTEP06	Central	DEM	1199	1851	6/1/2010	Terre Haute South 1st St	Terre Haute Water St	1	138		287	Uprate 13868 conductor to 100C operating temperature from South 1st St to Water St. New limit 1200A terminal equipment.	IN			Planned	$10,000			Y	A
A in MTEP06	Central	DEM	1244	1945	6/1/2013	Cayuga 23013 Wave Trap	Frankfort		230		797	Replace 1600A wave trap with a 2000A wave trap. Increase line rating of the Cayuga to Frankfort 23013 line.	IN			Planned	$68,733			Y	A
A in MTEP06	Central	DEM	1244	1946	6/1/2013	Frankfort 23013 Wave Trap	Cayuga		230		797	Replace 1600A wave trap with a 2000A wave trap. Increase line rating of the Cayuga to Frankfort 23013 line.	IN			Planned	$98,827			Y	A
A in MTEP06	Central	DEM	1246	1947	6/1/2011	Five Points 23030 Wave Trap	Geist		230		405	Replace 800A wave trap with a 2000A wave trap. Increase line rating to Geist.	IN			Planned	$24,038			Y	A
A in MTEP06	Central	DEM	1247	1948	6/1/2011	Greentown	Peru SE		230		478	Uprate 23021 circuit to 100C operating temp	IN			Planned	$28,403			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP06	Central	DEM	1251	1950	6/1/2011	Noblesville 23008 Wave Trap	Carmel 146th St Jct		230		405	Replace 800A wave trap with a 2000A wave trap. Increase 230kV line rating to Carmel 146th St Jct.	IN			Planned	$24,038			Y	A
A in MTEP06	Central	DEM	1253	1952	6/1/2011	Noblesville 23007 Wave Trap	Geist		230		405	Replace 800A wave trap with a 2000A wave trap. Increase line rating to Geist.	IN			Planned	$24,038			Y	A
A in MTEP06	Central	DEM	1254	1955	12/31/2009	Indiana Arsenal Jct	Clark Maritime Center		138		306	Construct 8.5 mi. of 138kV - 13857 line from Indiana Arsenal Jct (in the Charlestown area) to CMC. This line section will be owned by IMPA.	IN		8.5	Planned	$5,497,000			Y	A
A in MTEP06	Central	DEM	1257	2907	5/1/2011	Gibson	Bkr / line terminal		345			Gibson 345kV Bkr and Line Terminal for VECTREN's new 345 kV transmission line : Gibson to AB Brown to Reid (BREC)	IN			Planned	$0			Y	A
A in MTEP05	Central	DEM	624	1300	12/31/2010	Cloverdale	Plainfield South	1	138		No change	Upgrade static and grounding	IN	24.3		Planned	$1,816,905			Y	A
A in MTEP08	East	FE	1589	2672	6/1/2014	West Medina	Substation	1	138	69	90/120 MVA	New 138/69 kV transformer	OH			Planned	$4,131,000			Y	A
A in MTEP08	East	FE	1591	2674	6/1/2016	Newton Falls	Substation Upgrades	3	138	69	100/134 MVA	Replace 138/69 kV transformer	OH			Planned	$2,034,365			Y	A
A in MTEP08	East	FE	1596	2679	12/31/2009	Lakeview Substation	Capacitor Bank		34.5			Capacitor Bank Addition	OH			Planned	$577,214			Y	A
A in MTEP08	East	FE	1599	2190	6/1/2010	Wallbridge Junction	Maclean	1	138		308/375 MVA	Line Reconductor	OH	0.5		Proposed	$247,900			Y	A
A in MTEP08	East	FE	1599	2684	6/1/2010	Lemoyne	Oregon	1	138		286/286 MVA	New Line from 3 terminal lines.	OH	11.8		Planned	$1,020,000			Y	A
A in MTEP08	East	FE	1599	2685	6/1/2010	Frey	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	3.9		Planned				Y	A
A in MTEP08	East	FE	1599	2686	6/1/2010	Lemoyne	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	10.1		Planned				Y	A
A in MTEP08	East	FE	1601	2688	6/1/2012	Chamberlin	Shalersville	1	138		260/309 MVA	New Line	OH	12		Planned	$3,669,000			Y	A
A in MTEP08	East	FE	1909	3868	12/17/2010	Davis Besse	sub reconfiguration		345			substation breaker additions	OH			Planned	$2,501,000			Y	A
A in MTEP08	East	FE	1911	3870	11/1/2010	Fayette	substation addition		138	69		add transformer and breakers	OH			Planned	$4,000,000			Y	A
A in MTEP08	East	FE	1911	3871	11/1/2010	Fayette	Bryan/Stryker	1	69			New Line	OH		5	Planned	$8,678,421			Y	A
A in MTEP08	East	FE	1912	3872	12/31/2009	Cardington	Tangy	1	69			reconductor line	OH	16.8		Planned	$2,400,000			Y	A
A in MTEP08	East	FE	1918	3878	6/1/2014	Dale	Jackson	1	69			New Line	OH	3.9		Planned	$2,243,200			Y	A
A in MTEP08	East	FE	1921	3883	6/1/2013	Chittenden	Darrow	1	69			New Line	OH		3.87	Planned	$3,448,047			Y	A
A in MTEP08	East	FE	2096	3985	11/4/2010	Ashtabula Q-4	Stacy	1	138			New line extension from current 138kV Line	OH	12		Planned	$4,500,000			Y	A
A in MTEP08	East	FE	2096	3986	11/4/2010	Mayfield Q-4	Stacy	1	138			New line extension from current 138kV Line	OH	12		Planned	$4,500,000			Y	A
A in MTEP08	East	FE	2096	3987	11/4/2010	Stacy	substation	1	138			New 138kV substation	OH			Planned	$3,000,000			Y	A
A in MTEP08	East	FE	2096	3988	11/4/2010	Stacy	distribution transformer	1	138	36		New 138-36kV Distribution transformer	OH			Planned	$0			Y	A
A in MTEP07	West	GRE	1361	2264	9/28/2010	Badoura	Birch Lake	1	115		182		MN		16.03	Planned	$11,275,000			Y	A
A in MTEP06	West	GRE	1459	2499	1/1/2011	Dakota County Sub	transformer	1	345	16	224 MVA	one 224 MVA, 345/16 kV generator step-up transformer, a 16/4.1 kV station aux transformer, and two 16 kV circuit breakers and a 345 kV motor operated switch	MN			Planned	$275,000			Y	A
A in MTEP06	West	GRE	1459	2500	1/1/2011	Dakota County Sub	transformer	2	345	16	224 MVA	one 224 MVA, 345/16 kV generator step-up transformer, a 16/4.1 kV station aux transformer, and two 16 kV circuit breakers and a 345 kV motor operated switch	MN			Planned	$275,000			Y	A
A in MTEP06	West	GRE	1459	2501	1/1/2011	Dakota County Sub	new substation		345			new substation, along with NSP Blue Lake and Prairie Island transmission line construction	MN			Planned	$5,959,788	Y	Y	Y	A
A in MTEP05	West	GRE	599	753	2/8/2012	Crooked Lake	Enterprise Park	1	115		142		MN		3.5	Planned	$3,900,000			Y	A
A in MTEP05	West	GRE	599	754	10/11/2011	Enterprise Park 115-69 kV	transformer	1	115	69	84		MN			Planned	$3,000,000			Y	A
A in MTEP05	West	GRE	600	1078	3/25/2011	Scearcyville	Southdale	1	115		224	New line	MN		9	Planned	$6,523,000			Y	A
A in MTEP03	West	GRE	56	4573	11/1/2009	Shafer	Shafer Tap	1	161			Distribution conversion to 115 kV	MN		0	Planned	$278,357			Y	A
A in MTEP08	West	GRE,XEL,OTP,I	286	1104	7/1/2013	Alexandria SS	Waite Park (Quarry)	1	345		2085	Add a new 345 kV line from Alexandria Switching Station to Waite Park and terminal works	MN		55	Planned	$133,666,500	Y	Y	Y	A
A in MTEP08	West	GRE,XEL,OTP,I	286	1105	7/1/2015	Maple River	Alexandria SS	1	345		2085	Add a new 345 kV line from Maple River to Alexandria Switching Station substation and terminal works	MN/ND		135	Planned	$267,250,000	Y	Y	Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	GRE,XEL,OTP,I	286	2640	12/1/2011	Waite Park (Quarry)	Monticello	1	345		2085	Add a new 345 kV line from Waite Park to Monticello substation and terminal works	MN		35	Planned	$75,216,500	Y	Y	Y	A
A in MTEP08	West	GRE,XEL,OTP,I	286	2641	7/1/2013	Alexandria SS	Transformer	1	345	115	448	new transformer and terminal works	MN			Planned	$6,500,000	Y		Y	A
A in MTEP08	West	GRE,XEL,OTP,I	286	2976	12/1/2011	Quarry (St. Cloud)	345/115 transformer	1	345	115	448	new transformer and terminal works	MN			Planned	$7,367,000	Y		Y	A
A in MTEP08	West	GRE/MPC/XEL/	286	2642	12/1/2011	Waite Park	Transfomer		345	115	448	new transformer	MN			Proposed	$4,500,000	Y		Y	A
A in MTEP08	West	GRE/OTP	1033	587	12/30/2011	Silver Lake 230/41.6 kV	transformer	1	230	41.6	50		MN			Planned	$3,804,000			Y	A
A in MTEP08	Central	HE	1323	2183	9/1/2008	Sandborn Primary w/tap	HE 161 Transmission	1	161	69	150MVA	New Construction	IN		0.1	Planned	$6,000,000			Y	A
A in MTEP08	Central	HE	1635	3299	12/1/2009	Ramsey Primary	345kV Ring Bus	1	345		2000 AMP	Rebuild	IN			Planned	$7,000,000			Y	A
A in MTEP08	Central	HE	1923	3802	9/1/2009	Spring Valley Junction	69lV Switching Station	1	69		2000 AMP	Rebuild	IN			Planned	$2,600,000			NT	A
A in MTEP08	Central	HE	1926	3805	9/1/2008	Gwyneeville Primary	Pioneer Substation	1	69		2000 AMP	New Construction	IN		8	Planned	$1,000,000			NT	A
A in MTEP08	Central	HE	1927	3806	9/1/2010	Hubbell Primary		1	138		2000 AMP	Rebuild	IN			Planned	$3,000,000			Y	A
A in MTEP08	Central	HE	1928	3807	9/1/2011	Fairview Primary		1	138		2000 AMP	Rebuild	IN			Planned	$1,500,000			Y	A
A in MTEP08	Central	HE	1929	3808	9/1/2012	Georgetown Primary		1	138		2000 AMP	Rebuild	IN			Planned	$1,250,000			Y	A
A in MTEP08	Central	HE	2082	3978	9/1/2009	Shelbyville Intel Park Tapline	Shelbyville Intel Park	1	138			New Construction	IN		1	Planned	$250,000			Y	A
A in MTEP08	Central	HE	2082	3979	9/1/2009	Shelbyville Intel Park		1	138	12.5	2000 AMP	New Construction	IN			Planned	$750,000			Y	A
A in MTEP08	Central	HE	2083	3980	9/1/2009	Wayne County Indust Park Tap	Wayne County Indust Park	1	69			New Construction	IN		1	Planned	$250,000			NT	A
A in MTEP08	Central	HE	2083	3981	9/1/2009	Wayne County Indust Park		1	69	12.5	2000 AMP	New Construction	IN			Planned	$500,000			NT	A
A in MTEP08	Central	HE	2084	3984	9/1/2009	Worthington Primary		1	161	138	250MVA	Replace Existing	IN			Planned	$4,500,000			Y	A
A in MTEP08	Central	HE	2095	3982	9/1/2008	Sandborn Primary	Freelandville Switch	1	69			New Construction	IN		9.7	Planned	$2,000,000			NT	A
A in MTEP08	Central	HE	2095	3983	9/1/2008	Sandborn Primary	Carlisle Switch	1	69			New Construction	IN		9	Planned	$2,000,000			NT	A
A in MTEP06	Central	HE	1321	2179	3/1/2008	Napoleon	Capacitor & CB Addition, and bus upgrades	1	161		30MVAR	New Construction	IN			Planned	$800,000			Y	A
A in MTEP06	Central	HE	1321	2180	12/1/2008	Napoleon Primary	DCSS	1	161		338MVA	New Construction	IN		25	Planned	$7,200,000			Y	A
A in MTEP06	Central	HE	1322	2181	6/1/2008	Owensville Primary		1	138	69	150MVA	New Construction	IN			Planned	$5,500,000			Y	A
A in MTEP06	Central	HE	1322	2182	6/1/2008	Owensville Primary Tapline	Cinergy 138 (Gibson to Princeton)	1	138		215MVA	New Construction	IN		0.5	Planned	$2,500,000			Y	A
A in MTEP08	Central	IPL	1639	3301	6/1/2013	Various Locations	capacitors					Add capacitors to IPL General Distribution System	IN			Planned	$50,000			NT	A
A in MTEP06	Central	IPL	40	177	12/31/2009	Indian Creek	Julietta	1	138		286 MVA	New 138kV Line	IN		5	Planned	$2,500,000			Y	A
A in MTEP06	Central	IPL	40	178	12/31/2009	Cumberland	Julietta	1	138		286 MVA	New 138kV Line	IN		4.55	Planned	$2,500,000			Y	A
A in MTEP08	East	ITC	1661	3429	10/31/2009	St Clair	Remer	2	120			new line	MI			Under Construction	$800,000			Y	A
A in MTEP08	East	ITC	1663	3432	4/1/2010	Cable Termination	Throughtout System					replace cable terminations that have reached end of life and lack spare parts	MI			Planned	$4,000,000			Y	A
A in MTEP08	East	ITC	1664	3433	12/31/2008	Relay Betterment	Throughtout System					replace relays that do not meet up to date standards	MI			Planned	$1,130,000			Y	A
A in MTEP08	East	ITC	1857	3745	5/31/2010	Adams	Spokane	1	120			Break up 3-ended line	MI			Proposed	$850,000			Y	A
A in MTEP08	East	ITC	1857	3746	5/31/2010	Jewell	St. Clair	2	120			Break up 3-ended line	MI			Proposed	$550,000			Y	A
A in MTEP08	East	ITC	1866	2887	12/31/2009	Anti-galloping project	Throughout System						MI			Under Construction	$1,500,000			Y	A
A in MTEP08	East	ITC	1870	3757	6/1/2011	ClydeTP	Placid	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI	11.5		Planned				Y	A
A in MTEP08	East	ITC	1870	3758	6/1/2011	ClydeTP	Durant	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI	6.6		Planned				Y	A
A in MTEP08	East	ITC	1870	3759	6/1/2011	ClydeTP	Clyde	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI		3.3	Planned	$2,750,000			Y	A
A in MTEP08	East	ITC	1871	3760	11/1/2009	Hurst	Durant	1	120		343 MVA	Hurst taps the Genoa-Durant 120kV circuit	MI	8.2	0.5	Planned	$1,050,000			Y	A
A in MTEP08	East	ITC	1871	3761	11/1/2009	Hurst	Genoa	1	120		343 MVA	Hurst taps the Genoa-Durant 120kV circuit	MI	11.9	0.5	Planned	$1,050,000			Y	A
A in MTEP08	East	ITC	1873	3765	3/1/2011	Tahoe	Wixom	1	120		351 MVA	Creates at new Tahoe-Wixom 120kV;constructs 2.6 miles of 120 kV line circuit	MI		2.6	Planned	$2,800,000			Y	A
A in MTEP08	East	ITC	1875	3771	9/30/2009	Bad Axe	Wyatt	2	120		343 MVA	Builds a second Bad Axe - Wyatt 120 kV circuit	MI		2.95	Planned	$5,894,687	Y		Y	A
A in MTEP06	East	ITC	692	1383	6/30/2012	Bismarck 345 kV	Troy 345 kV	1	345		700		MI		15.4	Planned	$145,000,000	Y	Y	Y	A
A in MTEP06	East	ITC	692	1384	6/30/2012	Troy 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000	Y		Y	A
A in MTEP06	East	ITC	907	910	12/31/2011	Goodison 345 kV	Belle River 345	1	345		2151	Goodison 345 kV substation	MI	35.2		Planned	$6,000,000	Y	Y	Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP06	East	ITC	907	911	12/31/2011	Goodison 345 kV	Pontiac 345	1	345		2002	Goodison 345 kV substation	MI	6.3		Planned	$6,000,000	Y	Y	Y	A
A in MTEP06	East	ITC	907	912	12/31/2011	Goodison 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000	Y		Y	A
A in MTEP06	East	ITC	907	913	12/31/2011	Goodison 120 kV	Pontiac 120 kV	1	120		343		MI		6.3	Planned	$11,000,000	Y		Y	A
A in MTEP06	East	ITC	907	914	12/31/2011	Goodison 120 kV	Sunbird 120 kV	1	120		229		MI	3.55	2.87	Planned	$11,000,000	Y		Y	A
A in MTEP06	East	ITC	907	915	12/31/2011	Goodison 120 kV	Tienken 120 kV	1	120		343		MI	2.78	2.34	Planned	$9,000,000	Y		Y	A
A in MTEP06	East	ITC	907	916	12/31/2011	Spokane 120 kV	Tienken 120 kV	1	120		343		MI	0.1		Planned	$2,000,000	Y		Y	A
A in MTEP06	East	ITC	1011	1583	7/31/2009	Genoa 120 kV	Durant 120 kV	1	120		343		MI		8.5	Under Construction	$15,000,000			Y	A
A in MTEP06	East	ITC	1308	2141	12/31/2009	Bunce Creek PAR		1	220				MI			Planned	$25,000,000			Y	A
A in MTEP06	East	ITC	1309	2145	12/31/2009	Monroe 345 kV pos. MF	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1309	2147	12/31/2009	Monroe 345 kV pos. MM	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1309	2151	12/31/2009	Monroe 345 kV pos. BF	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1309	2152	12/31/2009	Monroe 345 kV pos. BM	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1309	2153	12/31/2009	Monroe 345 kV pos. BT	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1310	2154	9/30/2009	Waterman 230 kV pos. BF	circuit breaker		230			CB replacement	MI			Planned	$200,000			Y	A
A in MTEP06	East	ITC	1310	2155	9/30/2009	Waterman 230 kV pos. CF	circuit breaker		230			CB replacement	MI			Planned	$200,000			Y	A
A in MTEP06	East	ITC	1310	2158	12/31/2009	St. Clair 120 kV pos. KB	circuit breaker		120			CB replacement	MI			Planned	$150,000			Y	A
A in MTEP06	East	ITC	1310	2159	12/31/2009	St. Clair 120 kV pos. HS	circuit breaker		120			CB replacement	MI			Planned	$150,000			Y	A
A in MTEP06	East	ITC	1310	3419	12/31/2009	Monroe 345kV pos. MF	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1310	3420	12/31/2009	Monroe 345kV pos. MM	circuit breaker		345			CB replacement	MI			Planned	$250,000			Y	A
A in MTEP06	East	ITC	1310	3424	9/30/2009	Navarre 120kV pos. HX	circuit breaker		120			CB replacement	MI			Planned	$150,000			Y	A
A in MTEP06	East	ITC	1488	1584	12/31/2009	Placid 120 kV	Durant 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	16.7		Under Construction	$5,650,000			Y	A
A in MTEP06	East	ITC	1488	1585	12/31/2009	Placid 120 kV	Proud 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	14.3		Planned				Y	A
A in MTEP08	West	ITCM	1337	2184	12/31/2009	Rose Hollow Substation	transformer	1	161	69	75/75 MVA	New 161/69kV 75 MVA TRF	IA			Under Construction	$4,160,000			Y	A
A in MTEP08	West	ITCM	1337	4903	12/31/2009	Rose Hollow	West Branch	1	69		77 MVA	New Rose Hollow-West Branch 4 mile 69kV line.	IA		4	Planned				Y	A
A in MTEP08	West	ITCM	1340	2973	6/1/2011	Hazelton	345 termination		345		1195	Expand ring bus to a five breaker ring bus (min 2000 amp). Add one 345kV CB. Extend existing single dead-end tower to double dead-end tower. Four existing 345kV switches rated 1600 amps replaced with 2000 amp switches.	IA			Planned	$1,080,000			Y	A
A in MTEP08	West	ITCM	1340	2974	6/1/2011	Salem	345 termination		345		1195	Expand ring bus to a five breaker ring bus (min 2000 amp). Add one 345kV CB. Extend existing single dead-end tower to double dead-end tower. Four existing 345kV switches rated 1600 amps replaced with 2000 amp switches.	IA			Planned	$2,280,000			Y	A
A in MTEP08	West	ITCM	1340	4905	12/31/2011	Salem	Hazleton	1	345		1195	new line	IA		81	Planned	$110,000,000			Y	A
A in MTEP08	West	ITCM	1340	4906	12/31/2011	Salem	Transformer	2	345	161	450	Upgrade Salem 345 sub & add 2nd 345/161kV transformer	IA			Planned	$5,650,000			Y	A
A in MTEP08	West	ITCM	1341	2207	6/1/2009	Hazleton	transformer	2	161	69	75/75 MVA	replace transformer	IA			Under Construction	$900,000			Y	A
A in MTEP08	West	ITCM	1345	2546	6/1/2009	Quad Cities	Rock Creek	1	345		1195/1195 MV	upgrade limiting equipment	IA			Planned	$25,000			Y	A
A in MTEP08	West	ITCM	1345	2547	6/1/2009	Rock Creek	Salem	1	345		1195/1195 MV	upgrade limiting equipment	IA			Planned	$25,000			Y	A
A in MTEP08	West	ITCM	1346	2214	6/1/2009	Rock Creek	transformer	1	345	161	448	upgrade limiting equipment	IA			Planned	$13,400			Y	A
A in MTEP08	West	ITCM	1522	2599	12/31/2009	6th Street	Beverly	1	161		326	new line	IA		6.2	Planned	$7,200,000	Y		Y	A
A in MTEP08	West	ITCM	1522	4900	12/31/2009	6th Street	new 161 kV line terminal	1	161		558 MVA	new 161 kV line terminal	IA			Under Construction	$0	Y		Y	A
A in MTEP08	West	ITCM	1522	4901	12/31/2009	Beverly	new 161 kV line terminal	1	161		558 MVA	new 161 kV line terminal	IA			Planned	$0	Y		Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	ITCM	1618	2720	12/31/2010	Heron Lake	Lakefield Jct	1	161		446/446 MVA	Rebuild	MN	17		Planned	$6,940,000	Y		Y	A
A in MTEP08	West	ITCM	1619	2721	12/31/2009	Grand Mound 161-69 kV	transformer	2	161	69	74.7 MVA	new Xfmr	IA			Planned	$1,905,500			Y	A
A in MTEP08	West	ITCM	1619	2722	12/31/2009	Grand Mound	Maquoketa	1	161		200/200 MVA	New 161kV line	IA		2	Planned	$502,208			Y	A
A in MTEP08	West	ITCM	1619	2723	12/31/2009	East Calamus	Grand Mound	1	161		200/200 MVA	New 161kV line	IA			Planned				Y	A
A in MTEP08	West	ITCM	1619	2724	12/31/2009	East Calamus	Maquoketa	1	161			remove model branch	IA			Planned				Y	A
A in MTEP08	West	ITCM	1619	2725	12/31/2009	East Calamus T	Maquoketa	1	161			remove model branch	IA			Planned				Y	A
A in MTEP08	West	ITCM	1636	3290	12/31/2009	Waterbury breaker station	new switching station		69			Construct a new Waterbry 4-terminal 69kV switching station near the existing Johnsonville T location. Intersection of the GRE Wanda-Johnsonville T 69kV & ITC Cottonwood-Johnsonville T-Wabasso 69kV lines.	MN			Planned	$1,000,000			NT	A
A in MTEP08	West	ITCM	1636	4274	12/31/2009	Waterbury	capacitor		69		5.4 MVAR	Retire the Lamberton 69kV brekaker and move the Lamberton 5.4 MVAR cap to the new Waterbury Switch Station.	MN			Planned				NT	A
A in MTEP08	West	ITCM	1640	2732	12/31/2013	Marshalltown	Wellsburg	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	23.8	0	Planned	$6,900,000			Y	A
A in MTEP08	West	ITCM	1640	2733	12/31/2013	Wellsburg	Eldora	1	161		326/326 MVA	Rebuild Wellsburg-Eldora 115kV to 161kV line.	IA	11	0	Planned	$5,500,000			Y	A
A in MTEP08	West	ITCM	1640	2734	12/31/2013	Eldora	Iowa Falls Industrial	1	161		326/326 MVA	Rebuild Eldora-IA Falls Ind Tap 115kV to 161kV line. Build a new completely separate ROW 2 mile 161kV line section from the approximate IA Falls Ind Tap location to the IA Falls Industrial sub.	IA	10.7	2	Planned	$6,000,000			Y	A
A in MTEP08	West	ITCM	1640	2735	12/31/2013	Iowa Falls Industrial	Iowa Falls	1	161		262/262 MVA	Rebuild old IA Falls-IA Falls Industrial Tap 115kV to 161kV line. Operate IA Falls-IA Falls Industrial at 161kV. (1.54 miles IA Falls Ind Tap-IA Falls Ind already built to 161kV.	IA	2.75	0	Planned	$580,000			Y	A
A in MTEP08	West	ITCM	1640	2736	12/31/2013	Iowa Falls Industrial Tap	3-terminal line	1	161		262/262 MVA	Iowa Falls Industrial Tap bus (3-terminal line) will be eliminated.	IA	0	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2737	12/31/2013	Iowa Falls	Nuthatch	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	2.5	0	Planned	$1,000,000			Y	A
A in MTEP08	West	ITCM	1640	2738	12/31/2013	Marshalltown	Wellsburg	1	115			REMOVE model branch	IA	27	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2739	12/31/2013	Wellsburg	Eldora	1	115			REMOVE model branch	IA	11.5	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2740	12/31/2013	Eldora	Iowa Falls Industrial Tap	1	115			REMOVE model branch	IA	1.21	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2741	12/31/2013	Iowa Falls Industrial Tap	Iowa Falls	1	115			REMOVE model branch	IA	11.59	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2742	12/31/2013	Iowa Falls Industrial Tap	Iowa Falls Industrial	1	115			REMOVE model branch	IA	1.54	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2743	12/31/2013	Iowa Falls	Franklin	1	115			REMOVE model branch	IA	4.5	0	Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2745	12/31/2013	Eldora	transformer	1	161	34	20 MVA	Retire Eldora Sub	IA			Planned	$100,000			Y	A
A in MTEP08	West	ITCM	1640	2746	12/31/2013	Iowa Falls Industrial	transformer	1	161	69	75 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$1,500,000			Y	A
A in MTEP08	West	ITCM	1640	2747	12/31/2013	Iowa Falls	transformer	1	161	69	20 MVA	Retire both 115/34kV TRF	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2748	12/31/2013	Iowa Falls	transformer	1	161	34	50 MVA	Replace the 2 IA Falls 115/34kV TRFs with 1 161/34kV TRF	IA			Planned	$2,000,000			Y	A
A in MTEP08	West	ITCM	1640	2749	12/31/2013	Wellsburg	transformer	1	161	69	75 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$1,500,000			Y	A
A in MTEP08	West	ITCM	1640	2750	12/31/2013	Eldora	transformer	1	115	34	20 MVA	REMOVE transformer branch	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2751	12/31/2013	Iowa Falls Industrial	transformer	1	115	69	35 MVA	REMOVE transformer branch	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2752	12/31/2013	Iowa Falls	transformer	1	115	34	20 MVA	REMOVE transformer branch	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2753	12/31/2013	Iowa Falls	transformer	2	115	34	20 MVA	REMOVE transformer branch	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1640	2754	12/31/2013	Wellsburg	transformer	1	115	69	50 MVA	REMOVE transformer branch	IA			Planned	$0			Y	A
A in MTEP08	West	ITCM	1641	2755	6/1/2009	Ottumwa Generating Station	Cap Bank	1	161		50 MVAR	new 161kV Cap Bank	IA			Planned	$1,400,000			Y	A
A in MTEP08	West	ITCM	1643	2757	12/31/2010	Anita	Cap Bank	1	161		24 MVAR	new 161kV Cap Bank	IA			Proposed	$650,000			Y	A
A in MTEP08	West	ITCM	1644	2758	12/31/2010	Grand Junction	Cap Bank	1	161		24 MVAR	new 161kV Cap Bank	IA			Proposed	$650,000			Y	A
A in MTEP08	West	ITCM	1645	2759	12/31/2010	Leon	Cap Bank	1	69		7.2 MVAR	new 69kV Cap Bank	IA			Proposed	$150,000			NT	A
A in MTEP08	West	ITCM	1739	3533	12/31/2009	Arnold	Vinton	1	161		446/446 MVA	Rebuild existing line	IA	19.35		Planned	$7,198,420			Y	A
A in MTEP08	West	ITCM	1739	3534	12/31/2009	Vinton	Dysart	1	161		446/446 MVA	Rebuild existing line	IA	10.3		Planned	$3,821,840			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	ITCM	1739	3535	12/31/2009	Dysart	Washburn	1	161		446/446 MVA	Rebuild existing line	IA	8.3		Planned	$3,079,740			Y	A
A in MTEP08	West	ITCM	1744	3546	12/31/2011	Maquoketa	Grand Mound	1	161		326/326 MVA	Reconductor	IA	14.5		Planned	$6,900,000			Y	A
A in MTEP08	West	ITCM	1747	3554	6/1/2010	Elk	transformer	1	161	69	84 MVA	Upgrade transformer	MN			Planned	$2,000,000			Y	A
A in MTEP08	West	ITCM	1747	3555	6/1/2010	Elk	transformer	2	161	69	84 MVA	Upgrade transformer	MN			Planned	$2,000,000			Y	A
A in MTEP08	West	ITCM	1750	2853	12/31/2010	Goose Pond	3 terminal 161kV switching station		161			3 terminal 161kV switching station along the Palmyra-Twin Rivers 161kV line.	IA			Proposed	$1,800,000			Y	A
A in MTEP08	West	ITCM	1753	3559	6/30/2009	Winnebago Jct	transformer	1	161	69	75MVA	South 161/69kV TRF & substation upgrades	IA			Planned	$1,400,000			Y	A
A in MTEP08	West	ITCM	1754	2854	12/31/2009	Emery	Lime Creek (Road Move)		161			Rebuild a portion of the Emery-Lime Creek 161kV line (about 1 mile) Road Move	IA	1		Planned	$365,000			Y	A
A in MTEP08	West	ITCM	1755	3562	6/1/2009	Washington	North Crane Tap	1	69		72/72 MVA	Rebuild existing line	IA	1.075		Under Construction	$261,609			NT	A
A in MTEP08	West	ITCM	1755	3563	6/1/2009	Kalona Tap	North Crane Tap	1	69		72/72 MVA	Rebuild existing line	IA	9.17		Under Construction	$2,231,580			NT	A
A in MTEP08	West	ITCM	1755	3564	6/1/2009	Kalona Tap	Hills	1	69		69/69 MVA	Rebuild existing line	IA	7.63		Under Construction	$1,856,811			NT	A
A in MTEP08	West	ITCM	1756	2855	6/1/2009	Dyersville	Farley REC Tap	1	69		77/77 MVA	Reconductor the 69kV line from Dyersville-Farley REC Tap 69kV line.	IA	3.7		Under Construction	$805,795			NT	A
A in MTEP08	West	ITCM	1756	4290	6/1/2009	Farley REC Tap	Farley	1	69		77/77 MVA	Reconductor 1.64 miles out of the 2.3 total miles of Farley REC Tap-Farley 69kV line.	IA	1.64		Under Construction	$350,000			NT	A
A in MTEP08	West	ITCM	1756	4291	6/1/2009	Farley	Epworth	1	69		77/77 MVA	Reconductor the Farley-Epworth 69kV line.	IA	4.09		Under Construction	$224,702			NT	A
A in MTEP08	West	ITCM	1756	4292	6/1/2009	Epworth	Peosta T	1	69		77/77 MVA	Reconductor the Epworth-Peosta T 69kV line.	IA	2.1		Under Construction	$167,771			NT	A
A in MTEP08	West	ITCM	1756	4293	6/1/2009	Peosta T	Peoasta	1	69		77/77 MVA	Reconductor the Peosta T-Peosta 69kV line.	IA	2.2		Under Construction	$180,000			NT	A
A in MTEP08	West	ITCM	1756	4294	6/1/2009	Peosta	Amocoil	1	69		77/77 MVA	Reconductor the Peosta-Amoco Oil 69kV line.	IA	4.2		Under Construction	$209,646			NT	A
A in MTEP08	West	ITCM	1756	4295	6/1/2009	Amoco Oil	Seippel Rd	1	69		77/77 MVA	Reconductor the Amoco Oil-Seippel Rd 69kV line.	IA	0.81		Under Construction	$52,412			NT	A
A in MTEP08	West	ITCM	1757	3565	12/31/2008	Cambridge REC	Maxwell North	1	69		77/77 MVA	Rebuild existing line	IA	6.35		Planned	$2,100,000			NT	A
A in MTEP08	West	ITCM	1758	3566	12/31/2008	Beaver Channel	2nd Ave	1	69		77/77 MVA	Rebuild existing line	IA	2.5		Under Construction	$1,570,000			NT	A
A in MTEP08	West	ITCM	1758	3567	12/31/2008	Beaver Channel	Mill Creek	1	69		77/77 MVA	Rebuild existing line	IA	1.25		Under Construction	$336,000			NT	A
A in MTEP08	West	ITCM	1769	2864	12/31/2009	Belle Plaine	Hwy 30		69			Rebuild 1.4 miles		1.4		Planned	$110,000			Y	A
A in MTEP08	West	ITCM	1772	3560	12/31/2010	North Centerville	Cap Bank	1	69		7 MVAR	Install new 7 MVAR Cap	IA			Planned	$1,200,000			NT	A
A in MTEP08	West	ITCM	1972	2890	12/31/2009	Decorah Mill St	Cresco 69kV dbl ckt line		69			Rebuild 0.65 miles of 69kV line on the Mill St-Cresco 69kV dble ckt line		0.65		Planned	$203,000			NT	A
A in MTEP08	West	ITCM	2108	2821	12/31/2009	G358 GSU Substation	new switching station	1	161	34.5		Facilities, excluding the Transmission Owner Interconnection Facilities, required for a 4 terminal, 3 breaker switching station				Planned	$1,702,346	Y		Y	A
A in MTEP08	West	ITCM	2108	2822	12/31/2009	Winnebago	WinnCo	1	161			Transmission line taps to new 161 kV switching station.	IA			Planned	$103,650	Y		Y	A
A in MTEP08	West	ITCM	2108	2823	12/31/2009	Winnebago Junction	substation	1	161			Upgrade Winnebago Junction substation relays and carrier to accommodate the new switching station	IA			Planned	$56,848	Y		Y	A
A in MTEP08	West	ITCM	2108	2824	12/31/2009	WinnCo	substation	1	161			Upgrade Winnebago Junction substation relays and carrier to accommodate the new switching station	IA			Planned	$56,848	Y		Y	A
A in MTEP08	West	ITCM	2108	4030	12/31/2009	Microwave communication network						Upgrade Transmission Owner's microwave communication network	IA			Planned	$200,000	Y		Y	A
A in MTEP06	West	ITCM	1287	2116	6/1/2009	Salem 345/161 kV	transformer	1	345	161	450	Larger Xfmr	IA			Planned	$5,650,000	Y		Y	A
A in MTEP06	West	ITCM	1288	2117	12/31/2010	Hazleton 345/161	transformer	1	345	161	335/335	Larger Xfmr	IA			Planned	$5,650,000	Y		Y	A
A in MTEP06	West	ITCM	1289	2118	6/1/2009	Marshalltown	Toledo	1	115		233/233	Rebuild	IA	16		Under Construction	$4,712,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP06	West	ITCM	1289	2119	6/1/2010	Belle Plaine	Toledo	1	115		233/233	Rebuild	IA	18		Planned	$6,080,000			Y	A
A in MTEP06	West	ITCM	1289	2120	6/1/2011	Belle Plaine	Stoney Point	1	115		233/233	Rebuild	IA	27		Planned	$8,208,000			Y	A
A in MTEP06	West	ITCM	1342	2208	6/30/2010	Lewis Fields	Hiawatha	1	161		326/326 MVA	new line	IA		8.5	Planned	$8,151,600			Y	A
A in MTEP06	West	ITCM	1342	2209	6/30/2010	Lewis Fields	transformer	1	161	115	150/150 MVA	new transformer	IA			Planned	$6,200,000			Y	A
A in MTEP06	West	ITCM	1342	4902	6/30/2010	Hiawatha	new 161 kV line terminal	1	161		558 MVA	Add 161 kV breaker & associated equipment for the new 161 kV line terminal to Lewis Fields.	IA			Planned	$500,000			Y	A
A in MTEP06	West	ITCM	1344	2211	6/1/2012	Morgan Valley	Beverly	1	161		335	new line	IA		7.9	Proposed	$4,000,000			Y	A
A in MTEP06	West	ITCM	1344	2212	6/1/2012	Morgan Valley	transformer	1	345	161	335	new substation	IA			Proposed	$8,750,000			Y	A
A in MTEP06	West	ITCM	1473	1856	12/31/2009	Mason City Armor	Emery North	1	69		140/140	Rebuild existing line	IA	4.5		Planned	$1,060,000			NT	A
A in MTEP08	East	METC	480	1336	12/31/2009	Brickyard Jct.	Felch Road	1	138			Reconductor	MI	13		Planned	$10,000,000	Y		Y	A
A in MTEP08	East	METC	1443	2447	6/1/2009	Milham 138kV	Upjohn 138kV	1	138	12.5		Install a second distribuiton transformer served from Milham-Upjohn 138kV (Milham)	MI			Planned	$100,000			Y	A
A in MTEP08	East	METC	1448	2452	6/1/2014	Simpson 138kV			138	12.5		Install a second distribution transformer at Simpson (Simpson)	MI			Proposed	$2,200,000			Y	A
A in MTEP08	East	METC	1655	3389	8/31/2009	Twining 138kV	Breaker 177		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3390	7/31/2009	Twining 138kV	Breaker 188		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3391	6/30/2009	Twining 138kV	Breaker 288		138				MI			Under Construction	$160,000			Y	A
A in MTEP08	East	METC	1655	3397	10/31/2009	Ludington 345 kV	Breaker 26F7		345				MI			Planned	$300,000			Y	A
A in MTEP08	East	METC	1655	3401	12/31/2010	Weadock 138kV	Breaker 148		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3402	12/31/2010	Weadock 138kV	Breaker 188		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3403	12/31/2010	Weadock 138kV	Breaker 288		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3404	12/31/2010	Weadock 138kV	Breaker 388		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3405	12/31/2010	Weadock 138kV	Breaker 488		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3406	12/31/2010	Weadock 138kV	Breaker 500		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3407	12/31/2010	Weadock 138kV	Breaker 588		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1655	3408	12/31/2010	Weadock 138kV	Breaker 688		138				MI			Planned	$160,000			Y	A
A in MTEP08	East	METC	1656	3410	12/31/2009	Argenta	Palisades	1	345			relay upgrade	MI			Planned	$611,111			Y	A
A in MTEP08	East	METC	1656	3411	12/31/2009	Argenta	Palisades	2	345			relay upgrade	MI			Planned	$611,111			Y	A
A in MTEP08	East	METC	1656	3415	12/31/2009	Livingston	Tittibawassee		345			relay upgrade	MI			Planned	$611,111			Y	A
A in MTEP08	East	METC	1656	3416	12/31/2009	Palisades	Vergennes		345			relay upgrade	MI			Planned	$611,111			Y	A
A in MTEP08	East	METC	1656	3674	10/31/2009	Keystone	Ludington	1	345			relay upgrade	MI			Planned	$611,111			Y	A
A in MTEP08	East	METC	1793	3599	12/31/2009	Argenta 345 kV	Circuit Breaker		345			New Breaker	MI			Planned	$1,100,000			Y	A
A in MTEP08	East	METC	1793	3600	12/31/2009	Argenta 138 kV	Circuit Breaker		138			New Breaker	MI			Planned	$1,100,000			Y	A
A in MTEP08	East	METC	1796	3605	6/1/2011	Twining	Almeda	1	138			Reconductor	MI	22		Planned	$19,500,000	Y		Y	A
A in MTEP08	East	METC	1797	3606	5/31/2010	Almeda	Saginaw River	1	138			Reconductor	MI	25		Planned	$21,000,000	Y		Y	A
A in MTEP08	East	METC	1798	3607	6/1/2010	Campbell	Black River	1	138			New Line	MI		15	Planned	$0	Y		Y	A
A in MTEP08	East	METC	1798	3608	6/1/2010	Campbell	New Switching Station		138			New switching station tying Campbell to Black River	MI			Planned	$23,327,551	Y		Y	A
A in MTEP08	East	METC	1798	3609	6/1/2010	Black River	Circuit Breaker		138			New Breaker	MI			Planned	$0	Y		Y	A
A in MTEP08	East	METC	1799	3610	6/1/2011	Roosevelt	Tallmadge	1	345			Remove sag limits	MI			Planned	$1,000,000			Y	A
A in MTEP08	East	METC	1813	3643	12/31/2010	Cobb	Brickyard	1	138			Rebuild line	MI	4		Planned	$3,500,000			Y	A
A in MTEP08	East	METC	1813	3644	12/31/2010	Cobb	Tallmadge	1	138			Rebuild line	MI	4		Planned	$3,500,000			Y	A
A in MTEP08	East	METC	1813	3645	12/31/2010	Cobb	Tallmadge	2	138			Rebuild line	MI	4		Planned	$0			Y	A
A in MTEP08	East	METC	1813	3646	12/31/2010	Cobb	Four Mile	1	138			Rebuild line	MI	4		Planned	$3,500,000			Y	A
A in MTEP08	East	METC	1813	3647	12/31/2010	Cobb	Sternberg	1	138			Rebuild line	MI	4		Planned	$3,500,000			Y	A
A in MTEP08	East	METC	1814	3648	12/31/2011	Tippy	Chase	1	138			Reconductor	MI	30		Planned	$30,000,000	Y		Y	A
A in MTEP08	East	METC	1818	3668	5/31/2011	Algoma	Croton	1	138			Rebuild 138 kV Line (Prebuild 230 kV construction)	MI			Planned	$17,150,000	Y		Y	A
A in MTEP08	East	METC	1819	3669	12/31/2009	Felch Road	Croton	1	138			Rebuild 138 kV Line (Prebuild 230 kV construction)	MI			Planned	$7,750,000	Y		Y	A
A in MTEP08	East	METC	1820	2872	12/31/2008	METC Communication and Relaying Upgrade	Throughout system						MI			Proposed	$10,000,000			Y	A
A in MTEP08	East	METC	1829	3677	6/1/2009	Leoni	Beecher	1	138			Increase Capacity	MI			Planned	$450,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	East	METC	1834	3695	12/15/2011	Tirrell Road	Battle Creek	1	138			Tirrel Rd. taps the Battle Creek-Cochran 138kV circuit	MI			Planned	$100,000			Y	A
A in MTEP08	East	METC	1834	3696	12/15/2011	Tirrell Road	Cochran Jct.	1	138			Tirrel Rd. taps the Battle Creek-Cochran 138kV circuit	MI			Planned	$100,000			Y	A
A in MTEP08	East	METC	1838	3702	11/1/2009	College (formerly Meridian)	Delhi	1	138			Meridian Loops into the Delhi-Hagadorn 138kV circuit	MI			Planned				Y	A
A in MTEP08	East	METC	1838	3703	11/1/2009	College (formerly Meridian)	Hagadorn Jct.	1	138			Meridian Loops into the Delhi-Hagadorn 138kV circuit	MI			Planned	$2,200,000			Y	A
A in MTEP08	East	METC	1841	3708	6/1/2010	Eagles Landing	Cottage Grove	1	138			Eagles Landing Taps the Cottage Grove - East Tawas 138kV circuit	MI			Planned				Y	A
A in MTEP08	East	METC	1841	3709	6/1/2010	Eagles Landing	East Tawas	1	138			Eagles Landing Taps the Cottage Grove - East Tawas 138kV circuit	MI			Planned	$175,000			Y	A
A in MTEP08	East	METC	1964	4831	12/31/2009	Chester 138	Tap and switch	1	138		168MVA	Add 138 kV Tap and Switch	MI			Planned	$200,000			Y	A
A in MTEP07	East	METC	1817	3651	6/30/2009	Richland 345 kV	Richland 138 kV	1	345	138		New 345/138 kV transformer	MI			Under Construction	$4,268,777	Y		Y	A
A in MTEP07	East	METC	1817	3652	6/30/2009	Richland	Nelson Road	1	345			New switching station with Nelson Road-Tittabawassee cut in	MI			Under Construction	$6,219,578	Y		Y	A
A in MTEP07	East	METC	1817	3653	6/30/2009	Richland	Tittabawassee	1	345			New switching station with Nelson Road-Tittabawassee cut in	MI			Under Construction	$6,219,578	Y		Y	A
A in MTEP07	East	METC	1817	3655	7/31/2009	Richland	Orr Road #2	1	138			New 3-5 mile 138 kV Line	MI		3	Under Construction	$2,875,997	Y		Y	A
A in MTEP07	East	METC	1817	3666	12/31/2009	Tittabawassee	Substation Equipment		138			Remove reactors	MI			Planned				Y	A
A in MTEP07	East	METC	1817	3667	12/31/2009	Tittabawassee	Substation Equipment		138			Replace nine 138 kV breakers	MI			Planned	$2,234,922			Y	A
A in MTEP06	East	METC	981	1544	6/1/2013	Wabasis J. - N. Belding - Vergennes	Wabasis	1	138			Install aTap Pole and Switches	MI			Planned	$160,000			Y	A
A in MTEP06	East	METC	988	1551	12/1/2010	Simpson	Batavia	1	138				MI		30	Planned	$13,000,000	Y		Y	A
A in MTEP06	East	METC	1408	2411	12/31/2008	RTU/SCADA upgrades	Throughtout System		345	138		Install and/or upgrade numerous RTU/SCADA points	MI			Under Construction	$801,000			Y	A
A in MTEP06	East	METC	1425	2430	12/1/2009	Keystone 138kV	Elmwood 138kV	1	138			Install a new substation. Relay upgrades. (Gray Rd)	MI			Planned	$4,136,000			Y	A
A in MTEP06	East	METC	1433	2437	6/1/2011	Beals 138kV	Hazelwood 138kV	1	138			Install bulk substation served from the Beals Hazelwood 138kV Line (Buskirk)	MI			Planned	$2,200,000			Y	A
A in MTEP06	East	METC	1434	2438	6/1/2010	Spaulding 138kV			138			Install bulk substation served from the Spaulding 138kV ring bus (Five Mile)	MI			Planned	$750,000			Y	A
A in MTEP06	East	METC	1437	2441	6/1/2010	Argenta 138kV	Milham 138kV	1	138			Install a tap pole and two switches on Argenta-Milham 138kV Line (N Ave)	MI			Planned	$160,000			Y	A
A in MTEP06	East	METC	1438	2442	6/1/2010	Wexford 138kV	Tippy 138kV	1	138			Install a tap pole and one switch on Wexford Tippy 138kV Line (Potvin)	MI			Planned	$80,000			Y	A
A in MTEP06	East	METC	1440	2444	6/1/2010	Beals 138kV	Wayland 138kV	1	138			Install a tap pole and two switches on Beals Rd-Wayland-Hazelwood 138kV Line (Huckleberry)	MI			Planned	$80,000			Y	A
A in MTEP06	East	METC	1444	2448	6/1/2011	Bullock 138kV	Edenville Junction 138kV	1	138			Install a tap pole and two switches on Bullock-Edenville 138kV Line (Dublin)	MI			Planned	$160,000			Y	A
A in MTEP06	East	METC	1445	2449	6/1/2010	Emmet 138kV	distribution		138			Install a second distribution transformer at Emmet (Emmet)	MI			Planned	$2,750,000			Y	A
A in MTEP06	East	METC	1446	2450	6/1/2010	Gaines 138kV			138			Install bulk substation at Gaines (Gaines)	MI			Planned	$50,000			Y	A
A in MTEP06	East	METC	1447	2451	6/1/2012	Eureka 138kV	Vestaburg 138kV	1	138			Install bulk substation served from the Eureka-Deja-Vestaburg 138kV Line (Horseshoe Creek/Deja)	MI			Planned	$2,200,000			Y	A
A in MTEP06	East	METC	1449	2453	6/1/2012	Cobb 138kV	Tallmadge 138kV	2	138			Install bulk substation served from the Cobb-Tallmadge #2 138kV Line (Juniper)	MI			Planned	$160,000			Y	A
A in MTEP08	West	MP	1482	2262	4/1/2009	Pepin Lake 115/34.5	Transformer	1	115	34.5	39	new sub	MN			Under Construction	$2,836,500			Y	A
A in MTEP07	West	MP	277	579	5/1/2010	Pine River	Pequot Lakes	1	115		182	New Line	MN		8.9	Under Construction	$4,326,900	Y		Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP07	West	MP	277	2944	11/30/2009	Pine River	Substation Equipment	1	115	34.5	39	Substation Equipment & Transformer	MN			Under Construction	$3,991,500			Y	A
A in MTEP07	West	MP	1025	2659	7/1/2012	Blackberry 230			230			Blackberry Sub: 3 each-230 kV circuit breakers, 9 each-230 kV air break switches, structural steel, bus work and control equipment	MN			Planned	$3,163,583	Y		Y	A
A in MTEP07	West	MP	1025	2660	7/1/2012	Boswell 230	Swatara 230		230			Boswell to Swatara 34.6 Miles	MN			Planned	$34,069,591	Y		Y	A
A in MTEP07	West	MP	1025	2661	7/1/2012	Swatara 230	Riverton 230		230			Swatara to Riverton 33.2 Miles	MN			Planned	$24,878,937	Y		Y	A
A in MTEP07	West	MP	1025	2662	7/1/2012	Blackberry 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Boswell	MN			Planned	$3,017,108	Y		Y	A
A in MTEP07	West	MP	1025	2663	7/1/2012	Swatara 230/115 kV	transformer		230	115		New 230/115 kV Swatara Substation	MN			Planned	$8,817,640	Y		Y	A
A in MTEP07	West	MP	1025	2664	7/1/2012	Riverton 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Riverton	MN			Planned	$2,372,682	Y		Y	A
A in MTEP07	West	MP	1286	2115	12/31/2009	Two Harbors	capacitor		115		25 Mvar	New Switching station & 25 MVAR cap	MN			Under Construction	$2,970,500			Y	A
A in MTEP05	West	MP	600	2943	4/1/2010	Scearcyville	switching station		115			new switching station	MN			Planned	$3,500,000			Y	A
A in MTEP07	West	MP/GRE	277	2263	9/1/2009	Badoura	Pine River	1	115		182	New Line	MN		19.8	Under Construction	$10,333,200			Y	A
A in MTEP07	West	MP/GRE	277	2945	5/1/2010	Pequot Lakes	Substation Equipment	1	115			Substation Equipment	MN			Planned	$1,300,000			Y	A
A in MTEP07	West	MP/GRE	277	2946	11/30/2009	Badoura	Substation Equipment	1	115			Substation Equipment	MN			Under Construction	$3,204,900			Y	A
A in MTEP07	West	MP/GRE	1021	2947	10/1/2009	Embarrass 115	New Substation	1	115			New Substation	MN		15	Under Construction	$3,095,700			Y	A
A in MTEP07	West	MP/GRE	1021	2948	11/1/2009	Tower 115	New Substation	1	115			New Substation	MN		15	Under Construction	$3,094,700			Y	A
A in MTEP07	West	MP/GRE	1022	1591	9/1/2009	Badoura 115	Long Lake 115	1	115		182	New 115 kV line	MN		17	Under Construction	$8,621,000	Y		Y	A
A in MTEP06	West	MPC/XEL/OTP/I	279	1098	12/31/2011	Boswell	Wilton	1	230		495	Add a new 230 kV line between Boswell and Wilton with a Cass Lake 230/115 kV Tap approximately 18 miles from Wilton	MN		68	Proposed	$96,027,080	Y		Y	A
A in MTEP06	West	MPC/XEL/OTP/I	279	3584	12/31/2011	Cass Lake 230 kV	Cass Lake 115 kV	1	230	115	187 MVA	Add a 230/115 kV Transformer at Cass Lake	MN			Proposed	$5,000,000	N		Y	A
A in MTEP08	East	NIPS	1977	2767	6/1/2009	Leesburg	New 138/69 kV Substation		138	69		Install 138/69 kV Transformer and 2 69 kV Circuits at Leesburg Substation	IN			Proposed	$5,407,000			Y	A
A in MTEP08	East	NIPS	1978	2768	12/1/2009	Goshen Jct	Goshen Jct	1	69		81	Circuit 6976 - Reconductor 2/0 ACSR to 336.4kcm ACSR	IN	2.1		Planned	$190,000			Y	A
A in MTEP08	East	NIPS	1986	2776	12/1/2011	Green Acres	Transformer		138	69		Add new transformer	IN			Planned	$755,000			Y	A
A in MTEP08	East	NIPS	1992	2782	4/1/2009	Starke	Transformers	1 & 2	138	69	70	Upgrade 138/69 kV Transformer Capacity. Add Pumps.	IN			Planned	$126,000			Y	A
A in MTEP08	East	NIPS	1996	2786	12/1/2009	Angola	Switch #644	1	69		81	Circuit 6980 - Reconductor 2/0 CU to 336.4kcm ACSR	IN	12		Planned	$1,780,000			Y	A
A in MTEP08	East	NIPS	1997	2787	12/1/2012	Goshen Junction	Model Tap	1	69		81	Circuit 6977 - Reconductor 4/0 CU to 336.4kcm ACSR	IN	1.5		Planned	$357,000			Y	A
A in MTEP06	East	NIPS	1298	2128	1/1/2009	Inland #5	Marktown	1	138		316	Upgrade Connections and Circuit	IN	2.2		Planned	$750,000			Y	A
A in MTEP08	West	NWE	2008	3989	6/8/2008	Milltown Tap	Luck NSP		69		15	Rebuild the 34.5Kv system between Milltown and Luck NSP sub at 69KV with 477ASCR and horizontal post construction.	WI	1.3	0	Planned	$165,000			Y	A
A in MTEP08	West	NWE	2009	3990	6/9/2008	Milltown Tap	Eureka Tap		69		31	Rebuild the 34.5KV system between Milltown Tap and Eureka Tap at 69KV by replacing poles and using same conductor.	WI	1.5	0	Planned	$125,000			Y	A
A in MTEP08	West	NWE	2010	3991	6/9/2008	Eureka Tap	Balsam Lake		69		31	Rebuild the 34.5KV system between Eureka Tap and Balsam Lake at 69KV by replacing poles and using same conductor.	WI	3.5	0	Planned	$265,000			Y	A
A in MTEP08	West	NWE	2011	3992	12/9/2008	Frederic	Lewis		69		31	Rebuild the 34.5Kv system between Frederic and Lewis sub at 69KV with 477ASCR and horizontal post construction.	WI	2.8	0	Planned	$350,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	NWE	2012	3993	6/10/2008	Falun	Penta		69		47	Rebuild the 34.5Kv system between Falun and Penta sub at 69KV with 477ASCR and horizontal post construction.	WI	4.3	0	Planned	$538,000			Y	A
A in MTEP08	West	NWE	2013	3994	6/10/2008	Penta	Siren Tap		69		15	Rebuild the 34.5Kv system between Penta sub and Siren Tap at 69KV with 477ASCR and horizontal post construction.	WI	1.4	0	Planned	$175,000			Y	A
A in MTEP08	West	NWE	2014	3995	6/11/2008	Garfield	Balsam Lake		69		31	Rebuild the 69KV line with 477 ASCR and horizontal post construction.	WI	4	0	Proposed	$500,000			Y	A
A in MTEP08	West	NWE	2015	3996	6/11/2008	Balsam Lake Substation	Balsam Lake Substation		69			Build new Balsam Lake transmission substation	WI	0	0	Proposed	$500,000			Y	A
A in MTEP08	West	NWE	2016	3997	6/12/2008	Frederic	Coffee Cup		69		62	Reconductor 69KV line with 477ACSR	WI	2	0	Planned	$100,000			Y	A
A in MTEP08	West	NWE	2017	3998	6/12/2008	Milltown Tap	Balsam Lake		69		31	Reconductor 69KV line with 477ACSR	WI	5	0	Planned	$250,000			Y	A
A in MTEP08	West	NWE	2018	3999	6/12/2008	Balsam Lake	Centuria		69	12.5		Build new 69KV line to Centuria and build Distribution Sub	WI	0	4	Proposed	$750,000			Y	A
A in MTEP08	West	OTP	1792	3591	6/30/2010	Buffalo 115 kV	Casselton Ethanol 115 kV	1	115		329	A new 115 kv line from Casselton Ethanol to Buffalo	ND		17	Planned	$6,980,000			Y	A
A in MTEP08	West	OTP	2090	3582	12/31/2009	Cass Lake 115 kV	2x15 Mvar capacitor Bank		115		30 Mvar	Addition of 2 x 15 Mvar capacitor at the Cass Lake 115 kV bus	MN			Planned	$630,000			Y	A
A in MTEP08	West	OTP	2092	3585	12/31/2010	New East Fergus	New South Cascade	1	115		161	Analysis is not complete - Proposing to tap the Hoot Lake to Grant Co (63223-63219) 115 kV line approximately 1.5 miles from Hoot Lake and add approx 2 miles of new 115 kV line to provide additional source for Fergus Falls, MN load	MN		2	Proposed	$2,000,000			Y	A
A in MTEP06	West	OTP	1462	2514	11/30/2009	Rugby	radial line		230			The new 230 KV overhead radial transmission line Interconnection Facilities from the Interconnection Customer's collector substation to the Transmission Owner's Rugby Substation.	ND		9	Planned	$88,000			Y	A
A in MTEP06	West	OTP	1462	2515	11/30/2009	Rugby	bus		230			The Transmission Owner Network Upgrades consist of a 230 kV breaker within the Rugby Substation needed to accommodate the interconnection of the Interconnection Customer's 230 kV radial transmission line into the substation 230 kV bus.	ND			Planned	$104,809			Y	A
A in MTEP06	West	OTP	1462	2516	11/30/2009	Rugby	substation		230			The Transmission Owner will upgrade the Rugby Substation to accommodate the interconnection of the Interconnection Customer's 230 kV radial transmission line into the Rugby Substation.	ND			Planned	$705,931	Y		Y	A
A in MTEP08	West	OTP/MPC	971	235	12/31/2011	Winger 230-115 kV	transformer	1	230	115	187	Final Design not complete - Either add 2nd 230/115 kV TX or replace existing 187 MVA transformer with something larger	MN			Proposed	$3,715,351			Y	A
A in MTEP08	West	OTP/MPC	2091	3583	12/31/2009	Cass Lake 115 kV	Cass Lake 69, 41.6 kV	1	115	69	55 MVA	Replace existing transformer at Cass Lake with a 55 MVA 115/69/41.6 kV transformer	MN			Planned	$1,000,000			NT	A
A in MTEP08	Central	SIPC	1778	2871	7/1/2008	Hamilton (SIPC)	Norris (Ameren)		138			Construct a 138KV line connecting SIPC Hamilton Substation to Ameren Norris City Substation. This project includes the construction of 18 miles of 138KV line.	IL			Planned	$5,000,000			Y	A
A in MTEP03	Central	SIPC	81	60	7/1/2009	Marion	CarrierMills	1	161		286		IL		27	Planned	$7,083,000			Y	A
A in MTEP08	Central	Vectren	1001	1565	7/15/2009	Oak Grove 138/69 kV	transformer	1	138	69	168/176	new transformer	IN			Under Construction	$8,950,000			Y	A
A in MTEP08	Central	Vectren	1002	1566	12/31/2009	Northeast	Oak Grove	77	138		287/287	new line	IN		5	Planned	$2,800,000			Y	A
A in MTEP08	Central	Vectren	1002	1567	12/15/2009	Oak Grove	Culley	77	138		287/287	new line	IN		10	Under Construction	$5,700,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	Central	Vectren	1780	3570	6/1/2010	Aventine Ph II	Substation	1	69	12.5	16/20	2nd XFMR	IN			Planned	$1,325,000			NT	A
A in MTEP08	Central	Vectren	1782	3572	12/31/2009	Northeast Sub Bus reconfig	Substation	1	138			Rebuild existing straight bus with more reliable breaker and half scheme	IN			Planned	$3,300,000			Y	A
A in MTEP08	Central	Vectren	1783	3573	10/1/2009	Princeton Area Load Growth	Substation	1	69	12.5	16/20	2nd XFMR at Kings	IN			Under Construction	$400,000			NT	A
A in MTEP08	Central	Vectren	1784	3574	6/1/2012	Jasper#3 Sub Exp-Victory Line	Victory	1	69			Extend existing Victory line to new term at existing sub	IN			Planned	$1,250,000			NT	A
A in MTEP08	Central	Vectren	1785	3575	12/31/2009	Z83 Upgrade NE	Z83 Upgrade NW	83	138			Upgrade terminal equipment at NE and NW.	IN			Planned	$100,000			Y	A
A in MTEP08	Central	Vectren	1786	3576	12/31/2009	Z98 Upgrade AB Brown	Z98 Upgrade Point	98	138			Upgrade terminal equipment at AB Brown and Point	IN			Planned	$100,000			Y	A
A in MTEP08	Central	Vectren	1787	3577	6/1/2012	Dale Sub	Santa Clause Sub	75	69			New 69kV line from Dale Sub to Santa Clause Sub	IN			Planned	$3,300,000			NT	A
A in MTEP08	Central	Vectren	1788	3578	6/1/2012	St. Wendel Sub	Mohr Rd Sub	34	69			New 69kV line from St. Wendel Sub to Mohr Rd Sub	IN			Planned	$2,600,000			NT	A
A in MTEP08	Central	Vectren	1789	3579	6/1/2012	Boonville Sub	Boonville Pioneer Sub	56	69			New 69kV line from Boonville Sub to Boonville Pioneer Sub	IN			Planned	$1,400,000			NT	A
A in MTEP08	Central	Vectren	1790	3580	6/1/2012	NE Sub	Elliott Sub	52	69			Rebuild/Reconductor existing Y52 and loop into Sunbeam	IN			Planned	$1,500,000			NT	A
A in MTEP08	Central	Vectren	1791	3581	6/1/2012	Angel Mound Sub	East Side Sub	66	69			Uprate term equipment to increase capacity for Y66-2	IN			Planned	$300,000			NT	A
A in MTEP08	Central	Vectren	1970	1971	5/31/2011	AB Brown 345/138 kV	transformer	1	345	138	448/470	New 345 bus & transformer	IN			Planned	$7,680,032	Y		Y	A
A in MTEP06	Central	Vectren	1257	1972	5/31/2011	AB Brown	Gibson (Duke)	15	345		1430/1430	new line	IN		40	Planned	$39,400,000	Y	Y	Y	A
A in MTEP06	Central	Vectren	1257	1973	5/31/2011	AB Brown	Reid (BREC)	17	345		1430/1430	new line	IN/KY		24	Planned	$26,600,000	Y	Y	Y	A
A in MTEP08	East	WPSC	1209	1904	12/31/2010	Hersey	Bus Upgrade		69			Convert Single Bus to Breaker and half bus	MI			Planned	$4,500,000			Y	A
A in MTEP08	East	WPSC	1209	3847	12/31/2010	Hersey	Transformer Addition		138	69	150MVA	Add 150/168MVA transformer to the Hersey Sub	MI			Planned	$2,500,000			Y	A
A in MTEP08	East	WPSC	1209	3848	12/31/2010	Hersey	138kV Tap		138			Tap the Mecosta to Acuglas 138kV line to connect to the 138/69kV transformer at Hersey	MI			Planned	$1,000,000			Y	A
A in MTEP08	East	WPSC	1214	1909	12/31/2009	Garfield X	Grawn	1	69		143.4MVA	Rebuild Overloaded line	MI	7.68		Planned	$3,400,000			Y	A
A in MTEP08	East	WPSC	1219	1914	12/31/2009	Lake County	Star Lake		69		143.4MVA	Rebuild Overloaded Line	MI	7.72		Planned	$2,750,000			Y	A
A in MTEP08	East	WPSC	1219	2169	12/31/2009	Plains X	Star Lake		69		143.4MVA	Rebuild Overloaded line	MI	7.02		Planned	$3,450,000			Y	A
A in MTEP08	East	WPSC	1222	1917	12/31/2011	Lake County	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Planned	$2,550,000			Y	A
A in MTEP08	East	WPSC	1222	2129	12/31/2011	Lake County 138	Lake County 69		138	69	150MVA	Add 168MV transformer	MI			Planned	$3,500,000			Y	A
A in MTEP08	East	WPSC	1274	1996	12/31/2011	Allendale	Blendon		69		143.4MVA	Rebuild Overloaded line	MI	2.11		Planned	$825,000			Y	A
A in MTEP08	East	WPSC	1274	3257	12/31/2011	Allendale	Osipoff	1	69		143.4MVA	Rebuild Overloaded line	MI	14.53		Planned	$5,175,000			Y	A
A in MTEP08	East	WPSC	1276	1998	12/31/2011	Burnips	Goodwin		69		143.4MVA	Rebuild Overloaded line	MI	13.09		Planned	$4,975,000			Y	A
A in MTEP08	East	WPSC	1276	1999	12/31/2011	Wayland	Goodwin		69		143.4MVA	Rebuild Overloaded line	MI	4.58		Planned	$2,025,000			Y	A
A in MTEP08	East	WPSC	1311	2166	12/31/2012	Copemish	Karlin		69		143.4MVA	Rebuild Overloaded line	MI	13.59		Planned	$4,850,000			Y	A
A in MTEP08	East	WPSC	1311	2167	12/31/2012	Grawn	Karlin		69		143.4MVA	Rebuild Overloaded line	MI	6.61		Planned	$2,350,000			Y	A
A in MTEP08	East	WPSC	1313	2168	12/31/2010	Baldwin	Plains X		69		143.4MVA	Rebuild Overloaded line (Off peak case)	MI	6.94		Planned	$2,500,000			Y	A
A in MTEP08	East	WPSC	1313	3850	12/31/2010	Hersey	Lincoln X	1	69		143.4MVA	Rebuild Overloaded Line (Off peak case)	MI	3.05		Planned	$1,600,000			Y	A
A in MTEP08	East	WPSC	1313	3851	12/31/2010	Lincoln X	Baldwin	1	69		143.4MVA	Rebuild Overloaded Line (Off peak case)	MI	16.47		Planned	$5,900,000			Y	A
A in MTEP08	East	WPSC	1577	3129	12/31/2012	Copemish	Bretheren	1	69		143.4MVA	Rebuild Overloaded line	MI	10.81		Planned	$3,850,000			Y	A
A in MTEP08	East	WPSC	1577	3135	12/31/2012	Bretheren	Bass Lake	1	69		143.4MVA	Rebuild Overloaded line	MI	18.11		Planned	$6,450,000			Y	A
A in MTEP08	East	WPSC	1581	3134	12/31/2011	Alba	Graves X	1	69		143.4MVA	Rebuild Overloaded line	MI	4.72		Planned	$2,300,000			Y	A
A in MTEP08	East	WPSC	1581	3233	12/31/2011	East Jordan X	Graves X	1	69		143.4MVA	Rebuild Overloaded line	MI	7.14		Planned	$3,500,000			Y	A
A in MTEP08	East	WPSC	1581	3852	12/31/2011	Advance	Advance Dist.	1	69		198/257.4	Rebuild Overloaded Line	MI	0.91		Planned	$500,000			Y	A
A in MTEP08	East	WPSC	1581	3853	12/31/2011	Advance Dist.	East Jordan X	1	69		143.4MVA	Rebuild Overloaded Line	MI	4.66		Planned	$1,700,000			Y	A
A in MTEP08	East	WPSC	1586	3143	12/31/2014	Elmira	Advance	1	69		143.4MVA	Rebuild Overloaded line	MI	16.26		Proposed	$5,700,000			Y	A
A in MTEP08	East	WPSC	1586	3144	12/31/2010	Advance	Wilson	1	69		143.4MVA	Rebuild Overloaded line	MI	4.7		Planned	$2,462,500			Y	A
A in MTEP08	East	WPSC	1586	3145	12/31/2010	Wilson	Boyne City	1	69		143.4MVA	Rebuild Overloaded line	MI	3.04		Planned	$1,612,500			Y	A
A in MTEP08	East	WPSC	1586	3146	12/31/2010	Boyne City	Hayes X	1	69		143.4MVA	Rebuild Overloaded line	MI	0		Planned	$50,000			Y	A
A in MTEP08	East	WPSC	1586	3147	12/31/2010	Hayes X	Petoskey	1	69		143.4MVA	Rebuild Overloaded line	MI	10.48		Planned	$3,862,500			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	East	WPSC	1586	3148	12/31/2010	Petoskey	Petoskey Distribution	1	69		143.4MVA	Rebuild Overloaded line	MI	0		Planned	$50,000			Y	A
A in MTEP08	East	WPSC	1586	3149	12/31/2010	Petoskey Distribution	Oden	1	69		143.4MVA	Rebuild Overloaded line	MI	5.24		Planned	$1,962,500			Y	A
A in MTEP08	East	WPSC	1964	3854	5/31/2010	Chester 138	Chester 69	1	138	69	150MVA	Add 168MV transformer and substation	MI			Planned	$7,000,000			Y	A
A in MTEP08	East	WPSC	1964	3855	5/31/2010	Tap METC Island Rd. line	Chester 138kV	1	138		393.4MVA	Build new 138kV line to connect to a new 138/69kV transformer	MI	8		Planned	$4,000,000			Y	A
A in MTEP08	East	WPSC	1965	3856	5/31/2010	Gray 138	Gray 69	1	138	69	150MVA	Add 168MV transformer and substation	MI			Planned	$6,600,000			Y	A
A in MTEP08	East	WPSC	1967	3858	12/31/2010	Wayland	Middleville X	1	69		143.4MVA	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	10.69		Planned	$3,928,000			Y	A
A in MTEP08	East	WPSC	1967	3859	12/31/2010	Middleville X	Superior	1	69		143.4MVA	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	19.73		Planned	$7,092,000			Y	A
A in MTEP08	East	WPSC	1967	3860	12/31/2010	Superior	Odessa	1	69		143.4MVA	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	0.06		Planned	$30,000			Y	A
A in MTEP08	East	WPSC	1967	3861	12/31/2010	Odesa	Sebewa	1	69		143.4MVA	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	3.37		Planned	$1,366,000			Y	A
A in MTEP08	East	WPSC	1967	3862	12/31/2010	Sebewa	Portland	1	69		143.4MVA	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	6.85		Planned	$2,584,000			Y	A
A in MTEP08	East	WPSC	1968	3863	7/3/2009	Westwood	New Sub		69			Construct a new 69kV substation to sectionalize the exising Alba to Kalkaska line.	MI			Under Construction	$2,000,000			Y	A
A in MTEP06	East	WPSC	1227	1927	12/31/2009	Gaylord Generation	Bagley X	1	69		143.4MVA	Rebuild 69 kV Line	MI	4		Planned	$1,400,000			Y	A
A in MTEP06	East	WPSC	1272	1994	12/31/2012	Redwood 138	Redwood 69		138	69	65MVA	Add 75MV transformer	MI			Planned	$3,000,000			Y	A
A in MTEP06	East	WPSC	1465	2527	10/1/2008	Donaldson Creek Sub	interconnection upgrades		138			The 138 kV double circuit line with one side operated at 69 kV and the other at 138 kV, connecting the Transmission Owner's Donaldson Creek Substation and the Generating Facilities' 138 kV Collector Station will be designed and built by Transmission Owner	MI			Planned	$164,997			Y	A
A in MTEP06	East	WPSC	1465	2528	10/1/2008	Donaldson Creek Sub	radial line		138			Construction of a new 138 kV transmission line from the Generating Facility Collector Substation to the Transmission Owner's Donaldson Creek 138 kV Substation will be required. The first section of the line will consist of a short single circuit 138 kV se	MI		6	Planned	$1,080,000			Y	A
A in MTEP06	East	WPSC	1465	2529	10/1/2008	Donaldson Creek Sub	network upgrades		138			138 kV circuit breakers at POI, Below Grade Development for 138 kV Breakers 11B7, 11M9 and 11W8 including installation of the foundations, furnishing and installing the underground conduits and furnishing and installing the ground grid associated with 11B	MI			Planned	$845,291	Y		Y	A
A in MTEP06	East	WPSC	1465	2562	10/1/2008	Redwood 138/69	transformer		138	69		upgrade?	MI			Planned	$2,022,328	Y		Y	A
A in MTEP06	East	WPSC	1465	2563	10/1/2008	G418, 69 kV line upgrades			69			69 kV line upgrades	MI			Planned	$1,080,000	Y		Y	A
A in MTEP08	West	XEL	675	1364	6/1/2011	Westgate	Scott County	1	115		194 MVA	upgrade line	MN	20.1		Planned	$14,000,000			Y	A
A in MTEP08	West	XEL	1285	2114	6/1/2011	Glencoe	West Waconia	1	115		310/341	Build 18 miles 115 kV line from Glencoe - West Waconia	MN		18	Planned	$18,800,000	Y		Y	A
A in MTEP08	West	XEL	1368	2287	6/1/2010	Kinnickinnic	Three Lakes	1	69		-	New substation on existing Kinnickinnic - Roberts 69 kV line	WI			Planned				NT	A
A in MTEP08	West	XEL	1368	2288	6/1/2010	Three Lakes	Roberts	1	69		-	New substation on existing Kinnickinnic - Roberts 69 kV line	WI			Planned				NT	A
A in MTEP08	West	XEL	1368	2289	6/1/2010	Pine Lake	Three Lakes	1	115		-	New substation on existing Pine Lake - Willow River 115 kV line	WI			Planned				Y	A
A in MTEP08	West	XEL	1368	2290	6/1/2010	Three Lakes	Willow River	1	115		-	New substation on existing Pine Lake - Willow River 115 kV line	WI			Planned				Y	A
A in MTEP08	West	XEL	1368	2291	6/1/2010	Three Lakes	Transformer	1	115	69	112 MVA	New transformer at Three Lake sub	WI			Planned	$10,123,000			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	XEL	1369	2292	9/1/2010	Osceola	Sand Lake	1	69		84	Reconductor	WI			Planned	$400,000			NT	A
A in MTEP08	West	XEL	1370	2293	7/1/2010	Pine Lake	Rush River	1	161		-	Relocate the 69 kV rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI			Planned				Y	A
A in MTEP08	West	XEL	1370	2294	7/1/2010	Rush River	Crystal Cave	1	161		-	Relocate the 69 kV rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI			Planned				Y	A
A in MTEP08	West	XEL	1370	3277	7/1/2010	Rush River	transformer	1	161	23.9		New distribution substation	WI			Planned	$11,672,000			Y	A
A in MTEP08	West	XEL	1373	2297	6/1/2010	Ft. Ridgeley	West New Ulm	1	115		620	new Line	MN			Planned	$1,200,000			Y	A
A in MTEP08	West	XEL	1373	2298	6/1/2010	West New Ulm	New Ulm	1	69		84	Reconductor	MN			Planned	$300,000			NT	A
A in MTEP08	West	XEL	1375	2300	6/1/2010	Hazel Creek	Minnesota Valley	1	115		310	New 1115 kV Line	MN			Proposed	$5,000,000			Y	A
A in MTEP08	West	XEL	1375	2302	7/1/2009	Lake Yankton	SW Marshall	1	115		310	New 115 kV line	MN			Planned	$5,000,000			Y	A
A in MTEP08	West	XEL	1486	2282	2/1/2010	Mary Lake	City of Buffalo	1	69		116	New 115 kV line operated at 69 kV	MN			Planned	$2,190,000			NT	A
A in MTEP08	West	XEL	1487	2306	12/31/2011	Somerset	Stanton	1	69		84	New 69 kV line	WI			Planned	$9,247,500			NT	A
A in MTEP08	West	XEL	1545	2624	4/1/2010	South Bend	Wilmarth	1	115		139	Line terminations at Wilmarth and South Bend	MN			Planned	$280,000			Y	A
A in MTEP08	West	XEL	1548	2632	6/1/2010	La Crosse	Capacitor Bank		161		60 MVAR	Install capacitor banks to maintain contingent voltage	WI			Planned	$2,300,000			Y	A
A in MTEP08	West	XEL	1548	3278	6/1/2010	Monroe County	Capacitor		161		2x30 MVAR	capacitor banks	WI			Planned				Y	A
A in MTEP08	West	XEL	1549	2633	10/1/2010	Eau Claire	Hallie		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Substation to 161 kV	WI	1.5		Planned	$2,425,000			Y	A
A in MTEP08	West	XEL	1549	2634	2/1/2011	Hallie	Gravel Island		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Substation to 161 kV	WI	2.5		Planned	$2,865,000			Y	A
A in MTEP08	West	XEL	1549	2635	2/1/2011	Wheaton	Eau Claire		161		335	Terminate Wheaton - Presto Tap 161 kV Line at Eau Claire Substation	WI			Planned	$1,065,000			Y	A
A in MTEP08	West	XEL	1549	2636	12/1/2009	Wheaton Tap	Wheaton		161		335	Construct 2.2 miles of new 161 kV line, double-circuited with existing circuit, to avoid parallel three-terminal lines	WI		2.2	Planned	$2,902,000			Y	A
A in MTEP08	West	XEL	1549	2637	12/1/2010	Gravel Island	substation		161	69	70	Construct 161/69 kV Substation with two 70 MVA transformers	WI			Planned	$10,700,000			Y	A
A in MTEP08	West	XEL	1549	2638	2/1/2011	Wheaton	Eau Claire		161		434	Reconductor 4.3 Miles of 161 kV line with 795 ACSS conductor	WI	4.3		Planned	$645,000			Y	A
A in MTEP08	West	XEL	1953	3834	12/1/2010	St. Cloud	Sauk River	1	115		239 MVA	reconductor St. Cloud - Sauk River 115 kV line to 795 ACSS	MN			Planned	$5,264,000	Y		Y	A
A in MTEP08	West	XEL	1954	3835	12/1/2011	Cherry Creek	Split Rock	1,2	115			Separate the double circuit line to two single circuits	SD			Planned	$1,189,200			Y	A
A in MTEP08	West	XEL	1955	3836	7/1/2009	Grove Lake switching station			69			New three 69 kV switching station at Bangor tap	WI			Planned	$900,000			NT	A
A in MTEP08	West	XEL	1956	3837	12/1/2010	Lakefield	Blue Lake	1	345		908 MVA	Phase raise.	MN			Planned	$1,904,600			Y	A
A in MTEP08	West	XEL	1957	3838	6/1/2012	Southwest of Eau Claire (new sub)	new sub	1	161	69		New 161/69 kV Substation southwest of Eau Claire where Alma – Elk Mound 161 kV line intersects with Shawtown – Naples 69 kV line	WI			Planned	$7,080,000			Y	A
A in MTEP08	West	XEL	1957	3839	6/1/2012	new sub	London - Madison tap	1	69		84 MVA	Rebuild 69 kV line from London/Madison Tap to new substation	WI			Planned	$0			NT	A
A in MTEP08	West	XEL	1957	3840	6/1/2012	new sub	Union (DPC)	1	69		84 MVA	Construct 69 kV line from new substation to DPC Union Substation	WI			Planned	$0			NT	A
A in MTEP08	West	XEL	1957	3841	6/1/2012	new sub	Burnswick	1	69		84 MVA	Construct 69 kV line from new substation to DPC Brunswick Substation	WI			Planned	$0			NT	A
A in MTEP08	West	XEL	1958	3842	12/1/2012	Stone Lake	Edge Water	1	161		434 MVA	New 161 kV line from Stone Lake to Edgewater	WI			Planned	$26,185,641			Y	A
A in MTEP08	West	XEL	1958	3843	12/1/2012	Edge Water substation	upgrade to 161 kV		161			Convert the Edgewater 69 kV load to the new 161 kV line. Construct 161 kV facilities at Edgewater Substation	WI			Planned	$0			Y	A
A in MTEP08	West	XEL	1959	3846	6/1/2010	Yankee Doodle	Pilot Knob	1	115		310 MVA	115 kV line from Yankee Doodle to Pilot Knob	MN			Planned	$3,765,200			Y	A

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A in MTEP09	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$6,483,000	Y		Y	B>A
A in MTEP08	West	XEL	1960	3844	4/1/2011	Traverse	St. Peter	1	69		84 MVA	Upgrade to 84 MVA	MN			Planned	$720,000			NT	A
A in MTEP08	West	XEL	1961	3845	12/1/2010	Lake Emily	capacitor bank				10 MVAR	new 10 MVAR capacitor bank at Lake Emily	MN			Planned	$507,200			Y	A
A in MTEP07	West	XEL	1613	2653	5/30/2012	Hazel Run Substation			115			20 Mvar SVC	MN			Planned	$4,779,000	Y		Y	A
A in MTEP07	West	XEL	1614	2654	5/30/2012	Hazel Crk Substation			115			30 Mvar SVC	MN			Planned	$4,803,000	Y		Y	A
A in MTEP06	West	XEL	1457	2301	12/31/2010	Hazel Creek	Capacitor and SVC		115		53 & 33 Mvar	Capacitor 53 Mvar, SVC 33 Mvar	MN			Planned	$0	Y		Y	A
A in MTEP06	West	XEL	1457	2494	12/15/2009	Nobles	feeders		34.5			four new 50 MW 34.5 kV feeders and all associated equipment at Nobles County Sub.	MN			Planned	$1,100,000			NT	A
A in MTEP06	West	XEL	1457	2550	12/15/2009	Nobles County	substation		115			Substation upgrades	MN			Planned	$11,992,730	Y		Y	A
A in MTEP06	West	XEL	1457	2551	12/31/2010	Hazel Creek	substation		115			New Substation and in-and-out taps to transmission	MN			Planned	$10,962,000	Y		Y	A
A in MTEP06	West	XEL	1457	2552	12/31/2009	Fenton County	substation		115			Substation upgrades	MN			Planned	$776,000	Y		Y	A
A in MTEP06	West	XEL	1457	2565	12/15/2009	Nobles County	substation		345			345 kV substation upgrades	MN			Planned	$344,270	Y	Y	Y	A
A in MTEP06	West	XEL	1458	2299	12/31/2009	Yankee	Brookings County	2	115		620	New 115 kV line plus permitting and ROW	MN			Planned	$9,955,000	Y		Y	A
A in MTEP06	West	XEL	1458	2496	11/30/2011	Yankee	feeders		34.5			four new 50 MW underground feeder lines and all associated equipment	MN			Planned	$2,202,000			NT	A
A in MTEP06	West	XEL	1458	2549	12/31/2010	Hazel Creek	Capacitor and SVC		115		53 & 33 Mvar	Capacitor 53 Mvar, CB, SVC 33 Mvar	MN			Planned	$5,290,000	Y		Y	A
A in MTEP06	West	XEL	1458	2553	12/31/2009	Yankee	substation		115		120 MVA	Substation upgrades (new 115/34.5 transformer, 8-115 kV CB, 4 -34.5 kV CB)	MN			Planned	$7,120,000	Y		Y	A
A in MTEP06	West	XEL	1458	2554	12/31/2009	Brookings Co	substation	2	345	115	448 MVA	Substation upgrades (new 345/115 transformer, 3-115 kV CB, associated equip)	MN			Planned	$6,101,122	Y		Y	A
A in MTEP06	West	XEL	1458	2566	12/31/2009	Brookings Co	substation		345			Substation upgrades 4-345 kV CB	MN			Planned	$1,313,878	Y	Y	Y	A
A in MTEP06	West	XEL	1459	2564	1/1/2009	Dakota County Sub	in-and-out tap		345			tap Blue Lake-Prairie Island 345 kVl ine	MN			Planned	$2,425,500	Y	Y	Y	A
A in MTEP03	West	XEL	56	301	12/31/2010	Chisago	Lindstrom	1	115		310	New 115 kV line	MN	7		Planned	$10,100,000			Y	A
A in MTEP03	West	XEL	56	303	12/31/2010	Lawrence Creek	St Croix Falls	1	161		371	New 161 kV line	MN		2.05	Planned	$9,080,000			Y	A
A in MTEP03	West	XEL	56	304	12/31/2010	Lawrence Creek 161-115 kV	transformer	1	161	115	336	New substation with 161-115 kV transformer	MN			Planned	$6,000,000			Y	A
A in MTEP03	West	XEL	56	306	12/31/2010	Lindstrom	Shafer	1	115		310	New line	MN	2.8		Planned	$5,800,000			Y	A
A in MTEP03	West	XEL	56	310	12/31/2010	Shafer	Lawrence Creek	1	115		310	small amount new ROW	MN	6.2		Planned	$3,500,000			Y	A
A in MTEP03	West	XEL	56	1088	12/31/2010	Lawrence Creek 115-69 kV	transformer	1	115	69	70		MN			Planned	$1,631,000			Y	A
A in MTEP03	West	XEL	385	2283	12/31/2009	Brookings Co	White	2	345		2085	New 345 kV line	SD/MN			Planned				Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	1673	9/30/2015	Hampton Corner	North Rochester	1	345		2050	new line	MN		36	Planned	$57,560,000			Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	1675	12/15/2012	North Rochester	Transformer	1	345	161	448	new transformer and terminal works	MN			Planned	$15,650,000	Y		Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	1676	3/31/2014	North La Crosse	Transformer	1	345	161	448	new transformer and terminal works	WI			Planned	$9,500,000	Y		Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	1677	12/15/2012	North Rochester	Northern Hills	1	161		400	new line and termial works	MN		12.6	Planned	$18,661,000	Y		Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	1678	3/30/2015	North Rochester	Chester	1	161		400	new line	MN		14	Planned	$9,009,000			Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	2647	3/31/2014	North Rochester	North La Crosse	1	345		2050	new line and termial works	MN		82	Planned	$237,033,500	Y	Y	Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	2983	3/31/2013	Hampton Corner and North Rochester	substation	1	345			new substation	MN			Planned	$7,600,000			Y	A
A in MTEP08	West	XEL,RPU,SMP,I	1024	2984	12/15/2012	North Rochester	substation	1	345			new substation	MN			Planned	$4,986,500			Y	A
A in MTEP08	West	XEL/GRE	1545	2623	4/1/2010	New South Bend 161/115/69 kV Substation			161	115		new Substation South of Wimarth. The 161/115 kV transformer from Wilmarth has to be relocated to the new substation (South bend). The Sub also includes a 115/69 kV transformer (47 MVA).	MN			Planned	$6,405,000			Y	A
A in MTEP08	West	XEL/GRE	1545	2625	4/1/2010	South Bend	Ballard Corner	1	115		310	Upgrade the existing 69 kV line from South Bend - Hungry Hollow (Pohl Road tap) to 115 kV	MN			Planned	$4,300,000			Y	A
A in MTEP08	West	XEL/GRE	1545	2626	4/1/2010	Hungry Hollow	Pohl tap	1	115		310	Upgrade the existing 69 kV line from Hungry Hollow (Pohl Road tap) - Pohl tap to 115 kV	MN			Planned	$950,000			Y	A
A in MTEP08	West	XEL/GRE	1545	4830	3/31/2010	Stoney Creek 115/69 kV Substation		1	115	69	70	new Substation South of Wimarth.	MN			Planned	$5,800,000			Y	A

Appendix A-1: MTEP09 Appendix A Project Cost Allocations by Pricing Zones

Values shown below are subject to change depending on actual project costs [1]

Proj ID	Region	ISD	Zone	Total Shared Cost[2]	Pricing Zone																						Tot Proj Cost with 100% GIP[3]
					AMIL	AMMO	ATC	CWLD	CWLP	DUK	FE	GRE	HE	IPL	ITC	ITCM	MDU	METC	MI13AG	MI13ANG	MP	NIPS	NSP	OTP	SIPC	SMMPA	VECT	Total	
1240	Central	Jun-12	AMMO	12,966,000	1,290,374	11,675,626																						12,966,000	12,966,000
2053	Central	Jun-12	IPL	15,400,000	708,273					6,240,895			1,849,832	5,372,363													1,228,637	15,400,000	15,400,000
2375GIP	Central	Dec-10	DUK	2,220,000						2,220,000																		2,220,000	4,440,000
2472	Central	Dec-16	AMIL	66,019,000	55,537,728	922,943	1,453,906	30,769	118,648	1,309,800	1,434,493	129,490	71,693	333,668	1,170,434	392,893	80,485	902,567	64,359	16,850	234,531	373,605	1,116,319	99,537	50,217	33,250	140,815	66,019,000	66,019,000
2764	Central	Dec-10	AMIL	5,655,000	641,786	642,985	380,709	21,436	32,015	912,497	746,417	33,907	49,946	232,456	609,018	102,880	21,075	469,637	33,488	8,768	61,413	194,400	292,311	26,064	34,984	8,706	98,102	5,655,000	5,655,000
Central				102,260,000	58,178,160	13,241,555	1,834,615	52,205	150,662	10,683,192	2,180,910	163,397	1,971,472	5,938,486	1,779,452	495,772	101,560	1,372,205	97,847	25,617	295,944	568,005	1,408,630	125,602	85,201	41,956	1,467,554	102,260,000	104,480,000
1612	East	Jun-12	FE	37,738,044							37,738,044																	37,738,044	37,738,044
1828	East	Jun-10	METC	10,880,000	177,940	178,273	280,832	5,943	8,876	252,997	277,082	25,012	13,848	64,450	226,078	75,890	15,546	8,878,337		3,255	45,301	72,165	215,625	19,226	9,700	6,422	27,199	10,880,000	10,880,000
662	East	Jun-13	METC	39,800,002							160,204							39,247,405				392,393						39,800,002	39,800,002
East				88,418,046	177,940	178,273	280,832	5,943	8,876	252,997	38,175,330	25,012	13,848	64,450	226,078	75,890	15,546	48,125,743	-	3,255	45,301	464,558	215,625	19,226	9,700	6,422	27,199	88,418,046	88,418,046
1355	West	Nov-15	MDU	11,000,000													10,756,475							243,525				11,000,000	11,000,000
1775GIP	West	Dec-09	ITCM	1,011,754												1,011,754												1,011,754	2,023,508
2178GIP	West	Jun-12	NSP	5,003,591			42,075					416,512				1,387,061							2,838,006				319,937	5,003,591	10,007,181
2307	West	Jun-12	NSP	6,100,000								1,235,967				10,682					537,903		4,160,226	155,221				6,100,000	6,100,000
2339GIP	West	Dec-13	ITCM	11,050,400		226,438										10,086,496							737,466					11,050,400	22,100,800
2358	West	Dec-12	ITCM	5,400,000								40,388				4,797,540							562,072					5,400,000	5,400,000
2372GIP	West	Sep-09	ITCM	2,180,057												2,180,057												2,180,057	4,360,113
2452GIP	West	Oct-10	ATC	1,933,689			1,933,689																					1,933,689	3,867,377
2455GIP	West	Dec-10	ATC	2,232,478			2,232,478																					2,232,478	4,464,956
2562GIP	West	Feb-10	GRE	4,050,000								1,527,304				1,051,269							1,471,427					4,050,000	8,100,000
2750GIP	West	Oct-09	OTP	710,109																				710,109				710,109	1,420,217
2765GIP	West	Dec-08	NSP	59,050																			59,050					59,050	118,100
2786GIP	West	Dec-10	ITCM	12,765,916								207,416				12,301,101							257,398					12,765,916	25,531,831
2796GIP	West	Mar-11	ATC	2,475,495			2,475,495																					2,475,495	4,950,990
West				65,972,537	-	226,438	6,683,736	-	-	-	-	3,427,588	-	-	-	32,825,960	10,756,475	-	-	-	537,903	-	10,085,644	1,108,854	-	319,937	-	65,972,537	109,445,073
Midwest ISO Total				256,650,583	58,356,101	13,646,266	8,799,184	58,149	159,539	10,936,189	40,356,240	3,615,997	1,985,320	6,002,937	2,005,529	33,397,623	10,873,582	49,497,947	97,847	28,872	879,149	1,032,563	11,709,900	1,253,682	94,901	368,315	1,494,753	256,650,583	302,343,119

Notes:

(1) The allocations shown above are estimates which are based on current estimates of project costs and projected in-service dates.The actual allocations will vary depending on the actual project costs and actual in-service dates.

(2) Tot. Shared Cost reflects the Project cost subject to sharing and allocated to pricing zones in the Midwest ISO. This does not include 50% of the Network Upgrade cost of the Generator Interconnection Projects (GIP) assgined to the Generators and project cost allocated to zones outside of the Midwest ISO footprint.

(3) Tot Proj Cost with 100% GIP includes the total network upgrade costs for GIPs including the 50% assigned to the generators. This does not take into account those GIPs with agreements for Transmission Owners to reimburse the generators for 100% of their Network Upgrade costs.

Appendix A-2: MTEP 09 RECB Cost Allocation Summaries

Table A-2.1: MTEP09 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Values shown below (in $) are subject to change depending on actual project costs, actual In-Service Dates, and actual Fixed Charge Rates

Year	AMIL	AMMO	ATC	CWLD	CWLP	DUK	FE	GRE	HE	IPL	ITC	ITCM
2009	-	-	-	-	-	-	-	-	-	-	-	638,362
2010	35,588	35,655	889,400	1,189	1,775	494,599	55,416	351,947	2,770	12,890	45,216	3,324,014
2011	163,945	164,252	1,460,641	5,476	8,178	677,099	204,700	358,728	12,759	59,381	167,019	3,344,590
2012	563,675	2,499,377	1,469,056	5,476	8,178	1,925,278	7,752,309	697,301	382,725	1,133,854	167,019	4,583,647
2013	563,675	2,544,665	1,469,056	5,476	8,178	1,925,278	7,784,349	697,301	382,725	1,133,854	167,019	6,600,946
2014	563,675	2,544,665	1,469,056	5,476	8,178	1,925,278	7,784,349	697,301	382,725	1,133,854	167,019	6,600,946
2015	563,675	2,544,665	1,469,056	5,476	8,178	1,925,278	7,784,349	697,301	382,725	1,133,854	167,019	6,600,946
2016	11,671,220	2,729,253	1,759,837	11,630	31,908	2,187,238	8,071,248	723,199	397,064	1,200,587	401,106	6,679,525

Year	MDU	METC	MI13AG	MI13ANG	MP	NIPS	NSP	OTP	SIPC	SMMPA	VECT	Midwest ISO Total Annual Charges (Allocation*FCR)
2009	-	-	-	-	-	-	11,810	-	-	-	-	650,172
2010	3,109	1,775,667	-	651	9,060	14,433	400,700	145,867	1,940	1,284	5,440	7,608,610
2011	7,324	1,869,595	6,698	2,404	21,343	53,313	459,162	151,080	8,937	3,026	25,060	9,234,709
2012	7,324	1,869,595	6,698	2,404	128,923	53,313	1,971,223	182,124	8,937	67,013	270,788	25,756,236
2013	7,324	9,719,076	6,698	2,404	128,923	131,792	2,118,716	182,124	8,937	67,013	270,788	35,926,317
2014	7,324	9,719,076	6,698	2,404	128,923	131,792	2,118,716	182,124	8,937	67,013	270,788	35,926,317
2015	2,158,619	9,719,076	6,698	2,404	128,923	131,792	2,118,716	230,829	8,937	67,013	270,788	38,126,317
2016	2,174,716	9,899,589	19,569	5,774	175,830	206,513	2,341,980	250,736	18,980	73,663	298,951	51,330,117

Notes:

1. The annual cumulative charges shown above are estimates only which are based on current estimates of project costs, projected in-service dates, and an assumed Fixed Charge Rate of 20%. The Fixed Charge Rate methodology used for this table does not reflect the FERC Order on October 19, 2009 modifing the methodogy used to calculate the Fixed Charge Rate for each Transmission Owner. For the purpose of these estimates, project charges were assumed to begin in the project in-service year. The actual allocations/charges will vary depending on the actual project costs, actual in-service dates, and actual Fixed Charge Rates.

2. Annual charge for allocated projects costs shown above are a cumulative revenue requirement.
   Estimated Annual Charge for Allocated Project Cost = Allocated Project Cost x Fixed Charge Rate of Constructing TO

3. Annual charges shown above include charges due to allocations from projects that originate in a zone and those projects that originate in another zone.

4. For those Transmission Owner's that have agreements with Generators to reimburse them 100% of their Network Upgrade costs the 50% that is reimbursed to the generator is not recovered through Schedule 26 and is not included in Table A-3.1 Estimated Annual Charge for Allocated Project Cost.

Table A-2.2: RECB Cost Allocation of MTEP 09 Appendix A Projects

	AMIL	AMMO	ATC	CWLD	CWLP	DUK	FE	GRE	HE	IPL	ITC	ITCM
Total Shared Project Costs	71,674,000	12,966,000	6,641,662	-	-	2,220,000	37,738,044	4,050,000	-	15,400,000	-	32,408,126
Project Cost Allocation to Others	(15,494,487)	(1,290,374)		-	-	-	-	(2,522,696)	-	(10,027,637)	-	(2,031,178)
Project Cost Allocation from Others	2,176,587	1,970,640	2,157,523	58,149	159,539	8,716,189	2,618,196	2,088,693	1,985,320	630,574	2,005,529	3,020,675
Net Project Cost	58,356,101	13,646,266	8,799,184	58,149	159,539	10,936,189	40,356,240	3,615,997	1,985,320	6,002,937	2,005,529	33,397,623
Net Transmission Plant in Service per Attachment O - June 2009	395,727,022	414,758,709	2,194,063,378	14,395,971	26,328,367	1,201,194,650	673,058,700	387,525,032	102,134,218	88,500,451	745,912,000	514,765,000

	MDU	METC	MI13AG	MI13ANG	MP	NIPS	NSP	OTP	SIPC	SMMPA	VECT	Midwest ISO Total
Total Shared Project Costs	11,000,000	50,680,002	-	-	-	-	11,162,641	710,109	-	-	-	256,650,583
Project Cost Allocation to Others	(243,525)	(2,554,259)	-	-	-	-	(4,105,358)	-	-	-	-	(38,269,514)
Project Cost Allocation from Others	117,106	1,372,205	97,847	28,872	879,149	1,032,563	4,652,618	543,573	94,901	368,315	1,494,753	38,269,514
Net Project Cost	10,873,582	49,497,947	97,847	28,872	879,149	1,032,563	11,709,900	1,253,682	94,901	368,315	1,494,753	256,650,583
Net Transmission Plant in Service per Attachment O - June 2009	61,008,255	465,139,000	n/a	n/a	112,585,385	377,439,526	1,343,221,184	130,182,174	25,020,337	110,247,862	196,107,188	9,579,314,409

Appendix A-3: MTEP 06 thru MTEP 09 RECB Cost Allocation Summaries

Table A-3.1: MTEP06 thru 09 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Values shown below (in $) are subject to change depending on actual project costs, actual In-service Dates, and actual Fixed Charge Rates

Year	AMIL	AMMO	ATC	CWLD	CWLP	DUK	FE	GRE	HE	IPL	ITC	ITCM
2009	3,537,669	857,184	52,604,425	25,804	40,361	6,997,446	7,851,185	600,424	511,401	348,770	15,818,861	4,683,415
2010	3,649,446	7,324,991	54,258,240	27,520	825,852	8,281,176	7,931,199	985,889	515,336	367,271	15,945,411	8,958,715
2011	5,340,222	8,082,072	56,542,098	47,781	856,701	13,905,332	8,894,135	2,872,480	1,007,660	1,515,492	26,217,926	9,371,369
2012	11,771,018	10,975,910	57,594,976	64,750	900,389	15,965,222	17,328,026	3,434,883	1,423,380	2,797,190	49,721,561	10,936,218
2013	12,915,212	12,177,123	97,385,798	102,625	956,878	19,437,465	19,218,075	4,363,504	1,514,029	3,216,325	51,224,100	14,129,687
2014	13,505,556	12,766,741	103,676,245	122,167	986,024	20,311,729	20,176,710	4,920,669	1,560,144	3,432,576	51,999,331	18,321,156
2015	14,369,972	13,630,093	105,192,567	150,780	1,028,700	21,591,876	21,580,397	6,613,852	1,627,669	3,749,223	53,134,468	18,980,155
2016	25,477,517	13,814,681	105,483,348	156,934	1,052,429	21,853,836	21,867,296	6,639,750	1,642,008	3,815,957	53,368,555	19,058,733

Year	MDU	METC	MI13AG	MI13ANG	MP	NIPS	NSP	OTP	SIPC	SMMPA	VECT	Midwest ISO Total
2009	68,646	18,880,825	740	15,315	3,184,560	2,903,004	9,880,273	584,745	42,458	31,606	4,674,691	134,143,808
2010	73,064	31,760,068	740	66,690	4,058,183	3,188,191	13,704,212	901,558	45,178	33,464	4,682,403	167,584,798
2011	161,711	45,272,772	24,084	543,287	10,769,805	3,439,273	33,500,224	9,198,686	110,926	53,952	9,627,009	247,354,998
2012	221,035	47,290,673	29,847	544,782	15,634,337	3,670,804	41,504,106	9,899,949	138,830	2,475,086	9,955,481	314,278,453
2013	503,274	56,272,683	108,137	565,095	19,194,484	4,237,512	57,163,344	13,860,542	198,669	2,517,239	10,122,641	401,384,442
2014	553,996	56,857,008	148,530	575,576	19,855,259	4,486,876	77,451,038	13,922,691	229,543	3,282,150	10,208,886	439,350,601
2015	3,757,386	57,712,610	207,677	590,922	24,000,078	4,852,010	103,608,947	24,697,300	274,751	3,313,996	10,335,173	495,000,601
2016	3,773,483	57,893,124	220,548	594,292	24,046,984	4,926,731	103,832,211	24,717,207	284,794	3,320,646	10,363,336	508,204,401

Notes:

1. The annual cumulative charges shown above are estimates only which are based on current estimates of project costs, projected in-service dates, and an assumed Fixed Charge Rate of 20%. The Fixed Charge Rate methodology used for this table does not reflect the FERC Order on October 19, 2009 modifing the methodogy used to calculate the Fixed Charge Rate for each Transmission Owner. For the purpose of these estimates, project charges were assumed to begin in the project in-service year. The actual allocations/charges will vary depending on the actual project costs, actual in-service dates, and actual Fixed Charge Rates. The estimated project costs are based on the most up-to-date information available.

2. Annual charge for allocated projects costs shown above are a cumulative revenue requirement.
   Estimated Annual Charge for Allocated Project Cost = Allocated Project Cost x Fixed Charge Rate of Constructing TO

3. Annual charges shown above include charges due to allocations from projects that occur in their zone and those projects that originate in another zone.

4. For those Transmission Owner's that have agreements with Generators to reimburse them 100% of their Network Upgrade costs the 50% that is reimbursed to the generator is not recovered through Schedule 26 and is not included in Table A-3.1 Estimated Annual Charge for Allocated Project Cost.

Table A-3.2: RECB Cost Allocation of MTEP 06 thru 09 Appendix A Projects

	AMIL	AMMO	ATC	CWLD	CWLP	DUK	FE	GRE	HE	IPL	ITC	ITCM
Total Shared Project Costs	117,705,079	45,347,100	563,155,129	-	3,914,650	35,642,726	72,337,678	141,571,356	-	15,400,000	278,839,943	62,429,984
Project Cost Allocation to Others	(20,786,990)	(1,590,093)	(98,067,283)	-	-	(2,100,561)	(1,835,590)	(120,318,260)	-	(10,027,637)	(41,170,706)	(8,229,177)
Project Cost Allocation from Others	30,469,498	25,316,399	62,328,895	784,672	1,347,496	75,727,014	38,834,393	11,945,656	8,210,040	13,707,421	29,173,539	41,092,859
Net Project Cost	127,387,587	69,073,406	527,416,741	784,672	5,262,146	109,269,179	109,336,480	33,198,751	8,210,040	19,079,784	266,842,776	95,293,665
Net Transmission Plant in Service per Attachment O - June 2009	395,727,022	414,758,709	2,194,063,378	14,395,971	26,328,367	1,201,194,650	673,058,700	387,525,032	102,134,218	88,500,451	745,912,000	514,765,000

	MDU	METC	MI13AG	MI13ANG	MP	NIPS	NSP	OTP	SIPC	SMMPA	VECT	Midwest ISO Total
Total Shared Project Costs	11,000,000	254,138,330	-	-	181,649,897	13,434,528	518,003,473	116,372,101	-	-	110,080,032	2,541,022,004
Project Cost Allocation to Others	(243,525)	(10,465,136)	-	-	(70,092,791)	(891,614)	(43,104,823)	(1,220,207)	-	-	(62,918,840)	(493,063,233)
Project Cost Allocation from Others	8,110,940	45,792,423	1,102,742	2,971,461	8,677,814	12,090,739	44,262,403	8,434,143	1,423,971	16,603,230	4,655,486	493,063,233
Net Project Cost	18,867,415	289,465,618	1,102,742	2,971,461	120,234,920	24,633,654	519,161,053	123,586,036	1,423,971	16,603,230	51,816,678	2,541,022,004
Net Transmission Plant in Service per Attachment O - June 2009	61,008,255	465,139,000	n/a	n/a	112,585,385	377,439,526	1,343,221,184	130,182,174	25,020,337	110,247,862	196,107,188	9,579,314,409

Appendix B: Projects in Process

Appendix A contains projects which are being or have been approved by Midwest ISO Board of Directors. Transmission Owners are obligated to make a good faith effort to construct projects in Appendix A.

Appendix B projects have been reviewed by Midwest ISO staff for need and effectivenes.

Appendix C projects are new to planning process or conceptual

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Project Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Project ID: Midwest ISO project identifier
Project Name	Project name (short name)
Project Description	A description of the project's components
State	State project is located or a majority of project if in multiple states
State 2	If applicable, the second state the project is located
Allocation Type per FF	Project Type per Attachment FF of Tariff. BaseRel is Baseline Reliability, GIP is Generator Interconnection Project, TDSP is Transmission Delivery Service Project, RegBen is Regionally Beneficial Project, Other is non of the above. Preliminary project types may be designated for Appendix B and C projects
Share Status	Projects moving to Appendix A in current planning cycle are eligible for cost allocation per terms in Attachment FF. Projects are Shared, Not Shared or Excluded. Preliminary sharing designations may be input for Appendix B or C projects.
Other Type	Indicates the project driver behind Other type projects.
Estimated Cost	Total estimated project cost from Facility table
Expected ISD	Date when entire project is expected to be inservice. Expected ISD are in Facility table.
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Max kV	Maximum facility voltage in project. Summary information from Facility table
Min kV	Minimum facility voltage in project. Summary information form Facility table
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.

Appendix B: Project Table 10/16/2009 *Project Summary Information from Facility table*

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
B	Central	AmerenIL	1234	Havana, South-Mason City, West 138 kV	Increase ground clearance on 18.4 miles	IL					$642,300	6/1/2014	Proposed	138		B	Y
B	Central	AmerenIL	1236	Stallings-Prairie State Plant 345 kV	Replace 2000 A terminal equipment with 3000 A equipment	IL					$100,000	6/1/2012	Proposed	345		B	Y
B	Central	AmerenIL	1533	Washington Street-S. Bloomington - Upgrade Terminal Equipment	Replace terminal equipment at S. Bloomington	IL					$125,900	6/1/2011	Proposed	138		B	Y
B	Central	AmerenIL	1534	W. Mt. Vernon-Xenia - Upgrade Terminal Equipment	Replace terminal equipment at W. Mt. Vernon	IL		Other	Not Shared		$2,069,600	6/1/2011	Proposed	345		B	Y
B	Central	AmerenIL	1535	Wood River-Stallings	Replace terminal equipment at Stallings, reconductor portion of line	IL					$1,564,700	6/1/2012	Proposed	138		B	Y
B	Central	AmerenIL	1537	Mt. Vernon, West-S. Centralia - Upgrade Terminal Equipment	Replace terminal equipment at S. Centralia	IL					$200,000	6/1/2012	Proposed	138		B	Y
B	Central	AmerenIL	2114	IP03	Network upgrades for tariff service request	IL		GIP	In Suspension		$2,082,000	9/30/2009	Planned	138		B	Y
B	Central	AmerenIL	2117	IP08	Network upgrades for tariff service request	IL		GIP	In Suspension		$1,891,464	12/1/2010	Planned	138		B	Y
B	Central	AmerenIL	2118	IP04, IP08	Network upgrades: Line #1382 & #1384: Project of replacing approximately 47.1 circuit miles of existing three phase, single conductor, 477 MCM 30/7 ASCR with three phase 556.5 MCM 26/7 ACSS conductor. Approximately 121 existing wood H-frame type structures will be replaced with new wood H-frame type structures to gain additional ground clearance.	IL		GIP	In Suspension		$5,426,258	12/1/2010	Planned	138		B	Y
B	Central	AmerenIL	2239	Rising to Sidney 345 kV line	Build 345 kV circuit from Rising to Sidney in Illinois	IL		RegBen			$65,600,000	1/1/2014	Proposed	345		C>B	Y
B	Central	AmerenIL	2280	LaSalle-Oglesby Main 138 kV Line 1496	Reconductor 2.16 miles of 477 kcmil ACSR and 336 kcmil ACSR to 1200 A summer emergency capability	IL		BaseRel	Not Shared		$900,000	6/1/2013	Planned	138		B	Y
B	Central	AmerenMO	2774	Adair Wind Farm	Connect Wind Farm at Adair Substation	MO		GIP	In Suspension			12/1/2009	Planned	161		B	Y
B	West	ATC LLC	89	Mill Road 345/138 kV substation and transformer	Mill Road transformer - 345/138 ckt , Sum rate 500	WI					$29,200,000	6/1/2019	Proposed	345	138	B	Y
B	West	ATC LLC	174	Canal-Dunn Road 138 kV	Construct a 7.7 mile Canal - Dunn Road 138 ckt , Sum rate 400; install a new 138/69 kV transformer at Dunn Road substation.	WI			Not Shared		$20,302,363	6/1/2012	Proposed	138	69	B	Y
B	West	ATC LLC	333	Hiawatha-Indian Lake conversion to 138 kV and Hiawatha-Pine River-Mackinac conversion to 138 kV	Construct Mackinac 138 kV substation (new Straits substation), Relocate 69 kV Rexton tap to 69 kV Hiawatha-Pine River line (6909), Relocate 69 kV Trout Lake tap to 69 kV Hiawatha-Pine River line (6909), Construct Mackinac 138 kV substation additions (portions may be earlier for maintenance issues), Rebuild Hiawatha-Pine River-Mackinac 69 kV to 138 kV, Construct 138 kV bus and install one 138/69 kV, 50 MVA transformers at Pine River, Convert rebuilt Hiawatha-Indian Lake circuit (operated at 69 kV) to 138 kV, Construct 138 kV ring bus at Hiawatha SS, Install 138 kV substation modifications at Indian Lake SS	MI		Other	Excluded		$12,140,000	6/1/2050	Proposed	138		B	Y
B	West	ATC LLC	341	Rockdale-Mill Road 345 kV line projects	Construct Rockdale-Concord 345 kV line in parallel with existing 138 kV on existing double-width right-of-way. Construct a 345 kV bus and install a 345/138 kV, 500 MVA transformer at Concord. Convert Bark River-Mill Road 138 kV line to 345 kV. Construct a Concord-Bark River 345 kV line. Construct a 345 kV bus and install a 345/138 kV, 500 MVA transformer at Bark River	WI					$94,600,000	6/1/2019	Proposed	345	138	B	Y
B	West	ATC LLC	434	Butternut 28.8 MVAR capacitor bank	Butternut 138, 28.8 MVAR Capacitor bank	WI			Not Shared		$1,050,000	6/1/2016	Proposed	138		B	Y
B	West	ATC LLC	544	Bluemound 200 MVAR capacitor bank	Bluemound 138 kV 200 MVAR capacitors	WI		Other	Not Shared		$3,463,000	11/30/2011	Proposed	138		B	Y
B	West	ATC LLC	573	North Madison-West Middleton 345 kV	North Madison - West Middleton 345 kV line	WI					$46,700,000	6/1/2024	Proposed	345		B	Y
B	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	6/1/2010	Proposed	69		B	Y
B	West	ATC LLC	887	Bain 345 kV bus	Bain 345 kV bus	WI			Not Shared		$2,100,000	6/1/2014	Proposed	345		B	Y

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B	West	ATC LLC	1269	Arcadian transformer replacement	Replace Arcadian 345/138kV transformer #3 with a 500MVA transformer.	WI			Not Shared		$3,500,000	6/1/2011	Proposed	345	138	B	Y
B	West	ATC LLC	1270	Upgrade Arcadian - Waukesha 138kV lines	Increase clearances of the two Arcadian - Waukesha 138kV lines	WI		Other	Not Shared		$300,000	6/1/2010	Proposed	138		B	Y
B	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	10/1/2009	Proposed	69		B	Y
B	West	ATC LLC	1284	Tie the 138kV radial line Racine - Somers - Albers to the 138kV substation at Albers. Also upgrade the 138kV radial line to 345/477 summer normal/emergency ratings.	Tie the 138kV radial line Racine - Somers - Albers to the 138kV substation at Albers. Also upgrade the 138kV radial line to 345/477 summer normal/emergency ratings.	WI			Not Shared		$4,181,904	6/1/2050	Proposed	138		B	Y
B	West	ATC LLC	1353	Hiawatha - Pine River 69	Hiawatha - Pine River 69 kV maintenance rebuild to 138kV standards	MI			Not Shared		$70,850,000	6/1/2050	Proposed	69		B	Y
B	West	ATC LLC	1554	Indian Lake 138kV Capacitor Bank	Install one 16.33 MVAR 138kV capacitor bank at Indian Lake substation	MI		Other	Not Shared		$584,007	6/1/2010	Proposed	138		B	Y
B	West	ATC LLC	1622	Uprate Oak Creek-St Rita 138-kV	Increase clearance of the Oak Creek-St Rita 138-kV line	WI			Not Shared			6/1/2050	Proposed	138		B	Y
B	West	ATC LLC	1624	Uprate X-67 Portage-Trienda 138 kv line	Increase clearance and uprate SS equipment	WI			Not Shared		$1,404,000	6/1/2014	Proposed	138		B	Y
B	West	ATC LLC	1626	Summit Capacitor Banks	Install two 34.2 MVAR 138-kV capacitor banks at Summit substation	WI		Other	Not Shared		$2,100,000	4/1/2010	Proposed	138		B	Y
B	West	ATC LLC	1686	Brandon-Fairwater 69 kV line	Construct Brandon-Fairwater 69 kV line	WI		Other	Not Shared		$2,800,000	12/31/2009	Proposed	69		B	Y
B	West	ATC LLC	1687	Metomen 138-69 kV Tr Breaker Replacement	Replace the breaker on the Metomen 138-69 kV Tr to achieve a higher emergency rating	WI		Other	Not Shared		$3,386,618	6/1/2013	Proposed	138	69	B	Y
B	West	ATC LLC	1690	Rebuild Verona-Oregon 69 kV line	Rebuild the Verona-Oregon 69 kV line Y119	WI		Other	Not Shared		$6,100,000	6/1/2011	Proposed	69		B	Y
B	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	10/4/2010	Proposed	69		B	Y
B	West	ATC LLC	1704	Uprate Sheepskin-Dana 69 kv line	Uprate Sheepskin-Dana 69 kv line to 95 MVA	WI			Not Shared		$726,000	6/1/2013	Proposed	69		B	Y
B	West	ATC LLC	1705	Bass Creek area upgrades	Install a 138/69 kV transformer at Bass Creek substation, Uprate Townline Road-Bass Creek 138 kV line	WI		Other	Not Shared		$6,040,000	6/1/2013	Proposed	138	69	B	Y
B	West	ATC LLC	1950	2nd Kewaunee 345-138 kV Transformer	Reconfigure Kewaunee 345/138 kV switchyard and install a 2nd Kewaunee 345-138 kV transformer of 500 MVA.	WI		BaseRel	Shared		$17,500,000	5/4/2011	Proposed	345	138	B	Y
B	West	ATC LLC	2032	2nd Shorewood-Humboldt 138 kV UG cable	Add a second parallel underground line from Humboldt terminal to Shorewood	WI			Not Shared			6/1/2012	Proposed	138		B	Y
B	West	ATC LLC	2035	Uprate X23 Colley Rd Terminal	Uprate X23 Colley Rd Terminal (Colley Rd-Marine)	WI			Not Shared			6/1/2014	Proposed	138		B	Y
B	West	ATC LLC	2112	G546	Network upgrades for tariff service request; 100 MW at Sugar Creek substation	WI		GIP	In Suspension		$8,830,000	3/1/2010	Planned	138		B	Y
B	West	ATC LLC	2454	G590 Stony Brook	G590 G-T Interconnection From Techumseh Rd 138 kV bus. Upgrade Kaukauna Central tap - Tayco 138 kV line.	WI		GIP	Shared		$1,610,720	12/31/2009	Planned	138		B	Y
B	Central	DEM	1264	Speed	Replace existing 345/138 transformer at Speed with a new transformer rated at 3,000A or higher.	IN		BaseRel	Shared		$7,541,500	6/1/2013	Proposed	345	138	B	Y
B	Central	DEM	1521	Bloomington 13836 Switches	Replace the Bloomington 13836 600A breaker disconnect switches with 2000A switches. New limit 800A Wave Trap.	IN		BaseRel	Not Shared		$233,455	6/1/2016	Planned	138		B	Y
B	Central	DEM	1556	Wheatland to Whitestown 345	New 345 kV line from Wheatland to Whitestown	IN		RegBen	TBD		$113,000,000	5/1/2011	Proposed	345		B	Y
B	Central	DEM	1558	Close Wheatland Breaker	Close the breaker at IPL's Wheatland - make upgrade to Petersburg - Francisco and the Petersburg - Thompson 345 kV to address 1st contingency limitations	IN		Other			$11,435,000	5/1/2011	Proposed	345		B	Y
B	Central	DEM	2050	Dresser 345/138kV Bank 3 addition	Add a 3rd 345/138kV transformer at Dresser Sub	IN		BaseRel			$12,363,000	6/1/2012	Proposed	345	138	B	Y
B	East	FE	2256	Cloverdale-Tiger 69 kV Line- Reconductor and rebuild	Rebuild 0.87 miles of 336.4 ACSR with 795 ACSR	OH					$346,000	6/1/2012	Planned	69		C>B	Y

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B	East	FE	2258	Lyme Sub - 69 kV Cap Bank	Install a 14.4 MVAR 69 kV Capacitor Bank and cap switcher at Lyme Substation	OH					$600,000	6/1/2016	Planned	69		C>B	Y
B	East	FE	2261	Hanville 69kV Cap Bank	Add 14.4 MVAR cap bank at Hanville 69kV Substation.	OH					$800,000	6/1/2016	Planned	69		C>B	Y
B	East	FE	2268	Shenango Area 69kV Switching Station	Create new 69kV switching station to create 4 separate 69kV lines that will terminate at the new station to be located near existing Pulaski Substation.	PA		Other	Not Shared	Reliability	$2,835,000	6/1/2018	Planned	69		B	Y
B	West	GRE	602	Brownton - McLeod 115 kV line	Brownton - McLeod 115 kV line, Brownton 115/69 kV substation, Brownton 69 kV breaker station	MN					$5,575,000	6/1/2015	Proposed	115		B	Y
B	West	GRE	2098	G390, A252, A253	Network upgrades for tariff service request for G390, A252, A253	MN		GIP	In Suspension		$6,272,080	4/1/2011	Proposed	230		B	Y
B	West	GRE	2564	Sartell (SEA) 3.0 mile, 115 kV line	Sartell (SEA) 3.0 mile, 115 kV line	MN					$1,173,000	6/1/2010	Planned	115		C>B	Y
B	West	GRE	2566	Potato Lake (IM) 7 mile, 115 kV line	Potato Lake (IM) 7 mile, 115 kV line	MN					$3,252,000	6/1/2010	Planned	115		C>B	Y
B	West	GRE	2568	Floodwood 115/69 kV source	New 115/69 kV source	MN					$2,913,000	11/1/2010	Planned	115	69	C>B	Y
B	West	GRE	2577	Elmcrest (CE) 69 kV Substation	Elmcrest (CE) 69 kV Substation	MN					$140,000	6/1/2010	Proposed	69		C>B	Y
B	West	GRE	2620	Sandstone-Sandstone MP Temperature Upgrade	Sandstone-Sandstone MP Temperature Upgrade	MN					$74,400	6/1/2010	Proposed	69		C>B	Y
B	West	GRE	2624	Hudson 115 kV conversion	115 kV conversion	MN					$364,000	6/1/2010	Proposed	115		C>B	Y
B	West	GRE	2626	North Mankato Area Load Serving	Eagle Lake-Jamestown Rebuild	MN					$1,182,000	6/1/2010	Proposed	115		C>B	Y
B	West	GRE	2671	Soderville-Ham Lake-Johnsville (6.18 mi.) Retemp	Soderville-Ham Lake-Johnsville (6.18 mi.) Retemp	MN					$247,200	6/1/2010	Proposed	69		C>B	Y
B	West	GRE/ALTW	1354	Dotson - Searles 161	Dotson Corners Substation, Dotson-West New Ulm 115 kV line	MN		BRP/ GIP	TBD			12/31/2010	Planned	115	69	B	Y
B	Central	IPL, DEM	1557	Bloomington to Pritchard to Franklin to Hanna 345 kV line	Tap the Hanna - Stout 345 and Hanna - Francs 345 kV circuits into one new 345 kV Switching Station at the Franklin twp site and build station at Pritchard. Also adds 345 kV single circuit from Bloomington - Pritchard - Frankin Twp station.	IN		RegBen			$41,750,000	1/1/2014	Proposed	345		B	Y
B	East	ITC	1850	Hancock 230/120kV Transformer	Cut the Wixom-Quaker 230kV circuit into Hancock Station, install a 230/120kV transformer.	MI		BaseRel	Shared		$9,000,000	6/1/2011	Proposed	230	120	B	Y
B	East	ITC	1856	Belle River - Greenwood - Pontiac 345kV cut into Jewell	Cut the Pontiac section of the Belle River-Greenwood-Pontiac 345kV circuit into and out of Jewell station. Utilize an existing unused side of 345kV tower for one of the circuits into Jewell, and relocate the Jewell-Spokane 230kV circuit	MI		BaseRel	Shared		$4,900,000	6/1/2011	Proposed	345		B	Y
B	West	ITCM	1102	G113, 37111-01	Net: Transmission Owner shall construct a new 161 kV breaker position, including 2000A breaker, potential transformers (PT), current transformers (CT) and associated equipment and are detailed in Exhibit A1. Int: Interconnection Customer shall construct an approximately 7-mile 161kV transmission circuit from the Generating Facility to the Point of Interconnection.	MN		GIP	In Suspension			12/1/2003	Planned		1	B	Y
B	West	ITCM	1147	G298, 37061-02	Net: The Transmission Owner shall install a new 161kV line breaker on the Triboji- Wisdom Line and a new 161kV transformer breaker located on the existing #1 Triboji 161/69kV transformer and are shown in Exhibit A2.. Int: Generator shall construct a 161/34kV substation consisting of 161kV breaker, 161/34kV transformer, 34kV breakers and a 161kV line from (Bob what is name of Customer sub?) to the dead-end tower at the IPL Triboji substation.	IA		GIP	In Suspension		$615,000	12/31/2006	Planned	1		B	Y

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B	West	MDU	1134	G248, 37488-01	Net: The Transmission Owner shall construct two (2) one-way switches with load breaking capability, one on either side of the tap, RTU . Int: Generator shall construct _1_ Remote Terminal Unit as specified by MDU, 1500 ft. 41.6 kV line, specs to be reviewed and approved by MDU,	ND		GIP	In Suspension			12/1/2003	Planned		1	B	Y
B	West	MDU	1148	G297, 37664-01	Net: At the Glenham Jct Substation, two 115 kV line potential sources and sync-check relaying on breakers 7047 and 7050. · At the Bowdle Jct Substation, five 41.6 kV line potential sources and sync-check relaying on breakers 500, 510, 5049, 5050 and 6470 . Int:	SD		GIP	In Suspension			12/31/2004	Planned		1	B	Y
B	West	MDU	1153	G311, 37699-01	Net: The Transmission Owner shall install a larger 115/34.5kV substation transformer, and relaying associated with the new transformer. Add 34.5kV PTs, 34.5kV station service transformer, SCADA RTU, 115kV CVTs and 115kV line relaying at Gascoyne. Add sync-check relaying on breaker 2132 at the Hettinger Jct Substation. Int: Generator shall cause to be constructed the following interconnection facilities at Transmission Owner's Gascoyne Jct Substation: 2-circuit breaker disconnect switches, 1- "intertie circuit breaker" and associated 34.5kV line and intertie protective relaying, meters, 34.5kV potential and current transformers, arresters, the associated high voltage bus work, grounding, foundations, conduit and control wiring.	ND		GIP	In Suspension			9/1/2004	Planned		1	B	Y
B	East	METC	1815	Chase - Mecosta 138kV	Rebuild 8 miles of 138kV 110 and 115 CU to 954 ACSR. Prebuild to 230kV construction.	MI		BaseRel	Shared			6/1/2011	Planned	138		B	Y
B	East	METC	2502	McGulpin Shunt Reactor	Install shunt reactor McGulpin	MI		BaseRel	Not Shared		$3,000,000	12/31/2011	Planned	138		B	Y
B	East	METC	2822	Edenville Jct. - Warren 138kV	Reconductor the Edenville-Warren 138kV line to 954 ACSR	MI					$7,000,000	12/1/2016	Proposed	138		B	Y
B	West	MP	1292	Raise tower height on ETCO-Forbes 115 kV line	Raise tower height on ETCO-Forbes 115 kV line so the 336 ACSR conductor rating can reach 122/134 MVA	MN			Not Shared		$400,000	6/1/2011	Proposed	115		B	Y
B	west	MP	2547	Essar Phase 2	Phase II of the project adds a Direct Reduced Iron (DRI) facility which is scheduled to be operational in the fall of 2012 and increases total demand to 145 MW (a 50 MW increase).	MN					$15,548,716	10/30/2012	Proposed	230	14	B	Y
B	West	MP	2551	28L Tap	Remove Tap and put line on its own breaker	MN					$1,250,000	6/30/2010	Proposed	115		C>B	Y
B	West	MP	2762	Airpark	New 115/34.5 and 115/14 kV Substation	MN					$4,105,000	9/30/2010	Planned	115	14	C>B	Y
B	East	NIPS	1973	Leesburg to Northeast -- Upgrade Capacity	Increase circuit capacity between Leesburg and Northeast (8.5 mi.). Upgrade to 954 KCM ACSR.	IN					$5,279,000	12/1/2012	Proposed	138		C>B	Y
B	East	NIPS	1984	South Knox - New 138/69 kV Substation	South Knox- New 138-69 KV, 1-168 MVA Transformer Substation	IN					$12,568,000	12/1/2014	Proposed	138	69	C>B	Y
B	East	NIPS	1985	Circuit 6959 Wolcotville to S. Milford Reconductor	Reconductor 5.7 miles of Circuit 6959's existing 2/0 Cu to 336.4 kCM ACSR.	IN					$1,144,000	12/1/2014	Proposed	69		C>B	Y
B	East	NIPS	1987	Upgrade Circuit 6971 Relays at Oak Dale & Monticello	Replace existing 69 kV elctromechanical line relays at Oak Dale and Monticello Substations with new solid state SEL relays for Circuit 6971.	IN					$95,000	10/1/2011	Proposed	69		C>B	Y
B	East	NIPS	1988	Upgrade Circuit 6972 Relays at Oak Dale & Chalmers Substations	Replace existing 69 kV elctromechanical line relays at Oak Dale and Chalmers Substations with new solid state SEL relays for Circuit 6972.	IN					$95,000	10/1/2011	Proposed			C>B	Y
B	East	NIPS	1989	Upgrade Circuit 6959 - S Milford at Helmer Substation	Reconductor 5.7 miles of Circuit 6959's existing 2/0 Cu to 336.4 kCM ACSR.	IN					$894,000	12/1/2013	Proposed	69		C>B	Y

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B	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					$3,425,000	12/1/2010	Proposed	138	69	C>B	Y
B	East	NIPS	1995	New Thayer Substation 69kV Circuit	Extend a new 6 mile section of 69 KV line to provide a new 69 KV source and circuit from Thayer Substation. New circuit to tie into existing system (Cir. 6901).	IN					$1,782,000	6/1/2014	Proposed	69		C>B	Y
B	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					$8,412,524	12/1/2012	Proposed	345	138	C>B	Y
B	West	OTP	549	Jamestown Reactor Addition	Jamestown 115 kV 25 MVAR reactor	ND			Not Shared		$250,000	12/1/2013	Proposed	115		B	Y
B	West	OTP	585	Pelican Rapids 115 kV Line Uprate	Pelican Rapids - Pelican Rapids Turkey Plant 115 kV line	MN					$858,869	12/31/2013	Planned	115		B	Y
B	West	OTP	973	Big Stone II Generation Project	Build New Big Stone - Ortonville 230 kV Line, Convert Ortonville - Johnson Jct. 115 kV line to 230 kV, Convert Johnson Jct. - Morris 115 kV Line to 230 kV, Install a new Johnson Jct. 230/115 kV Transformer, Replace existing Morris 230/115 kV Transformer, Build New Big Stone - Canby 230 kV Line, Convert existing Canby - Granite Falls 115 kV Line to 230 kV, Install a new Canby 230/115 kV Transformer, Upgrade existing Big Stone - Browns Valley - Hankinson 230 kV Line Rebuild the Hankinson - Wahpeton 230 kV line Rebuild the Morris - Grant County 115 kV line Addition of a 5 Mvar capacitor bank at the Toronto 115 kV bus.	MN	SD ND				$176,166,221	1/1/2016	Planned	345	115	B	Y
B	West	SMP	2170	Sherco 3 Upgrade	Addition of 9 MW at Sherco 3, been SMP's share of proposed upgrade.	MN		TDSP	Direct Assigned		$19,000,000	12/1/2011	Proposed			C>B	Y
B	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 distrbution line.	MN		TDSP	Direct Assigned		$3,700,000	12/1/2010	Proposed	12.47		C>B	Y
B	West	SMP	2813	Byron-West Side	Second 161 kV line from Byron to Cascade Creek	MN		Other	Not Shared		$3,000,000	6/1/2012	Planned	161		B	Y
B	West	XEL	2107	G520	Network upgrades: Install new 3-position 115 kV substations (tapping Lake Yankton - Lyon County 115 kV line) with breakers, switches, buswork, steel, foundations, control house and associated equipment. Install new loop in-and-out tap, 3.5 miles of double circuit, 115 kV transmission line.	MN		GIP	In Suspension		$5,930,926	4/2/2009	Planned	115	34.5	B	Y
B	West	XEL	2115	G491	G491: One new 120 MVA, 118-36.2 kV transformer, three new 115 kV breakers and associated disconnect switches, one new 34.5 kV transformer low side main breaker and associated disconnect switches, control house expansion, structural steel and foundations associated with this new equipment, control and protection equipment associated with these new installations	MN		GIP	In Suspension		$4,363,152	9/1/2010	Planned	115		B	Y

Appendix B: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
B	West	XEL/GRE	1203	Brookings, SD - SE Twin Cities 345 kV project	Brookings County -Lyon County (Single Ckt w/ capability to string 2nd ckt in future) (Lyon County)- Franklin - Helena (Double Ckt)-(Helena)-Lk Marion-Hampton Corner (Single Ckt w/ capability for 2nd ckt in future) 345 kV; Lyon County - Hazel 345 kV line (Single Ckt w/ capability for 2nd ckt in future) (Hazel) - Minnesota Valley (Single Ckt w/ capability for 2nd ckt in future, initially operate at 230 kV)	MN	SD	Other	TBD		$695,323,369	9/1/2013	Planned	345	69	B	Y

Facility Table Field Legend

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Facilty Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Indicates the Project the Facility belongs to. Projects may have multiple facilities.
Facility ID	Facility ID: Midwest ISO facility identifier
Expected ISD	Expected In Service Date for this facility
From Sub	From substation for transmission line or location of transformer or other equipment
To Sub	To substation for transmission line or transformer designation
Ckt	Circuit identifier
Max kV	Maximum voltage of this facility
Min kV	Minumum voltage of this facility (transformer low-side voltage)
Summer Rate	Rating of the facility in applicable units
Upgrade Description	Brief description of transmission upgrade involving this facility
State	State the facility is located in
Miles Upg.	Transmission line miles on existing rights of way (ROW)
Miles New	Transmission line miles on new rights of way (ROW)
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Estimated Cost	Total estimated facility cost
Cost Shared	Y if facility is cost shared per Attachment FF
Postage Stamp	Y if facility has postage stamp cost allocation per Attachment FF
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.

Appendix B: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
B	Central	AmerenIL	2239	4153	1/1/2014	Rising	Sidney	1	345		1500 MVA	new line	IL		30	Proposed	$65,600,000			Y	C>B
B	Central	AmerenIP	1234	1933	6/1/2014	Havana, South	Mason City, West	1	138		160	Increase ground clearance on 18.4 miles	IL	18.4		Proposed	$642,300			Y	B
B	Central	AmerenIP	1236	1935	6/1/2012	Stallings	Prairie State Power Plant	1	345		1297	Replace 2000 A terminal equipment with 3000 A equipment at Stallings	IL			Proposed	$100,000			Y	B
B	Central	AmerenIP	1533	2610	6/1/2011	Washington Street	S. Bloomington	1	138		255	Replace terminal equipment at S. Bloomington	IL			Proposed	$125,900			Y	B
B	Central	AmerenIP	1534	2611	6/1/2011	W. Mt. Vernon	Xenia	1	345		1200	Replace terminal equipment at W. Mt. Vernon	IL			Proposed	$2,069,600			Y	B
B	Central	AmerenIP	1535	2612	6/1/2012	Wood River	Stallings	1	138		259	Replace terminal equipment at Stallings, reconductor section of line (Line # 1456)	IL	6		Proposed	$1,564,700			Y	B
B	Central	AmerenIP	1537	2614	6/1/2012	Mt. Vernon, West	S. Centralia	1	138		146	Replace terminal equipment at S. Centralia	IL			Proposed	$200,000			Y	B
B	Central	AmerenIP	2114	2839	9/30/2009	Mahomet Substation	Brokaw Substation	1	138			Tapping structures installed inline with line #1376: 138 XX Line Extension 477 MCM 30/7 ACSR, 138 YY Line Extension 477 MCM 30/7 ACSR	IL			Planned	$237,000	Y		Y	B
B	Central	AmerenIP	2114	2838	9/30/2009	Project IP03 Substation	substation	1	138			New (IP03) 138 kV Straight Bus Interconnection Substation, tap existing line #1376 Mahomet Substation to Brokaw Station.	IL			Planned	$1,845,000	Y		Y	B
B	Central	AmerenIP	2117	2846	12/1/2010	El Paso	CE Minok	1	138			Tapping structures installed inline with line #1382: 138 kV XX Line Extension 556.5 MCM 26/7 ACSS conductor and 7#8 Alumoweld shield wire, 138 kV YY Line Extension 556.5 MCM 26/7 ACSS conductor and 7#8 Alumoweld shield wire	IL			Planned	$230,000	Y		Y	B
B	Central	AmerenIP	2117	2845	12/1/2010	Project IP08 Substation	substation	1	138			New 138 kV Straight Bus Interconnection Substation, located north of the tap point to the Transmission Owner's El Paso substation and south of the tap point to the Transmission Owner's CE Minok substation on line #1382.	IL			Planned	$1,661,464	Y		Y	B
B	Central	AmerenIP	2118	2847	12/1/2009	Washington Street Substation	IP04 Substation	1	138			Line #1382 & #1384: Reconductor 477 MCM 30/7 ASCR with three phase 556.5 MCM 26/7 ACSS conductor.	IL		47.1	Planned	$5,426,258	Y		Y	B
B	Central	AmerenIP	2118	2848	12/1/2010	Oglesby Substation	IP08 Substation	1	138			Line #1382 & #1384: Reconductor 477 MCM 30/7 ASCR with three phase 556.5 MCM 26/7 ACSS conductor.	IL			Planned		Y		Y	B
B	Central	AmerenIP	2118	2849	12/1/2010	Raab Substation	substation	1	138			Retire substation	IL			Planned		Y		Y	B
B	Central	AmerenIP	2280	4196	6/1/2013	LaSalle	Oglesby Main	1	138		256	Reconductor 477 kcmil ACSR and 336 kcmil ACSR to 1200 A summer emerg.	IL	2.16		Planned	$900,000			Y	B
B	Central	AmerenMO	2774	4868	12/1/2009	Adair	Wind Farm	1	161			Connect Wind Farm to Adair Sub	MO			Planned		Y		Y	B
B	West	ATC LLC	89	3251	6/1/2019	Mill Rd	Tamarack	1	138		252/301	TapSussex-Tamarack into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	103	6/1/2019	Mill Road (renamed, was Lannon Junction)	transformer		345	138	500	transformer	WI			Proposed	$29,200,000			Y	B
B	West	ATC LLC	89	3246	6/1/2019	Mill Rd	Cypress	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3247	6/1/2019	Mill Rd	Arcadian	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3248	6/1/2019	Mill Rd	Bark River	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3249	6/1/2019	Mill Rd	Germantown	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3250	6/1/2019	Mill Rd	Sussex	1	138		252/301	TapSussex-Tamarack into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	174	442	6/1/2012	Canal	Dunn Road		138		400		WI		7.64	Proposed	$20,302,363			Y	B
B	West	ATC LLC	174	3477	6/1/2012	Dunn Road		1	138	69	60	Install 60 MVA 138/69 kV transformer at Dunn Road	WI			Proposed				Y	B
B	West	ATC LLC	333	474	6/1/2050	Hiawatha	Indian Lake (convert double circuit 138 kV from 69 kV operation to 138 kV o	2	138		279	rebuild in 2006 and convert in 2009	MI	40		Proposed	$200,000			Y	B
B	West	ATC LLC	333	891	6/1/2050	Mackinac	Substation relocation		138			Straits substation rename/relocation	MI			Proposed	$11,740,000			Y	B

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B	West	ATC LLC	333	596	6/1/2050	Hiawatha	Indian Lake (string second 138 kV circuit)	2	138		279	string 2nd 138 kV circuit	MI		40	Proposed	$200,000			Y	B
B	West	ATC LLC	341	477	6/1/2019	Concord 345/138 kV	transformer		345	138	500		WI			Proposed	$12,900,000			Y	B
B	West	ATC LLC	341	483	6/1/2019	Rockdale	Concord (rebuild to dbl ckt 138/345)	1	345		1200	rebuild to dbl ckt 138/345	WI	22.6		Proposed	$22,200,000			Y	B
B	West	ATC LLC	341	894	6/1/2019	Bark River	transformer		345	138	500	transformer	WI			Proposed	$8,400,000			Y	B
B	West	ATC LLC	341	893	6/1/2019	Concord	Bark River		345		815	new line	WI		19	Proposed	$50,300,000			Y	B
B	West	ATC LLC	341	895	6/1/2019	Bark River	Mill Road		345		815	convert 138 to 345 kV	WI	11		Proposed	$800,000			Y	B
B	West	ATC LLC	434	2063	6/1/2016	Butternut	Capacitor bank		138		28.8 Mvar		WI			Proposed	$1,050,000			Y	B
B	West	ATC LLC	544	898	11/30/2011	Bluemound	Capacitor bank		138		200 Mvar		WI			Proposed	$3,463,000			Y	B
B	West	ATC LLC	573	1265	6/1/2024	North Madison	West Middleton	1	345		1200		WI		20	Proposed	$46,700,000			Y	B
B	West	ATC LLC	884	884	6/1/2010	Spring Green	Capacitor bank		69		32 Mvar	install 2x 16.3 Mvar capacitor banks	WI			Proposed	$1,200,000			Y	B
B	West	ATC LLC	887	887	6/1/2014	Bain	New 345 kV bus		345			construct 345 kV bus	WI			Proposed	$2,100,000			Y	B
B	West	ATC LLC	1269	1988	6/1/2011	Arcadian 345-138kV	transformer	1	345	138	500	replace Arcadian 345/138kV transformer #2 & #3	WI			Proposed	$3,500,000			Y	B
B	West	ATC LLC	1270	1990	6/1/2010	Arcadian	Waukesha	1	138		426	Increase line clearance	WI	4		Proposed	$150,000			Y	B
B	West	ATC LLC	1270	1989	6/1/2010	Arcadian	Waukesha	2	138		426	Increase line clearance	WI	4		Proposed	$150,000			Y	B
B	West	ATC LLC	1282	2109	10/1/2009	Osceola 69			69		4.08 MVAR	Install 1-4.08 MVAR 69 kV cap bank at the Osceola substation in Houghton County, MI.	MI			Proposed	$800,000			Y	B
B	West	ATC LLC	1284	2113	6/1/2050	Albers	Somers	1	138		345/477		WI			Proposed				Y	B
B	West	ATC LLC	1284	2112	6/1/2050	Racine	Somers	1	138		345/477		WI			Proposed				Y	B
B	West	ATC LLC	1284	2111	6/1/2050	Racine	Albers	1	138		345/477		WI	8		Proposed	$4,181,904			Y	B
B	West	ATC LLC	1284	2110	6/1/2050	Albers	Tie	1	138				WI			Proposed	$0			Y	B
B	West	ATC LLC	1353	1993	6/1/2050	Hiawatha	Pine River	1	69		191 MVA SE	Maintenance rebuild of 69kV at 138kV standards	MI			Proposed	$70,850,000			Y	B
B	West	ATC LLC	1554	3102	6/1/2010	Indian Lake	Capacitor bank		138		16.33 MVAR		MI			Proposed	$584,007			Y	B
B	West	ATC LLC	1622	3256	6/1/2050	Oak Creek	St Rita	1	138		293/293	Increase clearance of the Oak Creek-St Rita 138-kV line	WI			Proposed				Y	B
B	West	ATC LLC	1624	3241	6/1/2014	Portage	Trienda	2	138		373/430	uprate X-67	WI	3.4		Proposed	$1,404,000			Y	B
B	West	ATC LLC	1626	3245	4/1/2010	Summit	Capacitor banks		138		2x34.2 MVAR		WI			Proposed	$2,100,000			Y	B
B	West	ATC LLC	1686	3462	12/31/2009	Brandon	Fairwater	1	69			Construct a Brandon-Fairwater 69 kV line	WI		4	Proposed	$2,800,000			Y	B
B	West	ATC LLC	1687	3463	6/1/2013	Metomen		1	138	69	100	Replace the 138/69 kV transformer at Metomen substation	WI			Proposed	$3,000,000			Y	B
B	West	ATC LLC	1687	4869	6/1/2013	Metomen	substation	1	138	69	47 MVA / 62 M	Replace the breaker on the Metomen 138-69 kV Tr to achieve a higher emergency rating	WI		0	Proposed	$386,618			Y	B
B	West	ATC LLC	1690	3469	6/1/2011	Verona	Oregon	1	69			Rebuild the Verona to Oregon 69 kV line Y119	WI			Proposed	$6,100,000			Y	B
B	West	ATC LLC	1691	3470	10/4/2010	McCue	Milton Lawns	1	69			Uprate McCue-Milton Lawns 69 kV line	WI			Proposed	$800,000			Y	B
B	West	ATC LLC	1704	3485	6/1/2013	Sheepskin	Dana	1	69		95 MVA	Uprate Sheepskin-Dana 69 kv line to 95 MVA	WI			Proposed	$726,000			Y	B
B	West	ATC LLC	1705	3486	6/1/2013	Bass Creek		1	138	69		Install a 138/69 kV transformer at Bass Creek substation	WI			Proposed	$6,040,000			Y	B
B	West	ATC LLC	1705	3487	6/1/2013	Townline Road	Bass Creek	1	138			Uprate Townline Road-Bass Creek 138 kV line	WI			Proposed				Y	B
B	West	ATC LLC	1950	3831	5/4/2011	Kewaunee	transformer	2	345	138	717 MVA SE	Add a 2nd Kewaunee 345-138 kV transformer	WI			Proposed	$17,500,000			Y	B
B	West	ATC LLC	2032	3911	6/1/2012	Humbolt Terminal	Shorewood	1	138		262/293 MVA	Add a second parallel underground line from Humboldt terminal to Shorewood, for modeling purposes the is an uprate to the Cornell-Shorewood 138 kV line as the Humbolt terminal is not modeled			2.68	Proposed				Y	B
B	West	ATC LLC	2035	3914	6/1/2014	Colley Rd	Marine	1	138		293/339 MVA	Uprate X-23 Colley Road Terminal				Proposed				Y	B
B	West	ATC LLC	2112	2833	3/1/2010	N. Lake Geneva Substation	substation	1	138			Replacement of the transceiver and related equipment for the N. Lake Geneva-Bowers Road 138-kV line.	WI			Planned	$52,000	Y		Y	B

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B	West	ATC LLC	2112	2830	3/1/2010	Bowers Road	Line 6541	1	138			Connection of 138 kV line 6541 into Bowers Road Substation				Planned	$754,000	Y		Y	B
B	West	ATC LLC	2112	2835	3/1/2010	St. Martins substation	substation	1	138			The St. Martins substation 138-kV main bus and line jumpers will be replaced with higher ampacity conductors rated at least 1300A SN.				Planned	$444,000	Y		Y	B
B	West	ATC LLC	2112	2829	3/1/2010	Bowers Road Substation	substation	1	138			New four-breaker, four-bus 138 kV sub in a ring bus configuration, three line positions for line 6541, fourth line position for G546				Planned	$4,591,000	Y		Y	B
B	West	ATC LLC	2112	2834	3/1/2010	Paris	Albers	1	138			The Paris-Albers 138-kV 3124 line will be re-conductored to achieve a line rating of at least 1280A SE rating and 1423A WE rating.	WI			Planned	$2,885,000	Y		Y	B
B	West	ATC LLC	2112	2831	3/1/2010	Sugar Creek Substation	substation	1	138			Replacement of the transceiver and related equipment for the Sugar Creek-Bowers Road 138-kV line.				Planned	$52,000	Y		Y	B
B	West	ATC LLC	2112	2832	3/1/2010	Burlington Substation	substation	1	138			Replacement of the transceiver and related equipment for the Burlington-Bowers Road 138-kV line.	IA			Planned	$52,000	Y		Y	B
B	West	ATC LLC	2454	4412	12/31/2009	Melissa	Tayco	1	138		160 MVA	Uprate terminal equip to achieve a 198 MVA SE rating	WI	0.3	0	Planned	$12,260			Y	B
B	West	ATC LLC	2454	4411	12/31/2009	Meadows	Melissa	1	138		169 MVA	Increase line clearance to achieve a 198 MVA SE rating	WI	1.1	0	Planned	$44,960			Y	B
B	West	ATC LLC	2454	4405	12/31/2009	STNYBRK Wind	substation	1	138			G-T Interconnection From Techumseh Rd 138 kV bus	WI			Planned	$1,234,700			Y	B
B	West	ATC LLC	2454	4410	12/31/2009	Kaukauna Central Tap	Meadows	1	138		169 MVA	Increase line clearance to achieve a 198 MVA SE rating	WI	7.8	0	Planned	$318,800			Y	B
B	Central	DEM	1264	1981	6/1/2013	Speed			345	138	717	Replace existing 345/138 transformer at Speed with a new transformer rated at 3,000A or higher.	IN			Proposed	$7,541,500			Y	B
B	Central	DEM	1521	2597	6/1/2016	Bloomington 230 (terminal equipment)	Bloomington NW		138		191	Replace the 600A 13836 bkr disconnect switches with 2000A switches. New limit 800A Wave Trap.	IN			Planned	$233,455			Y	B
B	Central	DEM	1556	3104	5/1/2011	Wheatland	Whitestown	1	345			New	IN		111	Proposed	$113,000,000			Y	B
B	Central	DEM	1558	3110	5/1/2011	Petersburg	Thompson	1	345		1195 MVA	Upgrade to fix 1st contingency for the Wheatland breaker close	IN			Proposed	$5,015,000			Y	B
B	Central	DEM	1558	3109	5/1/2011	Petersburg	Francisco	1	345		1195 MVA	Upgrade to fix 1st contingency for the Wheatland breaker close	IN			Proposed	$6,420,000			Y	B
B	Central	DEM	2050	3936	6/1/2012	Dresser	Bank 3	3	345	138	550	Add a 3rd 345/138kV transformer at Dresser Sub	IN			Proposed	$12,363,000			Y	B
B	East	FE	2256	4170	6/1/2012	Cloverdale	Tiger	1	69			reconductor line	OH			Planned	$346,000			Y	C>B
B	East	FE	2258	4172	6/1/2016	Lyme	capacitor bank	1	69			Capacitor Bank Addition	OH			Planned	$600,000			Y	C>B
B	East	FE	2261	4175	6/1/2016	Hanville	capacitor bank	1	69			Capacitor Bank Addition	OH			Planned	$800,000			Y	C>B
B	East	FE	2268	4182	6/1/2018	Shenango	Substation	1	69			New 69kV substation	PA			Planned	$2,835,000			Y	B
B	West	GRE	602	3885	12/31/2013	Brownton	69 kV breaker station		69			new 69 kV breaker station near Brownton	MN			Proposed	$900,000			NT	B
B	West	GRE	602	802	6/1/2015	Brownton	McLeod	1	115				MN		9	Proposed	$4,675,000			Y	B
B	West	GRE	1203	1893	9/1/2011	Lyon County	Transformer	1	345	115	448	new transformer	MN			Planned	$17,200,000			Y	B
B	West	GRE	1203	1882	9/1/2011	Lyon County	Franklin (tb named Cedar Mt)	1	345		2066	new line	MN		51.9	Planned	$127,600,000			Y	B
B	West	GRE	1203	2649	9/1/2011	Franklin (tb named Cedar Mt)	Transformer	1	345	115	448	new transformer	MN			Planned	$19,900,000			Y	B
B	West	GRE	1203	1885	9/1/2011	Franklin (tb named Cedar Mt)	Helena	2	345		2066	new line	MN		62.2	Planned	$0			Y	B
B	West	GRE	1203	1884	9/1/2011	Franklin (tb named Cedar Mt)	Helena	1	345		2066	new line	MN		62.2	Planned	$152,500,000			Y	B
B	West	GRE	1203	1883	9/1/2011	Lyon County	Franklin (tb named Cedar Mt)	2	345		2066	new line	MN		51.9	Planned	$0			Y	B

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B	West	GRE	1203	1895	6/1/2013	Hazel	Transformer	1	345	230	336	new transformer	MN			Planned	$25,800,000			Y	B
B	West	GRE	1203	1894	6/1/2013	Lake Marion	Transformer	1	345	115	448	new transformer	MN			Planned	$17,300,000			Y	B
B	West	GRE	1203	1896	6/1/2013	Hazel	Transformer	2	345	230	336	new transformer	MN			Planned	$0			Y	B
B	West	GRE	1203	1888	6/1/2013	Lyon County	Hazel	1	345		2066	new line	MN		23.5	Planned	$50,160,000			Y	B
B	West	GRE	1203	1889	6/1/2013	Hazel	Minnesota Valley	1	230		388	new line	MN		6	Planned	$12,540,000			Y	B
B	West	GRE	1203	1881	6/1/2013	Brookings County	Lyon County 345 kV	1	345		2066	new line	SD/MN		48.1	Planned	$97,900,000			Y	B
B	West	GRE	1203	1887	6/1/2013	Lake Marion	Hampton Corner	1	345		2066	new line	MN		18.5	Planned	$57,900,000			Y	B
B	West	GRE	1203	1886	6/1/2013	Helena	Lake Marion	1	345		2066	new line	MN		26.6	Planned	$83,900,000			Y	B
B	West	GRE	2098	2804	4/1/2011	Elk River #14 substation	Bunker Lake Distribution	1	230		271	Upgrade of Elk River #14 substation - Bunker Lake Distribution 230 kV to at least 271 MVA.	MN	14.3		Proposed	$4,894,756			Y	B
B	West	GRE	2098	2993	4/1/2011	RDF	Daytonport	1	69		78 MVA	Upgrade of RDF - Daytonport to at least 78 MVA	MN	3.7		Proposed	$1,377,324			NT	B
B	West	GRE	2564	4566	6/1/2010	Sartell	Le Sauk	1	115			Sartell Disribution Sub, 795 ACSS 115 kV radial line and switch	MN		3	Planned	$1,173,000			Y	C>B
B	West	GRE	2566	4569	6/1/2010	Potato Lake	Potato Lake Tap	1	115			New distribution built 115 (op 34.5)	MN		7	Planned	$3,252,000			Y	C>B
B	West	GRE	2568	4578	11/1/2010	Floodwood	transformer	1	115	69	28	Floodwood 115/69 kV source (Taconite Harbor), Floodwood 69 kV Cedar Valley outlet, Floodwood 115-69 kV Gowan outlet	MN		1	Planned	$2,913,000			Y	C>B
B	West	GRE	2577	4588	6/1/2010	Elmcrest	Elmcrest Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C>B
B	West	GRE	2620	4577	6/1/2010	Sandstone Tap	MP Sandstone	1	69		31	temperature upgrade	MN	0.93		Proposed	$74,400			NT	C>B
B	West	GRE	2624	4631	6/1/2010	Hudson	Hudson Tap	1	115		141.6		MN	0.5		Proposed	$364,000			Y	C>B
B	West	GRE	2626	4636	6/1/2010	Cleveland	Jamestown Tap	1	115		142		MN	3		Proposed	$1,182,000			Y	C>B
B	West	GRE	2671	4634	6/1/2010	Ham Lake	Soderville	1	69		75.8		MN	0.38		Proposed				NT	C>B
B	West	GRE	2671	4633	6/1/2010	Ham Lake	Johnsville	1	69		75.8	Retemp	MN	5.8		Proposed	$247,200			NT	C>B
B	West	GRE/XEL	1203	1898	6/1/2011	Morris	Transformer	2	230	115	150	Upgrade 100 MVA to 150 MVA	MN			Proposed	$4,000,000			Y	B
B	West	GRE/XEL	1203	1899	6/1/2011	Willmar	Transformer	2	115	69	112		MN			Proposed	$3,000,000			Y	B
B	West	GRE/XEL	1203	1891	6/1/2011	Brookings County	Toronto	1	115		310	new line	SD		20	Proposed	$19,223,369			Y	B
B	Central	IPL	1557	3106	1/1/2014	Bloomington	Pritchard	1	345		1386	New	IN		15	Proposed	$15,000,000			Y	B
B	Central	IPL	1557	3107	1/1/2014	Pritchard	Franklin Twp	1	345		956	New	IN		24	Proposed	$24,000,000			Y	B
B	Central	IPL	1557	3108	1/1/2014	Franklin Twp	Hanna	1	345		1386	New	IN		2.75	Proposed	$2,750,000			Y	B
B	East	ITC	1850	3733	6/1/2011	Hancock	Quaker	1	230			New Line resulting from Quaker-Wixom cut into Hancock	MI			Proposed				Y	B
B	East	ITC	1850	3734	6/1/2011	Hancock 230/120 kV	Transformer	1	230	120		New Transformer	MI			Proposed	$9,000,000			Y	B
B	East	ITC	1850	3732	6/1/2011	Hancock	Wixom	1	230			New Line resulting from Quaker-Wixom cut into Hancock	MI			Proposed				Y	B
B	East	ITC	1856	3744	6/1/2011	Jewell	Belle River - Greenwood Jct	1	345			Cut Pontiac-Greenwood-Belle River into Jewell creating Pontiac-Jewell and Jewell-Belle River-Greenwwod	MI			Proposed	$2,450,000			Y	B
B	East	ITC	1856	3743	6/1/2011	Jewell	Pontiac	1	345			Cut Pontiac-Greenwood-Belle River into Jewell creating Pontiac-Jewell and Jewell-Belle River-Greenwwod	MI			Proposed	$2,450,000			Y	B
B	West	MDU	1153	1803	9/1/2004	Crownbutte Wind (Gascoyne)	generator and associated network upgrades			1	19	new generator	ND			Planned				Y	B
B	East	METC	1815	3649	6/1/2011	Chase	Mecosta	1	138			Reconductor	MI	8		Planned				Y	B
B	East	METC	2502	4502	12/31/2011	McGulpin	reactor		138			Install 15 MVAR shunt reactor at McGulpin	MI			Planned	$3,000,000			Y	B
B	East	METC	2822	5397	12/1/2016	Edenville J.	Warren	1	138			Reconductor the Edenville-Warren 138kV line to 954 ACSR	MI	14.8		Proposed	$7,000,000			Y	B
B	West	MP	1292	2123	6/1/2011	ETCO	Forbes	1	115		122/134	Increase ground clearance	MN			Proposed	$400,000			Y	B
B	West	MP	2547	4560	10/30/2012	Essar Site 2	Essar site 1	1	230		465	Essar new Line	MN		2.5	Proposed				Y	B
B	West	MP	2547	4559	10/30/2012	Essar Site 2	Substation Equipment		230	14	166	Essar Substation Equipment & 2 Transformers	MN			proposed				Y	B
B	West	MP	2547	4558	10/30/2012	Essar Site 1	Substation Equipment		230	14	166	Essar Substation Equipment & 2 Transformers	MN			proposed				Y	B
B	West	MP	2547	4557	10/30/2012	Blackberry	Essar site 2	1	230		465	Essar new Line	MN		16	Proposed				Y	B
B	West	MP	2547	4556	10/30/2012	Essar Site 2	Shannon	1	230		423	Essar 94L Line reroute	MN		8	Proposed				Y	B

Appendix B: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
B	West	MP	2547	4555	10/30/2012	Boswell	Essar site 1	1	230		423	Essar Line 94L Line reroute	MN		16	Proposed	$15,548,716			Y	B
B	West	MP	2551	4562	6/30/2010	Boswell	Deer River	1	115		144	Move 28L Tap to it own Breaker	MN		0.5	Proposed	$1,250,000			Y	C>B
B	West	MP	2551	4563	6/30/2010	Boswell	Substation Equipment	1	115		144	115 kV Line entrance	MN			Proposed				Y	C>B
B	West	MP	2762	4776	9/30/2010	Airpark	Substation Equipment		115	34.5	39	Substation Equipment & Transformer	MN			Planned	$2,100,000			Y	C>B
B	West	MP	2762	4778	9/30/2010	Airpark	Substation Equipment		115	14	39	Substation Equipment & Transformer	MN			Planned	$2,005,000			Y	C>B
B	East	NIPS	1973	2763	12/1/2012	Leesburg	Northeast	1	138		287	Upgrade Connections and Circuit	IN	8.5		Proposed	$5,279,000			Y	C>B
B	East	NIPS	1984	2774	12/1/2014	South Knox	138/69 kV Substation		138	69		New Substation	IN			Proposed	$12,568,000			Y	C>B
B	East	NIPS	1985	2775	12/1/2014	Wolcottville	South Milford	1	69		81	Circuit 6959 - Reconductor 2/0 CU to 336.4kcm ACSR	IN	5.4		Proposed	$1,144,000			Y	C>B
B	East	NIPS	1987	2777	10/1/2011	Monticello	Oak Dale		69			Upgrade Circuit 6971 Relays.	IN			Proposed	$95,000			Y	C>B
B	East	NIPS	1988	2778	10/1/2011	Oak Dale	South Chalmers					Upgrade Circuit 6972 Relays.	IN			Proposed	$95,000			Y	C>B
B	East	NIPS	1989	2779	12/1/2013	South Milford	Helmer	1	69		81	Circuit 6959 - Reconductor 2/0 CU to 336.4kcm ACSR	IN	4.7		Proposed	$894,000			Y	C>B
B	East	NIPS	1991	2781	12/1/2010	East Winamac	Transformers	1 & 2	138	69	112	Upgrade 138/69 kV Transformer	IN			Proposed	$3,425,000			Y	C>B
B	East	NIPS	1995	2785	6/1/2014	Thayer	Liberty Park Ckt 6901		69			New Thayer Sub circuit.	IN		6	Proposed	$1,782,000			Y	C>B
B	East	NIPS	2322	4248	12/1/2012	Green Acres	Transformer		345	138	560	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			Proposed	$8,412,524			Y	C>B
B	West	OTP	549	1530	12/1/2013	Jamestown	Reactor		115		25 Mvar	Add a 1 x 25 MVAr reactor at OTP Jamestown substation	ND			Proposed	$250,000			Y	B
B	West	OTP	585	589	12/31/2013	Pelican Rapids	Pelican Rapids Turkey Plant	1	115		85	Convert an existing 41.6 kV line to 115 kV	MN	2.5		Planned	$858,869			Y	B
B	West	OTP	973	2952	12/31/2014	Hazel 230	Granite Falls 230	1	230		1040	Build new 230 kV line with 2-1272 ACSR for Big Stone II Generation Outlet (Alternative 1 and 2). This record, in part, replaces facility ID 1522.	MN	11		Planned	$8,250,000			Y	B
B	West	OTP	973	1524	12/31/2014	Big Stone 230	Browns Valley 230 kV		230		350	Upgrade line clearances along Big Stone - Browns Valley to achieve rating equal to thermal rating of line (Required Int. upgrade for Alts 1 and 2)	SD	38.7		Planned	$2,000,000			Y	B
B	West	OTP	973	3589	12/31/2014	Toronto 115 kV			115		5 Mvar	Addition of 5 Mvar Capacitor Bank	SD			Planned	$548,000			Y	B
B	West	OTP	973	2949	12/31/2014	Big Stone 230	Big Stone south 230	1	230		1040	Build new 230 kV line with 2-1272 ACSR for Big Stone II Generation Outlet (Alternative 1 and 2) This record, in part, replaces facility ID 1521.	SD		2	Planned	$870,000			Y	B
B	West	OTP	973	2950	12/31/2014	Big Stone south 230	Canby 230	1	230		1040	Build new 230 kV line with 2-1272 ACSR for Big Stone II Generation Outlet (Alternative 1 and 2). This record, in part, replaces facility ID 1521.	MN/SD		53	Planned	$39,750,000			Y	B
B	West	OTP	973	2951	12/31/2014	Canby 230	Hazel 230	1	230		1040	Build new 230 kV line with 2-1272 ACSR for Big Stone II Generation Outlet (Alternative 1 and 2). This record, in part, replaces facility ID 1522.	MN	28.2		Planned	$21,150,000			Y	B
B	West	OTP	973	3587	12/31/2014	Hankinson 230 kV	Wahpeton 230 kV	1	230		520	Rebuild existing 230 kV line.	ND	25.5		Planned	$21,000,000			Y	B
B	West	OTP	973	1525	12/31/2014	Morris 230/115 kV	transformer	1	230	115	336	Replace existing transformer at Morris with 336 MVA unit (Required Int. upgrade for Alternative 1)	MN			Planned	$6,100,000			Y	B
B	West	OTP	973	1523	12/31/2014	Canby 230/115 kV	transformer		230	115	336	Install a 230/115 kV Transformer for Big Stone II Generation Outlet (Alternative 1 and 2)	MN			Planned	$8,100,000			Y	B
B	West	OTP	973	1518	12/31/2014	Johnson Jct. 230/115 kV	transformer	1	230	115	112	Install a 230/115 kV Transformer for Big Stone II Generation Outlet (Alternative 1)	MN			Planned	$7,300,000			Y	B
B	West	OTP	973	1517	12/31/2014	Johnson Jct. 230	Morris 230	1	230		520	Convert existing 115 kV line to 230 kV with 1272 ACSR for Big Stone II Generation Outlet (Alternative 1)	MN	15.4		Planned	$9,400,000			Y	B

Appendix B: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
B	West	OTP	973	1516	12/31/2014	Ortonville 230	Johnson Jct. 230	1	230		520	Convert existing 115 kV line to 230 kV with 1272 ACSR for Big Stone II Generation Outlet (Alternative 1)	MN	24.6		Planned	$22,418,221			Y	B
B	West	OTP	973	1515	12/31/2014	Big Stone 230	Ortonville 230	1	230		520	Build new 230 kV line with 1272 ACSR for Big Stone II Generation Outlet (Alternative 1)	MN/SD		6.5	Planned	$5,200,000			Y	B
B	West	OTP	973	2956	1/1/2016	Canby 345/115/416 Kv	transformer	1	345	115	450	This project replaces the 230/115 kV Transformer at Canby (Facility ID 1523) with a 345/115/41.6 kv transformer.	MN			Planned	$2,100,000			Y	B
B	West	OTP	973	2954	1/1/2016	Big Stone South 345	Big Stone south 230	2	345	230	400	Install a new 345/230 kV transformer at the new Big Stone South Substation as part of the conversion of the Big Stone to Canby line from 230 kV operation to 345 kV operation	SD			Planned	$6,500,000			Y	B
B	West	OTP	973	2953	1/1/2016	Big Stone South 345	Big Stone south 230	1	345	230	400	Install a new 345/230 kV transformer at the new Big Stone South Substation as part of the conversion of the Big Stone to Canby line from 230 kV operation to 345 kV operation	SD			Planned	$6,500,000			Y	B
B	West	OTP	973	2957	1/1/2016	Canby 345	Hazel 345	1	345		1560	Build new 230 kV line with 2-1272 ACSR for Big Stone II Generation Outlet (Alternative 1 and 2)	MN	28.2		Planned	$250,000			Y	B
B	West	OTP	973	2955	1/1/2016	Big Stone south 345	Canby 345	1	345		1560	This project converts the Big Stone to Canby line from 230 kV operation to 345 kV operation.	MN/SD		53	Planned	$250,000			Y	B
B	West	OTP/MDU	973	3586	12/31/2014	Browns Valley 230 kV	Hankinson 230 kV		230		350	Upgrade line clearances along Browns Valley - Hankinson to achieve rating equal to thermal rating of line (Required Int. upgrade for Alts 1 and 2)	SD/ND	33.5		Planned	$1,730,000			Y	B
B	West	OTP/MRES	973	3588	12/31/2010	Morris 115 kV	Grant County 115 kV	1	115		329	Rebuild the existing 115 kV line	MN	27		Planned	$6,750,000			Y	B
B	West	SMP	2813	4023	6/1/2012	Byron	West Side	2	161		447 MVA	2nd 161 kV line from Byron - Cascade Creek	MN		8	Planned	$3,000,000	N		Y	B
B	West	XEL	1203	1897	9/1/2013	Franklin	Transformer	1	115	69	70	Upgrade 47 MVA to 70 MVA (Time line is dependant on SW MN - Twinc Cities 345 kV line	MN			proposed	$2,400,000			Y	B
B	West	XEL	1203	4224	9/1/2013	Franklin	Transformer	2	115	69	70	Upgrade 47 MVA to 70 MVA (Time line is dependant on SW MN - Twinc Cities 345 kV line	MN			Proposed	$4,000,000			Y	B
B	West	XEL	1354	3294	12/31/2010	West New Ulm	transformer	1	115	69	70		MN			Planned				Y	B
B	West	XEL	2107	2820	4/2/2009	G520 Substation	new substation	1	115	34.5		Install new 3-position 115 kV substation with breakers, switches, buswork, steel, foundations, control house and associated equipment. Install new loop in-and-out tap, 3.5 miles of double circuit, 115 kV transmission line.	MN		3.5	Planned	$5,930,926	Y		Y	B
B	West	XEL	2115	2840	9/1/2010	Chanarambie Substation	substation upgrades	1	115			G491: three new 115 kV breakers and disconnect switches, control house expansion, structural steel and foundations associated with this new equipment, control and protection equipment associated with these new installations	MN			Planned	$4,305,000	Y		Y	B
B	West	XEL	2115	2841	9/1/2010	Chanarambie	Lake Yankton	1	115			Three spans of the existing 115 kV transmission line between Chanarambie and Lake Yankton will be relocated immediately outside of the Chanarambie substation to accommodate the expansion of the substation for G491.	MN			Planned	$58,152	Y		Y	B

Appendix C: Projects to be Reviewed and Conceptual Projects

Appendix A contains projects which are being or have been approved by Midwest ISO Board of Directors. Transmission Owners are obligated to make a good faith effort to construct projects in Appendix A.

Appendix B projects have been reviewed by Midwest ISO staff for need and effectivenes.

Appendix C projects are new to planning process or conceptual

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Project Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Project ID: Midwest ISO project identifier
Project Name	Project name (short name)
Project Description	A description of the project's components
State	State project is located or a majority of project if in multiple states
State 2	If applicable, the second state the project is located
Allocation Type per FF	Project Type per Attachment FF of Tariff. BaseRel is Baseline Reliability, GIP is Generator Interconnection Project, TDSP is Transmission Delivery Service Project, RegBen is Regionally Beneficial Project, Other is non of the above. Preliminary project types may be designated for Appendix B and C projects
Share Status	Projects moving to Appendix A in current planning cycle are eligible for cost allocation per terms in Attachment FF. Projects are Shared, Not Shared or Excluded. Preliminary sharing designations may be input for Appendix B or C projects.
Other Type	Indicates the project driver behind Other type projects.
Estimated Cost	Total estimated project cost from Facility table
Expected ISD	Date when entire project is expected to be inservice. Expected ISD are in Facility table.
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Max kV	Maximum facility voltage in project. Summary information from Facility table
Min kV	Minimum facility voltage in project. Summary information form Facility table
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.

Appendix C: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	AmerenIL	1528	Rising Substation - Increase Xfmr Rating	Increase rating of existing 345/138 kV 450 MVA Transformer	IL					$171,600	6/1/2009	Proposed	345	138	C	Y
C	Central	AmerenIL	1536	Latham-Mason City - Reconductor	Reconductor from Latham Tap to Kickapoo Tap	IL						6/1/2012	Proposed	138		C	Y
C	Central	AmerenIL	1538	Pana, North-Ramsey, East - Rebuild Line	Rebuild 18.43 miles of line for operation at 120 degrees C.	IL					$2,702,200	6/1/2011	Proposed	138		C	Y
C	Central	AmerenIL	1539	Roxford Substation - Install 345 kV PCB	Install 345 kV PCB on Roxford-Stallings line position	IL					$1,200,000	6/1/2015	Proposed	345		C	Y
C	Central	AmerenIL	1540	Sidney-Windsor - Reconductor	Reconductor 13.1 miles to 1600 A Summer Emergency Capability	IL					$3,900,000	6/1/2014	Proposed	138		C	Y
C	Central	AmerenIL	2064	South Bloomington - Old Danvers 138 kV line - Reconductor	S Bloomington-Old Danvers 138 kV Line 1364 Reconductor 4.58 miles of 336 kcmil ACSR with minimum 1600 A SE capability (S Bloomington to Diamond Star Tap)	IL					$575,400	6/1/2011	Proposed	138		C	Y
C	Central	AmerenIL	2065	Stallings 345/138 kV Sub - Replace 560 MVA 345/138 kV transformer	Stallings 345/138 kV Substation Replace 560 MVA, 345/138 kV Transformer with 700 MVA unit (Utilize spare transformer for this project)	IL		BaseRel	Shared		$7,087,000	6/1/2012	Proposed	345	138	C	Y
C	Central	AmerenIL	2283	South Bloomington 138-34.5 kV Substation	Install 2 new 2000 A, 138 kV Bus-Tie breakers	IL					$1,030,000	6/1/2010	Proposed	138		C	Y
C	Central	AmerenIL	2286	Hennepin-Oglesby 138 kV Line 1516	Increase ground clearance on 14.46 miles of 795 kcmil ACSR	IL					$442,000	6/1/2011	Proposed	138		C	Y
C	Central	AmerenIL	2288	Washington Street Substation 'In-Out'	Tap IP Line 1364 and construct 0.17 miles 'in and out' for supply to Washington Street Substation. Replace existing tap to 138 kV Line 1326 with 'in and out' arrangement.	IL					$4,066,500	6/1/2011	Proposed	138		C	Y
C	Central	AmerenIL	2289	Benton-W. Frankfort 138 kV Line	Reconductor 9.62 miles of 350 kcmil Cu to carry 1200 A under summer emergency conditions	IL					$1,240,500	6/1/2012	Proposed	138		C	Y
C	Central	AmerenIL	2290	Joppa 345 kV Switching Station 2nd. Xfmr	Add 2nd. 345/161 kV, 560 MVA Transformer	IL		BaseRel			$6,480,000	6/1/2012	Proposed	345	161	C	Y
C	Central	AmerenIL	2293	N. LaSalle-LaSalle Jct. 138 kV Line 1556A	Reconductor 9.68 miles of 477 kcmil ACSR to 1600 A summer emergency capability	IL					$3,190,000	6/1/2012	Proposed	138		C	Y
C	Central	AmerenIL	2294	Stallings 345/138 kV Sub - 138 kV Bus-Tie CT Replacement	Reconnect or replace 1200 A CT in the 138 kV Bus-Tie Position 1302 to 2000 A capability.	IL						6/1/2012	Proposed	138		C	Y
C	Central	AmerenIL	2295	W. Mt. Vernon-E. W. Frankfort 345 kV	Upgrade terminal equipment to 3000 A continuous capability	IL					$1,100,000	6/1/2012	Proposed	345		C	Y
C	Central	AmerenIL	2299	Fargo 138-69 kV Substation	Install 138 kV Capacitor Bank	IL						6/1/2013	Proposed	138		C	Y
C	Central	AmerenIL	2300	Hennepin Plant - 138 kV Bus-Tie Breakers	Install 2-3000 A, 138 kV Breakers as Bus-Ties in the Hennepin North and South Buses. Swap connection to Transformer TT2 with breaker position 1556 or 6101.	IL		BaseRel			$8,254,000	6/1/2013	Proposed	138		C	Y
C	Central	AmerenIL	2301	Hennepin-Oglesby 138 kV Line 1556	Reconductor 8.37 miles of 477 kcmil ACSR to 1600 A summer emergency capability	IL					$3,958,000	6/1/2013	Proposed	138		C	Y
C	Central	AmerenIL	2302	Madison Industrial-Madison State Street 138 kV	Reconductor 2.35 miles of 795 kcmil SAC conductor to 1200 A summer emergency capability	IL						6/1/2013	Proposed	138		C	Y
C	Central	AmerenIL	2304	Marion South 161/138 kV Substation	Install second 300 MVA, 161/138 kV Transformer. Replace 1200 A terminal equipment on existing transformer with 1600 A equipment.	IL					$4,452,000	12/1/2013	Proposed	161	138	C	Y
C	Central	AmerenIL	2305	Monmouth Substation 138 kV Capacitor Bank	Install 30 Mvar, 138 kV capacitor bank	IL					$1,022,000	6/1/2013	Proposed	138		C	Y
C	Central	AmerenMO	2067	St Francois - Rivermines - 1 138 kV Line : Increase clearances to ground.	St. Francois-Rivermines-1 138 kV Increase ground clearance on 10.77 miles of 795 kcmil ACSR conductor	MO					$534,000	11/1/2009	Proposed	138		C	Y
C	Central	AmerenMO	2122	Belleau - GM - 3 to AECI Enon Substation 161 kV line	Belleau - GM - 3 to AECI Enon Substation 161 kV line	MO						6/1/2011	Proposed	161		C	Y
C	Central	AmerenMO	2292	Kelso 345/161 kV Substation	Replace 336 MVA, 345/161 kV Transformer with 450 MVA Transformer	MO		BaseRel			$6,146,000	6/1/2012	Proposed	345	161	C	Y
C	Central	AmerenMO	2296	Belleau 345/138 kV Substation - 2nd. Xfmr	Install 2nd. 560 MVA, 345/138 kV Transformer	MO		BaseRel			$8,169,000	6/1/2013	Proposed	345	138	C	Y
C	Central	AmerenMO	2297	Belleau 345/138 kV Substation - Install 138 kV capacitor bank	Install 138 kV, 120 Mvar capacitor bank (as 2-60 Mvar stages) At Belleau Substation	MO						6/1/2013	Proposed	138		C	Y

Appendix C: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	AmerenMO	2306	Nortwest Cape Area 345/161 kV Substation	Install 560 MVA, 345/161 kV Transformer. Provide 345 kV supply from 11 mile 345 kV line extension from Lutesville Substation	MO					$30,175,000	6/1/2015	Proposed	345	161	C	Y
C	West	ATC LLC	569	White River T-D interconnection	South Lake Geneva - White River 138 kV line	WI		Other	Excluded		$4,473,000	6/1/2014	Proposed	138	69	C	Y
C	West	ATC LLC	575	Pulliam-New Suamico conversion to 138 kV for T-D interconnection	Rebuild/Convert Pulliam-New Suamico 69 kV line to 138 kV	WI			Not Shared		$6,221,325	6/1/2016	Proposed	138		C	Y
C	West	ATC LLC	1143	G282, 37628-02	Net: rating of HILLMAN 138/69 kV TRANSFORMER 1 is upgraded to 100 MVA. Int: The Generator is required to provide a 138/34.5kV transformer, a circuit breaker and a disconnect switch on the high side of the 138/34.5kV transformer and 34.5kV facilities to connect the wind farm collection bus to the ATC substation.	WI		GIP	Shared			3/1/2010	Proposed		1	C	Y
C	West	ATC LLC	1621	New Birchwood-Lake Delton 138-kV line	Construct new Birchwood-Lake Delton 138-kV line	WI					$5,806,000	6/1/2015	Proposed	138		C	Y
C	West	ATC LLC	1623	Montrose Capacitor Banks	Install two 16.33 MVAR 69kV capacitor banks at Montrose substation	WI			Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	1625	North Randoph Transformer	Install a 500 MVA 345/138 kV transformer at the North Randolph 138 kv SS by looping in the Columbia-South Fond du Lac 345-kV line	WI					$9,718,000	12/31/2018	Proposed	345	138	C	Y
C	West	ATC LLC	1627	Uprate Bain-Albers 138-kV line	Increase clearance of the Bain-Albers 138-kV line	WI			Not Shared			6/1/2010	Proposed	138		C	Y
C	West	ATC LLC	1628	Replace Columbia T22 345/138-kV Transformer	Replace Columbia T22 345/138-kV Transformer	WI			Not Shared		$100,000	6/1/2015	Proposed	345	138	C	Y
C	West	ATC LLC	1629	Femrite 69-kV Capacitor Banks	Install two 16.33 MVAR 69kV capacitor banks at Femrite substation	WI			Not Shared			6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	1630	Femrite 138-kV Capacitor Banks	Install two 24.5 MVAR 138kV capacitor banks at Femrite substation	WI			Not Shared			6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	1688	Beardsley Street Circuit Breakers	Install two 69 kV breakers at Beardsley Street substation	WI			Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	1689	Ripon Capacitor Banks	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Ripon 69 kV substation	WI			Not Shared			6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	1692	Replace North Mullet River 69 kV metering CT	Replace the 400 amp metering CT at North Mullet River 69 kV substation	WI			Not Shared		$404,243	6/1/2011	Proposed	69		C	Y
C	West	ATC LLC	1693	Mears Corners Capacitor Banks	Install two 16.3 MVAR capacitor bank at Mears Corners 138 kV substation	WI			Not Shared		$1,080,000	6/1/2015	Proposed	138		C	Y
C	West	ATC LLC	1694	Rosiere Capacitor Banks	Install two 16.3 MVAR capacitor bank at Rosiere 138 kV substation	WI			Not Shared		$1,190,000	6/1/2015	Proposed	138		C	Y
C	West	ATC LLC	1695	Mukwonago Capacitor Banks	Install two 32 MVAR capacitor banks at Mukwonago 138 kV substation	WI			Not Shared			6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	1696	Gardner Park-Black Brook 115 kV line	Uprate Gardner Park-Black Brook 115 kV line	WI			Not Shared			6/1/2050	Proposed	115		C	Y
C	West	ATC LLC	1697	Brick Church-Walworth 69 kV line	Uprate Brick Church-Walworth 69 kV line to 115 MVA	WI			Not Shared		$716,000	6/1/2015	Proposed	69		C	Y
C	West	ATC LLC	1699	Mckenna Capacitor Banks	Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR and install a second new 10.8 MVAR capacitor bank	WI			Not Shared			6/1/2013	Proposed	69		C	Y
C	West	ATC LLC	1700	Ripon-Metomen 69 kV line	Construct a 69 kV line from SW Ripon to the Ripon-Metomen 69 kV line	WI			Not Shared			6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	1701	Blaney Park-Munising	Rebuild Blaney Park-Munising 69 kV to 138 kV	MI			Not Shared		$52,010,000	6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	1702	Replace Hillman transformer	Replace the existing 46 MVA Hillman 138/69 kV transformer with a 100 MVA transformer	WI			Not Shared		$1,958,000	6/1/2015	Proposed	138	69	C	Y
C	West	ATC LLC	1703	Boscobel Capacitor Banks	Install one 8.16 MVAR capacitor bank at Boscobel 69 kV substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank	WI			Not Shared			6/1/2013	Proposed	69		C	Y
C	West	ATC LLC	1706	Nine Springs-Pflaum 69 kV line	Loop Nine Springs-Pflaum 69 kV line into Femrite substation	WI			Not Shared		$5,360,000	6/1/2013	Proposed	69		C	Y
C	West	ATC LLC	1707	Holmes-Chandler 69 kV line	Rebuild/convert holmes-Chandler 69 kV line to 138 kV operation	WI			Not Shared		$56,300,000	6/1/2013	Proposed	138		C	Y

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C	West	ATC LLC	1708	Metomen and Mackford Prairie area upgrades	Construct Fairwater-Mackford Prairie 69 kV line, Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	WI		Other	Not Shared		$3,200,000	6/1/2018	Proposed	69		C	Y
C	West	ATC LLC	1709	Eden Capacitor Banks	Install two 16.33 MVAR 69 kV capacitor banks at Eden Substation	WI			Not Shared			6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	1710	Mazomanie capacitor banks	Install two 12.25 MVAR 69 kV capacitor banks at Mazomanie substation	WI			Not Shared			6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	1711	McCue 138/69 kV transformer	Install a second 138/69 kV transformer at McCue substation	WI			Not Shared		$2,810,000	6/1/2016	Proposed	138	69	C	Y
C	West	ATC LLC	1712	Horicon-East Beaver Dam 138 kV line	Construct a Horicon-East Beaver Dam 138 kV line	WI					$10,190,000	6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	1713	Yahara River upgrades	Loop the Deforest to Token Creek 69-kV line into the Yahara River Substation and install a 138/69-kV transformer at Yahara River, Uprate Yahara River-Token Creek 69-kV line	WI			Not Shared			6/1/2050	Proposed	138	69	C	Y
C	West	ATC LLC	1714	South Sheboygan Falls 138/69 kV transformer	Replace the existing 138/69-kV transformer at South Sheboygan Falls Substation with 100 MVA transformer	WI			Not Shared		$1,550,000	6/1/2050	Proposed	138	69	C	Y
C	West	ATC LLC	1715	Edgewater circuit breaker	Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	WI			Not Shared		$248,000	6/1/2018	Proposed	345		C	Y
C	West	ATC LLC	1716	Uprate Melissa-Tayco 138 kV line	Uprate the Melissa-Tayco 138 kV line to 229 MVA (300F)	WI			Not Shared			6/1/2016	Proposed	138		C	Y
C	West	ATC LLC	1717	Glenview 138/69 kV transformers	Replace two existing 138/69 kV transformers at Glenview Substaion with 100 MVA transformers	WI			Not Shared		$3,440,000	6/1/2014	Proposed	138	69	C	Y
C	West	ATC LLC	1718	Custer 138/69 kV transformer	Install a 138/69 kV transformer at Custer substation	WI			Not Shared			6/1/2016	Proposed	138	69	C	Y
C	West	ATC LLC	1719	Shoto-Custer 138 kV line	Construct a Shoto-Custer 138 kV line	WI					$14,110,000	6/1/2016	Proposed	138		C	Y
C	West	ATC LLC	1720	Wautoma 138/69 kV transformer	Install a second 138/69-kV transformer at Wautoma Substation	WI			Not Shared		$1,440,000	6/1/2017	Proposed	138	69	C	Y
C	West	ATC LLC	1721	Pulliam area 69 kV reconductor projects	Reconductor Pulliam-Danz 69kV line, reconductor Danz-Henry Street 69 kV line, reconductor Pulliam-Van Buren 69 kV line	WI			Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	1722	Aviation Capacitor Banks	Install two 16.3 MVAR 138kV capacitor banks at Aviation Substation	WI			Not Shared		$1,160,000	6/1/2018	Proposed	138		C	Y
C	West	ATC LLC	1723	Sunset Point transformer replacement	Replace two existing 138/69-kV transformers at Sunset Point Substation with 100 MVA transformers	WI			Not Shared		$3,540,000	6/1/2018	Proposed	138	69	C	Y
C	West	ATC LLC	1724	Hilltop Capacitor Bank	Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	WI			Not Shared			6/1/2023	Proposed	69		C	Y
C	West	ATC LLC	1725	Evansville-Brooklyn 69 kV line	Construct an Evansville-Brooklyn 69 kV line	WI			Not Shared		$8,120,000	6/1/2024	Proposed	69		C	Y
C	West	ATC LLC	1726	Uprate Royster-Sycamore 69 kV line	Uprate Royster-Sycamore 69 kV line to 115 MVA	WI			Not Shared		$790,000	6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	1727	Dunn Road-Egg Harbor 69 kV line	Construct a second Dunn Road-Egg Harbor 69 kV line	WI		Other	Not Shared		$11,795,610	6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	1728	Northside-City Limits 138 kV line	Construct a Northside-City Limits 138 kV line	WI			Not Shared			6/1/2050	Proposed	138		C	Y
C	West	ATC LLC	1729	Uprate Straits-McGulpin 138 kV	Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 200 F degree summer emergency ratings	MI			Not Shared		$300,000	1/31/2012	Proposed	138		C	Y
C	West	ATC LLC	1730	West Middleton-Blount 138 kV line	Construct a West Middleton-Blount 138 kV line	WI			Not Shared			6/1/2017	Proposed	138		C	Y
C	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	6/1/2024	Proposed	69		C	Y
C	West	ATC LLC	1732	Brick Church 69 kV mobile capacitor bank	Install 12.45 MVAR 69-kV mobile capacitor bank at Brick Church Substation	WI		Other	Not Shared		$600,000	6/1/2009	Proposed	69		C	Y
C	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		Other	Not Shared		$3,300,000	10/17/2009	Proposed	138		C	Y
C	West	ATC LLC	1941	Uprate Atlantic-M38 69 kV	Increase ground clearance for Atlantic-M38 69-kV to 167 deg F	MI			Not Shared			6/1/2013	Proposed	69		C	Y

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C	West	ATC LLC	1946	2nd Spring Green 138-69 kV Transformer	Install a 2nd Spring Green 138-69 kV Transformer with a 100 MVA summer normal rating	WI		Other	Not Shared		$1,400,000	6/1/2013	Proposed	138	69	C	Y
C	West	ATC LLC	1947	Uprate Black Earth-Stage Coach 69-kV	Uprate Black Earth-Stage Coach 69-kV				Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	1948	Remove Mobile Capacitor bank fromBrick Church 69-kV	Remove Mobile Capacitor bank from Brick Church 69-kV	WI			Not Shared			6/1/2011	Proposed	69		C	Y
C	West	ATC LLC	1949	Green Bay SW T-D	Construct 1.6 mile double circuit line to connect the new Green Bay SW SS to the Glory Rd-De Pere 138-kV line	WI			Not Shared			6/1/2018	Proposed	138		C	Y
C	West	ATC LLC	2019	Uprate Chandler Delta 69 kV #1	Increase line clearance to 167 deg F SE	MI			Not Shared			4/1/2010	Proposed	69		C	Y
C	West	ATC LLC	2020	Uprate Chandler Delta 69 kV #2	Increase line clearance to 167 deg F SE	MI			Not Shared			4/1/2010	Proposed	69		C	Y
C	West	ATC LLC	2025	Uprate Straits-Evergreen-Pine River 69 kV	Reconductor two phases of Straits-Evergreen and increase line clearance to 200 deg F SN/SE, Increase line clearance on Evergreen-Pine River to 185 deg F SN/SE	MI			Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	2026	Uprate Straits-Pine River 69 kV	Increase line clearance on Straits-Pine River to 185 deg F SN/SE	MI			Not Shared			6/1/2050	Proposed	69		C	Y
C	West	ATC LLC	2027	North Bluff cap bank 1x4.08 Mvar	Add a 4.08 Mvar 69 kV Capacitor bank at the North Bluff substation in Delta County, MI	MI			Not Shared			6/1/2010	Proposed	69		C	Y
C	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 3-12.45 Mvar 69 kV cap banks at Fulton	WI			Not Shared			4/1/2010	Proposed	69		C	Y
C	West	ATC LLC	2029	Brick Church 138 & 69kV Caps	Install 1-24.5 Mvar 138-kV capacitor bank and 1-18 Mvar 69-kV capacitor bank at Brick Church	WI			Not Shared			6/1/2011	Proposed	138		C	Y
C	West	ATC LLC	2030	Concord 4x24.5 138 kV Caps	Install 4-24.5 Mvar 138-kV capacitor bank at Concord	WI			Not Shared			6/1/2011	Proposed	138		C	Y
C	West	ATC LLC	2031	Y-32 Rebuild (Colley Rd-Brick Church 69 kV)	Y-32 Rebuild (Colley Rd-Brick Church 69 kV)	WI			Not Shared			6/1/2012	Proposed	69		C	Y
C	West	ATC LLC	2033	Uprate Bain-Kenosha 138-kV	Upgrade substation equipment at Bain & Kenosha	WI			Not Shared			6/1/2013	Proposed	138		C	Y
C	West	ATC LLC	2036	Uprate Y-40 Gran Grae-Boscobel 69 kV	Increase line clearance to 200/300 deg F SN/SE	WI			Not Shared			6/1/2017	Proposed	69		C	Y
C	West	ATC LLC	2037	Rebuild Dane-Okee 69 kV	Rebuild Dane-Okee 69 kV	WI			Not Shared			6/1/2015	Proposed	69		C	Y
C	West	ATC LLC	2038	Spring Valley-S Lake Geneva 138 kV	Construct Spring Valley-Twin Lakes-S Lake Geneva 138 kV	WI			Not Shared			6/2/2015	Proposed	138		C	Y
C	West	ATC LLC	2039	Uprate Crystal Falls-Aspen 69 kV	Increase line clearance to 300 deg F SE	MI			Not Shared			6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	2040	Sun Prairie 69kV Caps	Install 2x16.33 Mvar 69 kV capacitor banks at Sun Prairie	WI			Not Shared			6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	2041	Uiprate Forsyth 138-69 kV Tr	Address CT and/or relays limitations; uprate the summer emergency rating of the Forsyth 138/69 kV transformer to 57 MVA	MI		Other	Not Shared		$310,000	6/1/2017	Proposed	138	69	C	Y
C	West	ATC LLC	2042	Dam Heights 69kV Caps	Install 2x16.33 Mvar 69 kV caps at Dam Heights	WI			Not Shared			6/1/2017	Proposed	69		C	Y
C	West	ATC LLC	2043	Convert Necedah from 69 to 138 kV	Convert Necedah from 69 to 138 kV and tap into the Petenwell-Council Creek 138 kV line	WI			Not Shared			6/1/2018	Proposed	138		C	Y
C	West	ATC LLC	2044	Uprate Castle Rock-McKenna 69kV	Increase line clearance to 200 deg F SN/SE	WI		Other	Not Shared		$600,000	6/1/2018	Proposed	69		C	Y
C	West	ATC LLC	2045	Rebuild Victoria-Ontonagon 69 kV	Rebuild Victoria-Ontonagon 69 kV	MI			Not Shared			6/1/2018	Proposed	69		C	Y
C	West	ATC LLC	2046	North Monroe 69 kV Caps	Install 2x16.33 Mvar 69 kV capacitor banks at North Monroe	WI			Not Shared			6/1/2018	Proposed	69		C	Y
C	West	ATC LLC	2047	Rio 69kV Caps	Install 2x16.33 Mvar 69 kV capacitor banks at Rio	WI			Not Shared			6/1/2019	Proposed	69		C	Y
C	West	ATC LLC	2048	Rebuild Victoria-Mass 69 kV	Rebuild Victoria-Mass 69 kV	MI			Not Shared			6/1/2021	Proposed	69		C	Y
C	West	ATC LLC	2049	Verona-N Monroe 138kV	Build a 27 mile 138 kv line from Verona to North Monroe	WI			Not Shared			6/1/2024	Proposed	138		C	Y
C	West	ATC LLC	2055	Clear Lake-Arnett Rd 115 kV	Constrcust a 7.5 mile 115 kv line from Clear Lake to a new Arnett Rd distribution substation			Other	Not Shared		$12,200,000	6/1/2012	Proposed	115		C	Y
C	West	ATC LLC	2056	Uprate Oak Creek-Pennsylvania 138 kv	Uprate Oak Creek-Pennsylvania 138 kV	WI			Not Shared			6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	2162	2nd McCue-LaMar 69 kV line	Construct a 2nd McCue-LaMar 69 kV line	WI			Not Shared			6/1/2017	Proposed	69		C	Y
C	West	ATC LLC	2163	Replace Ellinwood Tr #2	Replace Ellinwood 138-69 kv Tr #2	WI		Other	Not Shared		$2,012,243	12/31/2010	Proposed	138	69	C	Y
C	West	ATC LLC	2164	Nelson Dewey 161-138 kv #2	Install a 2nd Nelson Dewey 161-138 kV Tr	WI			Not Shared		$4,729,000	2/1/2013	Proposed	161	138	C	Y
C	West	ATC LLC	2165	Uprate Femrite-Royster 69 kV	Uprate Femrite-Royster 69 kV	WI		Other	Not Shared		$441,446	6/1/2010	Proposed	69		C	Y

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C	West	ATC LLC	2451	Brodhead-S Monroe 69kV Rebuiild	Brodhead-S Monroe 69kV Rebuiild at 138 kV standard	WI		Other	Not Shared		$10,800,000	6/1/2012	Proposed	69		C	Y
C	West	ATC LLC	2777	Rebuild Gwinn-Munising 69 kV AuTrain line	Rebuild the existing 44-mile Gwinn-Munising 69 kV line at 138 kV standards, 69 kV operations.	MI					$44,000,000	6/1/2017	Proposed	69		C	Y
C	West	ATC LLC	2778	Rebuild Roberts-9 Mile 69 kV 6952 line	Rebuild the existing 54-mile Roberts-9 Mile 69 kV line at 138 kV standards, 69 kV operations.	MI					$54,000,000	6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	2779	New Chandler-18th Road 138 kV line + 18th Road 138/69 kV SS and xfmr	Buld a new 6-mile 138 kV line from Chandler to 18th Road, add a new 138/69 kV SS and 138/69 kV 150 MVA xfmr at 18th Road	MI					$19,000,000	6/1/2015	Proposed	138	69	C	Y
C	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		$2,700,236	4/25/2010	Proposed	345		C	Y
C	West	ATC LLC	2799	Frontier Load Interconnection	Convert 2x Straits-Piner River 69kV lines to 138kV, Uprate 2x Straits-McGulpin 138kV lines, Rebuild 2x Pine River-9Mile 69kV lines as a 138/69 kV double circuit line, construct a new 3 mile 69-kV line to Frontier	MI					$78,882,248	1/31/2012	Proposed	138	69	C	Y
C	West	ATC LLC	2800	Uprate Arpin-Hume 115-kV	Marshfield Electric & Water Department project to increase ground clearance to operate the line at 200 Deg F	WI						6/1/2009	Planned	115		C	Y
C	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						3/15/2010	Planned	138		C	Y
C	West	ATC LLC	2816	Uprate Forsyth-Munising 138kV	Increase line clearance to achieve a 200 deg F operating temperature	MI						4/30/2010	Planned	138		C	Y
C	West	ATC LLC	2817	Uprate Winona-M38 138kV	Increase line clearance to achieve a 125 deg F operating temperature	MI						3/15/2010	Planned	138		C	Y
C	West	ATC LLC	2818	Uprate Kaukauna Central Tap-Meadows Tap-Melissa 138kV	Increase line clearance to achieve a 200 deg F operating temperature	WI						4/1/2010	Planned	138		C	Y
C	West	ATC LLC	2819	Replace Bluemound 230/138kV transformerT3	Replace Bluemound 230/138kV transformer T3 with a 400 MVA unit	WI					$8,000,000	12/1/2011	Proposed	230	138	C	Y
C	West	ATC LLC	2820	Replace Bluemound 230/138kV transformerT1	Replace Bluemound 230/138kV transformer T1 with a 400 MVA unit	WI					$8,200,000	12/1/2012	Proposed	230	138	C	Y
C	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					$3,260,000	12/31/2010	Planned	138	69	C	Y
C	Central	DEM	840	Rushville 69kV Cap	Add 14.4 MVAR 69kV capacitor at Rushville.	IN		Other	Not Shared		$510,845	6/1/2016	Planned	69		C	NT
C	Central	DEM	1249	Frankfort 230 36MVAR 69kV capacitor	Install 36 MVAR 69kV capacitor	IN		Other	Not Shared		$632,358	12/31/2016	Planned	69		C	NT
C	Central	DEM	1518	Curliss 138/69	Construct a new Curliss 138/69kV, 150 MVA substation. Install one 69 kV circuit.	OH		Other	Not Shared		$4,675,000	6/1/2016	Planned	138	69	C	Y
C	Central	DEM	1520	Durbin 230/69	Construct a new Durbin 230/69kv 150mva substation with 2 69kv line terminals.	IN		Other	Not Shared	Reliability	$7,000,000	6/1/2014	Planned	230	69	C	Y
C	Central	DEM	1571	Rockville (IPL) to Avon East new 138KV line	Construct 4.3 miles / 954ACSR of 138kv line from IPL Rockville to Avon East	IN		Other			$2,980,000	6/1/2015	Planned	138		C	Y
C	Central	DEM	1900	Avon Industrial Park 138 (or 69)-12kV new dist sub	Avon Industrial Park (aka Central Logistics) - Construct 69/138-12kV - 22.4 MVA sub and 2.6 mile - 69kV radial line from roughly the Avon South sub - unknown if this will be a 69 or 138 kv sub	IN		Other			$923,000	6/1/2015	Proposed	138	12	C	NT
C	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	Planned	69		C	NT
C	Central	DEM	1904	Batesville to Hillenbrand 69kV uprate	Uprate 69kV Batesville to Hillenbrand to 100C – 4/0acsr – 2.1 miles – 69107 ckt	IN		Other	Not Shared		$115,961	6/1/2015	Planned	69		C	NT
C	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			$2,300,000	6/1/2012	Planned	69		C	NT
C	Central	DEM	2124	Brooklyn to HE Brooklyn 69kV Reconductor	Brooklyn Sub to HE Brooklyn Sub reconductor 1.28 miles of 6940 line 4/0 Cu with 954ACSR@100C	IN		Other	Not Shared		$320,000	6/1/2020	Planned	69		C	NT
C	Central	DEM	2125	Centerton 138/69kV Bk 1 replacement	Upgrade/replace existing 75MVA 138/69kV bank with 120MVA bank	IN		Other			$3,091,000	6/1/2020	Planned	138	69	C	NT
C	Central	DEM	2129	Plainfield S. to HE Mooresville Jct 69kV reconductor	Plainfield South to HE Mooresville Jct 69kV reconductor 4/0Cu with 954ACSR - 2.03 miles	IN		Other	Not Shared		$980,000	6/1/2020	Planned	69		C	NT

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C	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			$2,712,500	6/30/2013	Planned	69		C	NT
C	Central	DEM	2135	Franklin 230 Sub 69kV Cap	Franklin 230 Sub 69kV Cap - Install 36MVAR 69kV bus capacitor bank	IN		Other	Not Shared		$400,000	6/15/2014	Planned	69		C	NT
C	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		$0	6/30/2012	Planned	69		C	NT
C	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		$0	6/30/2012	Planned	69		C	NT
C	Central	DEM	2139	Greenwood West Sub 69kV #2 switch upgrade	Greenwood West Sub - upgrade (or replace, if required) 69kV Loadbreak switch #2 for 1200amp capacity in the 6999 ckt.	IN		Other	Not Shared		$50,000	6/30/2016	Planned	69		C	NT
C	Central	DEM	2140	Greenwood West to Lenore Jct 69kV reconductor	Greenwood West to Lenore Jct reconductor 69kV - 6949 ckt. with 477ACSR @ 100C conductor	IN		Other			$1,377,500	6/30/2013	Planned	69		C	NT
C	Central	DEM	2143	Frances Creek 345/69kV Bank 2	Add Frances Creek 345/69kV Bank 2 - 200MVA with LTC	IN		Other			$2,400,000	6/1/2014	Planned	345	69	C	NT
C	Central	DEM	2144	Franklin 230 to Earlywood 69kv Reconductor	Franklin 230kV sub to Earlywood sub reconductor 1.06 mile - 69kV - 69165 line with 954ACSR@100C	IN		Other	Not Shared		$424,000	6/30/2015	Planned	69		C	NT
C	Central	DEM	2145	Franklin 230/69 Bks 1&2 Replacement	Franklin 230 sub - Replace 230/69kV banks 1&2 each with a 200MVA LTC transformer	IN		Other			$4,800,000	6/1/2015	Planned	230	69	C	Y
C	Central	DEM	2146	HE Honey Creek Jct to Frances Creek Jct 69kv reconductor	HE Honey Creek Jct to Frances Creek Jct. reconductor 69kV - 1.12 mile line section of the 69102 ckt. with 954ACSR 100C conductor.	IN		Other	Not Shared		$420,000	6/30/2015	Planned	69		C	NT
C	Central	DEM	2147	Whiteland to Madison J 69kv reconductor	Whiteland Sub to Greenwood North Tap to Madison Ave Jct reconductor 3.44 mile 69kV - 6997 line with 954ACSR 100C conductor.	IN		Other			$1,376,000	6/30/2015	Planned	69		C	NT
C	Central	DEM	2328	Speed to HE Bethany 69kV - 6955 Reconductor Ph2	Speed to HE Bethany 69kV - 6955 Reconductor Ph2 - Replace 1.6 miles of 4/0 ACSR with 477 ACSR (new limiter 600A switches)	IN		Other	Not Shared		$480,000	6/1/2015	Planned	69		C	NT
C	Central	DEM	2329	Clarksville to Indiana Arsenal 69kv - 6955 ckt. reconductor	Clarksville to Indiana Arsenal 69kv - 6955 ckt. reconductor 1.1 miles of 4/0acsr with 477ACSR at 100C (this is Phase 2 remainder of 4/0ACSR in this line section)	IN		Other	Not Shared		$330,000	6/1/2014	Planned	69		C	NT
C	Central	DEM	2330	New Albany to HE Georgetown 69kv - 6970 ckt. Reconductor	New Albany to HE Georgetown 69kv - 6970 ckt. Reconductor 1.24 miles of 4/0acsr with 477acsr@100C	IN		Other	Not Shared		$666,000	6/1/2014	Planned	69		C	NT
C	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	9/1/2010	Planned	138	13.1	C	Y
C	Central	DEM	2337	Enyart Sub - 138kv-13.1kv - New Sub	Enyart Sub-Construct New Sub and Associated Feeder Construction	OH		Other	Not Shared		$150,000	12/30/2015	Planned	138	13.1	C	Y
C	Central	DEM	2795	Pioneer 765	New 765 kV line from Rockport (AEP) to Greentown (DEM)	IN					$1,000,000,000	5/1/2015	Proposed	765		C	Y
C	Central	DEM, IPL	2783	Wheatland - Bloomington 345 kV line	Build new 345 kV circuits from Wheatland Power Facility to Bloomington substation	IN					$105,000,000	5/1/2012	Proposed	345		C	Y
C	East	FE	1593	Galion - Replace 138/69kV #2 TR	Replace 138/69kV #2 transformer unit with a larger unit at Galion Substation.	OH					$1,090,000	6/1/2016	Planned	138	69	C	Y
C	East	FE	1602	Clark-Broadview-E.Springfield: Create 138kV Loop around City of Springfield	Initiate beginning steps for potential Loop of Clark-Urbana 138kV and E.Spring-Tangy 138kV lines in and out of Broadview Substation. New 138kV Substation at existing Broadview 69kV switching station with (2) 138/69kV transformers.	OH					$12,330,486	6/1/2015	Proposed	138	69	C	Y

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C	East	FE	1603	E.Springfield-London-Tangy: New 138kV source to Springfield	Initiate beginning steps for potential build of new 138kV line from Tangy Substation to London Substation. Build new 138kV circuit from London to East Springfield Substation on existing open circuit position	OH					$23,902,942	6/1/2015	Proposed	138		C	Y
C	East	FE	1606	Barberton - South Akron - Install New 138 kV Line	Construct a new 8.1 mile Barberton - South Akron 138 kV line, using existing tower position on existing line.	OH					$3,490,000	6/1/2017	Planned	138		C	Y
C	East	FE	1916	Mansfield Area - New 69kV Switching Station	Construct new 69kV Switching station tying together Leaside, Longview, Cook, and Galion Substations via 4 area transmission lines.	OH					$2,942,000	6/1/2017	Planned	69		C	Y
C	East	FE	2250	Fulton 345-138kV Sub	Construct Fulton Substation near the crossing point of the Allen Junction-Midway 345kV and Delta-Swanton 138kV lines, loop both lines into the new 345/138kV ring bus substation, install one 345/138kV transformer.	OH		BaseRel	Shared		$13,931,500	6/1/2017	Proposed	345		C	Y
C	East	FE	2251	Lynch 69kV Cap Bank addition	Install a 69kV 14.4MVAR cap bank at Lynch Substation.	OH					$381,200	6/1/2011	Planned	69		C	Y
C	East	FE	2252	Lime City 138 kV Capacitor Bank	Install 2-138kV 26 MVAR cap banks at Lime City Substation.	OH					$1,000,000	6/1/2016	Planned	138		C	Y
C	East	FE	2257	Chamberlin Sub - Ins 2nd 345/138 kV transformer	Install a second 345/138 kV transformer at Chamberlin Substation. Install a 345 kV breaker to create a new position on the ring bus. Install a 138 kV breaker to complete a string on the breaker-and-half configuration.	OH					$6,000,000	6/1/2016	Planned	345	138	C	Y
C	East	FE	2259	Adams 69kV Cap Bank	Install a 14.4 MVAR 69 kV Capacitor Bank and Cap Switcher at Adams Substation	OH					$600,000	6/1/2015	Planned	69		C	Y
C	East	FE	2260	Beaver - Davis Besse #2 345kV Line	Work with MISO to develop potential solution to transfer limitations identified in MISO and RFC studies. RFC identified Loading of the [FE] Lakeview-[FE] Greenfield and [FE] Ottawa-[FE] Lakeview 138 kV lines limits FCITC values for many power transfers.	OH					$16,500,000	6/1/2015	Proposed	345		C	Y
C	East	FE	2262	Wellington Muni	Provide separate source to Wellington Muni out of new exit from Wellington 138-69kV Substation.	OH					$500,000	6/1/2016	Planned	69		C	Y
C	East	FE	2267	Pine-Allegheny - new 69kV line.	Create new 69kV line from Pine Substation to Allegheny Substation.	PA					$2,685,300	6/1/2015	Planned	69		C	Y
C	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					$19,500	6/1/2010	Planned	138		C	Y
C	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					$1,794,800	6/1/2012	Planned	69		C	Y
C	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					$4,930,000	6/1/2012	Planned	138		C	Y

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C	East	FE	2805	Cook-Longview: 69kV Reconductor	Reconductor Cook-Longview 69 kV (~6.5 mi.). Project includes upgrading line terminals at both Cook and Longview Substations. Replace 336.4 ACSR with 795 ACSR conductor. Significant Dx underbuild conductor will be replaced (1/o CU) with 336 ACSR also, along with normal transfer work. 2008: Engineering 2009: Construction (Tx, Dx, and Sub) *** Notice: Design estimates updated [9-26-07]. New estimate sheets attached *** 6.20.07 in-service date changed to reflect new schedule to complete this project, Cook-Longview 69kV, by 6/1/09. The in-service date for the Cook-Galion 69kV line is going to be moved up to 6/1/08. Dollars moved to 2009 budget year to reflect work being done in 2009.	OH					$299,251	6/1/2014	Planned	69		C	Y
C	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.	OH					$85,000	6/1/2012	Planned	69		C	Y
C	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.	OH					$157,000	6/1/2010	Planned	69		C	Y
C	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.	OH					$79,400	6/1/2010	Planned	69		C	Y
C	West	GRE	1018	Little Falls - Pierz conversion to 115 kV	Convert Little Falls - Pierz 34 kV line to 115 kV operation	MN					$900,000	6/1/2011	Proposed	115		C	Y
C	West	GRE	2565	Frazer Bay Development	Frazer Bay Development	MN					$16,552,452	11/1/2011	Planned	115	69	C	Y
C	West	GRE	2567	Northport (BENCO) 1 mile, dbl ckt 115 kV line	Northport (BENCO) 1 mile, dbl ckt 115 kV line	MN					$1,570,000	6/1/2010	Planned	115		C	Y
C	West	GRE	2569	Shoal Lake (Lawrence Lake) 115 kV line	Shoal Lake (Lawrence Lake) 115 kV line	MN					$6,067,048	6/1/2010	Proposed	115		C	Y
C	West	GRE	2570	Ravenna (DEA) 161 kV Substation	Ravenna (DEA) 161 kV Substation	MN					$962,455	6/1/2012	Proposed	161		C	Y
C	West	GRE	2571	MN Pipeline-Menahga 8.0 mile line	MN Pipeline-Menahga 8.0 mile line	MN					$3,144,000	11/1/2011	Proposed	115		C	Y
C	West	GRE	2572	Lawndale Substation	Lawndale Substation	MN					$1,727,500	6/1/2016	Proposed	115		C	Y
C	West	GRE	2573	H-Frame 230 kV Storm Structures	H-Frame 230 kV Storm Structures	ND					$950,000	4/1/2010	Planned	230		C	Y
C	West	GRE	2574	St. Lawrence Substation and Tap - MVEC	St. Lawrence Substation and Tap - MVEC	MN					$300,000	6/1/2011	Proposed	115		C	Y
C	West	GRE	2576	Pokegama (LCP) 8.0 mile, 115 kV line	Pokegama (LCP) 8.0 mile, 115 kV line	MN					$3,784,000	6/1/2010	Proposed	115		C	Y
C	West	GRE	2578	Rum River (CE) 69 kV Substation	Rum River (CE) 69 kV Substation	MN					$140,000	6/1/2010	Proposed	69		C	Y
C	West	GRE	2579	Foster Lake (WH) 69 kV Substation	Foster Lake (WH) 69 kV Substation	MN					$140,000	6/1/2011	Proposed	69		C	Y
C	West	GRE	2580	Round Lake (CE) 69 kV Substation	Round Lake (CE) 69 kV Substation	MN					$140,000	6/1/2010	Proposed	69		C	Y
C	West	GRE	2581	Niniger (DEA) 115 kV Substation	Niniger (DEA) 115 kV Substation	MN					$800,000	6/1/2010	Proposed	115		C	Y
C	West	GRE	2582	Pine Island (Goodhue) 8.0 mile, 69 kV line	Pine Island (Goodhue) 8.0 mile, 69 kV line	MN					$3,380,000	6/1/2011	Proposed	69		C	Y
C	West	GRE	2583	South Dayton (CE) 115 kV Substation	South Dayton (CE) 115 kV Substation	MN					$205,000	11/1/2011	Proposed	115		C	Y
C	West	GRE	2584	Eden Valley (Meeker) 1.0 mile, 69 kV line	Eden Valley (Meeker) 1.0 mile, 69 kV line	MN					$545,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2585	Montrose (WH) 2 mile, 115 kV line	Montrose (WH) 2 mile, 115 kV line	MN					$1,101,000	6/1/2012	Proposed	115		C	Y
C	West	GRE	2586	Athens (EC) 69 kV Substation	Athens (EC) 69 kV Substation	MN					$140,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2587	North Milaca (EC) 69 kV Substation	North Milaca (EC) 69 kV Substation	MN					$140,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2588	Hardy Lake (CWP) 115 kV Substation	Hardy Lake (CWP) 115 kV Substation	MN					$205,000	11/1/2012	Proposed	115		C	Y
C	West	GRE	2589	Rich Valley (DEA) 2.0 mile, 69 kV line	Rich Valley (DEA) 2.0 mile, 69 kV line	MN					$950,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2590	Enfield (WH) 2.0 mile, 69 kV line	Enfield (WH) 2.0 mile, 69 kV line	MN					$950,000	6/1/2013	Proposed	69		C	Y
C	West	GRE	2591	Barrows (CWP) 1.0 mile, 115 kV line	Barrows (CWP) 1.0 mile, 115 kV line	MN					$894,000	11/1/2014	Proposed	115		C	Y
C	West	GRE	2592	Shaminau Lake (CWP) 5 mile, 115 kV line	Shaminau Lake (CWP) 5 mile, 115 kV line	MN					$2,380,000	11/1/2014	Proposed	115		C	Y
C	West	GRE	2593	Bass Lake (CWP) 3 mile, 69 kV line	Bass Lake (CWP) 3 mile, 69 kV line	MN					$1,325,000	6/1/2014	Proposed	69		C	Y
C	West	GRE	2594	Whitefish (CWP) 4.0 mile, 69 kV line	Whitefish (CWP) 4.0 mile, 69 kV line	MN					$1,720,000	11/1/2014	Proposed	69		C	Y
C	West	GRE	2595	Air Lake (DEA) 115 kV Substation	Air Lake (DEA) 115 kV Substation	MN					$860,000	6/1/2013	Proposed	115		C	Y

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C	West	GRE	2596	Knife Lake (EC) 8.0 mile, 69 kV line	Knife Lake (EC) 8.0 mile, 69 kV line	MN					$5,116,000	6/1/2014	Proposed	69		C	Y
C	West	GRE	2597	Beaver Lake (SEA) 1.0 mile, 115 kV line	Beaver Lake (SEA) 1.0 mile, 115 kV line	MN					$944,000	11/1/2015	Proposed	115		C	Y
C	West	GRE	2598	Cornfield (CE) 8.0 mile, 69 kV line	Cornfield (CE) 8.0 mile, 69 kV line	MN					$6,260,000	6/1/2015	Proposed	69		C	Y
C	West	GRE	2599	Shell Lake (IM) 5.0 mile, 115 kV line	Shell Lake (IM) 5.0 mile, 115 kV line	MN					$2,380,000	11/1/2015	Proposed	115		C	Y
C	West	GRE	2600	Big Sandy (LCP) 4.0 mile, 69 kV line	Big Sandy (LCP) 4.0 mile, 69 kV line	MN					$1,880,000	11/1/2015	Proposed	69		C	Y
C	West	GRE	2601	Riverside Point (MLEC) 3.0 mile, 115 kV line	Riverside Point (MLEC) 3.0 mile, 115 kV line	MN					$1,549,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2602	Hennriette (EC) 69 kV Substation	Hennriette (EC) 69 kV Substation	MN					$140,000	6/1/2015	Proposed	69		C	Y
C	West	GRE	2603	Brunswick (EC) 10.0 mile, 69 kV line	Brunswick (EC) 10.0 mile, 69 kV line	MN					$6,620,000	6/1/2016	Proposed	69		C	Y
C	West	GRE	2604	Cambridge East (EC) 1.75 mile, 69 KV line	Cambridge East (EC) 1.75 mile, 69 KV line	MN					$1,590,750	6/1/2016	Proposed	69		C	Y
C	West	GRE	2605	Bunker Lake #2 (CE at GRE) 69 kV Substation	Bunker Lake #2 (CE at GRE) 69 kV Substation	MN					$140,000	6/1/2016	Proposed	69		C	Y
C	West	GRE	2606	Pease (EC) 69 kV Substation	Pease (EC) 69 kV Substation	MN					$140,000	6/1/2016	Proposed	69		C	Y
C	West	GRE	2607	Wealthwood (MLEC) 69 kV Substation	Wealthwood (MLEC) 69 kV Substation	MN					$140,000	11/1/2017	Proposed	69		C	Y
C	West	GRE	2608	Portage Lake (CWP) 4.0 mile, 115 kV line	Portage Lake (CWP) 4.0 mile, 115 kV line	MN					$2,197,000	11/1/2019	Proposed	115		C	Y
C	West	GRE	2609	Woman Lake (CWP) 0.5 mile, 115 kV line	Woman Lake (CWP) 0.5 mile, 115 kV line	MN					$424,000	11/1/2019	Proposed	115		C	Y
C	West	GRE	2610	Mission Lake (CWP) 69 kV Substation	Mission Lake (CWP) 69 kV Substation	MN					$140,000	11/1/2019	Proposed	69		C	Y
C	West	GRE	2611	Esko (LCP) 115 kV Substation	Esko (LCP) 115 kV Substation	MN					$205,000	11/1/2020	Proposed	115		C	Y
C	West	GRE	2614	Hoffman 2.4 MVAr capacitor bank	Hoffman 2.4 MVAr capacitor bank	MN						6/1/2015	Proposed			C	Y
C	West	GRE	2615	Framnas 2.4 MVAr capacitor bank	Framnas 2.4 MVAr capacitor bank	MN						6/1/2012	Proposed			C	Y
C	West	GRE	2616	Holmes 1.2 MVAr capacitor bank	Holmes 1.2 MVAr capacitor bank	MN						6/1/2011	Proposed			C	Y
C	West	GRE	2618	Elk River 14-Elk River West Rebuild	Elk River 14-Elk River West Rebuild	MN					$1,168,500	6/1/2012	Proposed	69		C	Y
C	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					$16,010,000	11/1/2011	Proposed	230	69	C	Y
C	West	GRE	2622	High Island Conversion to 115 kV	115 kV conversion	MN					$3,082,500	6/1/2011	Proposed	115		C	Y
C	West	GRE	2623	Lismore 115 kV upgrade	115 kV conversion	MN					$1,269,000	6/1/2010	Proposed	115		C	Y
C	West	GRE	2625	Panther-Melville Tap 69 kV line	Panther-Melville Tap 69 kV line	MN					$40,000	6/1/2010	Planned	69		C	Y
C	West	GRE	2627	Elko (DEA) 115 kV Substation	Elko (DEA) 115 kV Substation	MN					$205,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2628	Thompson Lake-Remmele Tap Reconductor to ACSS	Thompson Lake-Remmele Tap Reconductor to ACSS	MN					$513,600	6/1/2011	Proposed	69		C	Y
C	West	GRE	2629	Waco-Rice Lake to ACSS	Waco-Rice Lake to ACSS	MN					$429,600	6/1/2010	Proposed	69		C	Y
C	West	GRE	2630	Resag Big Fork-Wirt Tap-Jessie Lake Retemp	Resag Big Fork-Wirt Tap-Jessie Lake Retemp	MN					$1,290,400	11/1/2012	Proposed	69		C	Y
C	West	GRE	2631	Resag Deer River-Jessie Lake Retemp	Resag Deer River-Jessie Lake Retemp	MN					$1,321,600	11/1/2012	Proposed	69		C	Y
C	West	GRE	2632	Onigum 115 kV Conversion	Onigum 115 kV Conversion	MN					$4,680,350	6/1/2011	Proposed	115		C	Y
C	West	GRE	2633	Donnelly 115 kV Conversion	Donnelly 115 kV Conversion	MN					$625,000	6/1/2010	Proposed	115		C	Y
C	West	GRE	2634	Floodwood-Cromwell	Floodwood-Cromwell	MN					$17,286,000	6/1/2013	Proposed	115		C	Y
C	West	GRE	2635	Sturgeon Lake-Sandstone	Sturgeon Lake-Sandstone	MN					$9,075,700	11/1/2011	Proposed	69		C	Y
C	West	GRE	2636	Spicer 230/69 kV Source	Spicer 230/69 kV Source	MN					$14,558,922	6/1/2012	Proposed	230	69	C	Y
C	West	GRE	2637	Credit Rvr Tap-Clearly Lake 115 kV (op. 69 kV) Rebuild	Credit Rvr Tap-Clearly Lake 115 kV (op. 69 kV) Rebuild	MN					$440,700	6/1/2010	Proposed	115		C	Y
C	West	GRE	2638	Macville 230/69 kV Sub and 115 kV line	Macville 230/69 kV Sub and 115 kV line	MN					$21,139,884	11/1/2012	Proposed	230	69	C	Y
C	West	GRE	2639	Parkwood-Village Ten to ACSS	Parkwood-Village Ten to ACSS	MN					$72,000	6/1/2011	Proposed	69		C	Y
C	West	GRE	2640	Mora Capacitor	Mora Capacitor	MN					$2,124,400	6/1/2012	Proposed	69		C	Y
C	West	GRE	2641	Lakeside Capacitor Bank	Lakeside Capacitor Bank	MN					$236,600	6/1/2011	Proposed	69		C	Y
C	West	GRE	2642	Parkwood-Woodcrest-Coon Creek	Parkwood-Woodcrest-Coon Creek	MN					$3,548,250	6/1/2012	Proposed	69		C	Y
C	West	GRE	2643	Parkers Prairie 115 kV conversion	Parkers Prairie 115 kV conversion	MN					$901,000	6/1/2011	Proposed	115		C	Y
C	West	GRE	2644	Westwood 115 kV conversion	Westwood 115 kV conversion	MN					$364,000	6/1/2010	Proposed	115		C	Y
C	West	GRE	2645	Merriam Jct Capacitor	Merriam Jct Capacitor	MN					$243,800	6/1/2011	Proposed	69		C	Y
C	West	GRE	2646	Taconite Harbor-Schroeder	Taconite Harbor-Schroeder	MN					$627,150	11/1/2013	Proposed	69		C	Y
C	West	GRE	2647	Cromwell Dist-Wright 69 kV Rebuild	Cromwell Dist-Wright 69 kV Rebuild	MN					$1,717,850	11/1/2012	Proposed	69		C	Y
C	West	GRE	2648	Milaca Breaker	Milaca Breaker	MN					$335,000	6/1/2010	Proposed	69		C	Y
C	West	GRE	2649	Parkwood-Johnsville ReConductor to ACSS	Parkwood-Johnsville ReConductor to ACSS	MN					$416,000	6/1/2012	Proposed	69		C	Y

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C	West	GRE	2650	Bunker Lake-Andover Tap (PEX portion) Reconductor to ACSS	Bunker Lake-Andover Tap (PEX portion) Reconductor to ACSS	MN					$152,000	6/1/2013	Proposed	69		C	Y
C	West	GRE	2651	North Mankato Area Load Serving	LeSeuer Tap-St. Thomas	MN					$1,351,500	6/1/2012	Proposed	69		C	Y
C	West	GRE	2652	Liberty Second Transformer	Liberty Second Transformer	MN					$3,394,835	6/1/2013	Proposed	115	69	C	Y
C	West	GRE	2653	Soderville-East Bethel Rebuild	Soderville-East Bethel Rebuild	MN					$1,075,000	6/1/2014	Proposed	69		C	Y
C	West	GRE	2654	St. Stephen	St. Stephen	MN					$625,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2655	Le Homme Dieu 115 kV conversion	Le Homme Dieu 115 kV conversion	MN					$364,000	6/1/2013	Proposed	115		C	Y
C	West	GRE	2656	Fergus Falls 115 kV project	Fergus Falls 115 kV project	MN					$1,679,000	6/1/2014	Proposed	115		C	Y
C	West	GRE	2657	Alexandria - Albany (50.0 mi.) 115 kV lin	Alexandria - Albany (50.0 mi.) 115 kV lin	MN					$24,103,500	6/1/2016	Proposed	115	69	C	Y
C	West	GRE	2658	Coon Creek Substation and Coon Creek-HWY 65 Rebuild double circuit	Coon Creek Substation and Coon Creek-HWY 65 Rebuild double circuit	MN					$7,853,902	6/1/2015	Proposed	69		C	Y
C	West	GRE	2659	Randolph (DEA) 115 kV Substation	Randolph (DEA) 115 kV Substation	MN					$860,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2660	Perham 3.0 MVAr capacitor bank	Perham 3.0 MVAr capacitor bank	MN						6/1/2009	Proposed			C	Y
C	West	GRE	2661	New York Mills 3.6 MVAr capacitor bank	New York Mills 3.6 MVAr capacitor bank	MN						6/1/2010	Proposed			C	Y
C	West	GRE	2662	High Island Conversion to 115 kV	High Island Conversion to 115 kV	MN					$4,530,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2663	Clearly Lake-Credit River 115 kV Rebuild	Clearly Lake-Credit River 115 kV Rebuild	MN					$322,050	6/1/2013	Proposed	115		C	Y
C	West	GRE	2664	Mantrap and Potato Lake 115 kV Conversion	Mantrap and Potato Lake 115 kV Conversion	MN					$2,738,750	11/1/2013	Proposed	115		C	Y
C	West	GRE	2665	Schroeder-Lutsen 115 kV Rebuild	Schroeder-Lutsen 115 kV Rebuild	MN					$4,258,670	6/1/2015	Proposed	69		C	Y
C	West	GRE	2666	Carver County-Assumption to 115 kV	Carver County-Assumption to 115 kV	MN					$1,983,900	6/1/2014	Proposed	115		C	Y
C	West	GRE	2667	Rush City-Adrian Robinson Rush City Dist Retemp	Rush City-Adrian Robinson Rush City Dist Retemp	MN					$284,800	6/1/2014	Proposed	69		C	Y
C	West	GRE	2668	Osage Regulator	Osage Regulator	MN						6/1/2015	Proposed			C	Y
C	West	GRE	2669	Dickinson-West St. Cloud Transformer Replacement	Dickinson-West St. Cloud Transformer Replacement	MN					$2,039,835	6/1/2011	Proposed	115	69	C	Y
C	West	GRE	2670	North Perham 115/41.6 Source	North Perham 115/41.6 Source	MN					$4,235,028	6/1/2012	Proposed	115	41.6	C	Y
C	West	GRE	2672	Rush City - Bear Creek - Effie Transformer Swap	Rush City - Bear Creek - Effie Transformer Swap	MN					$3,211,422	6/1/2011	Proposed	230	69	C	Y
C	West	GRE	2673	Dalbo-St. Francis (14 mi.) 69 kV line	Dalbo-St. Francis (14 mi.) 69 kV line	MN					$6,165,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2674	Milaca-Long Siding (8.86 mi.) Rebuild	Milaca-Long Siding (8.86 mi.) Rebuild	MN					$2,488,500	6/1/2011	Proposed	69		C	Y
C	West	GRE	2675	West St. Cloud Breaker for Sartell line	West St. Cloud Breaker for Sartell line	MN					$1,942,000	6/1/2012	Proposed	115		C	Y
C	West	GRE	2676	Paynesville-Watkins 69 kV line	Paynesville-Watkins 69 kV line	MN					$6,180,000	6/1/2012	Proposed	69		C	Y
C	West	GRE	2677	Princeton-Princeton Tap (5.12 mi.) Reconductor to ACSS	Princeton-Princeton Tap (5.12 mi.) Reconductor to ACSS	MN					$409,600	6/1/2012	Proposed	69		C	Y
C	West	GRE	2678	Zimmerman 19.6 MVAr capacitor	Zimmerman 19.6 MVAr capacitor	MN					$291,800	6/1/2012	Proposed	69		C	Y
C	West	GRE	2679	Ramsey-Grand Forks (81.02 mi.) 230 kV Rebuild	Ramsey-Grand Forks (81.02 mi.) 230 kV Rebuild	ND					$38,484,500	11/1/2020	Proposed	230		C	Y
C	West	GRE	2680	Shamineau Lake-North Parker (13.6 Mile) 115 kV line	Shamineau Lake-North Parker (13.6 Mile) 115 kV line	MN					$5,734,800	6/1/2016	Proposed	115		C	Y
C	West	GRE	2681	St. Boni Second 115/69 kV Substation Improvements	St. Boni Second 115/69 kV Substation Improvements	MN					$2,359,835	6/1/2014	Proposed	115	69	C	Y
C	West	GRE	2682	Lake Marion 140 MVA Transformer Replacement	Lake Marion 140 MVA Transformer Replacement	MN					$1,939,835	6/1/2014	Proposed	115	69	C	Y
C	West	GRE	2683	Bloom 115 kV upgrade	Bloom Tap 115 kV line, 3-way switch in Fenton-Nobles 115 kV line #2	MN					$1,269,000	6/1/2015	Proposed	115		C	Y
C	West	GRE	2684	Assumption-Belle Plaine to 115 kV	Assumption-Belle Plaine to 115 kV	MN					$4,332,810	6/1/2016	Proposed	115		C	Y
C	West	GRE	2685	Lake Marion-Lake Marion Tap to 115 kV Double Circuit	Lake Marion-Lake Marion Tap to 115 kV Double Circuit	MN					$1,297,620	6/1/2016	Proposed	115		C	Y
C	West	GRE	2686	Lake Marion Tap-Elko-New Market to 115 kV	Lake Marion Tap-Elko-New Market to 115 kV	MN					$2,343,400	6/1/2016	Proposed	115		C	Y
C	West	GRE	2687	New Market-Helena 115 kV line	New Market-Helena 115 kV line, Helena 115 kV breaker and line termination, New Market 115/69 kV source	MN					$10,215,028	6/1/2016	Proposed	115		C	Y
C	West	GRE	2688	Elk River West-Waco Rebuild	Elk River West-Waco Rebuild	MN					$1,476,300	6/1/2015	Proposed	69		C	Y
C	West	GRE	2689	Breezy Point-Breezy Point Tap Retemp	Breezy Point-Breezy Point Tap Retemp	MN					$180,000	11/1/2015	Proposed	69		C	Y

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C	West	GRE	2690	Delano Tap-Willow (8.5 mi) Retemp	Delano Tap-Willow (8.5 mi) Retemp	MN					$680,000	6/1/2015	Proposed	69		C	Y
C	West	GRE	2691	Orrock 345/115 kV source and Orrock-Waco-Liberty 115 kV line.	Orrock 345/115 kV source and Orrock-Waco-Liberty 115 kV line.	MN					$19,661,825	6/1/2017	Proposed	345	69	C	Y
C	West	GRE	2692	Little Falls-Pierz (12.0 Mile) 115 kV line	Little Falls-Pierz (12.0 Mile) 115 kV line. Little Falls-Lastrup 115 kV line and 34.5 kV underbuild, Little Falls 3 way switch	MN					$6,711,000	6/1/2018	Proposed	115		C	Y
C	West	GRE	2693	Litchfield 2 mile line temprature upgrade	Litchfield 2 mile line temprature upgrade	MN					$160,000	6/1/2016	Proposed	69		C	Y
C	West	GRE	2694	Spirit Lake-Spirit Lake Switch Retemp	Spirit Lake-Spirit Lake Switch Retemp	MN					$144,800	6/1/2016	Proposed	69		C	Y
C	West	GRE	2695	Riverton-Oak Lawn 69 kV Reconductor to ACSS	Riverton-Oak Lawn 69 kV Reconductor to ACSS	MN					$579,200	11/1/2016	Proposed	69		C	Y
C	West	GRE	2696	Itasca-Mantrap 115 kV loop	Itasca-Mantrap 115 kV loop	MN					$20,502,070	6/1/2018	Proposed	115		C	Y
C	West	GRE	2697	Elizabeth 3.0 MVAr capacitor bank	Elizabeth 3.0 MVAr capacitor bank	MN						6/1/2017	Proposed			C	Y
C	West	GRE	2698	Gunn 115 kV Conversion	Gunn 115 kV Conversion	MN					$344,000	11/1/2017	Proposed	115		C	Y
C	West	GRE	2699	Blackberry 115 kV Conversion	Blackberry 115 kV Conversion	MN					$523,000	11/1/2017	Proposed	115		C	Y
C	West	GRE	2700	Pine Center 9.0 MVAR 69 kV cap bank	Pine Center 9.0 MVAR 69 kV cap bank	MN					$251,000	6/1/2017	Proposed	69		C	Y
C	West	GRE	2701	Big Swan - Litchfield 115 kV line	Big Swan-Litchfield 115 kV line, Big Swan 115 kV breaker and deadend, Litchfield 69 kV breaker and deadend	MN					$4,891,000	6/1/2018	Proposed	115		C	Y
C	West	GRE	2702	Dalbo 230 kV source	Dalbo 230 kV source	MN					$56,774,816	6/1/2020	Proposed	230	69	C	Y
C	West	GRE	2703	Hugo-Blaine Reconductor	Hugo-Blaine Reconductor	MN					$531,200	6/1/2017	Proposed	69		C	Y
C	West	GRE	2704	Rebuild Milaca-Ogilvie 69 kV.	Rebuild Milaca-Ogilvie 69 kV.	MN					$2,982,150	6/1/2017	Proposed	69		C	Y
C	West	GRE	2705	Liberty-Becker 69 kV reconductor	Liberty-Becker 69 kV reconductor	MN					$64,000	6/1/2017	Proposed	69		C	Y
C	West	GRE	2706	Princeton-Long Siding Rebuild	Princeton-Long Siding Rebuild	MN					$431,750	6/1/2018	Proposed	69		C	Y
C	West	GRE	2707	Shamineau Lake 30 MVA, 115/34.5 kV source	Shamineau Lake 30 MVA, 115/34.5 kV source	MN					$6,120,950	6/1/2019	Proposed	115	34.5	C	Y
C	West	GRE	2708	Blaine Second Transformer	Blaine Second Transformer	MN					$3,573,598	6/1/2018	Proposed	230	69	C	Y
C	West	GRE	2709	Wright-Round Lake 69 kV Rebuild	Wright-Round Lake 69 kV Rebuild	MN					$2,575,600	11/1/2018	Proposed	69		C	Y
C	West	GRE	2710	Prior Lake Conversion to 115 kV	Prior Lake Conversion to 115 kV	MN					$2,000,000	6/1/2018	Proposed	115		C	Y
C	West	GRE	2711	Blaine 69 kV cap bank	Blaine 69 kV cap bank	MN						6/1/2018	Proposed	69		C	Y
C	West	GRE	2712	Enterprise Park-Energy Park 69 kV reconductor.	Enterprise Park-Energy Park 69 kV reconductor to 397 ACSS, Energy Park 69 kV 3-way switch upgrade	MN					$216,800	6/1/2018	Proposed	69		C	Y
C	West	GRE	2713	Grasston-Pine City 69 kV rebuild.	Grasston-Pine City 69 kV rebuild.	MN					$2,225,450	6/1/2018	Proposed	69		C	Y
C	West	GRE	2714	Elk River S14 69 kV cap bank.	Elk River S14 69 kV cap bank.	MN						6/1/2018	Proposed	69		C	Y
C	West	GRE	2715	Rush Switch-Rock Lake 69 kV reconductor	Rush Switch-Rock Lake 69 kV reconductor	MN					$738,400	6/1/2018	Proposed	69		C	Y
C	West	GRE	2716	Soderville -Ham Lake (0.38 mi.) Reconductor	Soderville -Ham Lake (0.38 mi.) Reconductor	MN					$30,400	6/1/2019	Proposed	69		C	Y
C	West	GRE	2717	Linwood-North Branch 69 kV reconductor	Linwood-North Branch 69 kV reconductor	MN					$1,019,750	6/1/2019	Proposed	69		C	Y
C	West	GRE	2718	Albany - West St.Cloud (17 mi.) 115 kV lin	Albany - West St.Cloud (17 mi.) 115 kV lin	MN					$8,749,000	6/1/2019	Proposed	115		C	Y
C	West	GRE	2719	East Cambridge-South Cambridge 69 kV line	East Cambridge-South Cambridge 69 kV line	MN					$2,656,500	6/1/2019	Proposed	69		C	Y
C	West	GRE	2720	Side Lake-Meadowbrook 115 kV Line Rebuild	Side Lake-Meadowbrook 115 kV Line Rebuild	MN					$4,152,500	6/1/2020	Proposed	115		C	Y
C	West	GRE	2721	Cashel	Cashel	MN						6/1/2019	Proposed			C	Y
C	West	GRE	2722	Lutsen-Cascade 115kV line	Lutsen-Cascade 115kV line	MN						6/1/2021	Proposed	115		C	Y
C	West	GRE	2723	Cascade-Grand Marais Tap 115kV line	Cascade-Grand Marais Tap 115kV line	MN						6/1/2021	Proposed	115		C	Y
C	West	GRE	2724	Pierz 300 MVA, 230/115 kV Source and Line Outlets	Pierz 300 MVA, 230/115 kV Source and Line Outlets	MN						6/1/2022	Proposed	230	115	C	Y
C	West	GRE	2725	Arrowhead 115 kV Conversion	Arrowhead 115 kV Conversion	MN						6/1/2015	Proposed	115		C	Y
C	West	GRE	2726	Loon Lake-St. Clair 69 (115) kV line	Loon Lake-St. Clair 69 (115) kV line	MN					$9,787,000	6/1/2017	Proposed	115		C	Y
C	West	GRE	2727	Bunker Lake 69 kV cap bank.	Bunker Lake 69 kV cap bank.	MN							Proposed	69		C	Y
C	West	GRE	2728	Fox Lake-Heron Lake 69 kV projects	Fox Lake-Heron Lake 69 kV projects	MN					$2,122,500	6/1/2019	Proposed	69		C	Y
C	West	GRE	2729	Minneota 5.4 MVAR cap bank	Minneota 5.4 MVAR cap bank	MN					$236,000	6/1/2015	Proposed	69		C	Y
C	West	GRE	2730	Al-Corn 161 kV cap bank	Al-Corn 161 kV cap bank	MN					$536,000	6/1/2018	Proposed	161		C	Y
C	West	GRE	2731	Lake Lillian (KEPCA) 3.0 mile, 69 kV line	Lake Lillian (KEPCA) 3.0 mile, 69 kV line	MN					$1,115,000	6/1/2012	Proposed	69		C	Y

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C	West	GRE	2732	Cambria (MN Valley) 10.0 mile, 115 kV line	Cambria (MN Valley) 10.0 mile, 115 kV line	MN							Proposed	115		C	Y
C	West	GRE	2733	Dahlgren (MN Valley) 115 kV Substation	Dahlgren (MN Valley) 115 kV Substation	MN					$860,000	6/1/2016	Proposed	115		C	Y
C	West	GRE	2734	Savage (MN Valley) 115 kV Substation	Savage (MN Valley) 115 kV Substation	MN					$860,000	6/1/2016	Proposed	115		C	Y
C	Central	IPL	897	Thompson 345/138kV Autotransformer	Add new 345/138kV autotransformer at Thompson Substation	IN		BaseRel			$7,200,000	6/1/2012	Proposed	345	138	C	Y
C	Central	IPL	2051	Petersburg - Thompson 345 kV line Capacity Upgrade	Increase Capacity from 956 MVA to 1195 MVA	IN		BaseRel				6/1/2012	Proposed	345		C	Y
C	Central	IPL	2052	Petersburg - Francis Creek -Hanna 345 kV line Capacity Upgrade	Increase Capacity from 956 MVA to 1195 MVA	IN		BaseRel				6/1/2012	Proposed	345		C	Y
C	East	ITC	694	Saratoga Station	Saratoga 345/120 kV switching station	MI					$29,600,000	12/31/2018	Proposed	345	120	C	Y
C	East	ITC	908	Lulu Station	Tap the Majestic to Lemoyne and Milan to Allen Junction to Monroe 3-4 345 kV circuits into a new 345 kV Switching Station at the Lulu site. Project also adds three miles 345 kV double circuit tower from Monroe to cut the Lulu-Leymoyne circuit into Monroe, moving the Leymone 345 kV interconnection with First Energy to the Monroe 3-4 345 kV bus	MI					$4,500,000	6/1/2018	Proposed	345		C	Y
C	East	ITC	1012	Wayne - Newburg Split	Establish new Wayne-Newburgh 120 kV circuit 3 using currently paralleled wire from existing Wayne-Newburgh circuit 2	MI						6/1/2014	Proposed	120		C	Y
C	East	ITC	1295	Quaker - Southfield	Adds a new 120 kV circuit from the Quaker station to the Southfield station.	MI						6/30/2016	Proposed	120		C	Y
C	East	ITC	1382	Michigan 765 kV Backbone	Project constructs a 765 kV circuit from AEP's Cook station to a new 765 kV station at the Kenowa 345 kV (METC) station including one 765/345 kV transformer at Kenowa. A new 765 kV circuit from the Kenowa station to a new 765 kV station at the Denver location including a 765/138 kV transformer. A new 765 kV circuit from the Denver station to a new 765 kV station at the Sprague Creek location including a 765/345 kV transformer at Sprague Creek. A new 765 kV circuit from the Sprague Creek station to a new 765 kV station at the Bridgewater site including two 765/345 kV transformers. A new 765 kV circuit from Bridgewater to a new 765 kV station near the Indiana - Ohio border tapping the Dumont to Marysville 765 kV circuit. A new 765 kV circuit from the Bridgewater station to AEP's South Canton 765 kV station. The project will also tap the Blackfoot to Madrid 345 kV circuit at the new Sprague Creek 345 kV station and create two Blackfoot to Sprague Creek 345 kV circuits and one Madrid to Sprague Creek 345 kV circuit. And	MI					$2,500,000,000	12/31/2016	Proposed	765	138	C	Y
C	East	ITC	1550	Hager - Sunset 120 kV	Transposes the existing cabled line entrance of the Hager-Sunset 120 kV Line with the overhead line entrance of the Sunset-Southfield 120 kV line to increase the thermal rating of Hager-Sunset.	MI						5/31/2015	Proposed	120		C	Y
C	East	ITC	1842	Bunce Creek - Greenwood 230 kV	Construct a new 36 mile Bunce Creek - Greenwood 230 kV circuit on 954 ACSR 230 kV DCT utilizing existing right of way. Rebuild adjacent circuits to 954 ACSR.	MI						6/1/2017	Proposed	345	120	C	Y

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C	East	ITC	1843	Waterman - Essex 230kV	Construct 8.5 miles of new 230 kV Cable from Waterman to Essex, Add a new 230 kV bus and 230/120 kV transformer at Essex Station	MI						6/1/2013	Proposed	230	120	C	Y
C	East	ITC	1844	Essex-Mack 120kV	Rebuild 2.4 miles of circuit from Essex to Voyager and from Voyager to Mack to 954 ACSR 2-circuit tower construction and create a new Essex - Mack 120 kV line	MI						6/1/2013	Proposed	120		C	Y
C	East	ITC	1845	Blackfoot 345kV - Hemphill 138kV	Install a 345/230kV transformer at Blackfoot, build a new 230kV circuit from Blackfoot-Hemphill (17 miles on existing ROW), build a new 230kV bus at Hemphill, and install a new 230/138kV transformer at Hemphill	MI						6/1/2013	Proposed	345	138	C	Y
C	East	ITC	1846	Evergreen Position HN Equipment Upgrade	Upgrade trainers and Bus #102	MI						6/1/2012	Proposed	120		C	Y
C	East	ITC	1847	DIG-Waterman / Navarre-Waterman 230kV	Build 2.5 miles of new 120 kV circuit in the current Navarre-Waterman 230 kV ROW and move both Detroit Edison's 120 kV Navarre-Maxwell and ITCT's Zug-Waterman 120 kV circuits to the new poles. Use the empty side of the tower to break up the 3-ended Dig-Navarre-Waterman 230 kV line and create Dig-Waterman 230 kV circuit and Navarre-Waterman 230 kV circuit.	MI						6/1/2014	Proposed	230		C	Y
C	East	ITC	1848	Bad Axe - Tuscola 120kV	Construct new 34 mile Bad Axe - Tuscola 120 kV circuit on 954ACSR 230 kV DCT. Rebuild Tuscola - Arrowhead and Arrowhead - Bad Axe on adjacent side of towers with 954 ACSR.	MI						6/1/2016	Proposed	120		C	Y
C	East	ITC	1849	Coventry 345kV Breaker	Add a 345 kV breaker at Coventry to prevent loss of entire 345 kV bus for loss of the Coventry to Majestic 345 kV circuit.	MI						6/1/2016	Proposed	345		C	Y
C	East	ITC	1851	Hager-Sunset 120kV cable entrance	Install a 2nd (parallel) 120kV cable entrance (400 ft) into Sunset.	MI						6/1/2016	Proposed	120		C	Y
C	East	ITC	1852	Drexel-Southfield 120kV cable entrance	Install a 2nd (parallel) 120kV cable entrance (0.4 miles) into Southfield.	MI						6/1/2017	Proposed	120		C	Y
C	East	ITC	1853	Newburgh - Peru 120kV	Replace line entrance and 2.1 miles of 477 ACSR with 954 ACSR conductor	MI						6/1/2017	Proposed	120		C	Y
C	East	ITC	1854	Trenton Channel - Riverview 120kV	Install a new 120 kV circuit from Trenton Channel to Riverview utilizing the existing de-energized Trenton Channel to Jefferson circuit to get from Trenton Channel to Jefferson. From Jefferson to Riverview (2.2 miles), either install a new 120 kV line or replace the existing double circuit towers with triple circuit towers. Also replace a wave trap on Riverview-Ironton 120kV	MI						6/1/2018	Proposed	120		C	Y
C	East	ITC	1855	Troy-Formtech 120kV	Reconstruct the 0.8 mileTroy-Formtech portion of the Troy-Lincoln and Troy-Chestnut 120kV circuits to 954 ACSR	MI						6/1/2019	Proposed	120		C	Y
C	East	ITC	1858	Wayne 345 kV Overloaded S.E. Replacement	Replace various pieces of station equipment that are overloaded at Wayne station under normal conditions and for various contingencies.	MI						6/1/2010	Proposed	345		C	Y
C	East	ITC	1859	Castle 120kV Station	Build a new 120kV station near point where the Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits pass by each other. Cut those three circuits into the new station. Line Rebuilds (6.6 miles of DCT) on portions of Quaker-Drake, Northwest-Drake, and Sunset-Southfield to remove 477 ACSR and replace it with 954 ACSR.	MI						6/1/2014	Proposed	120		C	Y
C	East	ITC	1867	Outage reduction project 2009	Throughout System	MI						12/31/2009	Proposed			C	Y

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C	East	ITC	1868	Cato GIS replacement	Like for Like Replacement (Over $1 million)	MI						12/31/2010	Planned	120		C	Y
C	West	ITCM	1738	Bertram-Hills 161kV Reconductor	Reconductor 33 miles of 161kV from Bertram to new Rose Hollow to Hills	IA		BaseRel	Shared		$13,000,000	12/31/2012	Proposed	161		C	Y
C	West	ITCM	1741	G517: Dotson - Storden - Heron Lake 161kV	Network upgrades for G517. Build a new Heron Lake - Cottonwood Co 161 kV line and a new Cottonwood Co 161 kV switch station. Build Cottonwood Co to Dotson 161kV line.	MN					$36,719,820	12/31/2010	Planned	161		C	Y
C	West	ITCM	1742	Split Rock-Heron Lake 161kV Rebuild	Rebuild from Split Rock-Magnolia-Elk-Heron Lake 161kV line.	MN		BaseRel	Shared		$22,800,000	12/31/2012	Proposed	161		C	Y
C	West	ITCM	1746	Lakefield-Adams 161kV Rebuild	Rebuild Lakefield-Fox Lake-Rutland-Winnebago-Hayward-Adams 161kV line to double ckt 345 & 161kV. Allow for a 345kV line position for future use.	IA		BaseRel	Shared		$66,900,000	12/31/2015	Proposed	161		C	Y
C	West	ITCM	2830	Lakefield Jct. – Rutland 345kV	Build a new 345kV station at Rutland and add a new 345/161kV transformer. Build a new 345kV circuit from Lakefield Jct station to Rutland 345kV station.	MN					$98,500,000	1/1/2014	Proposed	345	161	C	Y
C	West/Cer	ITCM, AmerenIL	2785	Northwest Iowa (New Substation)-Sorenson HVDC	Build new +/- 800 kV bi-pole HVDC line from a new Northwest Iowa substation to the existing Sorenson substation. The project will be capable of transferring approximately 1,500 MW independently or up to 7,900 MW coupled with the complimentary project (Owner_PrjID 7) below. The project(s) also envision a regional collector system that will be vetted through the RGOSII stakeholder process. The project sponsor also recommends that project be studied in a staged fashion such that it is capable to go in service at a lower voltage and transfer rating and grow over time.	IA	IN				$1,900,500,000	5/1/2014	Proposed	800		C	Y
C	West/Cer	ITCM, AmerenIL	2794	Northwest Iowa (New Substation)-Collins HVDC	Build new +/- 800 kV bi-pole HVDC line from a new Northwest Iowa substation to the existing Collins substation. The project will be capable of transferring approximately 1,500 MW independently or up to 7,900 MW coupled with the complimentary project (PrjID 2785) above. The project(s) also envision a regional collector system that will be vetted through the RGOSII stakeholder process. The project sponsor also recommends that project be studied in a staged fashion such that it is capable to go in service at a lower voltage and transfer rating and grow over time.	IA	IL				$1,625,000,000	5/1/2014	Proposed	800		C	Y
C	East	METC	642	Argenta - Hazelwood(Sag) 138 ckt # 1	Argenta - Hazelwood(Sag) 138 ckt # 1	MI			Excluded		$50,000	6/1/2017	Proposed	138		C	Y
C	East	METC	984	Denver 345/138 kV station	Build new 345/138 kV station, 50 miles 345 kV line, 60 miles 138 kV lines	MI					$77,132,000	6/1/2018	Proposed	345		C	Y
C	East	METC	987	Emmet - Stover 138 kV Line	Build 30 miles new 138 kV line, 795 ACSS	MI					$10,250,000	6/1/2013	Proposed	138		C	Y
C	East	METC	1225	Thompson Rd-Tallman 138 kV	Thompson Road - Tallman 138 kV line	MI					$5,000,000	5/1/2018	Proposed	138		C	Y
C	East	METC	1428	Roosevelt substation	Add 345/138kV transformer and new 138kV line to Black River along with breakers at Roosevelt and Black River	MI					$16,000,000	5/1/2013	Proposed	345	138	C	Y
C	East	METC	1429	Barry-Thompson Rd 138kV line	Build new 17mile 138kV line from Barry to Thompson Rd	MI					$20,000,000	6/1/2018	Proposed	138		C	Y
C	East	METC	1430	Buck Creek switching station	Convert 138/46kV substation to a switching station by installing 3 high side 138kV breakers at Buck Creek	MI					$4,500,000	6/1/2017	Proposed	138		C	Y
C	East	METC	1431	Vergennes-Kendrick-Plaster Creek 138kV line	Build new 16mile 138kV line from Vergennes to Kendrick and puchase Kendrick-Plaster Creek spur	MI					$14,000,000	6/1/2017	Proposed	138		C	Y
C	East	METC	1432	Withey Lake-Twining 138kV line	Rebuild 0.2 miles of Withey Lake-Twining 138kV line	MI					$100,000	6/1/2018	Proposed	138		C	Y
C	East	METC	1573	Donaldson Creek 138kV Capacitor	Install minimum 23.3 MVAR 138kV capacitor	MI						6/1/2011	Proposed	138		C	Y
C	East	METC	1657	Terminal Equipment Upgrade	throughout system	MI							Proposed			C	Y
C	East	METC	1795	David Jct. - Bingham 138kV	Rebuild 19 miles of 138kV 336.4 ACSR to 954 ACSR.	MI		BaseRel	TBD		$11,700,000	6/1/2010	Proposed	138		C	Y

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C	East	METC	1800	Argenta-Riverview 138kV	Fix Sag limit, Retap or upgrade 1200A CT's at both ends, Upgrade 1200A Breaker 377 and 1200A Switch 377 at Riverview	MI						6/1/2013	Proposed	138		C	Y
C	East	METC	1801	Thetford-Hemphill 230kV	Rebuild the Thetford-Hemphill 16 mile 138kV circuit to 954 ACSR 230kV & install a 230/138kV transformer at Thetford. A portion of this line from Hemphill north to be relocated to the tower currently holding Garfield-Hemphill, which needs to be rebuilt anyhow.	MI						6/1/2014	Proposed	230		C	Y
C	East	METC	1802	Keystone 345/138kV Transformers	Replace both 345/138kV transformers at Keystone with 300/400/500 MVA units.	MI						6/1/2013	Proposed	345	138	C	Y
C	East	METC	1803	Clearwater-Stover-Livingston 138kV	Rebuild the 31 mile Clearwater-Stover-Livingston 138kV line to 230kV 954 ACSR DCT, operate at 138kV (leaving 1 side vacant for future use).	MI						6/1/2013	Proposed	138		C	Y
C	East	METC	1804	Marquette - Easton Jct. 138kV	Upgrade two CTs, two impedance relays and breakers 1020, 2030 at Marquette	MI						6/1/2014	Proposed	138		C	Y
C	East	METC	1805	Livingston-Emmet-Oden 138kV	Rebuild the Livingston-Emmet and Emmet-Oden 138kV circuits with 954 ACSR DCT, creating two circuits from both Livingston-Emmet and Emmet-Oden. Total line rebuild is 33 miles	MI						6/1/2014	Proposed	138		C	Y
C	East	METC	1807	Richland - Bullock 230kV	Swap the existing Bullock-Gleaner and Tittabawassee-Begole 138 kV lines, and open the Begole-Tittabawassee 138 kV line, and build 3.2 miles of new DCT into Richland, creating Bullock -Richland, Richland-Begole, and Tittabawassee-Gleaner 138 kV lines. Convert 8.3 miles of the new Bullock to Richland 138 kV line to 230 kV 954 ACSR. Install a new 345/230 kV transformer at Richland and a new 230/138 kV transformer at Bullock.	MI						6/1/2016	Proposed	345	138	C	Y
C	East	METC	1808	Four Mile - Cowan Lake Jct.	Rebuild 15.5 miles of 336/477 to 954 ACSR.	MI						6/1/2017	Proposed	138		C	Y
C	East	METC	1809	Keystone - Tippy 138kV	Rebuild the 27 mile Keystone to Hodenpyl 138 kV line to 954 ACSR (Pre-build to 230 kV construction).	MI		BaseRel	Shared		$29,990,000	6/1/2011	Planned	138		C	Y
C	East	METC	1811	Keystone - Gray Rd. 138kV	Construct a new 9 mile 138kV 954 ACSR circuit from Keystone to Gray Road.	MI						6/1/2018	Proposed	138		C	Y
C	East	METC	1812	Gary Road 345kV Station	Build a new 345 kV switching station [Gary Road] at the junction of Nelson Road to Richland, Nelson Road to Goss and Tittabawassee to Thetford 345 kV lines	MI						6/1/2018	Proposed	345		C	Y
C	East	METC	1816	Mecosta - Croton 138kV	Rebuild 22 miles of 138kV 110 CU to 954 ACSR. Prebuild to 230kV construction.	MI						6/1/2013	Proposed	138		C	Y
C	East	METC	1825	Outage reduction project 2009	Throughout system	MI						12/31/2009	Proposed			C	Y
C	East	METC	1831	Northern 230 kV Loop	Tap the Ludington - Kenowa 345 kV circuit 1 with the new 345/230 kV EHV substation at Felch Road. Also install a new 345/230 kV transformer at Livingston and Tittabawassee. Install a new 230/138 kV transformer at Tippy and Mio. Construct a new 76 mile 230 kV 1431 ACSR circuit from Tippy to Felch Road, 79 mile 230 kV 1431 ACSR circuit from Tippy to Livingston, 42 mile 230 kV 1431 ACSR circuit from Livingston to Mio, and 79 mile 230 kV 1431 ACSR circuit from Mio to Tittabawassee	MI						6/1/2018	Proposed	345	138	C	Y
C	East	METC	2490	North Belding - Vergennes 138kV	Upgrade terminal equipment.	MI		BaseRel	Not Shared		$550,000	6/1/2013	Proposed	138		C	Y
C	East	METC	2809	Garfield-Hemphill 138kV	Replace 9.1 miles of 336 ACSR with 1431 ACSR	MI		Other	Excluded		$11,740,000	6/1/2014	Proposed	138		C	Y
C	East	METC	2810	Delhi - Canal Jct 138kV	Rebuild 7.5 miles of 138kV line to 954 ACSR	MI					$5,500,000	6/1/2014	Proposed	138		C	Y
C	East	METC	2811	East Tawas - Karn 138kV	Rebuild 68 miles of 138kV to 954 ACSR.	MI					$50,200,000	6/1/2015	Proposed	138		C	Y
C	East	METC	2812	Twining - Alcona 138kV	Rebuild the Twining-Mio 138kV line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI					$56,000,000	6/1/2017	Proposed	138		C	Y

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C	West	MP	2548	Hilltop	Add second 230/115 kV Transformer capacity and 230 kV line	MN						6/1/2019	Proposed	230	115	C	Y
C	West	MP	2549	15L Upgrade	Thermal Upgrade of MP Line #15	MN						6/1/2014	Proposed	115		C	Y
C	West	MP	2761	Pollymet	add new 138/14 kV substaion off MP 138 KV Line #1	MN					$2,005,000	9/30/2010	Planned	115	14	C	Y
C	East	MPPA	2073	GT - SA Reconductor	Reconductoring the line from Grand Traverse 1 to South Airport. Replacing 1.14 miles of 477ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$340,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2074	SA - BWX Reconductor	Reconductoring the line from South Airport to Barlow Junction. Replacing 2.15 miles of 477ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$640,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2075	BWX - CDX Reconductor	Reconductoring the line from Barlow Junction to Cass Road Junction. Replacing 1.34 miles of 477ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$395,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2076	CDX - CD Reconductor	Reconductoring the line from Cass Road Junction to Cass Road Sub. Replacing 1.66 miles of 477ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$490,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2077	CDX - HL Reconductor	Reconductoring the line from Cass Road Junction to Hall Street Sub. Replacing .55 miles of 477ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$170,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2078	Gray - HL Reconductor	Reconductoring and constructing the line from the proposed new Gray Rd. Sub to Hall Street Sub. Replacing 3.82 miles of 4/0 ACSR (63.6/85.5 MVA rating) with 795 ACSR (108/140 MVA rating)	MI					$1,130,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2079	SA Switches	Replacing 600 Amp switches with 1200 Amp switches at the South Airport Sub.	MI					$70,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2080	BWX Switches	Replacing 600 Amp switches with 1200 Amp switches at the Barlow Junction.	MI					$200,000	7/1/2010	Planned	69		C	NT
C	East	MPPA	2081	CDX Switches	Replacing 600 Amp switches with 1200 Amp switches at the Cass Road Junction.	MI					$150,000	7/1/2010	Planned	69		C	NT
C	East	NIPS	1979	Maple Sub - 69 kV Switched Capacitors	Add two steps of 8.1 MVAR capacitors on the Maple Substation 69 kV bus.	IN					$1,080,000	12/1/2010	Proposed	69		C	Y
C	East	NIPS	1980	Babcock Sub - 69 kV Switched Capacitors	Add two to three steps of 9.0 MVAR capacitors on the Babcock Substation 69 kV bus. .	IN					$1,052,000	12/1/2011	Proposed	69		C	Y
C	East	NIPS	1981	Kreitzburg Sub - 69 kV Switched Capacitors	Add two steps of 9.0 MVAR capacitors on the Kreitzburg Substation 69 kV bus. .	IN					$1,052,000	12/1/2011	Proposed	69		C	Y
C	East	NIPS	1990	Upgrade Circuit 6986 - Dekalb to Angola Substation	Rebuild 22.5 miles of Circuit 6986's existing 2/0 Cu line to 336.4 kCM ACSR.	IN					$2,680,000	12/1/2012	Proposed	69		C	Y
C	East	NIPS	1994	Circuit 6977 - Midway to Bristol Subs - Recond 4.1 miles	Upgrade (reconductor) 4.1 miles of 69 KV line to 336.4 KCM ACSR between Midway and Bristol Substations.	IN					$788,000	5/1/2010	Proposed	69		C	Y
C	East	NIPS	1998	Circuits 6962 & 6937 - Lawton to E. Winamac - Rebuild 4.5 Miles	Rebuild existing double circuit 69 kV line between East Winamac and Lawton. Rebuild with new poles and conductors for 4.5 miles.	IN					$988,000	12/1/2011	Proposed	69		C	Y
C	East	NIPS	2000	Circuit 6977 - Goshen Jct to Model Sub Tap	Upgrade (reconductor) .5 miles of 69 KV line to 336.4 KCM ACSR.	IN					$52,000	12/1/2009	Planned	69		C	Y
C	East	NIPS	2003	Circuit 6937 Sw 854 to Bruce Lake Sub - Rebuild	Rebuild existing 69 kV line between Bruce Lake Substation and Switch 854.	IN					$359,000	12/1/2011	Proposed	69		C	Y
C	East	NIPS	2312	Marktown Sub - Replace 138kv BT Breaker	Marktown Sub - Replace 138 kV BT Breaker	IN					$113,636	6/1/2009	Proposed	138		C	Y

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C	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					$310,943	12/1/2009	Proposed	138		C	Y
C	East	NIPS	2319	South Chalmers MO 62 load breaks and switch replacement.	Upgrade Switch and install Load breaks	IN					$71,797	12/1/2010	Proposed	69		C	Y
C	East	NIPS	2320	Circuits 13874-Pole Replacement	Replace 30 wood poles with direct embedded steel poles, reinforce up to 70 additional poles, inspect and replace static wire as needed. First half of a two part project which will complete work begun in 2008.	IN					$988,648	12/1/2009	Proposed	138		C	Y
C	East	NIPS	2792	Northwest circuit reconfiguration	Phase I: Split existing Dune Acres Substation 138 kV bus into two sections to form a double bus. Add (2) new POT's and additional system protection (differential relaying) to provide adequate protection for a normally split 138 kV bus. Phase II: Reconfigure 138 kV circuits at Mitchell switchyard to address SF-6 breaker maintenance	IN					$2,236,000	12/1/2011	Proposed	138		C	Y
C	West	OTP	2746	Turtle Lake-Mercer 41.6 kV Line Upgrade	Rebuild Existing 18-Mile 41.6 kV Line	ND					$500,000	11/1/2015	Proposed	41.6		C	Y
C	West	OTP	2747	Edgeley-Gackle Jct. 41.6 kV Line Upgrade	Rebuild Existing 18-Mile 41.6 kV Line	ND					$600,000	12/31/2010	Proposed	41.6		C	Y
C	West	OTP	2748	Roslyn-Eden 41.6 kV Line Upgrade	Rebuild Existing 9-Mile 41.6 kV Line	SD					$210,000	6/30/2011	Proposed	41.6		C	Y
C	West	OTP	2752	Bartlett 41.6/4.16 kV Substation Expansion	Expand Existing 41.6/4.16 kV Substation at Bartlett to Handle a Load Increase	ND					$130,000	6/1/2009	Proposed	41.6	4.16	C	Y
C	West	OTP	2823	Gwinner Capacitor Bank	Install Capacitor Bank on 115 kV at Gwinner, ND. Two 8 MVAR.	ND					$600,000	12/31/2010	Proposed	115	12.5	C	Y
C	West	OTP	2824	Hensel Capacitor Bank	Install Capacitor Bank on 115 kV at Hensel, ND. Two 15 MVAR.	ND					$750,000	12/31/2010	Proposed	115	41.6	C	Y
C	West	OTP/MPC	2742	Bemidji-Wilton 115 kV Line Upgrade	Replace Terminal Equipment on This Existing Line to Increase Capacity	MN					$150,000	10/31/2010	Proposed	115		C	Y
C	West	OTP/MPC	2744	Winger-Thief River Falls 230 kV Line	Build New 55-Mile 230 kV Line to Support Projected Load Increases	MN					$35,000,000	1/1/2013	Proposed	230		C	Y
C	West	OTP/MPC	2745	Plummer-Thief River Falls 115 kV Capacitor Bank	Install New Capacitor Bank in Northwest MN for Voltage Support During Contingencies	MN					$750,000	11/1/2015	Proposed	115		C	Y
C	West	OTP/MPC	2826	Clearbrook Capacitor Bank	Install Capacitor Bank on 115 kV at Clearbrook, MN. One 34 MVAR.	MN					$750,000	12/31/2010	Proposed	115		C	Y
C	West	OTP/MPC	2827	Karlstad Capacitor Bank	Install Capacitor Bank on 115 kV at Karlstad. One 14 MVAR.	MN					$500,000	12/31/2010	Proposed	115		C	Y
C	West	OTP/MPC	2828	Thief River Falls Capacitor Bank	Install Capacitor Bank on 115 kV at Thief River Falls. One 15 MVAR.	MN					$750,000	12/31/2010	Proposed	115		C	Y
C	West	SMP	2166	City of St Peter, MN load serving upgrades	Adding approx 7.0 mimles of new 69kV transmission line and a new load serving substation (Estimated in service 2010)	MN					$6,000,000	12/1/2010	Proposed	69	69	C	NT
C	West	SMP	2167	City of Redwood Falls, MN load serving upgrades	Adding approx 6.4 miles of new 115kV transmission line and a new load serving substation (Estimated in service 2010)	MN					$4,000,000	12/1/2010	Proposed	69	69	C	NT
C	Central	Vectren (SIGE)	2460	Leonard Rd 69kV Substation	Add new 69kV switching substation near Leonard Rd	IN		Other			$2,000,000	6/1/2013	Planned	69		C	NT
C	Central	Vectren (SIGE)	2462	Y53 Stringtown to Folz Reconductor	Reconductor existing 69kV line for more capacity	IN		Other			$1,000,000	6/1/2013	Proposed	69		C	NT
C	Central	Vectren (SIGE)	2463	Y31 Mt Vernon to Givens 69kV recond.	Reconductor existing 69kV line for more capacity	IN		Other			$5,700,000	6/1/2013	Proposed	69		C	NT
C	Central	Vectren (SIGE)	2464	Y33 Mt Vernon to New Harmony 69kV recond.	Reconductor existing 69kV line for more capacity	IN		Other			$9,375,000	6/1/2013	Proposed	69		C	NT
C	West	XEL	2177	RES (230 kV Corridor study)	Convert Minn Valley - Panther - McLeod - Blue Lake 230 kV line to Double circuit 345 kV from Hazel to McLeod to West Waconia to Blue Lake.	MN						6/1/2016	Proposed	345	115	C	Y

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C	West	XEL	2767	Fenton 115/69 kV Interconnection	This project is to 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	MN				$3,710,000	1/1/2012	Planned	115	69	C	Y
C	Central	AmerenIL	2232	MTEP08 Reference Future EHV Overlay - East Moline to Kewanee	Build 345 kV circuit from East Moline to Kewanee in Illinois	IL					$44,000,000	8/1/2018	Conceptual	345	138	C	Y
C	Central	AmerenIL	2233	MTEP08 Reference Future EHV Overlay - Kewanee to Tazewell	Build 345 kV circuit from Kewanee to Tazewell in Illinois	IL					$85,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2234	MTEP08 Reference Future EHV Overlay - Palmyra to Meradosia	Build 345 kV circuit from Palmyra to Meradosia in Illinois	IL	MO				$75,000,000	8/1/2018	Conceptual	345	138	C	Y
C	Central	AmerenIL	2235	MTEP08 Reference Future EHV Overlay - Meradosia to Ipava	Build 345 kV circuit from Meradosia to Ipava in Illinois	IL					$54,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2236	MTEP08 Reference Future EHV Overlay - Meradosia to Pawnee	Build 345 kV circuit from Meradosia to Pawnee in Illinois	IL					$78,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2237	MTEP08 Reference Future EHV Overlay - Pana to Mt. Zion	Build 345 kV circuit from Pana to Mt. Zion in Illinois	IL					$42,000,000	8/1/2018	Conceptual	345	138	C	Y
C	Central	AmerenIL	2238	MTEP08 Reference Future EHV Overlay - Mt. Zion to Kansas	Build 345 kV circuit from Mt. Zion to Kansas in Illinois	IL					$73,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2240	MTEP08 Reference Future EHV Overlay - Kansas to Sugar Creek	Build 345 kV circuit from Kansas to Sugar Creek in Illinois	IL					$34,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2241	MTEP08 Reference Future EHV Overlay - Merom to Newton	Build 345 kV circuit from Merom to Newton in Illinois	IL	IN				$60,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2242	MTEP08 Reference Future EHV Overlay - Norris City to Albion	Build 345 kV circuit from Norris City to Albion in Illinois	IL					$37,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenIL	2243	MTEP08 Reference Future EHV Overlay - Baldwin to Joppa	Build 345 kV circuit from Baldwin to Joppa in Illinois	IL					$123,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	AmerenMO	2248	MTEP08 Reference Future EHV Overlay - Ottumwa to Thomas Hill	Build 345 kV circuit from Ottumwa in Iowa to Thomis Hill in Missouri	MO	IA				$154,432,990	8/1/2018	Conceptual	345		C	Y
C	West	AMIL, ATC, GRI	2773	Green Power Express 765kV	Construct a 765kV network including 11 new 765/345kV substations (13 new 765/345kV TRFs) and approximately 3000 miles of new 765kV line. Proposed substation locations include 2 in North Dakota, 1 in South Dakota, 4 in Minnesota, and 3 in Iowa. This 765kV network wil tie to the existing 765kV substations in Plano, IL and Sullivan, IN.						$12,392,000,000	12/31/2020	Conceptual	765	345	C	Y
C	West	Midwest ISO	2179	MTEP08 Reference Future EHV Overlay - Dorsey to Riel	Builds 500 kV circuit from Dorsey Station in Manitoba to Riel Station in Manitoba	Manitoba					$46,000,000	8/1/2018	Conceptual	500		C	Y
C	West	Midwest ISO	2180	MTEP08 Reference Future EHV Overlay - Riel to Maple River	Builds 500 kV circuit from Riel Station in Manitoba to Maple River Station in North Dakota	Manitot	ND				$374,000,000	8/1/2018	Conceptual	500	115	C	Y
C	West	Midwest ISO	2181	MTEP08 Reference Future EHV Overlay - Maple River to Blue Lake	Builds 500 kV circuit from Maple River Station in North Dakota to Blue Lake Station in Minnesota	SD	MN				$401,000,000	8/1/2018	Conceptual	500	345	C	Y
C	West	Midwest ISO	2182	MTEP08 Reference Future EHV Overlay - Maple River to Watertown	Builds 345 kV circuit from Maple River Station in North Dakato to Watertown Station in South Dakota	ND	SD				$202,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2183	MTEP08 Reference Future EHV Overlay - Watertown to Split Rock	Builds 345 kV circuit from Watertown Station in South Dakota to Splitrock station in South Dakota	SD					$131,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2184	MTEP08 Reference Future EHV Overlay - Splitrock to "New Blue Earth Sub"	Builds 345 kV circuit from Splitrock Station in South Dakota to a New Blue Earth Station in Minnesota	SD	MN				$205,000,000	8/1/2018	Conceptual	765	345	C	Y
C	West	Midwest ISO	2185	MTEP08 Reference Future EHV Overlay - Adams to Hampton Corners	Builds 765 kV circuit from Adams Station in Minnesota to Hampton Corners Station in Minnesota	MN					$282,000,000	8/1/2018	Conceptual	765	345	C	Y
C	West	Midwest ISO	2186	MTEP08 Reference Future EHV Overlay - Sherburne County to Chisago City	Builds 345 kV circuit from Sherbourne County Station to Chisago County Station in Minnesota	MN					$69,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2187	MTEP08 Reference Future EHV Overlay - Sherburne County to "New SW MPLS Sub"	Builds 345 kV circuit from Sherbourne County Station to New SW Minneapolis Station in Minnesota	MN					$68,000,000	8/1/2018	Conceptual	345		C	Y

Appendix C: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	West	Midwest ISO	2188	MTEP08 Reference Future EHV Overlay - "New SW MPLS Sub" to Hampton Corners	Builds 765 kV circuit from Hampton Corner Station to New SW Minneapolis Station in Minnesota	MN					$260,000,000	8/1/2018	Conceptual	765		C	Y
C	West	Midwest ISO	2189	MTEP08 Reference Future EHV Overlay - Hampton Corners to Chisago Cty (east mpls loop)	Builds 345 kV circuit from Hampton Corner Station to Chisago County Station in Minnesota	MN					$103,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2190	MTEP08 Reference Future EHV Overlay - Watertown to "New SW MPLS Sub"	Builds 345 kV circuit from Watertown Station in South Dakota to New SW Minneapolis Station in Minnesota	SD	MN				$230,000,000	8/1/2018	Conceptual	765	345	C	Y
C	West	Midwest ISO	2191	MTEP08 Reference Future EHV Overlay - "New SW MPLS Sub" to "New Blue Earth Sub"	Builds 765 kV circuit from New SW Minneapolis Station to New Blue Earth Station in Minnesota	MN					$215,000,000	8/1/2018	Conceptual	765		C	Y
C	West	Midwest ISO	2192	MTEP08 Reference Future EHV Overlay - "New Blue Earth Sub" to Lehigh	Builds 765 kV Circuit from New Blue Earth Station in Minnesota to Lehigh Station in Iowa	MN	IA				$273,000,000	8/1/2018	Conceptual	765	345	C	Y
C	West	Midwest ISO	2193	MTEP08 Reference Future EHV Overlay - Lehigh to Toledo	Builds 765 kV circuit from Lehigh Station to Toledo Station in Iowa	IA					$313,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2194	MTEP08 Reference Future EHV Overlay - Toledo to Montgomery	Builds 765 kV circuit from Toledo Station in Iowa to Montgomery Station in Missouri	IA	MO				$871,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2195	MTEP08 Reference Future EHV Overlay - Montgomery to Coffeen	Builds 765 kV circuit from Montgomery Station in Missouri to Coffeen Station in Illinois	MO	IL				$373,000,000	8/1/2018	Conceptual	765	345	C	Y
C	Central	Midwest ISO	2196	MTEP08 Reference Future EHV Overlay - Montgomery to St. Francois	Builds 765 kV circuit from Montgomery Station to St. Francois Station in Missouri	MO					$387,000,000	8/1/2018	Conceptual	765	345	C	Y
C	Central	Midwest ISO	2197	MTEP08 Reference Future EHV Overlay - St. Francois to Rockport	Builds 765 kV circuit from St. Francois Station in Missouri to Rockport Station in Indiana (Located in 3 States: 15% in MO, 56% in IL, 29% in IN	IL	IN				$599,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2198	MTEP08 Reference Future EHV Overlay - Rockcreek to Pontiac	Builds 765 kV circuit from Rock Creek Station in Iowa to Pontiac Station in Illinois	IA	IL				$378,000,000	8/1/2018	Conceptual	765	345	C	Y
C	Central	Midwest ISO	2199	MTEP08 Reference Future EHV Overlay - Pontiac to Dequine	Builds 765 kV circuit from Pontiac Station in Illinois to Dequine Station in Indiana	IL	IN				$265,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2200	MTEP08 Reference Future EHV Overlay - Dequine to "Chicago"	Build 765 kV circuit from Dequine Station to New South Chicago Station in Indiana	IN					$161,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2201	MTEP08 Reference Future EHV Overlay - Sullivan to Dequine	Build 765 kV circuit from Dequine Station to Sullivan Stating in Indiana	IN					$309,000,000	8/1/2018	Conceptual	765	345	C	Y
C	Central	Midwest ISO	2202	MTEP08 Reference Future EHV Overlay - Dequine to Greentown	Build 765 kV circuit from Dequine Station to Greentown Station in Indiana	IN					$281,000,000	8/1/2018	Conceptual	765		C	Y
C	Central	Midwest ISO	2203	MTEP08 Reference Future EHV Overlay - Greentown to Blue Creek	Build 765 kV circuit from Greentown Station to Blue Creek Station in Indiana	IN					$191,000,000	8/1/2018	Conceptual	765		C	Y
C	East	Midwest ISO	2204	MTEP08 Reference Future EHV Overlay - Cook to Evans	Build 765 kV circuit from Cook Station to Evans Station in Michigan	MI					$319,000,000	8/1/2018	Conceptual	765	345	C	Y
C	East	Midwest ISO	2205	MTEP08 Reference Future EHV Overlay - Evans to Spreague	Build 765 kV circuit from Evans Station to Spreague Station in Michigan	MI					$304,000,000	8/1/2018	Conceptual	765		C	Y
C	East	Midwest ISO	2206	MTEP08 Reference Future EHV Overlay - Spreague to Bridgewater	Build 765 kV circuit from Spreague Station to Bridgewater Station in Michigan	MI					$135,000,000	8/1/2018	Conceptual	765	345	C	Y
C	East	Midwest ISO	2207	MTEP08 Reference Future EHV Overlay - Bridgewater to Blue Creek	Build 765 kV circuit from Bridgewater Station in Michigan to Blue Creek Station in Indiana (1% in Indiana, 26% in OH, 73% in MI)	MI	OH				$447,000,000	8/1/2018	Conceptual	765	345	C	Y
C	East	Midwest ISO	2208	MTEP08 Reference Future EHV Overlay - Dead River to Livingston	Build 345 kV circuit from Dead River Station to Livingston Station in Michigan	MI					$329,000,000	8/1/2018	Conceptual	345		C	Y
C	East	Midwest ISO	2209	MTEP08 Reference Future EHV Overlay - Bridgewater to South Canton	Build 765 kV circuit from Bridgewater Station in Michigan to South Canton Station in Ohio	MI	OH				$538,000,000	8/1/2018	Conceptual	765		C	Y
C	West	Midwest ISO	2210	MTEP08 Reference Future EHV Overlay - Chisago Cty to Longwood	Build 345 kV circuit from Chisago County Station in Minnesota to Longwood Station in Wisconsin	MN	WI				$165,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2211	MTEP08 Reference Future EHV Overlay - Longwood to Greenwood	Build 345 kV circuit from Longwood Station to Greenwood Station in Wisconsin	WI					$200,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2212	MTEP08 Reference Future EHV Overlay - Adams to Rockcreek	Build 765 kV circuit from Adams Station in Minnesota to Rock Creek Station in Iowa	MN	IA				$627,000,000	8/1/2018	Conceptual	765		C	Y

Appendix C: Project Table 10/16/2009

Project Summary Information from Facility table

Target Appendix	Region	Geographic Location by TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	Midwest ISO	2213	MTEP08 Reference Future EHV Overlay - Ghent to Buffinton	Build 345 kV circuit from Ghent Station to Buffington Station in Kentucky	KY					$47,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2214	MTEP08 Reference Future EHV Overlay - Glenham to Ellendale	Build 345 kV circuit from Glenham in South Dakota to Ellendale in North Dakota	SD	ND				$47,000,000	8/1/2018	Conceptual	345	230	C	Y
C	Central	Midwest ISO	2215	MTEP08 Reference Future EHV Overlay - Coffeen to Sullivan	Build 765 kV circuit from Coffeen Station in Illinois to Sullivan Station in Indiana	IL	IN				$322,000,000	8/1/2018	Conceptual	765		C	Y
C	West	Midwest ISO	2217	MTEP08 Reference Future EHV Overlay - Granite Falls-Twin Cities	Build 345 kV circuit from Granite Falls (Hazel sub) to Blue Lake (Twin Cities) in Minnesota	MN					$162,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2219	MTEP08 Reference Future EHV Overlay - Maple River to Ellendale	Build 345 kV double circuit line from Maple River to Ellendale in North Dakota	ND					$239,000,000	8/1/2018	Conceptual	345	230	C	Y
C	West	Midwest ISO	2220	MTEP08 Reference Future EHV Overlay - Ellendale to Bigstone	Build 345 kV double circuit line from Big Stone in South Dakota to Ellendale in North Dakota	ND	SD				$265,000,000	8/1/2018	Conceptual	345	230	C	Y
C	West	Midwest ISO	2221	MTEP08 Reference Future EHV Overlay - Bigstone to Watertown	Build 345 kV double circuit line from Watertown to Big Stone in South Dakota	SD					$140,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2222	MTEP08 Reference Future EHV Overlay - Minn Valley-Blue Lk 230	Build 230 kV double circuit line from Minnesota Valley to West Waconia Station in Minnesota	MN					$274,000,000	8/1/2018	Conceptual	345	230	C	Y
C	West	Midwest ISO	2223	MTEP08 Reference Future EHV Overlay - Lakefield to Adams	Build 345 kV double circuit line from Lakefield to Adams Station in Minnesota	MN					$334,000,000	8/1/2018	Conceptual	345	161	C	Y
C	West	Midwest ISO	2224	MTEP08 Reference Future EHV Overlay - Bigstone to Morris to Alexandria	Build 345 kV double circuit line from Big Stone in South Dakota to Morris and then to Alexandria Station in Minnesota	SD	MN				$215,000,000	8/1/2018	Conceptual	345	230	C	Y
C	West	Midwest ISO	2225	MTEP08 Reference Future EHV Overlay - Big Stone-Crow River	Build 345 kV double circuit line from Big Stone in South Dakota to Crow River in Minnesota	SD	MN				$328,000,000	8/1/2018	Conceptual	345	115	C	Y
C	West	Midwest ISO	2226	MTEP08 Reference Future EHV Overlay - Adams-N Rochester	Build 345 kV double circuit line from Adams Station to North Rochester in Minnesota	MN					$101,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2227	MTEP08 Reference Future EHV Overlay - Monticello-W Waconia-Helena	Build 345 kV double circuit line from Monticello to West Waconia to Helena in Minnesota	MN					$102,000,000	8/1/2018	Conceptual	345		C	Y
C	West	Midwest ISO	2230	MTEP08 Reference Future EHV Overlay - Salem to West Middleton	Build 345 kV circuit from West Middleton in Wisconsin to Salem Station in Iowa	IA	WI				$102,000,000	8/1/2018	Conceptual	345	138	C	Y
C	West	Midwest ISO	2231	MTEP08 Reference Future EHV Overlay - LaCrosse-Columbia	Build 345 kV circuit from LaCrosse to Columbia Station in Wisconsin	WI					$186,000,000	8/1/2018	Conceptual	345	138	C	Y
C	East	Midwest ISO	2244	MTEP08 Reference Future EHV Overlay - should be Stillwell to Burr Oak	Build 345 kV circuit from Stillwell to Burr Oak station in Indiana	IN					$28,000,000	8/1/2018	Conceptual	345		C	Y
C	East	Midwest ISO	2245	MTEP08 Reference Future EHV Overlay - Avon Lake to Fox	Build 345 kV circuit from Avon Lake to Fox station in Ohio	OH					$24,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	Midwest ISO	2246	MTEP08 Reference Future EHV Overlay - Pete 765/345 Autotransformation	Add Pete 765/345 kV autotransformer in Indiana	IN					$20,000,000	8/1/2018	Conceptual	765	345	C	Y
C	Central	Midwest ISO	2247	MTEP08 Reference Future EHV Overlay - 'Gwynn 765/345 Autotransformation	Add Gwynn 765/345 kV autotransformer in Indiana	IN					$20,000,000	8/1/2018	Conceptual	765	345	C	Y
C	East	NIPS	1983	Dekalb Sub - Upgrade 138/69 Transformer	Replace the existing No.1 138/69 KV 56 MVA transformer with a 138/69 kV 112 MVA transformer.	IN					$1,700,000	12/1/2013	Conceptual	138	69	C	Y
C	East	NIPS	1993	South Valparaiso - New 138/69 kV Substation	South Valparaiso - New 138/69 Substation, (3) 69 kV line extensions	IN					$4,917,000	12/1/2012	Conceptual	138	69	C	Y
C	East	NIPS	2321	Miller Sub - Add 138KV Capacitors - 100.0 MVAR	Add one step of 100 MVAR capacitors on the Miller Substation 138 kV bus. Engineering only in 2010.	IN					$974,838	9/1/2011	Conceptual	138		C	Y
C	East	NIPS	2323	Hiple Sub to Northport Sub - New 138 kV Line	Add new 138 kV terminals at Hiple and Northport Substations, and construct a new 10 mile 954 KCM ACSR 138 kV line between these two substations. Engineering only on 2008.	IN					$5,770,000	12/1/2016	Conceptual	138		C	Y
C	East	NIPS	2324	East Plymouth - New 345-138 Substation	Add East Plymouth 345/138 kV, 1-560 MVA Transformer Sub - New	IN					$18,884,017	5/1/2016	Conceptual	345	138	C	Y

Facility Table Field Legend

Project table has blue highlighted header. A project may have multiple facilties.
Facility table has yellow highlighted header. A project's facilities may have different in service dates.

Facilty Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEP09 planning cycle. "A in MTEP09" projects were reviewed and approved in MTEP09. This column also indicates what projects were approved in prior MTEPs that are not yet in service.
Region	Midwest ISO Planning Region: Central, East or West
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems
PrjID	Indicates the Project the Facility belongs to. Projects may have multiple facilities.
Facility ID	Facility ID: Midwest ISO facility identifier
Expected ISD	Expected In Service Date for this facility
From Sub	From substation for transmission line or location of transformer or other equipment
To Sub	To substation for transmission line or transformer designation
Ckt	Circuit identifier
Max kV	Maximum voltage of this facility
Min kV	Minumum voltage of this facility (transformer low-side voltage)
Summer Rate	Rating of the facility in applicable units
Upgrade Description	Brief description of transmission upgrade involving this facility
State	State the facility is located in
Miles Upg.	Transmission line miles on existing rights of way (ROW)
Miles New	Transmission line miles on new rights of way (ROW)
Plan Status	Indicates where project is in implementation. Proposed, Planned, Under Construction, In Service. Summary information from Facility table
Estimated Cost	Total estimated facility cost
Cost Shared	Y if facility is cost shared per Attachment FF
Postage Stamp	Y if facility has postage stamp cost allocation per Attachment FF
MISO Facility	Y for facilities under Midwest ISO functional control. NT for non-transferred facilities.
App ABC	Appendix the project is in. B>A or C>B for projects moving during this planning cycle.

Appendix C: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
C	Central	Ameren	1539	2616	6/1/2015	Roxford	Stallings	1	345		1195	Install PCB at Roxford Substation	IL			Proposed	$1,200,000			Y	C
C	Central	AmerenCILCO	2299	4215	6/1/2013	Fargo 138-69 kV Substation	138 kV Capacitor Bank		138			Install 138 kV Capacitor Bank (size to be determined)	IL			Proposed				Y	C
C	Central	AmerenCIPS	2289	4205	6/1/2012	Benton	W. Frankfort	1	138		175	Reconductor 350 kcmil Copper with 1200 A summmer emergency capability	IL	9.62		Proposed	$1,240,500			Y	C
C	Central	AmerenCIPS	2290	4206	6/1/2012	Joppa	2nd. 345/161 kV Transformer		345	161	560	Install 2nd. 345/161 kV, 560 MVA Transformer	IL			Proposed	$6,480,000			Y	C
C	Central	AmerenCIPS	2304	4219	12/1/2013	Marion South	2nd. 161/138 kV, 300 MVA Transformer		161	138	300	Install 2nd. 161/138 kV, 300 MVA Transformer, upgrade terminal eqpt. To 1600 A	IL			Proposed	$4,452,000			Y	C
C	Central	AmerenIL	1538	2615	6/1/2011	Pana, North	Ramsey, East	1	138		240	Rebuild line for operation at 120 degrees C	IL	18.43		Proposed	$2,702,200			Y	C
C	Central	AmerenIL	2064	3973	6/1/2011	South Bloomington	Diamond Star Tap	1	138		382	Reconductor 4.58 miles of 336 ACSR in S Bloomington - Danvers line to 1600 Amps	IL	4.58		Proposed	$575,400			Y	C
C	Central	AmerenIL	2065	3960	6/1/2012	Stallings	Stallings substation	1	345	138	700	Replace 560 MVA 345 / 138 KV Stallings transformer with 700 MVA.	IL			Proposed	$7,087,000			Y	C
C	Central	AmerenIL	2065	3961	6/1/2012	Stallings	Stallings Tap (Wood River - Venice 138 kV line)	1	138		280	Replace terminal equipment at Stallings on Wood River - Venice 138 kV line (Line # 1452)	IL			Proposed				Y	C
C	Central	AmerenIP	1528	2604	6/1/2009	Rising	Transformer	1	345	138	478	Increase rating of existing 450 MVA Transformer	IL			Proposed	$171,600			Y	C
C	Central	AmerenIP	1536	2613	6/1/2012	Latham	Mason City	1	138		255	Reconductor Latham Tap-Kickapoo Tap	IL	15.75		Proposed				Y	C
C	Central	AmerenIP	1540	2617	6/1/2014	Sidney	Windsor	1	138		321	Reconductor to 1600 A Summer Emergency	IL	13.1		Proposed	$3,900,000			Y	C
C	Central	AmerenIP	2283	4199	6/1/2010	South Bloomington	138 kV Bus		138			Install two new 2000 A, 138 kV Bus-Tie Breakers	IL			Proposed	$1,030,000			Y	C
C	Central	AmerenIP	2286	4202	6/1/2011	Hennepin	Oglesby Line 1516	1	138		214	Increase ground clearance on 14.46 miles of 795 kcmil ACSR conductor	IL	14.46		Proposed	$442,000			Y	C
C	Central	AmerenIP	2288	4204	6/1/2011	Line 1364 (new tap)	Washington Street Substation	2	138			Tap 138 kV Line 1364 for 'in-out' arrangement, replace Line 1326 w/ 'in-out'	IL		0.17	Proposed	$4,066,500			Y	C
C	Central	AmerenIP	2293	4209	6/1/2012	N. Lasalle	La Salle Jct.	1	138		321	Reconductor 477 kcmil ACSR w/ 1600 A summer emergency capability in L1556A	IL	9.68		Proposed	$3,190,000			Y	C
C	Central	AmerenIP	2294	4210	6/1/2012	Stallings 345/138 kV Substation	138 kV Bus-Tie Position 1302		138		478	Reconnect or replace 1200 A CT to 2000 A	IL			Proposed				Y	C
C	Central	AmerenIP	2295	4211	6/1/2012	W. Mt. Vernon	E. W. Frankfort	1	345		1200	Upgrade terminal equipment to 3000 A	IL			Proposed	$1,100,000			Y	C
C	Central	AmerenIP	2300	4216	6/1/2013	Hennepin Plant	2-3000 A PCB's		138			Install 2-3000 A, 138 kV Bus-Tie Breaker	IL			Proposed	$8,254,000			Y	C
C	Central	AmerenIP	2301	4217	6/1/2013	Hennepin	Oglesby Line 1556	1	138		321	Reconductor 477 kcmil ACSR to 1600 A summer emergency capability	IL	8.37		Proposed	$3,958,000			Y	C
C	Central	AmerenIP	2302	4218	6/1/2013	Madison Industrial	Madison State Street	1	138		240	Reconductor 795 SAC to 1200 A summer emergency capability	IL	2.35		Proposed				Y	C
C	Central	AmerenIP	2305	4220	6/1/2013	Monmouth 138/69 kV Substation	30 Mvar, 138 kV Capacitor Bank		138			Install 30 Mvar, 138 kV Capacitor Bank	IL			Proposed	$1,022,000			Y	C
C	Central	AmerenMO	2067	3959	11/1/2009	St. Francois	Rivermines	1	138		214	Increase clearances to ground for 90 degrees C operation of 795 ACSR	MO	10.77		Proposed	$534,000			Y	C
C	Central	AmerenMO	2122	3977	6/1/2011	Belleau - GM - 3 161 kV line	AECI Enon Substation	1	161		280	Extend 1 mile of line to AECI Enon Substation	MO		1	Proposed				Y	C
C	Central	AmerenMO	2292	4208	6/1/2012	Kelso	345/161 kV, 336 MVA Transformer		345	161	450	Replace 345/161 kV, 336 MVA Transformer w/ 450 MVA Transformer	MO			Proposed	$6,146,000			Y	C
C	Central	AmerenMO	2296	4212	6/1/2013	Belleau 345/138 kV Substation	2nd. 345/138 kV, 560 MVA Transformer		345	138	560	Install 2nd. 345/138 kV, 560 MVA Transformer	MO			Proposed	$8,169,000			Y	C
C	Central	AmerenMO	2297	4213	6/1/2013	Belleau 345/138 kV Substation	120 Mvar, 138 kV Capacitor Bank		138			Install 120 Mvar, 138 kV Capacitor Bank (Install as 2-60 Mvar stages)	MO			Proposed				Y	C
C	Central	AmerenMO	2298	4214	6/1/2013	AECI's Enon 345/161 kV Substation	2-345 kV PCB's		345			Install 2-PCB's on incoming 345 kV lines at AECI's Enon Substation	MO			Proposed	$2,460,000			Y	C
C	Central	AmerenMO	2306	4221	6/1/2015	Northwest Cape 345/161 kV	New Substation		345	161	560	Install 560 MVA, 345/161 kV Transformer, 3-161 kV outlet lines	MO			Proposed	$12,570,000			Y	C
C	Central	AmerenMO	2306	4222	6/1/2015	Lutesville	Northwest Cape	1	345		1793	Install approximately 11 miles of new line to supply substation	MO		11	Proposed	$17,605,000			Y	C

Appendix C: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
C	West	ATC LLC	569	1250	6/1/2014	South Lake Geneva	White River	1	138		355	line to new T-D substation	WI		3	Proposed	$2,500,000			Y	C
C	West	ATC LLC	569	1251	6/1/2014	South Lake Geneva 138-69 kV	transformer	1	138	69			WI			Proposed	$1,973,000			Y	C
C	West	ATC LLC	575	1270	6/1/2016	Pulliam (now Bayport)	Suamico	1	138				WI			Proposed	$3,199,539			Y	C
C	West	ATC LLC	575	1271	6/1/2016	Suamico	Sobieski	1	138				WI			Proposed	$1,510,893			Y	C
C	West	ATC LLC	575	1272	6/1/2016	Sobieski	Pioneer	1	138				WI			Proposed	$1,510,893			Y	C
C	West	ATC LLC	1621	3239	6/1/2015	Birchwood	Lake Delton	1	138		383/478	Build a new line between Birchwood & Lake Delton	WI	5		Proposed	$5,806,000			Y	C
C	West	ATC LLC	1623	3240	6/1/2050	Montrose	Capacitor banks		69		2x16.33 MVAR	Add caps to a New SS to be tapped into Y-42 between Verona & Belleville in Late 2012	WI			Proposed				Y	C
C	West	ATC LLC	1625	3244	12/31/2018	North Randolph	South Fond du Lac	1	345		1096/1096	Tap Columbia-South Fond du Lac into North Randolph	WI			Proposed				Y	C
C	West	ATC LLC	1625	3243	12/31/2018	North Randolph	Columbia	1	345		1096/1096	Tap Columbia-South Fond du Lac into North Randolph	WI			Proposed	$9,718,000			Y	C
C	West	ATC LLC	1625	3242	12/31/2018	North Randolph	Transformer	1	345	138	500/500	Install a 500 MVA 345/138 kV transformer at the North Randolph 138 kv SS by looping in the Columbia-South Fond du Lac 345-kV line	WI			Proposed				Y	C
C	West	ATC LLC	1627	3252	6/1/2010	Bain	Albers	1	138		343/343	'Increase clearance of the Bain-Albers 138-kV line	WI			Proposed				Y	C
C	West	ATC LLC	1628	3253	6/1/2015	Columbia T22 345-138 kV	Transformer	2	345	138	527/574	Replace Columbia T22 345/138-kV Transformer	WI			Proposed	$100,000			Y	C
C	West	ATC LLC	1629	3254	6/1/2014	Femrite	Capacitor banks		69		2x16.33 MVAR		WI			Proposed				Y	C
C	West	ATC LLC	1630	3255	6/1/2014	Femrite	Capacitor banks		138		2x24.5 MVAR		WI			Proposed				Y	C
C	West	ATC LLC	1688	3466	6/1/2050	Beardsley			69			Install two 69 kV breakers at Beardsley Street substation	WI			Proposed				Y	C
C	West	ATC LLC	1689	3467	6/1/2016	Ripon			69		1x4.1 MVAR	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR	WI			Proposed				Y	C
C	West	ATC LLC	1689	3468	6/1/2016	Ripon			69		1x8.2 MVAR	Install a new 8.2 MVAR capacitor bank at Ripon 69 kV substation	WI			Proposed				Y	C
C	West	ATC LLC	1692	3471	6/1/2011	North Mullet River			69			Replace the 400 amp metering CT at North Mullet River 69 kV substation	WI			Proposed	$404,243			Y	C
C	West	ATC LLC	1693	3472	6/1/2015	Mears Corners			138		2x16.3 MVAR	Install two 16.3 MVAR capacitor bank at Mears Corners 138 kV substation	WI			Proposed	$1,080,000			Y	C
C	West	ATC LLC	1694	3473	6/1/2015	Rosiere			138		2x16.3 MVAR	Install two 16.3 MVAR capacitor bank at Rosiere 138 kV substation	WI			Proposed	$1,190,000			Y	C
C	West	ATC LLC	1695	3474	6/1/2014	Mukwonago			138		2x32 MVAR	Install two 32 MVAR capacitor banks at Mukwonago 138 kV substation	WI			Proposed				Y	C
C	West	ATC LLC	1696	3475	6/1/2050	Gardner Park	Black Brook	1	115			Uprate Gardner Park-Black Brook 115 kV line	WI			Proposed				Y	C
C	West	ATC LLC	1697	3476	6/1/2015	Brick Church	Walworth	1	69		115 MVA	Uprate Brick Church-Walworth 69 kV line to 115 MVA	WI			Proposed	$716,000			Y	C
C	West	ATC LLC	1699	3479	6/1/2013	Mckenna			69		10.8	Install a second new 10.8 MVAR capacitor bank	WI			Proposed				Y	C
C	West	ATC LLC	1699	3478	6/1/2013	Mckenna			69		4.5	Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR	WI			Proposed				Y	C
C	West	ATC LLC	1700	3480	6/1/2014	SW Ripon	Ripon-Metomen	1	69			Construct a 69 kV line from SW Ripon to the Ripon-Metomen 69 kV line	WI			Proposed				Y	C
C	West	ATC LLC	1701	3481	6/1/2014	Blaney Park	Munising	1	138			Rebuild Blaney Park-Munising 69 kV to 138 kV	MI			Proposed	$52,010,000			Y	C
C	West	ATC LLC	1702	3482	6/1/2015	Hillman		1	138	69	100 MVA	Replace the existing 46 MVA Hillman 138/69 kV transformer with a 100 MVA transformer	WI			Proposed	$1,958,000			Y	C
C	West	ATC LLC	1703	3484	6/1/2013	Boscobel			69		8.16 MVAR	Upgrade existing 5.4 MVAR bank at Boscobel substation with an 8.16 MVAR bank	WI			Proposed				Y	C

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C	West	ATC LLC	1703	3483	6/1/2013	Boscobel			69		8.16 MVAR	Install one 8.16 MVAR capacitor bank at Boscobel 69 kV substation	WI			Proposed				Y	C
C	West	ATC LLC	1706	3488	6/1/2013	Nine Springs	Pflaum	1	69			Loop Nine Springs-Pflaum 69 kV line into Femrite substation	WI			Proposed	$5,360,000			Y	C
C	West	ATC LLC	1707	3489	6/1/2013	Holmes	Chandler	1	138			Rebuild/convert holmes-Chandler 69 kV line to 138 kV operation	MI/WI	40	14	Proposed	$56,300,000			Y	C
C	West	ATC LLC	1708	3490	6/1/2018	Fairwater	Mackford Prairie	1	69			Construct Fairwater-Mackford Prairie 69 kV line	WI		5	Proposed	$3,200,000			Y	C
C	West	ATC LLC	1708	3491	6/1/2018	Ripon	Metomen	2	69			Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	WI	5		Proposed				Y	C
C	West	ATC LLC	1709	3492	6/1/2014	Eden			69		2x16.33 MVAR	Install two 16.33 MVAR 69 kV capacitor banks at Eden Substation	WI			Proposed				Y	C
C	West	ATC LLC	1710	3493	6/1/2014	Mazomanie			69		2x12.25 MVAR	Install two 12.25 MVAR 69 kV capacitor banks at Mazomanie substation	WI			Proposed				Y	C
C	West	ATC LLC	1711	3494	6/1/2016	McCue			138	69		Install a second 138/69 kV transformer at McCue substation	WI			Proposed	$2,810,000			Y	C
C	West	ATC LLC	1712	3495	6/1/2014	Horicon	East Beaver Dam	1	138			Construct a Horicon-East Beaver Dam 138 kV line	WI		9	Proposed	$10,190,000			Y	C
C	West	ATC LLC	1713	3496	6/1/2050	Deforest	Token Creek	1	69			Loop the Deforest to Token Creek 69-kV line into the Yahara River Substation	WI		1	Proposed				Y	C
C	West	ATC LLC	1713	3498	6/1/2050	Yahara River		1	138	69		Install a 138/69 kV transformer at Yahara River	WI			Proposed				Y	C
C	West	ATC LLC	1713	3497	6/1/2050	Yahara River	Token Creek	1	69			Uprate Yahara River-Token Creek 69-kV line	WI			Proposed				Y	C
C	West	ATC LLC	1714	3499	6/1/2050	South Sheboygan Falls		1	138	69	100 MVA	Replace the existing 138/69-kV transformer at South Sheboygan Falls Substation with 100 MVA transformer	WI			Proposed	$1,550,000			Y	C
C	West	ATC LLC	1715	3500	6/1/2018	Edgewater			345		1200 A	Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	WI			Proposed	$248,000			Y	C
C	West	ATC LLC	1716	3501	6/1/2016	Melissa	Tayco	1	138		229 MVA	Uprate the Melissa-Tayco 138 kV line to 229 MVA (300F)	WI			Proposed				Y	C
C	West	ATC LLC	1717	3502	6/1/2014	Glenview		1	138	69	100 MVA	Replace two existing 138/69 kV transformers at Glenview Substaion with 100 MVA transformers	WI			Proposed	$1,720,000			Y	C
C	West	ATC LLC	1717	3503	6/1/2014	Glenview		2	138	69	100 MVA	Replace two existing 138/69 kV transformers at Glenview Substaion with 100 MVA transformers	WI			Proposed	$1,720,000			Y	C
C	West	ATC LLC	1718	3504	6/1/2016	Custer		1	138	69		Install a 138/69 kV transformer at Custer substation	WI			Proposed				Y	C
C	West	ATC LLC	1719	3505	6/1/2016	Shoto	Custer	1	138			Construct a Shoto-Custer 138 kV line	WI	9.94		Proposed	$14,110,000			Y	C
C	West	ATC LLC	1720	3506	6/1/2017	Wautoma		2	138	69		Install a second 138/69-kV transformer at Wautoma Substation	WI			Proposed	$1,440,000			Y	C
C	West	ATC LLC	1721	3507	6/1/2050	Danz	Henry Street	1	69			Reconductor Danz-Henry Street 69 kV line	WI	1.5		Proposed				Y	C
C	West	ATC LLC	1721	3509	6/1/2050	Pulliam	Danz	1	69			Reconductor Pulliam-Danz 69 kV line	WI	3		Proposed				Y	C
C	West	ATC LLC	1721	3508	6/1/2050	Pulliam	Van Buren	1	69			Reconductor Pulliam-Van Buren 69 kV line	WI	2		Proposed				Y	C
C	West	ATC LLC	1722	3510	6/1/2018	Aviation			138		2x16.3 MVAR	Install two 16.3 MVAR 138kV capacitor banks at Aviation Substation	WI			Proposed	$1,160,000			Y	C
C	West	ATC LLC	1723	3512	6/1/2018	Sunset Point		2	138	69	100 MVA	Replace two existing 138/69-kV transformers at Sunset Point Substation with 100 MVA transformers	WI			Proposed	$1,770,000			Y	C
C	West	ATC LLC	1723	3511	6/1/2018	Sunset Point		1	138	69	100 MVA	Replace two existing 138/69-kV transformers at Sunset Point Substation with 100 MVA transformers	WI			Proposed	$1,770,000			Y	C
C	West	ATC LLC	1724	3513	6/1/2023	Hilltop			69		1x12.2 MVAR	Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	WI			Proposed				Y	C

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C	West	ATC LLC	1725	3514	6/1/2024	Evansville	Brooklyn		69			Construct an Evansville-Brooklyn 69 kV line	WI		8	Proposed	$8,120,000			Y	C
C	West	ATC LLC	1726	3515	6/1/2016	Royster	Sycamore		69		115 MVA	Uprate Royster-Sycamore 69 kV line to 115 MVA	WI	3.35		Proposed	$790,000			Y	C
C	West	ATC LLC	1727	3516	6/1/2016	Dunn Road	Egg Harbor	2	69			Construct a second Dunn Road-Egg Harbor 69 kV line	WI		12.66	Proposed	$11,795,610			Y	C
C	West	ATC LLC	1728	3517	6/1/2050	Northside	City Limits	1	138			Construct a Northside-City Limits 138 kV line	WI		3.16	Proposed				Y	C
C	West	ATC LLC	1729	3519	1/31/2012	Straits	McGulpin	3	138		127 MVA	Uprate the Straits-McGulpin 138 kV line 9903 for Frontier T-D	MI	2.5		Proposed	$150,000			Y	C
C	West	ATC LLC	1729	3518	1/31/2012	Straits	McGulpin	1	138		127 MVA	Uprate the Straits-McGulpin 138 kV line 9901 for Frontier T-D	MI	2.5		Proposed	$150,000			Y	C
C	West	ATC LLC	1730	3520	6/1/2017	West Middleton	Blount	1	138			Construct a West Middleton-Blount 138 kV line	WI		5	Proposed				Y	C
C	West	ATC LLC	1731	3521	6/1/2024	Blount	Ruskin	1	69			Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line	WI			Proposed	$6,500,000			Y	C
C	West	ATC LLC	1732	3522	6/1/2009	Brick Church			69		1x12.45	Install 12.45 MVAR 69-kV mobile capacitor bank at Brick Church Substation	WI			Proposed	$600,000			Y	C
C	West	ATC LLC	1940	3819	10/17/2009	M38	Capacitor Bank		138		1x8.16 Mvar	Expand the M38 substation and install one 8.16 MVAR 138 kV capacitor bank at the M38 substation	MI			Proposed	$3,300,000			Y	C
C	West	ATC LLC	1941	3820	6/1/2013	Atlantic	M38	1	69		48 MVA SE	Increase ground clearance for Atlantic-M38 69-kV to 167 deg F	MI	21.79		Proposed				Y	C
C	West	ATC LLC	1946	3825	6/1/2013	Spring Green	transformer	2	138	69	100 MVA SE	Install a 2nd Spring Green 138-69 kV Transformer	WI			Proposed	$1,400,000			Y	C
C	West	ATC LLC	1947	3826	6/1/2050	Black Earth	Stage Coach	1	69		69 MVA SE	Uprate Black Earth-Stage Coach 69-kV	WI	6.7		Proposed				Y	C
C	West	ATC LLC	1948	3827	6/1/2011	Brick Church	Capacitor Bank		69		-12.24 Mvar	Remove Mobile Capacitor bank fromBrick Church 69-kV	WI			Proposed				Y	C
C	West	ATC LLC	1949	3828	6/1/2018	Glory Rd	Green BaySW	1	138		289 MVA	Construct 1.6 mile double circuit line to connect the new Green Bay SW SS to the Glory Rd-De Pere 138-kV line	WI		1.6	Proposed				Y	C
C	West	ATC LLC	1949	3829	6/1/2018	De Pere	Green BaySW	1	138		289 MVA	Construct 1.6 mile double circuit line to connect the new Green Bay SW SS to the Glory Rd-De Pere 138-kV line	WI		1.6	Proposed				Y	C
C	West	ATC LLC	1949	3830	6/1/2018	Green Bay SW			138			Construct 1.6 mile double circuit line to connect the new Green Bay SW SS to the Glory Rd-De Pere 138-kV line	WI			Proposed				Y	C
C	West	ATC LLC	2019	3887	4/1/2010	Chandler	Delta	1	69		70 MVA SE	Increase line clearance to 167 deg F SE		5.5		Proposed				Y	C
C	West	ATC LLC	2020	3888	4/1/2010	Chandler	Delta	2	69		70 MVA SE	Increase line clearance to 167 deg F SE		7.65		Proposed				Y	C
C	West	ATC LLC	2025	3897	6/1/2050	Evergreen	Pine River	1	69		39 MVA SN/SE	Increase line clearance on Evergreen-Pine River to 185 deg F SN/SE	MI	23.87		Proposed				Y	C
C	West	ATC LLC	2025	3896	6/1/2050	Straits	Evergreen	1	69		43 MVA SN/SE	Reconductor two phases of Straits-Evergreen and increase line clearance to 200 deg F SN/SE	MI	1.4		Proposed				Y	C
C	West	ATC LLC	2026	3898	6/1/2050	Straits	Pine River	1	69		39 MVA SN/SE	Increase line clearance on Straits-Pine River to 185 deg F SN/SE	MI	25		Proposed				Y	C
C	West	ATC LLC	2027	3899	6/1/2010	North Bluff	capacitor		69		1x4.08 Mvar	Add a 4.08 Mvar 69 kV Capacitor bank at the North Bluff substation in Delta County, MI				Proposed				Y	C
C	West	ATC LLC	2028	3900	4/1/2010	McCue	RC7 (Harmony Tap)	1	69		115 MVA SE	Uprate Y-61 McCue-RC7(Harmony Tap) 69 kV line to achieve 300 deg F SE line ratings		1.2		Proposed				Y	C
C	West	ATC LLC	2028	3902	4/1/2010	Fulton	capacitor		69		3x12.45 Mvar	Install 3-12.45 Mvar 69 kV cap banks at Fulton				Proposed				Y	C
C	West	ATC LLC	2028	3901	4/1/2010	RC7 (Harmony Tap)	La Mar	1	69		115 MVA SE	Uprate Y-61 RC7(Harmony Tap)-La Mar 69 kV line to achieve 300 deg F SE line ratings		2.6		Proposed				Y	C

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C	West	ATC LLC	2029	3903	6/1/2011	Brick Church	capacitor		138		1x24.5 Mvar	Install 1-24.5 Mvar 138-kV capacitor bank at Brick Church	WI			Proposed				Y	C
C	West	ATC LLC	2029	3904	6/1/2011	Brick Church	capacitor		69		1x18Mvar	Install 1-18 Mvar 69-kV capacitor bank at Brick Church	WI			Proposed				Y	C
C	West	ATC LLC	2030	3905	6/1/2011	Concord	capacitor		138		4x24.5 Mvar	Install 4-24.5 Mvar 138-kV capacitor bank at Concord				Proposed				Y	C
C	West	ATC LLC	2031	3909	6/1/2012	Clinton Tap	Sharon Tap	1	69		95/131 MVA S	Rebuild Clinton Tap-Sharon Tap 69 kV		9		Proposed				Y	C
C	West	ATC LLC	2031	3906	6/1/2012	Colley Rd	Enzyme Bio Systems Tap	1	69		84/115 MVA S	Rebuild Colley Rd-Enzyme Bio Systems Tap 69 kV		0.98		Proposed				Y	C
C	West	ATC LLC	2031	3908	6/1/2012	RC3 (Clinton)	Clinton Tap	1	69		95/131 MVA S	Rebuild RC3 (Clinton)-Clinton Tap 69 kV		1.55		Proposed				Y	C
C	West	ATC LLC	2031	3910	6/1/2012	Sharon Tap	Brick Church	1	69		84/115 MVA S	Rebuild Sharon Tap-Brick Church 69 kV		3.82		Proposed				Y	C
C	West	ATC LLC	2031	3907	6/1/2012	Enzyme Bio Systems Tap	RC3 (Clinton)	1	69		95/131 MVA S	Rebuild Enzyme Bio Systems Tap-RC3 (Clinton) 69 kV		5.33		Proposed				Y	C
C	West	ATC LLC	2033	3912	6/1/2013	Bain	Kenosha	1	138		406/438 MVA	Upgrade substation equipment at Bain & Kenosha	WI			Proposed				Y	C
C	West	ATC LLC	2036	3916	6/1/2017	Wauzeka	Boscobel	1	69		73/99 MVA SN	Increase line clearance to 200/300 deg F SN/SE		12		Proposed				Y	C
C	West	ATC LLC	2036	3915	6/1/2017	Gran Grae	Wauzeka	1	69		73/99 MVA SN	Increase line clearance to 200/300 deg F SN/SE		7.3		Proposed				Y	C
C	West	ATC LLC	2037	3917	6/1/2015	Dane	Lodi Tap	1	69		87/123 MVA S	Rebuild Dane-Lodi Tap 69 kV		4.39		Proposed				Y	C
C	West	ATC LLC	2038	3919	6/2/2015	Twin Lakes	S Lake Geneva	1	138		293/403 MVA S	Construct Twin Lakes-S Lake Geneva 138 kV	WI		12	Proposed				Y	C
C	West	ATC LLC	2038	3918	6/2/2015	Spring Valley	Twin Lakes	1	138		293/403 MVA S	Construct Spring Valley-Twin Lakes 138 kV	WI		12	Proposed				Y	C
C	West	ATC LLC	2039	3920	6/1/2016	Crystal Falls	Aspen	1	69		49 MVA SE	Increase line clearance to 300 deg F SE		18.84		Proposed				Y	C
C	West	ATC LLC	2040	3921	6/1/2016	Sun Prairie	capacitor		69		2x16.33 Mvar	Install 2x16.33 Mvar 69 kV capacitor banks at Sun Prairie	WI			Proposed				Y	C
C	West	ATC LLC	2041	3922	6/1/2017	Forsyth	transformer	1	138	69	57 MVA SE	Address CT and/or relays limitations				Proposed	$310,000			Y	C
C	West	ATC LLC	2042	3923	6/1/2017	Dam Heights	capacitor		69		2x16.33 Mvar	Install 2x16.33 Mvar 69 kV caps at Dam Heights				Proposed				Y	C
C	West	ATC LLC	2043	3924	6/1/2018	Necedah	sub conversion	1	138			Convert Necedah from 69 to 138 kV and tap into the Petenwell-Council Creek 138 kV line				Proposed				Y	C
C	West	ATC LLC	2044	3925	6/1/2018	Castle Rock	A13(Quincy)	1	69		49/49 MVA SN	Increase line clearance to 200 deg F SN/SE		0.9		Proposed				Y	C
C	West	ATC LLC	2044	3926	6/1/2018	A13(Quincy)	McKenna	1	69		49/49 MVA SN	Increase line clearance to 200 deg F SN/SE		7.6		Proposed	$600,000			Y	C
C	West	ATC LLC	2045	3929	6/1/2018	UPPSCO Tap	Ontonagon	1	69		95/131 MVA S	Rebuild Victoria-Ontonagon 69 kV	MI	1.64		Proposed				Y	C
C	West	ATC LLC	2045	3927	6/1/2018	Victoria	Rockland Jct 1	1	69		95/131 MVA S	Rebuild Victoria-Ontonagon 69 kV		2.38		Proposed				Y	C
C	West	ATC LLC	2045	3928	6/1/2018	Rockland Jct 1	UPPSCO Tap	1	69		95/131 MVA S	Rebuild Victoria-Ontonagon 69 kV		10.74		Proposed				Y	C
C	West	ATC LLC	2046	3930	6/1/2018	North Monroe	capacitor		69		2x16.33 Mvar	Install 2x16.33 Mvar 69 kV capacitor banks at North Monroe				Proposed				Y	C
C	West	ATC LLC	2047	3931	6/1/2019	Rio	capacitor		69		2x16.33 Mvar	Install 2x16.33 Mvar 69 kV capacitor banks at Rio				Proposed				Y	C
C	West	ATC LLC	2048	3932	6/1/2021	Victoria	Rockland Jct 2	1	69		95/131 MVA S	Rebuild Victoria-Mass 69 kV		2.52		Proposed				Y	C
C	West	ATC LLC	2048	3934	6/1/2021	Rockland	Mass	1	69		95/131 MVA S	Rebuild Victoria-Mass 69 kV		4.81		Proposed				Y	C
C	West	ATC LLC	2048	3933	6/1/2021	Rockland Jct 2	Rockland	1	69		95/131 MVA S	Rebuild Victoria-Mass 69 kV		0.78		Proposed				Y	C
C	West	ATC LLC	2049	3935	6/1/2024	Verona	North Monroe	1	138		293/403 MVA S	Build a 27 mile 138 kv line from Verona to North Monroe			27	Proposed				Y	C
C	West	ATC LLC	2055	3941	6/1/2012	Clear Lake	Arnett Rd	1	115		175 MVA SE	Constrcust a 7.5 mile 115 kv line from Clear Lake to a new Arnett Rd distribution substation			7.5	Proposed	$12,200,000			Y	C
C	West	ATC LLC	2055	3942	6/1/2012	Arnett Rd			115		175 MVA SE	Constrcust a new Arnett Rd distribution substation				Proposed				Y	C
C	West	ATC LLC	2056	3943	6/1/2014	Oak Creek	Pennsylvania	1	138		525 MVA SE	Uprate Oak Creek-Pennsylvania 138 kV	WIS	4.5		Proposed				Y	C
C	West	ATC LLC	2162	4001	6/1/2017	McCue	LaMar	1	69		95/131 SN/SE	New 69-kV line	WI		3.42	Proposed				Y	C
C	West	ATC LLC	2163	4002	12/31/2010	Ellinwood		2	138	69	100/100 SN/SE	Replace Ellinwood 138-69 kv Tr #2	WI			Proposed	$2,012,243			Y	C

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C	West	ATC LLC	2164	4003	2/1/2013	Nelson Dewey		2	161	138	210/286 SN/SE	Install a 2nd Nelson Dewey 161-138 kV Tr	WI			Proposed	$4,729,000			Y	C
C	West	ATC LLC	2165	4004	6/1/2010	Femrite	Royster	1	69		95/131 SN/SE	Uprate Royster terminal equipment	WI	3.8		Proposed	$441,446			Y	C
C	West	ATC LLC	2451	4396	6/1/2012	Brodhead	Whisling Wind		69		80 MVA SN	Uprate line	WI	3.8		Proposed	$5,400,000			Y	C
C	West	ATC LLC	2451	4395	6/1/2012	South Monroe	Whisling Wind		69		80 MVA SN	Uprate line	WI	3.8		Proposed	$5,400,000			Y	C
C	West	ATC LLC	2777	4879	6/1/2017	Gwinn	Munising	1	69			Rebuild the existing 44-mile Gwinn-Munising 69 kV line at 138 kV standards, 69 kV operations.	MI	44		Proposed	$44,000,000			Y	C
C	West	ATC LLC	2778	4880	6/1/2016	Roberts	9 Mile	1	69			Rebuild the existing 54-mile Roberts-9 Mile 69 kV line at 138 kV standards, 69 kV operations.	MI	54		Proposed	$54,000,000			Y	C
C	West	ATC LLC	2779	4883	6/1/2015	18th Road		1	138	69		Add a new 138/69 kV 150 MVA xfmr at 18th Road	MI			Proposed	$2,000,000			Y	C
C	West	ATC LLC	2779	4881	6/1/2015	Chandler	18th Road	1	138	69		Buld a new 6-mile 138 kV line from Chandler to 18th Road	MI		6	Proposed	$6,000,000			Y	C
C	West	ATC LLC	2779	4882	6/1/2015	18th Road		1	138	69		Add a new 138/69 kV SS at 18th Road	MI			Proposed	$11,000,000			Y	C
C	West	ATC LLC	2793	4913	4/25/2010	Point Beach	Sheboygan EC	1	345		1096 MVA	G883/4 Increase ground clearance of the Point Beach-Sheboygan EC 345-kV to 167 deg F	WI	51.1		Proposed	$2,700,236			Y	C
C	West	ATC LLC	2799	4928	1/31/2012	Pine River	substation	1	138	69	150 MVA	Add a Pine River 138/69 kV transformer & Construct a 138 kV bus at Pine River	MI			Proposed	$3,000,000			Y	C
C	West	ATC LLC	2799	4924	1/31/2012	Kinchelo Tap	Frontier	1	69		84 MVA	Construct a 3 mile line to connect the Frontier load	MI		3	Proposed	$3,882,248			Y	C
C	West	ATC LLC	2799	4926	1/31/2012	Pine River	9 mile	1	69		95 MVA	Rebuild/reconductor Pine River-9Mile 69-kV line 6923	MI	16.76		Proposed	$11,000,000			Y	C
C	West	ATC LLC	2799	4925	1/31/2012	Straits	9 mile	1	138		381 MVA	Rebuild 6921 9Mile-Pine River and 6904 Pine River-Straits 69-kV lines as a Straits-9Mile 138 kV line	MI	41.76		Proposed	$34,500,000			Y	C
C	West	ATC LLC	2799	4927	1/31/2012	Straits	Pine River	1	138		381 MVA	Convert/rebuild/reconductor Straits-Pine River 69-kV line 6905 to a 138kV line	MI	25	3	Proposed	$23,500,000			Y	C
C	West	ATC LLC	2799	4929	1/31/2012	9 Mile	substation	1	138	69	150 MVA	Add a 9Mile 138/69 kV transformer & Construct a 138 kV bus at 9mile	MI			Proposed	$3,000,000			Y	C
C	West	ATC LLC	2800	4930	6/1/2009	Arpin	Hume	1	115		236 MVA	Marshfield Electric & Water Department project to increase ground clearance to operate the line at 200 Deg F	WI	13.5		Planned				Y	C
C	West	ATC LLC	2815	4952	3/15/2010	Lake Park	City Limits	1	138		218 MVA	Increase line clearance to achieve a 200 deg F operating temperature	WI	2		Planned				Y	C
C	West	ATC LLC	2815	4951	3/15/2010	City Limits	Combined Locks Tap	1	138		218MVA	Increase line clearance to achieve a 200 deg F operating temperature	WI	3.2		Planned				Y	C
C	West	ATC LLC	2816	4953	4/30/2010	Forsyth	Munising	1	138		143 MVA	Increase line clearance to achieve a 200 deg F operating temperature	MI	45.3		Planned				Y	C
C	West	ATC LLC	2817	4954	3/15/2010	Winona	M38	1	138		116 MVA	Increase line clearance to achieve a 125 deg F operating temperature	MI	19.9		Planned				Y	C
C	West	ATC LLC	2818	4956	4/1/2010	Meadows Tap	Melissa	1	138		160 MVA	Increase line clearance to achieve a 200 deg F operating temperature	WI	1.1		Planned				Y	C
C	West	ATC LLC	2818	4955	4/1/2010	Kaukauna Central Tap	Meadows Tap	1	138		169 MVA	Increase line clearance to achieve a 200 deg F operating temperature	WI	7.8		Planned				Y	C
C	West	ATC LLC	2819	4957	12/1/2011	Bluemound	transformer	3	230	138	400 MVA	Replace Bluemound 230/138kV transformer T3 with a 400 MVA unit	WI			Proposed	$8,000,000			Y	C
C	West	ATC LLC	2820	4958	12/1/2012	Bluemound	transformer	1	230	138	400 MVA	Replace Bluemound 230/138kV transformer T1 with a 400 MVA unit	WI			Proposed	$8,200,000			Y	C
C	West	ATC LLC	2821	4959	12/31/2010	North Fond du Lac	transformer	1	138	69	100 MVA	Replace NFL transformers T31 & T32 with a single 100MVA unit	WI			Planned	$3,260,000			Y	C
C	Central	DEM	840	819	6/1/2016	Rushville	Capacitor		69		14.4 MVAR	Add capacitor	IN			Planned	$510,845			NT	C
C	Central	DEM	1249	1957	12/31/2016	Frankfort 230	Capacitor		69		36 MVAR	Install 36 MVAR 69kV capacitor	IN			Planned	$632,358			NT	C
C	Central	DEM	1518	2594	6/1/2016	Curliss	transformer	1	138	69	150	Install new Curliss 138-69 kV sub in the 5884 ckt, 150 MVA xfmr, Install one 69 kV circuit.	OH			Planned	$4,675,000			Y	C

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C	Central	DEM	1520	2596	6/1/2014	Durbin	230/69 substation		230	69		Build a new 230 69kv 150mva sub with 2 69kv line terminals	IN			Planned	$7,000,000			Y	C
C	Central	DEM	1571	3123	6/1/2015	IPL Rockville	Avon East	1	138		306	Construct 4.3 miles / 954ACSR of 138kv line from IPL Rockville to Avon East	IN		4.3	Planned	$2,980,000			Y	C
C	Central	DEM	1900	3796	6/1/2015	Avon Industrial Park	new dist sub	1	138	12	306	Avon Industrial Park (aka Central Logistics) - Construct 69/138-12kV - 22.4 MVA sub and 2.6 mile - 69kV radial line from roughly the Avon South sub - unknown if this will be a 69 or 138 kv sub	IN		2.6	Proposed	$923,000			NT	C
C	Central	DEM	1903	3800	6/1/2014	Fishers North	Fishers 69	1	69		245	Reconductor 1.05 miles 69kV line from Fishers No to Fishers with 954ACSR@100C conductor	IN	1.05		Planned	$455,229			NT	C
C	Central	DEM	1904	3801	6/1/2015	Batesville	Hillenbrand	1	69		53	Uprate 69kV Batesville to Hillenbrand to 100C – 4/0acsr – 2.1 miles – 69107 ckt	IN	2.1		Planned	$115,961			NT	C
C	Central	DEM	2123	2908	6/1/2012	Bloomington 230	Martinsville SE Jct	1	69		153	Bloomington to Martinsville 69kV - 6903 ckt. - Rebuild 9.2 miles of 336ACSR with 954ACSR@100C	IN	9.2		Planned	$2,300,000			NT	C
C	Central	DEM	2124	2909	6/1/2020	Brooklyn	HE Brooklyn	1	69		153	Brooklyn Sub to HE Brooklyn Sub reconductor 1.28 miles of 6940 line 4/0 Cu with 954ACSR@100C	IN	1.28		Planned	$320,000			NT	C
C	Central	DEM	2125	2910	6/1/2020	Centerton	transformer	1	138	69	168	Upgrade/replace existing 75MVA 138/69kV bank with 150MVA bank	IN			Planned	$3,091,000			NT	C
C	Central	DEM	2129	2914	6/1/2020	Plainfield South	HE Mooresville Jct	1	69		153	Plainfield South to HE Mooresville Jct 69kV reconductor 4/0Cu with 954ACSR 2.03 miles	IN	2.03		Planned	$980,000			NT	C
C	Central	DEM	2134	2919	6/30/2013	Bloomington 230	Needmore Jct.	1	69		143	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	10.85		Planned	$2,712,500			NT	C
C	Central	DEM	2135	2920	6/15/2014	Franklin 230	capacitor		69		36 MVAR	Franklin 230 Sub 69kV Cap - Install 36MVAR 69kV bus capacitor bank	IN			Planned	$400,000			NT	C
C	Central	DEM	2136	2921	6/30/2012	Greenwood HE Honey Creek Jct	Frances Creek Jct	1	69		100	Greenwood HE Honey Creek Jct to Frances Creek Jct uprate 69kV - 69102 line 1.12 mile for 100C	IN	1.12		Planned	$0			NT	C
C	Central	DEM	2137	2922	6/30/2012	Greenwood Averitt Rd Jct	HE Honey Creek Jct	1	69		100	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	1.05		Planned	$0			NT	C
C	Central	DEM	2139	2924	6/30/2016	Greenwood West	switch		69		143	Greenwood West Sub - upgrade (or replace, if required) 69kV Loadbreak switch #2 for 1200amp capacity in the 6999 ckt.	IN			Planned	$50,000			NT	C
C	Central	DEM	2140	2925	6/30/2013	Greenwood West	Lenore Jct.	1	69		100	Greenwood West to Lenore Jct reconductor 69kV - 6949 ckt. with 477ACSR @ 100C conductor	IN	5.51		Planned	$1,377,500			NT	C
C	Central	DEM	2143	2929	6/1/2014	Frances Creek	bank 2	2	345	69	200	Add Frances Creek 345/69kV Bank 2 - 200MVA with LTC	IN			Planned	$2,400,000			NT	C
C	Central	DEM	2144	2930	6/30/2015	Franklin 230	Earlywood	1	69		143	Franklin 230kV sub to Earlywood sub reconductor 1.06 mile - 69kV - 69165 line with 954ACSR@100C	IN	1.06		Planned	$424,000			NT	C
C	Central	DEM	2145	2932	6/1/2015	Franklin 230	Bank 2	2	230	69	239	Replace 230/69kV bank 2 with a 200MVA LTC transformer	IN			Planned	$2,400,000			Y	C
C	Central	DEM	2145	2931	6/1/2015	Franklin 230	Bank 1	1	230	69	239	Replace 230/69kV bank 1 with a 200MVA LTC transformer	IN			Planned	$2,400,000			Y	C

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C	Central	DEM	2146	2933	6/30/2015	HE Honey Creek Jct	Frances Creek Jct	1	69		143	HE Honey Creek Jct to Frances Creek Jct. reconductor 69kV - 1.12 mile line section of the 69102 ckt. with 954ACSR 100C conductor.	IN	1.12		Planned	$420,000			NT	C
C	Central	DEM	2147	2934	6/30/2015	Whiteland	Madison Ave Jct	1	69		143	Whiteland Sub to Greenwood North Tap to Madison Ave Jct reconductor 3.44 mile 69kV - 6997 line with 954ACSR 100C conductor.	IN	3.44		Planned	$1,376,000			NT	C
C	Central	DEM	2328	4260	6/1/2015	Speed	HE Bethany	1	69		71.7	Speed to HE Bethany 69kV - 6955 Reconductor Ph2 - Replace 1.6 miles of 4/0 ACSR with 477 ACSR (new limiter 600A switches)	IN	1.6		Planned	$480,000			NT	C
C	Central	DEM	2329	4261	6/1/2014	Clarksville	Indiana Arsenal	1	69		100	Clarksville to Indiana Arsenal 69kv - 6955 ckt. reconductor 1.1 miles of 4/0acsr with 477ACSR at 100C (this is Phase 2 remainder of 4/0ACSR in this line section)	IN	1.1		Planned	$330,000			NT	C
C	Central	DEM	2330	4262	6/1/2014	New Albany	HE Georgetown	1	69		100	New Albany to HE Georgetown 69kv - 6970 ckt. Reconductor 1.24 miles of 4/0acsr with 477acsr@100C	IN	1.24		Planned	$666,000			NT	C
C	Central	DEM	2333	4265	9/1/2010	BREC Huston	distribution sub		138	13.1		New Butler REC Huston Sub 138kV - F3281 loop through sub w/ 954acsr	OH			Planned	$433,238			Y	C
C	Central	DEM	2337	4269	12/30/2015	ENYART SUB	distribution sub	1	138	13.1		Enyart Sub-Construct New Sub and Associated Feeder Construction - Between Foster & Montgomery in 5487 line	OH			Planned	$150,000			Y	C
C	Central	DEM	2795	4917	5/1/2015	Rockport (AEP)	Greentown (DEM)	1	765			New 765 kV line from Rockport (AEP) to Greentown (DEM)	IN		240	Proposed	$1,000,000,000			Y	C
C	Central	DEM, IPL	2783	3105	5/1/2012	Wheatland	Bloomington	1	345		1200	new line	IN		61	Proposed	$105,000,000			Y	C
C	East	FE	1593	2676	6/1/2016	Galion	Substation Upgrades	2	138	69	100/134 MVA	Replace 138/69 kV transformer	OH			Planned	$1,090,000			Y	C
C	East	FE	1602	2690	6/1/2015	Broadview	Substation	1	138	69	78/100 MVA	New 138/69 kV transformer	OH			Proposed				Y	C
C	East	FE	1602	2691	6/1/2015	Broadview	Substation	2	138	69	78/100 MVA	New 138/69 kV transformer	OH			Proposed				Y	C
C	East	FE	1602	2692	6/1/2015	Clark	Broadview	1	138		199/229 MVA	New Line	OH	11.3		Proposed				Y	C
C	East	FE	1602	2693	6/1/2015	Broadview	Urbana	1	138		276/309 MVA	New Line	OH	5.2		Proposed				Y	C
C	East	FE	1602	2694	6/1/2015	East Springfield	Broadview	1	138		199/241 MVA	New Line	OH	11.8		Proposed	$12,330,486			Y	C
C	East	FE	1602	2695	6/1/2015	Broadview	Mill Creek	1	138		151/174 MVA	New Line	OH	36		Proposed				Y	C
C	East	FE	1602	2689	6/1/2015	Broadview	Substation		138			New Substation	OH			Proposed				Y	C
C	East	FE	1603	2670	6/1/2015	London	Darby	1	138				OH	20.6		Proposed				Y	C
C	East	FE	1603	2671	6/1/2015	Darby	Tangy	1	138				OH	18		Proposed				Y	C
C	East	FE	1603	2669	6/1/2015	East Springfield	London	2	138				OH		15	Proposed	$23,902,942			Y	C
C	East	FE	1606	2698	6/1/2017	Barberton	South Akron	1	138		192/229 MVA	New Line	OH	8.1		Planned	$3,490,000			Y	C
C	East	FE	1916	3876	6/1/2017	New Mansfield	New 69kV Substation		69			New Substation	OH			Planned	$2,942,000			Y	C
C	East	FE	2250	4163	6/1/2017	Fulton	Substation	1	345			Add a new 345/138kV substation at the junction of the Allen Junction-Midway 345kV and Delta-Swanton 138kV Lines	OH		1	Proposed	$13,931,500			Y	C
C	East	FE	2251	4164	6/1/2011	Lynch	capacitor bank	1	69			Capacitor Bank Addition	OH			Planned	$381,200			Y	C
C	East	FE	2252	4165	6/1/2016	Lime City	capacitor bank	1	138			Capacitor Bank Addition	OH			Planned	$1,000,000			Y	C
C	East	FE	2257	4171	6/1/2016	Chamberlin	Substation	4	345	138		New 345/138 kV Transformer	OH			Planned	$6,000,000			Y	C
C	East	FE	2259	4173	6/1/2015	Adams	capacitor bank	1	69			Capacitor Bank Addition	OH			Planned	$600,000			Y	C
C	East	FE	2260	4174	6/1/2015	Beaver	Davis Besse	2	345			New Line	OH		50	Proposed	$16,500,000			Y	C
C	East	FE	2262	4176	6/1/2016	Wellington	Wellington Muni	1	69			New Line	OH		0.5	Planned	$500,000			Y	C
C	East	FE	2267	4181	6/1/2015	Pine	Allegheny	1	69			New Line	PA		10	Planned	$2,685,300			Y	C
C	East	FE	2802	4932	6/1/2010	Brookside	Burger	1	138			Equipment upgrade	OH			Planned	$19,500			Y	C
C	East	FE	2803	4933	6/1/2012	Campbell	Macdowell	1	69			New Line	PA		3.7	Planned	$1,794,800			Y	C
C	East	FE	2804	4934	6/1/2012	Station Upgrade			138			Add new 138kV breaker and associated relaying.	OH			Planned	$4,930,000			Y	C
C	East	FE	2805	4935	6/1/2014	Cook	Longview	1	69			Reconductor	OH		6.5	Planned	$299,251			Y	C
C	East	FE	2806	4936	6/1/2012	New Castle	State Line	1	69			Terminal upgrade	PA			Planned	$85,000			Y	C
C	East	FE	2807	4937	6/1/2010	New Castle	State Line	1	69			Raise design temperature	PA		1	Planned	$157,000			Y	C

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C	East	FE	2808	4938	6/1/2010	New Castle	State Line	1	69			Replace relaying to increase loabability	PA			Planned	$79,400			Y	C
C	West	GRE	1018	640	6/1/2011	Little Falls	CWP Little Falls	1	115		196	115 kv line operated at 34.5	MN	4		Proposed	$900,000			Y	C
C	West	GRE	2565	4585	6/1/2010	Cook	Frazer Bay	1	69			477 ACSR, 69 kV	MN		12	Proposed				NT	C
C	West	GRE	2565	4584	6/1/2010	Tower	Transformer	1	115	69	70	New Substation	MN		0	Proposed				Y	C
C	West	GRE	2565	4567	11/1/2011	Tower	Frazer Bay	1	69			New Distribution	MN		15	Planned	$16,552,452			NT	C
C	West	GRE	2567	4572	6/1/2010	Northport	Northport Tap	1	115			New Distribution	MN		1	Planned	$1,570,000			Y	C
C	West	GRE	2569	4580	6/1/2010	Shoal Lake	Nashwauk Tap	1	115			Distribution conversion to 115 kV	MN		8	Proposed	$6,067,048			Y	C
C	West	GRE	2570	4581	6/1/2012	Ravenna	Ravenna Tap	1	161			New Distribution	MN		0	Proposed	$962,455			Y	C
C	West	GRE	2571	4582	11/1/2011	MN Pipeline	Menahga	1	115		42	MN Pipeline-Menahga 115 kV line operated at 34.5 kV, Menahga 2-way switch	MN		8	Proposed	$3,144,000			Y	C
C	West	GRE	2572	4583	6/1/2016	Lawndale	Lawndale Tap	1	115		196	Lawndale 795 ACSS 115 kV line and switch	MN	2.5		Proposed	$1,727,500			Y	C
C	West	GRE	2573	4805	4/1/2010	H-Frame 230 kV Storm Structures			230			H-Frame 230 kV Storm Structures	Mn			Planned	$950,000			Y	C
C	West	GRE	2574	4586	6/1/2011	St. Lawrence	St. Lawrence Tap	1	115			St. Lawrence 69 kV 3-way switch	MN		0.5	Proposed	$300,000			Y	C
C	West	GRE	2576	4587	6/1/2010	Pokegama	Pokegama Tap	1	115			New Distribution	MN		8	Proposed	$3,784,000			Y	C
C	West	GRE	2578	4589	6/1/2010	Rum River	Rum River Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2579	4590	6/1/2011	Foster Lake	Foster Lake Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2580	4591	6/1/2010	Round Lake	Round Lake Tpa	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2581	4592	6/1/2010	Niniger	Niniger Tap	1	115			115 kV substation	MN		0	Proposed	$800,000			Y	C
C	West	GRE	2582	4593	6/1/2011	Pine Island	Pine Island Tap	1	69			New Distribution	MN		8	Proposed	$3,380,000			NT	C
C	West	GRE	2583	4594	11/1/2011	South Drayton	South Dayton Tap	1	115			New Distribution	MN		0	Proposed	$205,000			Y	C
C	West	GRE	2584	4595	6/1/2012	Eden Valley	Eden Valley Tap	1	69			New Distribution	MN		1	Proposed	$545,000			NT	C
C	West	GRE	2585	4596	6/1/2012	Montrose	Montrose Tap	1	115			New Distribution	MN		2	Proposed	$1,101,000			Y	C
C	West	GRE	2586	4597	6/1/2012	Athens	Substation	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2587	4598	6/1/2012	North Milaca	North Milaca Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2588	4599	11/1/2012	Hardy Lake	Hardy Lake Tap	1	115			New Distribution	MN		0	Proposed	$205,000			Y	C
C	West	GRE	2589	4600	6/1/2012	Rich Valley	Rich Valley Tap	1	69			New Distribution	MN		2	Proposed	$950,000			NT	C
C	West	GRE	2590	4601	6/1/2013	Enfield	Enfield Tap	1	69			New Distribution	MN		2	Proposed	$950,000			NT	C
C	West	GRE	2591	4602	11/1/2014	Barrows	Barrows Tap	1	115			New Distribution	MN		1	Proposed	$894,000			Y	C
C	West	GRE	2592	4603	11/1/2014	Shamineau Lake	Shamineau Lake Tap	1	115			New Distribution	MN		5	Proposed	$2,380,000			Y	C
C	West	GRE	2593	4604	6/1/2014	Bass Lake	Bass Lake Tap	1	69			New Distribution	MN		3	Proposed	$1,325,000			NT	C
C	West	GRE	2594	4605	11/1/2014	Whitefish	Whitefish Tap	1	69			New Distribution	MN		4	Proposed	$1,720,000			NT	C
C	West	GRE	2595	4606	6/1/2013	Air Lake	Substation	1	115			New Distribution	MN		0	Proposed	$860,000			Y	C
C	West	GRE	2596	4607	6/1/2014	Knife Lake	Knife Lake Tap	1	69			New Distribution	MN		8	Proposed	$5,116,000			NT	C
C	West	GRE	2597	4608	11/1/2015	Beaver Lake	Beaver Lake Tap	1	115			New Distribution	MN		1	Proposed	$944,000			Y	C
C	West	GRE	2598	4609	6/1/2015	Cornfield	Cornfield Tap	1	69			New Distribution	MN		10	Proposed	$6,260,000			NT	C
C	West	GRE	2599	4610	11/1/2015	Shell Lake	Shell Lake Tap	1	115			New Distribution	MN		5	Proposed	$2,380,000			Y	C
C	West	GRE	2600	4611	11/1/2015	Big Sandy	Big Sandy Tap	1	69			New Distribution	MN		4	Proposed	$1,880,000			NT	C
C	West	GRE	2601	4612	6/1/2015	Riverside Point	Riverside Point Tap	1	115			New Distribution	MN		3	Proposed	$1,549,000			Y	C
C	West	GRE	2602	4613	6/1/2015	Henriette	Henriette Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2603	4614	6/1/2016	Brunswick	Brunswick Tap	1	69			New Distribution	MN		16	Proposed	$6,620,000			NT	C
C	West	GRE	2604	4615	6/1/2016	Cambridge East	Cambridge East Tap	1	69			New Distribution	MN		1.75	Proposed	$1,590,750			NT	C
C	West	GRE	2605	4616	6/1/2016	Bunker Lake Bulk	Substation	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2606	4617	6/1/2016	Pease	Pease Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2607	4618	11/1/2017	Wealthwood	Wealthwood tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2608	4619	11/1/2019	Portage Lake	Portage Lake Tap	1	115			New Distribution	MN		4	Proposed	$2,197,000			Y	C
C	West	GRE	2609	4620	11/1/2019	Woman Lake	Woman Lake Tap	1	115			New Distribution	MN		0.5	Proposed	$424,000			Y	C
C	West	GRE	2610	4621	11/1/2019	Mission Lake	Mission Lake Tap	1	69			New Distribution	MN		0	Proposed	$140,000			NT	C
C	West	GRE	2611	4622	11/1/2020	Esko	Esko Tap	1	115			New Distribution	MN		0	Proposed	$205,000			Y	C
C	West	GRE	2614	4808	6/1/2015	Hoffman 2.4 MVAr capacitor bank						Hoffman 2.4 MVAr capacitor bank	Mn			Proposed				Y	C
C	West	GRE	2615	4809	6/1/2012	Framnas 2.4 MVAr capacitor bank						Framnas 2.4 MVAr capacitor bank	Mn			Proposed				Y	C
C	West	GRE	2616	4810	6/1/2011	Holmes 1.2 MVAr capacitor bank						Holmes 1.2 MVAr capacitor bank	Mn			Proposed				Y	C

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C	West	GRE	2618	4625	6/1/2012	Elk River 14	Elk River West	1	69		135.9	Rebuild	MN	2.46		Proposed	$1,168,500			NT	C
C	West	GRE	2621	4627	11/1/2011	Effie	transformer	1	230	69	60		MN			Proposed	$9,847,500			Y	C
C	West	GRE	2621	4628	11/1/2011	Effie	Big Fork	1	69		108	Effie-Big Fork 69 kV line, Wirt Tap 3-way switch, Jessie Lake 3-way switch, Big Fork 3-way switch	MN		19	Proposed	$6,162,500			NT	C
C	West	GRE	2622	4629	6/1/2011	High Island	High Island Tap	1	115		315.5	High Island 115 kV line and 3-way switch	MN		7.5	Proposed	$3,082,500			Y	C
C	West	GRE	2623	4630	6/1/2010	Lismore	Lismore Tap	1	115		140	3-way switch in Fenton-Nobles 115 kV line #2, Lismore tap 115 kV line	MN		2	Proposed	$1,269,000			Y	C
C	West	GRE	2625	4635	6/1/2010	Panther	Melville	1	69			Panther - Melville motor operated switch	MN		0.1	Planned	$40,000			NT	C
C	West	GRE	2627	4637	6/1/2015	Elko	Elko Tap	1	115			New Distribution	MN		0	Proposed	$205,000			Y	C
C	West	GRE	2628	4638	6/1/2011	Thompson Lake	Remmele Tap	1	69		92.1		MN	6.42		Proposed	$513,600			NT	C
C	West	GRE	2629	4639	6/1/2010	Waco	Rice Lake	1	69		92.1	Reconductor 115 kV line	MN	5.37		Proposed	$429,600			NT	C
C	West	GRE	2630	4640	11/1/2012	Big Fork	Wirt Tap	1	69		35	Resag	MN	8.07		Proposed	$1,290,400			NT	C
C	West	GRE	2630	4641	11/1/2012	Wirt Tap	Jessie Lake	1	69		35	Resag	MN	8.07		Proposed				NT	C
C	West	GRE	2631	4642	11/1/2012	Deer River	Jessie Lake	1	69		58.8	Resag	MN	16.52		Proposed	$1,321,600			NT	C
C	West	GRE	2632	4643	6/1/2011	Onigum	Birch Lake	1	115		140	Onigum 115 kV conversion, Birch Lake 115 kV breaker and deadend	MN	9.45		Proposed	$4,680,350			Y	C
C	West	GRE	2633	4644	6/1/2010	Donnelly	Substation	1	115			115 kV conversion	MN	1.25		Proposed	$625,000			Y	C
C	West	GRE	2634	4645	6/1/2013	Floodwood	Cromwell	1	115		310	New 115 kV Cromwell-Floodwood Line	MN	29		Proposed	$17,286,000			Y	C
C	West	GRE	2635	4646	11/1/2011	Sturgeon Lake	Sandstone	1	69		107.9	Sturgeon Lake-Sandstone 69 kV line, Sturgeon Lake 3-way switch, Sandstone Switch-Sandstone retemp, reuse Sandstone 3-way switch	MN		28.58	Proposed	$9,075,700			NT	C
C	West	GRE	2636	4649	6/1/2012	Spicer	transformer	1	230	69	140		MN			Proposed				Y	C
C	West	GRE	2636	4648	6/1/2012	Spicer	Kandiyohi	1	69		85	Spicer-Kandiyohi 69 kV double circuit	MN		1.5	Proposed				NT	C
C	West	GRE	2636	4647	6/1/2012	Spicer	Atwater	1	115		140	Spicer-Atwater 115 kV double circuit	MN		10	Proposed	$14,558,922			Y	C
C	West	GRE	2637	4650	6/1/2010	Credit River Tap	Cleary Lake	1	115		142	Rebuild to 477 SWP	MN	1.3		Proposed	$440,700			Y	C
C	West	GRE	2638	4652	11/1/2012	Macville	Blind Lake	1	115		315.9		MN		22	Proposed				Y	C
C	West	GRE	2638	4653	11/1/2012	Blind Lake	transformer	1	115	69	84		MN			Proposed				Y	C
C	West	GRE	2638	4651	11/1/2012	Macville	transformer	1	230	115	300		MN			Proposed	$21,139,884			Y	C
C	West	GRE	2639	4654	6/1/2011	Parkwood	Villiage Ten	1	69		120.1	Parkwood-Villiage Ten to ACSS	MN	0.9		Proposed	$72,000			NT	C
C	West	GRE	2640	4655	6/1/2012	Mora	Substation	1	69			Mora 12.6 MVAr cap bank and future breaker station	MN			Proposed	$2,124,400			NT	C
C	West	GRE	2641	4656	6/1/2011	Lakeside	Substation	1	69			Lakeside 5.4 MVAr Cap Bank	MN			Proposed	$236,600			NT	C
C	West	GRE	2642	4657	6/1/2012	Parkwood	Woodcrest	1	69		135.9	Parkwood-Woodcrest #2, Parkwood breaker and deadend	MN	2		Proposed	$3,548,250			NT	C
C	West	GRE	2642	4658	6/1/2012	Woodcrest	Coon Creek	1	69		135.9	Woodcrest-Coon Creek #2	MN	1.5		Proposed				NT	C
C	West	GRE	2643	4659	6/1/2011	Parkers Prairie	Parkers Prairie Tap	1	115		141.6	Parkers Prairie Conversion	MN		2	Proposed	$901,000			Y	C
C	West	GRE	2644	4660	6/1/2010	Westwood	Westwood Tap	1	115		141.6	Westwood 115 kV conversion	MN		0.5	Proposed	$364,000			Y	C
C	West	GRE	2645	4661	6/1/2011	Merriam Junction	Substation	1	69			Merriam Junction 7.2 MVAr Cap Bank	MN			Proposed	$243,800			NT	C
C	West	GRE	2646	4663	11/1/2013	Taconite Harbor	Schroeder	1	69		85	Rebuild	MN	1.85		Proposed	$627,150			NT	C
C	West	GRE	2647	4664	11/1/2012	Cromwell	Wright	1	69		107.9	Cromwell-Wright 336 ACSS 69 kV rebuild	MN	7.31		Proposed	$1,717,850			NT	C
C	West	GRE	2648	4665	6/1/2010	Milaca	Substation	1	69			Milaca breaker	MN		0	Proposed	$335,000			NT	C
C	West	GRE	2649	4666	6/1/2012	Parkwood	Johnsville	1	69		120.1	Reconductor to ACSS	MN	5.2		Proposed	$416,000			NT	C
C	West	GRE	2650	4667	6/1/2013	Bunker Lake Bulk	Andover Tap	1	69			Reconductor to ACSS	MN	1.9		Proposed	$152,000			NT	C
C	West	GRE	2651	4668	6/1/2012	LeSueur Tap	St. Thomas	1	69		144	Rebuild	MN	3.5		Proposed	$1,351,500			NT	C
C	West	GRE	2652	4669	6/1/2013	Liberty	transformer	2	115	69	140	Liberty second 140 MVA transformer	MN			Proposed	$3,394,835			Y	C
C	West	GRE	2653	4670	6/1/2014	Soderville	East Bethel	1	69		135.9	Rebuild	MN	2.5		Proposed	$1,075,000			NT	C
C	West	GRE	2654	4671	6/1/2015	St. Stephen	Substation	1	115			Substation conversions to 115 kV	MN	1.25		Proposed	$625,000			Y	C
C	West	GRE	2655	4672	6/1/2013	Le Homme Dieu	Substation	1	115			Substation conversions to 115 kV	MN	0.5		Proposed	$364,000			Y	C
C	West	GRE	2656	4673	6/1/2014	Fergus Falls	Fergus Falls Tap	1	115		141.6	1 mile 115 kV double circuit, 2 breakers at Fergus	MN	1		Proposed	$1,679,000			Y	C
C	West	GRE	2657	4675	6/1/2016	Albany	transformer	1	115	69	70	Albany 115/69 kV source	MN			Proposed				Y	C
C	West	GRE	2657	4674	6/1/2016	Alexandria	Albany	1	115		315.5	Alexandria-Albany 115 kV line, Alexandria 115 kV breaker and deadend	MN	50		Proposed	$24,103,500			Y	C
C	West	GRE	2658	4676	6/1/2015	Coon Creek	Transformer	1	69		210	Coon creek 115/69 kV source	MN			Proposed	$7,853,902			NT	C

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C	West	GRE	2658	4677	6/1/2015	Coon Creek	HWY 65	1	69		135.9	Coon Creek-Northtown-Airport-HWY 65 double circuit	MN	5.25		Proposed				NT	C
C	West	GRE	2659	4678	6/1/2015	Randolph	Randoph Tap	1	115			New Distribution	MN		0	Proposed	$860,000			Y	C
C	West	GRE	2660	4812	6/1/2009	Perham 3.0 MVAr capacitor bank						Perham 3.0 MVAr capacitor bank	Mn			Proposed				Y	C
C	West	GRE	2661	4813	6/1/2010	New York Mills 3.6 MVAr capacitor bank						New York Mills 3.6 MVAr capacitor bank	Mn			Proposed				Y	C
C	West	GRE	2662	4679	6/1/2015	High Island	Arlington	1	115		315		MN		10	Proposed	$4,530,000			Y	C
C	West	GRE	2663	4680	6/1/2013	Cleary Lake	Credit River	1	115		142	Rebuild to 477 SWP	MN	0.95		Proposed	$322,050			Y	C
C	West	GRE	2664	4681	11/1/2013	Mantrap	Potato Lake	1	115		140	Mantrap 115 kV rebuild/underbuild, long lake 115 kV breaker and deadend	MN	6.25		Proposed	$2,738,750			Y	C
C	West	GRE	2665	4682	6/1/2015	Schroeder	Lutsen	1	69		85	Rebuild	MN	11.53		Proposed	$4,258,670			NT	C
C	West	GRE	2666	4683	6/1/2014	Carver County	Assumption	1	115		315	Rebuild	MN	5.1		Proposed	$1,983,900			Y	C
C	West	GRE	2667	4684	6/1/2014	Rush City	Adrian Robinson	1	69		58.8	Rush City distribution retemp	MN	3.15		Proposed	$284,800			NT	C
C	West	GRE	2668	4814	6/1/2015	Osage Regulator						Osage Regulator	Mn			Proposed				Y	C
C	West	GRE	2669	4685	6/1/2011	Dickinson	transformer	1	115	69	140	Dickinson 140 MVA transformer replacement	MN			Proposed	$2,039,835			Y	C
C	West	GRE	2669	4686	6/1/2011	West St. Cloud	transformer	1	115	69	84	Move Dickinson 84 MVA transformer to W. St. Cloud	MN			Proposed				Y	C
C	West	GRE	2670	4687	6/1/2012	North Perham	transformer	1	115	41.6	70	North Perham land acquisition and 115/41.6 kV source	MN			Proposed	$4,235,028			Y	C
C	West	GRE	2672	4689	6/1/2011	Bear Creek	transformer	1	230	69	84	Rush City move to Bear Creek	MN			Proposed				Y	C
C	West	GRE	2672	4688	6/1/2011	Rush City	transformer	1	230	69	140	Rush City transformer replacement	MN			Proposed	$3,211,422			Y	C
C	West	GRE	2673	4690	6/1/2012	Dalbo	St. Francis	1	69		135.9	Dalbo-St. Francis 69 kV double circuit, Dalbo switch, St. Francis switch	MN		11	Proposed	$6,165,000			NT	C
C	West	GRE	2674	4691	6/1/2011	Milaca	Long Siding	1	69		135.9	Milaca - Long Siding 477 ACSS Rebuild	MN	2.46		Proposed	$2,488,500			NT	C
C	West	GRE	2675	4692	6/1/2012	West St. Cloud	Substation	1	115			West St. Cloud Line Termination	MN			Proposed	$1,942,000			Y	C
C	West	GRE	2676	4693	6/1/2012	Paynesville	Watkins	1	69		85	Paynesville-Watkins 69 kV 477 ACSR, Paynesville 3-way switch/breaker and deadend, Watkins 3-way switch	MN	17		Proposed	$6,180,000			NT	C
C	West	GRE	2677	4694	6/1/2012	Princeton	Princeton Tap	1	69		135.9	Reconductor to ACSS	MN	5.12		Proposed	$409,600			NT	C
C	West	GRE	2678	4695	6/1/2012	Zimmerman	Substation	1	69			Zimmerman 19.6 MVAr Cap bank	MN			Proposed	$291,800			NT	C
C	West	GRE	2679	4696	11/1/2020	Ramsey	Grand Forks	1	230			230 kV rebuild	MN	81.02		Proposed	$38,484,500			Y	C
C	West	GRE	2680	4697	6/1/2016	Shamineau Lake	North Parker	1	115		42	Shamineau Lake-North Parker 115 kV line, Shamineau Lake 3-way switch, North Parker 3-way switch	MN		13.6	Proposed	$5,734,800			Y	C
C	West	GRE	2681	4698	6/1/2014	St. Boni	transformer	1	115	69	140	Second 115/69 kV transformer at St. Boni, St Boni breaker to Delano	MN			Proposed	$2,359,835			Y	C
C	West	GRE	2682	4699	6/1/2014	Lake Marion	transformer	1	115	69	140		MN			Proposed	$1,939,835			Y	C
C	West	GRE	2683	4700	6/1/2015	Bloom Tap	Bloom	1	115		140	Bloom Tap 115 kV line, 3-way switch in Fenton-Nobles 115 kV line #2	MN	2		Proposed	$1,269,000			Y	C
C	West	GRE	2684	4701	6/1/2016	Assumption	Belle Plaine	1	115		315	Assumption-Belle Plain upgrade, Converty Assumption and St. Lawrence to 115 kV	MN	10.29		Proposed	$4,332,810			Y	C
C	West	GRE	2685	4702	6/1/2016	Lake Marion	Lake Marion Tap	1	115		315	Lake Marion-Lake Marion Tap to 115 kV double circuit	MN	2.43		Proposed	$1,297,620			Y	C
C	West	GRE	2686	4703	6/1/2016	Lake Marion	New Market	1	115		315	Lake Marion-Elko-New Market	MN	5.6		Proposed	$2,343,400			Y	C
C	West	GRE	2687	4704	6/1/2016	New Market	Helena	1	115		315	New Market-Helena 115 kV line, Helena 115 kV breaker and line termination, New Market 115/69 kV source	MN	15		Proposed	$10,215,028			Y	C
C	West	GRE	2688	4705	6/1/2015	Elk River West	Waco	1	69		135.9	Rebuild	MN	2.79		Proposed	$1,476,300			NT	C
C	West	GRE	2689	4706	11/1/2015	Breezy Point	Breezy Point Tap	1	69		45.5	Retemp	MN	2.25		Proposed	$180,000			NT	C
C	West	GRE	2690	4707	6/1/2015	Delano Tap	Willow	1	69		58.8	Retemp	MN	8.5		Proposed	$680,000			NT	C
C	West	GRE	2691	4711	6/1/2017	Liberty	Thompson Lake	1	115		135.9	Reconductor	MN	3.29		Proposed				Y	C
C	West	GRE	2691	4709	6/1/2017	Orrock	Waco	1	115	69	315.9/135.9	Double Circuit	MN	3.5		Proposed				Y	C
C	West	GRE	2691	4710	6/1/2017	Thompson Lake	Waco	1	115	69	315.9/135.9	Double Circuit	MN	10.33		Proposed				Y	C
C	West	GRE	2691	4708	6/1/2017	Orrock	transformer	1	345	115	336		MN			Proposed	$19,661,825			Y	C

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C	West	GRE	2692	4712	6/1/2018	Little Falls	Lastrup	1	115		315.9	Little Falls-Lastrup 115 kV line and 34.5 kV underbuild, Little Falls 3-way switch	MN		12	Proposed	$6,711,000			Y	C
C	West	GRE	2693	4713	6/1/2016	Litchfield	Litchfield Municipal	1	69		45.4	upgrade	MN	2		Proposed	$160,000			NT	C
C	West	GRE	2694	4714	6/1/2016	Spirit Lake	Spirit Lake Switch	1	69		35	Retemp	MN	1.81		Proposed	$144,800			NT	C
C	West	GRE	2695	4715	11/1/2016	Riverton	Oak Lawn	1	69		83	Reconductor to ACSS	MN	7.41		Proposed	$579,200			NT	C
C	West	GRE	2696	4721	6/1/2018	MN Pipeline Tap	Hubbard	1	115		140	Itasca-Mantrap 115 kV loop, double circuit	MN	2.5		Proposed				Y	C
C	West	GRE	2696	4716	6/1/2018	Potato Lake	Shell Lake	1	115		140	Itasca-Mantrap 115 kV loop	MN		17	Proposed	$20,502,070			Y	C
C	West	GRE	2696	4717	6/1/2018	Shell Lake	Pine Point	1	115		140	Itasca-Mantrap 115 kV loop	MN	5.33		Proposed				Y	C
C	West	GRE	2696	4718	6/1/2018	Shell Lake	Osage	1	115		140	Itasca-Mantrap 115 kV loop	MN	6		Proposed				Y	C
C	West	GRE	2696	4719	6/1/2018	Osage	MN Pipeline	1	115		140	Itasca-Mantrap 115 kV loop	MN	9		Proposed				Y	C
C	West	GRE	2696	4720	6/1/2018	MN Pipeline	MN Pipeline Tap	1	115		140	Itasca-Mantrap 115 kV loop	MN	4		Proposed				Y	C
C	West	GRE	2697	4816	6/1/2017	Elizabeth 3.0 MVAr capacitor bank						Elizabeth 3.0 MVAr capacitor bank	Mn			Proposed				Y	C
C	West	GRE	2698	4722	11/1/2017	Gunn	Gunn Tap	1	115		114	Gunn 115 kV line and 3-way switch	MN	0.5		Proposed	$344,000			Y	C
C	West	GRE	2699	4723	11/1/2017	Blackberry	Blackberry Tap	1	115		114	Blackberry 115 kV line and 3-way switch	MN	1		Proposed	$523,000			Y	C
C	West	GRE	2700	4724	6/1/2017	Pine Center	Substation	1	69			Pine Center 9.0 MVAr 69 kV Cap Bank	MN			Proposed	$251,000			NT	C
C	West	GRE	2701	4725	6/1/2018	Big Swan	Litchfield	1	115			Big Swan-Litchfield 115 kV line, Big Swan 115 kV breaker and deadend, Litchfield 69 kV breaker and deadend	MN	9		Proposed	$4,891,000			Y	C
C	West	GRE	2702	4726	6/1/2020	Dalbo	transformer	1	230	69		Dalbo 230/69 kV source	MN			Proposed	$56,774,816			Y	C
C	West	GRE	2702	4727	6/1/2020	Dalbo	Milaca	1	230			Rush City-Dalbo 230 kV line	MN		24.5	Proposed				Y	C
C	West	GRE	2702	4728	6/1/2020	Dalbo	Rush City	1	230			Dalbo-Milaca 230 kV line	MN		31.35	Proposed				Y	C
C	West	GRE	2703	4729	6/1/2017	Hugo	Blaine	1	69		92.1	Reconductor	MN	6.64		Proposed	$531,200			NT	C
C	West	GRE	2704	4730	6/1/2017	Milaca	Ogilvie	1	69		107.9	69 kV rebuild	MN	12.69		Proposed	$2,982,150			NT	C
C	West	GRE	2705	4731	6/1/2017	Liberty	Becker	1	69		120.1	Reconductor to 397 ACSS	MN	0.8		Proposed	$64,000			NT	C
C	West	GRE	2706	4732	6/1/2018	Princeton	Long Siding	1	69		135.9	Rebuild to 477 ACSS	MN	1.57		Proposed	$431,750			NT	C
C	West	GRE	2707	4733	6/1/2019	Shamineau Lake	transformer	1	115	34.5	30		MN			Proposed				Y	C
C	West	GRE	2707	4734	6/1/2019	Motley	Shamineau Lake	1	115	34.5		Motley-Shamineau Lake 115 kV line with 34.5 underbuild	MN		7.75	Proposed	$6,120,950			Y	C
C	West	GRE	2708	4735	6/1/2018	Blaine	Transformer	1	230	69	112	Second Blaine 112 MVA transformer and buswork	MN			Proposed	$3,573,598			Y	C
C	West	GRE	2709	4736	11/1/2018	Wright	Round lake	1	69		107.9	Rebuild to 336 ACSS at 69 kV	MN	10.96		Proposed	$2,575,600			NT	C
C	West	GRE	2710	4737	6/1/2018	Prior Lake	substation redesign & reconfiguration	1	115			Conversion to 115 kV	MN			Proposed	$2,000,000			Y	C
C	West	GRE	2711	4817	6/1/2018	Blaine 69 kV cap bank			69			Blaine 69 kV cap bank	Mn			Proposed				Y	C
C	West	GRE	2712	4738	6/1/2018	Enterprise Park	Energy Park	1	69		120.1	Reconductor to 397 ACSS, Energy Park 69 kV 3-way switch upgrade	MN	1.46		Proposed	$216,800			NT	C
C	West	GRE	2713	4739	6/1/2018	Grasston	Pine City	1	69		107.9	69 kV rebuild	MN	9.47		Proposed	$2,225,450			NT	C
C	West	GRE	2714	4818	6/1/2018	Elk River S14 69 kV cap bank.			69			Elk River S14 69 kV cap bank.	Mn			Proposed				Y	C
C	West	GRE	2715	4740	6/1/2018	Rush Switch	Rock Lake	1	69		92.1	69 kV reconductor	MN	9.23		Proposed	$738,400			NT	C
C	West	GRE	2716	4741	6/1/2019	Soderville	Ham Lake	1	69			Reconductor	MN	0.38		Proposed	$30,400			NT	C
C	West	GRE	2717	4742	6/1/2019	Linwood	North Branch	1	69			Reconductor 69 kV to 266 ACSS	MN	12.19		Proposed	$1,019,750			NT	C
C	West	GRE	2718	4743	6/1/2019	Albany	West St. Cloud	1	115			Albany-West St. Cloud 115 kV line, Albany breaker, West St. Cloud breaker	MN		17	Proposed	$8,749,000			Y	C
C	West	GRE	2719	4744	6/1/2019	Cambridge	South Cambridge	1	69				MN	3.5		Proposed	$2,656,500			NT	C
C	West	GRE	2720	4745	6/1/2020	Side Lake	Meadowbrook	1	115			Rebuild	MN	15.1		Proposed	$4,152,500			Y	C
C	West	GRE	2721	4819	6/1/2019	Cashel						Cashel	Mn			Proposed				Y	C
C	West	GRE	2722	4820	6/1/2021	Lutsen	Cascade		115			Lutsen-Cascade 115kV line	Mn			Proposed				Y	C
C	West	GRE	2723	4821	6/1/2021	Cascade-Grand Marais Tap 115kV line			115			Cascade-Grand Marais Tap 115kV line	Mn			Proposed				Y	C
C	West	GRE	2724	4822	6/1/2022	Pierz 300 MVA, 230/115 kV Source and Line Outlets			230	115		Pierz 300 MVA, 230/115 kV Source and Line Outlets	Mn			Proposed				Y	C
C	West	GRE	2725	4823	6/1/2015	Arrowhead 115 kV Conversion			115			Arrowhead 115 kV Conversion	Mn			Proposed				Y	C

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C	West	GRE	2726	4746	6/1/2017	Loon Lake	St. Clair	1	115		144	New Loon Lake- St. Clair 115 kV line, Loon Lake 69 kV circuit breaker	MN		19	Proposed	$9,787,000			Y	C
C	West	GRE	2727	4824		Bunker Lake 69 kV cap bank.			69			Bunker Lake 69 kV cap bank.	Mn			Proposed				Y	C
C	West	GRE	2728	4747	6/1/2019	Fox Lake	Heron Lake	1	69			Rebuilt to 477 ACSR	MN	6.25		Proposed	$2,122,500			NT	C
C	West	GRE	2729	4748	6/1/2015	Minneota	Substation	1	69			Minneota 5.4 MVAr Cap Bank	MN			Proposed	$236,000			NT	C
C	West	GRE	2730	4749	6/1/2018	Al-Corn	Substation	1	161			Al-corn 2-15 MVAr 161 kV cap bank	MN	1.46		Proposed	$536,000			Y	C
C	West	GRE	2731	4750	6/1/2012	Lake Lillian	Lake Lillian Tap	1	69			New Distribution	MN		2	Proposed	$1,115,000			NT	C
C	West	GRE	2732	4825		Cambria (MN Valley) 10.0 mile, 115 kV line			115			Cambria (MN Valley) 10.0 mile, 115 kV line	Mn			Proposed				Y	C
C	West	GRE	2733	4751	6/1/2016	Dahlgren	Dahlgren Tap	1	115			New Distribution	MN		0	Proposed	$860,000			Y	C
C	West	GRE	2734	4752	6/1/2016	Savage	Savage Tap	1	115			New Distribution	MN		0	Proposed	$860,000			Y	C
C	Central	IPL	897	907	6/1/2012	Thompson 345-138 kV	transformer	1	345	138	500 MVA	New 345/138kV Autotransformer	IN			Proposed	$7,200,000			Y	C
C	Central	IPL	2051	3937	6/1/2012	Petersburg	Thompson	1	345		1195 MVA	Increase line rating	IN	96		Proposed				Y	C
C	Central	IPL	2052	3938	6/1/2012	Petersburg	Hanna/Frances Creek	1	345		1195 MVA	Increase line rating	IN	111		Proposed				Y	C
C	East	ITC	694	1393	12/31/2018	Saratoga 345 kV	Belle River 345	1	345		2259		MI	16.5	4.2	Proposed	$6,000,000			Y	C
C	East	ITC	694	1394	12/31/2018	Saratoga 345/120 kV	transformer	1	345	120	700		MI			Proposed	$5,000,000			Y	C
C	East	ITC	694	1391	12/31/2018	Saratoga 345 kV	Greenwood 345 kV	2	345		2552		MI		13.4	Proposed	$13,500,000			Y	C
C	East	ITC	694	1390	12/31/2018	Saratoga 345 kV	Greenwood 345 kV	1	345		2241		MI	13.4		Proposed	$600,000			Y	C
C	East	ITC	694	1389	12/31/2018	Saratoga 120 kV	Burns 2 120 kV	1	120		313		MI	17.7	0.6	Proposed	$700,000			Y	C
C	East	ITC	694	1392	12/31/2018	Saratoga 345 kV	Pontiac 345 kV	1	345		1769		MI	42.9		Proposed	$600,000			Y	C
C	East	ITC	694	1388	12/31/2018	Saratoga 120 kV	Bunce Creek 120 kV	1	120		313		MI	12.5	0.6	Proposed	$700,000			Y	C
C	East	ITC	694	1387	12/31/2018	Saratoga 120 kV	Wabash 120 kV	1	120		299		MI	13.6	0.6	Proposed	$700,000			Y	C
C	East	ITC	694	1386	12/31/2018	Saratoga 120 kV	Robin 120 kV	1	120		444		MI	23.3	0.6	Proposed	$700,000			Y	C
C	East	ITC	694	1385	12/31/2018	Saratoga 345/120 kV (sw sta provisions)	transformer		345	120			MI			Proposed	$1,100,000			Y	C
C	East	ITC	908	1579	6/1/2018	Lulu	Monroe 1-2	1	345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI	12.1	3	Proposed				Y	C
C	East	ITC	908	3711	6/1/2018	Lulu 345 kV	New Switching Station		345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI			Proposed				Y	C
C	East	ITC	908	935	6/1/2018	Lulu	Milan	1	345			switching station Majestic-Lemoyne and Milan-Allen cut in. New Monroe 1-2 and Lemoyne-Lulu into Monroe 3-4	MI	16		Proposed				Y	C
C	East	ITC	908	936	6/1/2018	Lulu	Monroe 3-4	1	345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI	15		Proposed				Y	C
C	East	ITC	908	1580	6/1/2018	Lemoyne	Monroe 3-4	1	345		2000		MI	33.1	3	Proposed	$4,500,000			Y	C
C	East	ITC	908	937	6/1/2018	Lulu	Lemoyne	1	345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI	42		Proposed				Y	C
C	East	ITC	908	938	6/1/2018	Lulu	Allen Junction	1	345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI	19		Proposed				Y	C
C	East	ITC	908	934	6/1/2018	Lulu	Majestic	1	345			New switching station with Majestic-Lemoyne and Milan-Allen cut in. New line to Monroe 1-2 and cut Lemoyne-Lulu into Monroe 3-4	MI	51		Proposed				Y	C
C	East	ITC	1012	1582	6/1/2014	Wayne	Newburg	3	120			New line (un-six wire Newburg - Wayne 2)	MI		2.8	Proposed				Y	C
C	East	ITC	1295	2124	6/30/2016	Quaker 120	Southfield 120	1	120		183/232	new line	MI		7.35	Proposed				Y	C

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C	East	ITC	1382	2376	12/31/2016	Bridgewater 345 kV	Majestic 345 kV	2	345		1828	Taps the Majestic-Milan 345 kV Circuit	MI			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2384	12/31/2016	Bridgewater 765/345 kV	transformer	2	765	345	3040	New 765/345 kV Xfmr at Bridgewater	MI			Proposed	$25,000,000			Y	C
C	East	ITC	1382	2381	12/31/2016	Denver 765/138 kV	transformer	1	765	138	1119	New 765/138 kV Xfmr at Denver	MI			Proposed	$25,000,000			Y	C
C	East	ITC	1382	2380	12/31/2016	Kenowa 765/354 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Kenowa	MI			Proposed	$25,000,000			Y	C
C	East	ITC	1382	2379	12/31/2016	Sprague Creek 345 kV	Madrid 345 kV	1	345		795	Taps the Blackfoot-Madrid 345 kV Circuit	MI			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2383	12/31/2016	Bridgewater 765/345 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Bridgewater	MI			Proposed	$25,000,000			Y	C
C	East	ITC	1382	2378	12/31/2016	Sprague Creek 345 kV	Blackfoot 345 kV	1	345		795	Taps the Blackfoot-Madrid 345 kV Circuit	MI			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2372	12/31/2016	Site A 765 kV	Dumont 765 kV	1	765		4465	Taps Current Marysville-Dumont 765 kV line	IN/OH			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2373	12/31/2016	Site A 765 kV	Marysville 765 kV	1	765		4465	Taps Current Marysville-Dumont 765 kV line	IN/OH			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2382	12/31/2016	Sprague Creek 765/345 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Sprague Creek	MI			Proposed	$25,000,000			Y	C
C	East	ITC	1382	2368	12/31/2016	Kenowa 765 kV	Denver 765	1	765		4465	30 miles of new 765 kV line and new 765 kV Denver Station	MI		30	Proposed	$150,000,000			Y	C
C	East	ITC	1382	2374	12/31/2016	Bridgewater 765 kV	South Canton 765 kV	1	765		4465	170 miles of new 765 kV line	MI/OH		170	Proposed	$600,000,000			Y	C
C	East	ITC	1382	2369	12/31/2016	Sprague Creek 765 kV	Denver 765 kV	1	765		4465	100 miles of new 765 kV line and new 765 kV Sprague Creek Station	MI		100	Proposed	$400,000,000			Y	C
C	East	ITC	1382	2377	12/31/2016	Bridgewater 345 kV	Milan 345 kV	1	345		1828	Taps the Majestic-Milan 345 kV Circuit	MI			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2370	12/31/2016	Sprague Creek 765 kV	Bridgewater 765 kV	1	765		4465	50 miles of new 765 kV line and new 765 kV Bridgewater Station	MI		50	Proposed	$225,000,000			Y	C
C	East	ITC	1382	2367	12/31/2016	Cook 765 kV	Kenowa 765 kV	1	765		4465	100 miles of new 765 kV line and new 765 kV Kenowa Station	MI		100	Proposed	$400,000,000			Y	C
C	East	ITC	1382	2375	12/31/2016	Bridgewater 345 kV	Majestic 345 kV	1	345		1828	Taps the majestic end of the Allen Junction-Maj-Monroe 3 ender	MI			Proposed	$10,000,000			Y	C
C	East	ITC	1382	2371	12/31/2016	Bridgewater 765 kV	Site A 765 kV	1	765		4465	135 miles of new 765 kV line and new 765 kV Site A Station	IN/OH		135	Proposed	$530,000,000			Y	C
C	East	ITC	1550	2639	5/31/2015	Hager 120 kV	Sunset 120 kV	1	120		351	Transpose line entrance with the Sunset-Southfield 120 kV circuit	MI	0.1		Proposed				Y	C
C	East	ITC	1842	3713	6/1/2017	Bunce Creek 230/120 kV	Transformer	1	230	120		New Transformer	MI			Proposed				Y	C
C	East	ITC	1842	3715	6/1/2017	Greenwood	Kilgore	1	120			reconductor line	MI	0.34		Proposed				Y	C
C	East	ITC	1842	3714	6/1/2017	Greenwood 345/230 kV	Transformer	1	345	230		New Transformer	MI			Proposed				Y	C
C	East	ITC	1842	3716	6/1/2017	Kilgore	Lee	1	120			reconductor line	MI	10.3		Proposed				Y	C
C	East	ITC	1842	3717	6/1/2017	Lee	Menlo	1	120			reconductor line	MI	17		Proposed				Y	C
C	East	ITC	1842	3712	6/1/2017	Bunce Creek	Greenwood	1	230			New Line (existing ROW)	MI		36	Proposed				Y	C
C	East	ITC	1842	3718	6/1/2017	Menlo	Bunce Creek	1	120			reconductor line	MI	8.6		Proposed				Y	C
C	East	ITC	1843	3720	6/1/2013	Essex 230/120 kV	Transformer	1	230	120		New Transformer	MI			Proposed				Y	C
C	East	ITC	1843	3719	6/1/2013	Essex	Waterman	1	230			New Cable	MI		8.5	Proposed				Y	C
C	East	ITC	1844	3721	6/1/2013	Essex	Mack (Voyager)	1	120			reconductor line	MI	2.4		Proposed				Y	C
C	East	ITC	1844	3722	6/1/2013	Essex	Mack	2	120			New Line (existing ROW)	MI		2.4	Proposed				Y	C
C	East	ITC	1845	3710	6/1/2013	Hemphill	Transformer	2	230	138		New Transformer	MI			Proposed				Y	C
C	East	ITC	1845	3723	6/1/2013	Blackfoot	Hemphill	1	230			New Line (existing ROW)	MI		17	Proposed				Y	C
C	East	ITC	1845	3724	6/1/2013	Blackfoot	Transformer	1	345	230		New Transformer	MI			Proposed				Y	C
C	East	ITC	1846	3725	6/1/2012	Evergreen 120 kV	Substation Equipment		120			Trainer and Bus work	MI			Proposed				Y	C
C	East	ITC	1847	3726	6/1/2014	DIG	Waterman	1	230			Break up 3-ended line	MI			Proposed				Y	C
C	East	ITC	1847	3727	6/1/2014	Navarre	Waterman	1	230			Break up 3-ended line	MI			Proposed				Y	C
C	East	ITC	1848	3728	6/1/2016	Bad Axe	Tuscola	1	120			New Line (existing ROW)	MI		34	Proposed				Y	C
C	East	ITC	1848	3729	6/1/2016	Tuscola	Arrowhead	1	120			reconductor line	MI	15.3		Proposed				Y	C
C	East	ITC	1848	3730	6/1/2016	Arrowhead	Bad Axe	1	120			reconductor line	MI	19		Proposed				Y	C
C	East	ITC	1849	3731	6/1/2016	Coventry 345 kV	Substation Equipment		345			New Breaker	MI			Proposed				Y	C
C	East	ITC	1851	3735	6/1/2016	Hager	Sunset	1	120			New Cable	MI		0.1	Proposed				Y	C
C	East	ITC	1852	3736	6/1/2017	Drexel	Southfield	1	120			New Cable	MI		0.4	Proposed				Y	C
C	East	ITC	1853	3737	6/1/2017	Newburgh	Peru	1	120			reconductor line	MI	2.1		Proposed				Y	C
C	East	ITC	1854	3739	6/1/2018	Jefferson	Riverview	1	120			new line	MI		2.2	Proposed				Y	C
C	East	ITC	1854	3738	6/1/2018	Trenton Channel	Jefferson	1	120			New Line (existing ROW)	MI			Proposed				Y	C
C	East	ITC	1854	3740	6/1/2018	Riverview	Ironton	1	120			Replace Wave Trap	MI			Proposed				Y	C

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C	East	ITC	1855	3741	6/1/2019	Troy	Lincoln (Formtech1)	1	120			reconductor line	MI	0.8		Proposed				Y	C
C	East	ITC	1855	3742	6/1/2019	Troy	Chesnut (Formtech2)	1	120			reconductor line	MI	0.8		Proposed				Y	C
C	East	ITC	1858	3747	6/1/2010	Wayne 345 kV	Substation Equipment		345			replace overloaded station equipment	MI			Proposed				Y	C
C	East	ITC	1859	3751	6/1/2014	Castle	Sunset	1	120		300 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3749	6/1/2014	Castle	Southfield	1	120		218 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3752	6/1/2014	Castle	Northwest	1	120		388 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3753	6/1/2014	Castle	Northwest	2	120		388 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3754	6/1/2014	Castle	Drake	1	120		300 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3750	6/1/2014	Castle	Southfield	2	120		218 MVA	New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1859	3748	6/1/2014	Castle 120 kV	Substation		120			New switching station with Southfield-Sunset, Southfield-Northwest, and Northwest-Drake circuits cut into Castle	MI			Proposed				Y	C
C	East	ITC	1868	3755	12/31/2010	Cato 120 kV	Substation Equipment		120			GIS Replacement	MI			Planned				Y	C
C	West	ITCM	1738	3536	12/31/2012	Bertram	Hills	1	161		446/446 MVA	Reconductor the Bertram-Rose Hollow-Hills	IA	32.2		Proposed	$13,000,000			Y	C
C	West	ITCM	1741	3292	12/31/2010	Heron Lake	South Storden	1	161		440	Rebuild line to higher capacity	MN			Planned	$6,818,660	Y		Y	C
C	West	ITCM	1741	4026	12/31/2010	Heron Lake Substation			161							Planned	$4,195,530	Y		Y	C
C	West	ITCM	1741	4028	12/31/2010	South Storden	Cottonwood County	1	161				MN			Planned	$4,092,575	Y		Y	C
C	West	ITCM	1741	4025	12/31/2010	Cottonwood County substation			161							Planned	$4,833,216	Y		Y	C
C	West	ITCM	1741	2235	12/31/2010	Storden (Cottonwood County)	Dotson	1	161		446	New line	MN	26		Planned	$16,379,839	Y		Y	C
C	West	ITCM	1741	4027	12/31/2010	Communication System Upgrades			161							Planned	$400,000	Y		Y	C
C	West	ITCM	1742	3544	12/31/2011	Elk	Brewster	1	161		326/326 MVA	Rebuild existing line	MN	3.32		Proposed	$1,600,000			Y	C
C	West	ITCM	1742	4392	12/31/2011	Brewster	Heron Lake	1	161		326/326 MVA	Rebuild existing line	MN	14.64		Proposed	$7,000,000			Y	C
C	West	ITCM	1742	3542	12/31/2012	Split Rock	Magnolia	1	161		446/446 MVA	Rebuild existing line	MN	11		Proposed	$5,200,000			Y	C
C	West	ITCM	1742	3543	12/31/2012	Magnolia	Elk	1	161		326/326 MVA	Rebuild existing line	MN	18.75		Proposed	$9,000,000			Y	C
C	West	ITCM	1746	3549	12/31/2011	Fox Lake	Rutland	1	161		446/446 MVA	Rebuild existing line	MN	17		Proposed	$8,100,000			Y	C
C	West	ITCM	1746	3550	12/31/2012	Rutland	Winnebago	1	161		446/446 MVA	Rebuild existing line	MN	14.6		Proposed	$7,000,000			Y	C
C	West	ITCM	1746	3551	12/31/2013	Lakefield	Fox Lake	1	161		446/446 MVA	Rebuild existing line	MN	22.3		Proposed	$10,700,000			Y	C
C	West	ITCM	1746	3552	12/31/2014	Winnebago	Hayward	1	161		446/446 MVA	Rebuild existing line	MN	49.09		Proposed	$23,600,000			Y	C
C	West	ITCM	1746	3553	12/31/2015	Hayward	Adams	1	161		446/446 MVA	Rebuild existing line	MN	36.39		Proposed	$17,500,000			Y	C
C	West	ITCM	2830	4972	1/1/2014	Rutland	345/161 kV transformer	1	345	161	336					Proposed				Y	C
C	West	ITCM	2830	4971	1/1/2014	Lakefield Jct	Rutland	1	345		1500			39.4		Proposed	$98,500,000			Y	C
C	East	ITCM, AmerenIL	2785	4895	5/1/2014	Sorenson	+/- 800KV DC converter station	1	800		6400	new +/- 800KV DC converter station	IN			Proposed	$1,900,500,000			Y	C
C	West	ITCM, AmerenIL	2785	4893	5/1/2014	New Substation in NW Iowa	+/- 800KV DC converter station	1	800		6400	new +/- 800KV DC converter station	IA			Proposed				Y	C
C	West, Ce	ITCM, AmerenIL	2785	4894	5/1/2014	New Substation in NW Iowa	Sorenson	1	800		6400	new +/- 800KV DC line	IA, IL, IN		667	Proposed				Y	C
C	Central	ITCM, AmerenIL, Non-MISO	2794	4916	5/1/2014	Collins	+/- 800KV DC converter station	1	800		3950	new +/- 800KV DC converter station	IL			Proposed	$1,625,000,000			Y	C

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C	West	ITCM, AmerenIL, Non-MISO	2794	4914	5/1/2014	New Substation in NW Iowa	+/- 800KV DC converter station	1	800		3950	new +/- 800KV DC converter station	IA			Proposed				Y	C
C	West, Ce	ITCM, AmerenIL, Non-MISO	2794	4915	5/1/2014	New Substation in NW Iowa	Collins	1	800		3950	new +/- 800KV DC line	IA, IL		500	Proposed				Y	C
C	East	METC	642	1325	6/1/2017	Argenta	Hazelwood(Sag)	1	138			conductor sag	MI	0.1		Proposed	$50,000			Y	C
C	East	METC	984	1547	6/1/2018	Denver Station	New Station		345			New Station	MI			Proposed	$77,132,000			Y	C
C	East	METC	987	1550	6/1/2013	Emmet	Stover	1	138				MI			Proposed	$10,250,000			Y	C
C	East	METC	1225	1925	5/1/2018	Thompson Road	Tallman	1	138				MI	19.2		Proposed	$5,000,000			Y	C
C	East	METC	1428	2432	5/1/2013	Roosevelt 138kV	Black River 138kV		138			Install new 3mile 795 ACSS 138kV line from Roosevelt-Black River with a 138kV breaker at each end	MI			Proposed	$10,000,000			Y	C
C	East	METC	1428	2431	5/1/2013	Roosevelt 345kV	345/138kV transformer		345	138		Add 345/138kV transformer along with two 345kV breakers	MI			Proposed	$6,000,000			Y	C
C	East	METC	1429	2433	6/1/2018	Barry 138kV	Thompson Road 138kV		138			Build new 17mile 138kV line from Barry to Thompson Rd	MI			Proposed	$20,000,000			Y	C
C	East	METC	1430	2434	6/1/2017	Buck Creek 138kV	138kV Breakers		138			Convert 138/46kV substation to a switching station by installing 3 high side 138kV breakers at Buck Creek	MI			Proposed	$4,500,000			Y	C
C	East	METC	1431	2435	6/1/2017	Vergennes 138kV	Kendrick 138kV		138			Build new 16mile 138kV line from Vergennes to Kendrick and puchase Kendrick-Plaster Creek spur	MI			Proposed	$14,000,000			Y	C
C	East	METC	1432	2436	6/1/2018	Withey Lake 138kV	Twining 138kV		138			Rebuild 0.2 miles of Withey Lake-Twining 138kV line	MI			Proposed	$100,000			Y	C
C	East	METC	1573	3125	6/1/2011	Donaldson Creek	Donaldson Creek-New Capacitor		138		23.3 Mvar	New 23.3 Mvar Capacitor	MI			Proposed				Y	C
C	East	METC	1657	2852		Terminal Equipment Upgrade						throughout system	MI			Proposed				Y	C
C	East	METC	1795	3604	6/1/2010	David Jct.	Bingham	1	138			reconductor (removes sag limits)	MI	19		Proposed	$11,700,000			Y	C
C	East	METC	1800	3612	6/1/2013	Argenta 138 kV	Substation Equipment		138			upgrade CT	MI			Proposed				Y	C
C	East	METC	1800	3613	6/1/2013	Riverview 138 kV	Substation Equipment		138			upgdrade CT, breaker, and switch	MI			Proposed				Y	C
C	East	METC	1800	3611	6/1/2013	Argenta	Riverview	1	138			Remove sag limits	MI			Proposed				Y	C
C	East	METC	1801	3615	6/1/2014	Thetford 230/138 kV	Transformer	1	230			New Transformer	MI			Proposed				Y	C
C	East	METC	1801	3886	6/1/2014	Thetford	Hemphill	1	230			Rebuild to operate at 230 kV	MI	16		Proposed				Y	C
C	East	METC	1802	3616	6/1/2013	Keystone 345/138 kV	Transformer	1	345	138		Replace Transformer	MI			Proposed				Y	C
C	East	METC	1802	3617	6/1/2013	Keystone 345/138 kV	Transformer	2	345	138		Replace Transformer	MI			Proposed				Y	C
C	East	METC	1803	3618	6/1/2013	Clearwater	Stover	1	138			Reconductor (230 kV construction, operate at 138 kV)	MI			Proposed				Y	C
C	East	METC	1803	3619	6/1/2013	Stover	Livingston	1	138			Reconductor (230 kV construction, operate at 138 kV)	MI			Proposed				Y	C
C	East	METC	1804	3620	6/1/2014	Marquette	Substation Equipment		138			upgrade station equipment (CT's, relays, breakers)	MI			Proposed				Y	C
C	East	METC	1805	3622	6/1/2014	Livingston	Emmet	2	138			new line (existing ROW)	MI			Proposed				Y	C
C	East	METC	1805	3623	6/1/2014	Emmet	Oden	1	138			reconductor	MI			Proposed				Y	C
C	East	METC	1805	3621	6/1/2014	Livingston	Emmet	1	138			reconductor	MI			Proposed				Y	C
C	East	METC	1805	3624	6/1/2014	Emmet	Oden	2	138			new line (existing ROW)	MI			Proposed				Y	C
C	East	METC	1807	3627	6/1/2016	Begole	Richland	1	138			new line resulting from line re-configuration	MI			Proposed				Y	C
C	East	METC	1807	3628	6/1/2016	Gleaner	Tittabawassee	1	138			new line resulting from line re-configuration	MI			Proposed				Y	C
C	East	METC	1807	3629	6/1/2016	Richland 345/230 kV	Transformer	1	345	230		New Transformer	MI			Proposed				Y	C
C	East	METC	1807	3630	6/1/2016	Bullock 230/138 kV	Transformer	1	230	138		New Transformer	MI			Proposed				Y	C
C	East	METC	1807	3626	6/1/2016	Bullock	Richland	1	138			new line resulting from line re-configuration	MI			Proposed				Y	C
C	East	METC	1808	3631	6/1/2017	Cowan Lake Jct	Four Mile	1	138			reconductor	MI	15.5		Proposed				Y	C
C	East	METC	1809	3632	6/1/2011	Keystone	Hodenpyl		138			Rebuild the 27 mile 138 kV line to 954 ACSR (Pre-build to 230 kV)	MI	27		Planned	$29,990,000			Y	C
C	East	METC	1811	3635	6/1/2018	Gray Rd	Keystone	1	138			new line (existing WPC ROW)	MI		9	Proposed				Y	C

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C	East	METC	1812	3640	6/1/2018	Gary Road	Goss	1	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3636	6/1/2018	Gary Road 345 kV	New Switching Station		345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3637	6/1/2018	Gary Road	Nelson Road	1	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3639	6/1/2018	Gary Road	Richland	1	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3641	6/1/2018	Gary Road	Tittabawassee	1	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3642	6/1/2018	Gary Road	Thetford	1	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1812	3638	6/1/2018	Gary Road	Nelson Road	2	345			New switching station with Nelson Road-Richland, Nelson Road-Goss, and Tittabawassee-Thetford cut in	MI			Proposed				Y	C
C	East	METC	1816	3650	6/1/2013	Mecosta	Croton	1	138			Reconductor	MI	22		Proposed				Y	C
C	East	METC	1831	3687	6/1/2018	Livingston	Mio	1	230			New line (existing ROW)	MI		42	Proposed				Y	C
C	East	METC	1831	3686	6/1/2018	Mio	Transformer	1	230	138		New Transformer	MI			Proposed				Y	C
C	East	METC	1831	3684	6/1/2018	Livingston	Transformer	3	345	230		New Transformer	MI			Proposed				Y	C
C	East	METC	1831	3689	6/1/2018	Mio	Tittabawassee	1	230			New line (existing ROW)	MI		79	Proposed				Y	C
C	East	METC	1831	3685	6/1/2018	Tippy	Livingston	1	230			New line (existing ROW)	MI		79	Proposed				Y	C
C	East	METC	1831	3681	6/1/2018	Felch Road	Transformer	1	345	230		New Transformer	MI			Proposed				Y	C
C	East	METC	1831	3688	6/1/2018	Tittabawassee	Transformer	3	345	230		New Transformer	MI			Proposed				Y	C
C	East	METC	1831	3679	6/1/2018	Ludington	Felch Road	1	345			new line resulting from line re-configuration	MI			Proposed				Y	C
C	East	METC	1831	3680	6/1/2018	Kenowa	Felch Road	1	345			new line resulting from line re-configuration	MI			Proposed				Y	C
C	East	METC	1831	3683	6/1/2018	Tippy	Felch Road	1	230			New line (existing ROW)	MI		76	Proposed				Y	C
C	East	METC	1831	3682	6/1/2018	Tippy	Transformer	1	230	138		New Transformer	MI			Proposed				Y	C
C	East	METC	2490	4486	6/1/2013	North Belding			138			Terminal equipment upgrade	MI			Proposed	$275,000			Y	C
C	East	METC	2490	4487	6/1/2013	Vergennes			138			Terminal equipment upgrade	MI			Proposed	$275,000			Y	C
C	East	METC	2809	4453	6/1/2014	Hemphill			138			Relay replacement	MI			Proposed	$380,000			Y	C
C	East	METC	2809	336	6/1/2014	Garfiled	Hemphill	1	138			Reconductor	MI	9.1		Proposed	$11,360,000			Y	C
C	East	METC	2810	4941	6/1/2014	Delhi	Canal Jct	1	138			Rebuild 7.5 miles of 138kV line to 954 ACSR	MI	18.7		Proposed	$5,500,000			Y	C
C	East	METC	2811	4942	6/1/2015	Karn	East Tawas	1	138			Rebuild 68 miles of 138kV to 954 ACSR.	MI	80		Proposed	$50,200,000			Y	C
C	East	METC	2812	4508	6/1/2017	Whittemore	Loud Dam	1	138			Rebuild the Twining-Mio 138kV line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI	16		Proposed	$27,000,000			Y	C
C	East	METC	2812	4507	6/1/2017	Twining	Whittemore	1	138			Rebuild the Twining-Mio 138kV line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI	13		Proposed	$17,000,000			Y	C
C	East	METC	2812	4509	6/1/2017	Loud Dam	Alcona	1	138			Rebuild the Twining-Mio 138kV line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI	10		Proposed	$12,000,000			Y	C
C	West	MP	2548	4564	6/1/2019	Hilltop	Substation Equipment		230	115	366	Add second 183 MVA 230/115 kV Transformer	MN			Proposed				y	C
C	West	MP	2548	4565	6/1/2019	Hilltop	Arrowhead		230		470	Upgrade 115 kV line to 230 kV	MN	10		Proposed				y	C
C	West	MP	2549	4561	6/1/2014	15th AVE West	Fond du Lac H.E.	1	115		182	MP Line #15 Upgarde	MN	11.33		Proposed				y	C
C	West	MP	2761	4780	9/30/2010	Dunka Road	Substation Equipment		115	14	15	Substation Equipment & Transformer	MN			Planned	$2,005,000			Y	C
C	East	MPPA	2073	3946	7/1/2010	Grand Traverse 1	South Airport Junction		69		108/140 MVA	Reconductoring	MI	1.14		Planned	$340,000			NT	C
C	East	MPPA	2074	3947	7/1/2010	South Airport Junction	Barlow Junction		69		108/140 MVA	Reconductoring	MI	2.15		Planned	$640,000			NT	C
C	East	MPPA	2075	3948	7/1/2010	Barlow Junction	Cass Road Junction		69		108/140 MVA	Reconductoring	MI	1.34		Planned	$395,000			NT	C

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C	East	MPPA	2076	3949	7/1/2010	Cass Road Junction	Cass Road Sub		69		108/140 MVA	Reconductoring	MI	1.66		Planned	$490,000			NT	C
C	East	MPPA	2077	3950	7/1/2010	Cass Road Junction	Hall Street Sub		69		108/140 MVA	Reconductoring	MI	0.55		Planned	$170,000			NT	C
C	East	MPPA	2078	3951	7/1/2010	Gray Road Sub	Hall Street Sub		69		108/140 MVA	Reconductoring	MI	3.82		Planned	$1,130,000			NT	C
C	East	MPPA	2079	3952	7/1/2010	South Airport Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$70,000			NT	C
C	East	MPPA	2080	3953	7/1/2010	Barlow Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$200,000			NT	C
C	East	MPPA	2081	3954	7/1/2010	Cass Road Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$150,000			NT	C
C	East	NIPS	1979	2769	12/1/2010	Maple	Capacitor		69			Add two steps of 8.1 MVAR capacitors on the Maple Substation 69 kV bus.	IN			Proposed	$1,080,000			Y	C
C	East	NIPS	1980	2770	12/1/2011	Babcock	Capacitor		69			Add 2 to 3 - 9 .0 MVAR stages	IN			Proposed	$1,052,000			Y	C
C	East	NIPS	1981	2771	12/1/2011	Kreitzburg	Capacitor		69			Add 2 to 3 - 9 .0 MVAR stages	IN			Proposed	$1,052,000			Y	C
C	East	NIPS	1990	2780	12/1/2012	Dekalb	Angola	1	69		81	Circuit 6986 - Reconductor 2/0 CU to 336.4kcm ACSR	IN	16.5		Proposed	$2,680,000			Y	C
C	East	NIPS	1994	2784	5/1/2010	Midway	Bristol	1	69		81	Circuit 6977 - Reconductor 2/0 ACSR to 336.4kcm ACSR	IN	4.1		Proposed	$788,000			Y	C
C	East	NIPS	1998	2788	12/1/2011	East Winamac	Lawton	1	69			Rebuild old pole line. Ckts 6962 & 6937	IN	4.5		Proposed	$988,000			Y	C
C	East	NIPS	2000	2790	12/1/2009	Goshen Junction	Model Tap	1	69		81	Circuit 6977 - Reconductor 4/0 ACSR to 336.4kcm ACSR	IN	0.5		Planned	$52,000			Y	C
C	East	NIPS	2003	2793	12/1/2011	Bruce Lake	Sw. 854	1	69			Circuit 6937 - Rebuild old pole line.	IN			Proposed	$359,000			Y	C
C	East	NIPS	2312	4239	6/1/2009	Marktown	Breaker		138			Marktown Sub - Replace 138 kV BT Breaker	IN			Proposed	$113,636			Y	C
C	East	NIPS	2315	4242	12/1/2009	Dune Acres	Substation Equipment		138			Upgrade microwave communication equipment and install new fiber optic communication equipment, between Bailly Substation and the Dune Acres Substation yard.	IN			Proposed	$310,943			Y	C
C	East	NIPS	2319	4245	12/1/2010	South Chalmers	Switch #62		69			South Chalmers MO 62 load breaks and switch replacement.	IN			Proposed	$71,797			Y	C
C	East	NIPS	2320	4246	12/1/2009	Thayer	Starke	1	138			Circuit 13874 - Replace 30 wood poles with direct embedded steel poles, reinforce up to 70 additional poles, inspect and replace static wire as needed. First half of a two part project which will complete work begun in 2008.	IN			Proposed	$988,648			Y	C
C	East	NIPS	2792	4919	12/1/2011	Northwest	circuit reconfiguration		138			Northwest circuit reconfig	IN			Proposed	$2,236,000			Y	C
C	West	OTP	2746	4769	11/1/2015	Turtle Lake 41.6 kV	Mercer 41.6 kV		41.6		30 MVA	Rebuild Existing 18-Mile 41.6 kV Line	ND			Proposed	$500,000			NT	C
C	West	OTP	2747	4770	12/31/2010	Edgeley 41.6 kV	Gackle Jct. 41.6 kV		41.6		30 MVA	Rebuild Existing 18-Mile 41.6 kV Line	ND			Proposed	$600,000			NT	C
C	West	OTP	2748	4771	6/30/2011	Roslyn 41.6 kV	Eden 41.6 kV		41.6		30 MVA	Rebuild Existing 9-Mile 41.6 kV Line	SD			Proposed	$210,000			NT	C
C	West	OTP	2752	4775	6/1/2009	Bartlett 41.6/4.16 kV			41.6	4.16	5 MVA	Expand Existing 41.6/4.16 kV Substation at Bartlett to Handle a Load Increase	ND			Proposed	$130,000			NT	C
C	West	OTP	2823	4961	12/31/2010	Gwinner 115 kV	Gwinner 12.5 kV		115	12.5	2 x 8 MVAR	Install New Capacitor Bank on Gwinner 115 kV line for Voltage Support During Contingencies	ND			Proposed	$600,000			Y	C
C	West	OTP	2824	4962	12/31/2010	Hensel 115 kV	Hensel 69/41.6 kV		115	41.6	2 x 15 MVAR	Install New Capacitor Bank on Hensel 115 kV line for Voltage Support During Contingencies	ND			Proposed	$750,000			Y	C
C	West	OTP/MPC	2742	4765	10/31/2010	Bemidji 115 kV	Wilton 115 kV		115		157 MVA	Replace Terminal Equipment on This Existing Line to Increase Capacity	MN			Proposed	$150,000			Y	C
C	West	OTP/MPC	2744	4767	1/1/2013	Winger 230 kV	Thief River Falls 230 kV		230		390 MVA	Build New 55-Mile 230 kV Line to Support Projected Load Increases	MN			Proposed	$35,000,000			Y	C
C	West	OTP/MPC	2745	4768	11/1/2015	Plummer 115 kV			115		To Be Determi	Install New Capacitor Bank in Northwest MN for Voltage Support During Contingencies	MN			Proposed	$750,000			Y	C
C	West	OTP/MPC	2826	4964	12/31/2010	Clearbrook 115 kV	34 MVAR capacitor bank		115		34 MVAR	Install Capacitor Bank on 115 kV at Clearbrook, MN. One 34 MVAR.	ND			Proposed	$750,000			Y	C
C	West	OTP/MPC	2827	4965	12/31/2010	Karlstad 115 kV	14 MVAR capacitor bank		115		14 MVAR	Install Capacitor Bank on 115 kV at Karlstad. One 14 MVAR.	ND			Proposed	$500,000			Y	C

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C	West	OTP/MPC	2828	4966	12/31/2010	Thief River Falls 115 kV	15 MVAR capacitor bank		115		15 MVAR	Install Capacitor Bank on 115 kV at Thief River Falls. One 15 MVAR.	ND			Proposed	$750,000			Y	C
C	West	SMP	2166	4005	12/1/2010	Tap Existing Area Line	New Load Serving Sub at St Peter	1	69	69	69	Add 7.0 Miles 69kV line and construct new load serving substation at St Peter	MN		7	Proposed	$6,000,000			NT	C
C	West	SMP	2167	4006	12/1/2010	Tap Existing Area Line	New Load Serving Sub at Redwood Falls	1	69	69	69	Add 6.4 Miles 115kV line and construct load serving substation at Redwood Falls	MN		4	Proposed	$4,000,000			NT	C
C	Central	Vectren	2460	4424	6/1/2013	Leonard Rd 69kV Substation		1	69			Add new 69kV switching substation near Leonard Rd	IN			Planned	$2,000,000			NT	C
C	Central	Vectren	2462	4426	6/1/2013	Stringtown	Folz	50-3	69			Reconductor existing 69kV line for more capacity	IN			Proposed	$1,000,000			NT	C
C	Central	Vectren	2463	4427	6/1/2013	Givens	North West	31	69			Reconductor existing 69kV line for more capacity	IN			Proposed	$5,700,000			NT	C
C	Central	Vectren	2464	4428	6/1/2013	Mt Vernon	New Harmony	33	69			Reconductor existing 69kV line for more capacity	IN			Proposed	$9,375,000			NT	C
C	West	XEL	2177	4020	6/1/2016	West Waconia	transformer	1	345	115	448 MVA	345/115 kV transformer at West Waconia	MN			Proposed				Y	C
C	West	XEL	2177	4015	6/1/2016	Hazel	McLeod	1	345		2066 MVA	Upgrade Minn Valley - McLeod 230 kV line to double circuit 345 kV	MN			Proposed				Y	C
C	West	XEL	2177	4016	6/1/2016	Hazel	McLeod	2	345		2066 MVA	Upgrade Minn Valley - McLeod 230 kV line to double circuit 345 kV	MN			Proposed				Y	C
C	West	XEL	2177	4017	6/1/2016	McLeod	West Waconia	1	345		2066 MVA	Upgrade McLeod - Blue Lake 230 kV line to double circuit 345 kV with a step down to 115 kV at WestWaconia.	MN			Proposed				Y	C
C	West	XEL	2177	4018	6/1/2016	McLeod	Blue Lake	2	345		2066 MVA	Upgrade McLeod - Blue Lake 230 kV line to double circuit 345 kV with a step down to 115 kV at WestWaconia.	MN			Proposed				Y	C
C	West	XEL	2177	4019	6/1/2016	West Waconia	Blue Lake	1	345		2066 MVA	Upgrade McLeod - Blue Lake 230 kV line to double circuit 345 kV with a step down to 115 kV at WestWaconia.	MN			Proposed				Y	C
C	West	XEL	2767	4795	1/1/2012	Fenton	Transformer	1	115	69	47	new transformer	MN			Planned	$2,143,430			Y	C
C	West	XEL	2767	4794	1/1/2012	Fenton	in and out between Chandler tap and Lake Wilson	1	69			new line	MN		3	Planned	$1,566,570			Y	C
C	Central	AmerenIL	2232	4146	8/1/2018	Kewanee	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000			Y	C
C	Central	AmerenIL	2232	4102	8/1/2018	Kewanee	East Moline	1	345		1000	new line	IL		30.6	Conceptual	$34,000,000			Y	C
C	Central	AmerenIL	2233	4147	8/1/2018	Kewanee	Tazewell	1	345		1000	new line	IL		60	Conceptual	$85,000,000			Y	C
C	Central	AmerenIL	2234	4103	8/1/2018	Meredosa	Palmyra	1	345		1000	new line	MO\IL		52.9	Conceptual	$65,000,000			Y	C
C	Central	AmerenIL	2234	4148	8/1/2018	Meredosia	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000			Y	C
C	Central	AmerenIL	2235	4149	8/1/2018	Meredosia	Ipava	1	345		1000	new line	IL		38.1	Conceptual	$54,000,000			Y	C
C	Central	AmerenIL	2236	4150	8/1/2018	Meredosia	Pawnee	1	345		1000	new line	IL		54.5	Conceptual	$78,000,000			Y	C
C	Central	AmerenIL	2237	4104	8/1/2018	Mt. Zion	Pana	1	345		1000	new line	IL		29.1	Conceptual	$32,000,000			Y	C
C	Central	AmerenIL	2237	4151	8/1/2018	Mt. Zion	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000			Y	C
C	Central	AmerenIL	2238	4152	8/1/2018	Mt. Zion	Kansas	1	345		1000	new line	IL		51	Conceptual	$73,000,000			Y	C
C	Central	AmerenIL	2240	4154	8/1/2018	Kansas	Sugar Creek	1	345		1000	new line	IL		23.7	Conceptual	$34,000,000			Y	C
C	Central	AmerenIL	2241	4155	8/1/2018	Newton	Merom	1	345		1000	new line	IL		42	Conceptual	$60,000,000			Y	C
C	Central	AmerenIL	2242	4156	8/1/2018	Norris City	Albion	1	345		1000	new line	IL		25.8	Conceptual	$37,000,000			Y	C
C	Central	AmerenIL	2243	4157	8/1/2018	Baldwin	Joppa	1	345		872	new line	IL		86.8	Conceptual	$123,000,000			Y	C
C	Central	AmerenMO	2248	4160	8/1/2018	Ottumwa	Thomas Hill	1	345		740	new line	IA/MO		107	Conceptual	$154,432,990			Y	C
C	West	AMIL, ITCM	2773	4866	12/31/2020	Plano	Hazleton	1	765		3975/4570 MV	Build 215 miles of new 765kV from the Hazleton substation in IA to the Plano substation in IL.	IA		215	Conceptual	$774,000,000			Y	C
C	West	ATC LLC	2773	4850	12/31/2020	North Madison	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in WI. Substation will have a single 765/345kV TRF tying to the North Madison 345kV system and a single 765kV line terminal.	WI			Conceptual	$85,000,000			Y	C

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Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
C	West	ATC LLC, XEL	2773	4857	12/31/2020	North Madison	Adams	1	765		3975/4570 MV	Build 250 miles of new 765kV from the Adams substation in southeast MN to the North Madison substaton in WI.	MN/WI		250	Conceptual	$900,000,000			Y	C
C	West	DEM, AMIL, ITC	2773	4867	12/31/2020	Sullivan	Grimes	1	765		3975/4570 MV	Build 455 miles of new 765kV from the Grimes substation in IA to the Sullivan substation in IN.	IA/MO/IL/IN		455	Conceptual	$1,638,000,000			Y	C
C	West	GRE, OTP	2773	4865	12/31/2020	Antelope Valley	New North Dakota	1	765		3975/4570 MV	Build 135 miles of new 765kV from the Chisago substation in MN to the new North Dakota substation in ND.	SD/ND/IA		135	Conceptual	$486,000,000			Y	C
C	West	GRE, OTP, XEL	2773	4864	12/31/2020	Chisago	New North Dakota	1	765		3975/4570 MV	Build 355 miles of new 765kV from the Chisago substation in MN to the new Nroth Dakota substation in ND.	SD/ND/IA		355	Conceptual	$1,278,000,000			Y	C
C	West	GRE, XEL	2773	4855	12/31/2020	Helena	Adams	1	765		3975/4570 MV	Build 130 miles of new 765kV from the Helena Substation to the Adams substation in southeast MN.	MN		130	Conceptual	$468,000,000			Y	C
C	West	GRE, XEL	2773	4854	12/31/2020	Helena	Chisago	1	765		3975/4570 MV	Build 160 miles of new 765kV from the Helena Substation to the Adams substation in southeast MN.	MN		160	Conceptual	$576,000,000			Y	C
C	West	GRE, XEL	2773	4853	12/31/2020	Helena	Lakefield	1	765		3975/4570 MV	Build 115 miles of new 765kV from the Helena Substation to the Lakefield substation in southwest MN.	MN		115	Conceptual	$414,000,000			Y	C
C	West	GRE, XEL	2773	4844	12/31/2020	Helena	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in MN. Substation will have a single 765/345kV TRF tying to the Helena 345kV system and three 765kV line terminals.	MN			Conceptual	$120,000,000			Y	C
C	West	ITCM	2773	4847	12/31/2020	Iowa new substation	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in IA. Substation will have a single 765/345kV TRF and three 765kV line terminals.	IA			Conceptual	$120,000,000			Y	C
C	West	ITCM	2773	4860	12/31/2020	Lakefield	New IA Substation	1	765		3975/4570 MV	Build 100 miles of new 765kV from the Lakefield substation in southwest MN to a new IA substation in western IA.	MN/IA		100	Conceptual	$360,000,000			Y	C
C	West	ITCM	2773	4858	12/31/2020	Lakefield	Adams	1	765		3975/4570 MV	Build 140 miles of new 765kV from the Lakefield substation in southwest MN to the Adams substation in southeast MN.	MN		140	Conceptual	$504,000,000			Y	C
C	West	ITCM	2773	4849	12/31/2020	Hazleton	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in IA. Substation will have a single 765/345kV TRF tying to the Hazleton 345kV system and two 765kV line terminals.	IA			Conceptual	$110,000,000			Y	C
C	West	ITCM	2773	4845	12/31/2020	Lakefield	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new two TRF 765/345kV substation in southwest MN. Substation will have two 765/345kV TRFs tying to the Lakefield 345kV system and four 765kV line terminals.	MN			Conceptual	$220,000,000			Y	C
C	West	ITCM	2773	4862	12/31/2020	Fort Thompson	New IA Substation	1	765		3975/4570 MV	Build 305 miles of new 765kV from the new IA substation to the Fort Thompson substation in SD.	SD/IA		305	Conceptual	$1,098,000,000			Y	C
C	West	ITCM, MEC	2773	4861	12/31/2020	Grimes	New IA Substation	1	765		3975/4570 MV	Build 115 miles of new 765kV from the new IA substation to Grimes substation near Des Moines, IA.	IA		115	Conceptual	$414,000,000			Y	C
C	West	ITCM, XEL	2773	4859	12/31/2020	Lakefield	Fort Thompson	1	765		3975/4570 MV	Build 240 miles of new 765kV from the Lakefield substation in southwest MN to the Fort Thompson substation in SD.	MN/SD		240	Conceptual	$864,000,000			Y	C
C	West	ITCM, XEL	2773	4856	12/31/2020	Hazleton	Adams	1	765		3975/4570 MV	Build 85 miles of new 765kV from the Hazleton substation in IA to the Adams substation in southeast MN.	MN/IA		85	Conceptual	$306,000,000			Y	C

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C	West	MEC	2773	4848	12/31/2020	Grimes	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in IA. Substation will have a single 765/345kV TRF tying to the Grimes 345kV system and two 765kV line terminals.	IA			Conceptual	$110,000,000			Y	C
C	West	MISO	2179	4053	8/1/2018	Riel	Dorsey	1	500		2200	new line	Manitoba		25	Conceptual	$46,000,000			Y	C
C	West	MISO	2180	4055	8/1/2018	Maple River	Transformer	1	500	230	1200	new transformer	ND			Conceptual	$15,000,000			Y	C
C	West	MISO	2180	4031	8/1/2018	Riel	Maple River	1	500		2673	new line	Manitoba/ND		203	Conceptual	$344,000,000			Y	C
C	West	MISO	2180	4054	8/1/2018	Riel	Transformer	1	500	115	430	new transformer	Manitoba			Conceptual	$15,000,000			Y	C
C	West	MISO	2181	4056	8/1/2018	Blue Lake	Transformer	1	500	345	2000	new transformer	MN			Conceptual	$20,000,000			Y	C
C	West	MISO	2181	4032	8/1/2018	Maple River	Blue Lake	1	500		1540	new line	SD/MN		222	Conceptual	$381,000,000			Y	C
C	West	MISO	2182	4083	8/1/2018	Maple River	Watertown	1	345		600	new line	ND/SD		142	Conceptual	$202,000,000			Y	C
C	West	MISO	2183	4084	8/1/2018	Watertown	Split Rock	1	345		800	new line	SD		92.4	Conceptual	$131,000,000			Y	C
C	West	MISO	2184	4052	8/1/2018	Blue Earth	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000			Y	C
C	West	MISO	2184	4078	8/1/2018	Blue Earth	Split Rock	1	345		628	new line	SD/MN		130	Conceptual	$185,000,000			Y	C
C	West	MISO	2185	4034	8/1/2018	Adams	Hampton Corner	1	765		4776	new line	MN		77	Conceptual	$247,000,000			Y	C
C	West	MISO	2185	4058	8/1/2018	Adams	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$15,000,000			Y	C
C	West	MISO	2185	4059	8/1/2018	Hampton Corner	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000			Y	C
C	West	MISO	2186	4085	8/1/2018	Sherbourne County	Chisago County	1	345		1000	new line	MN		48.4	Conceptual	$69,000,000			Y	C
C	West	MISO	2187	4079	8/1/2018	SW Minneapolis	Sherbourne County	1	345		1000	new line	MN		47.9	Conceptual	$68,000,000			Y	C
C	West	MISO	2188	4035	8/1/2018	SW Minneapolis	Hampton Corner	1	765		4008	new line	MN		93	Conceptual	$260,000,000			Y	C
C	West	MISO	2189	4086	8/1/2018	Hampton Corner	Chisago County	1	345		972	new line	MN		72.2	Conceptual	$103,000,000			Y	C
C	West	MISO	2190	4077	8/1/2018	SW Minneapolis	Watertown	1	345		600	new line	SD/MN		148	Conceptual	$210,000,000			Y	C
C	West	MISO	2190	4051	8/1/2018	SW Minneapolis	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000			Y	C
C	West	MISO	2191	4036	8/1/2018	SW Minneapolis	Blue Earth	1	765		4776	new line	MN		73	Conceptual	$215,000,000			Y	C
C	West	MISO	2192	4057	8/1/2018	Lehigh	Transformer	1	765	345	2767.5	new transformer	IA			Conceptual	$15,000,000			Y	C
C	West	MISO	2192	4033	8/1/2018	Blue Earth	Lehigh	1	765		4368	new line	MN/IA		85	Conceptual	$258,000,000			Y	C
C	West	MISO	2193	4043	8/1/2018	Lehigh	Toledo	1	765		4008	new line	IA		97	Conceptual	$313,000,000			Y	C
C	Central	MISO	2194	4041	8/1/2018	Montgomery	Toledo	1	765		2640	new line	IA/MO		275	Conceptual	$871,000,000			Y	C
C	Central	MISO	2195	4042	8/1/2018	Montgomery	Coffeen	1	765		3576	new line	MO/IL		111	Conceptual	$343,000,000			Y	C
C	Central	MISO	2195	4071	8/1/2018	Coffeen	Transformer	1	765	345	2767.5	new transformer	IL			Conceptual	$15,000,000			Y	C
C	Central	MISO	2195	4063	8/1/2018	Montgomery	Transformer	1	765	345	2767.5	new transformer	MO			Conceptual	$15,000,000			Y	C
C	Central	MISO	2196	4062	8/1/2018	St. Francois	Transformer	1	765	345	2767.5	new transformer	MO			Conceptual	$15,000,000			Y	C
C	Central	MISO	2196	4040	8/1/2018	Montgomery	St Francois	1	765		3408	new line	MO		120	Conceptual	$372,000,000			Y	C
C	Central	MISO	2197	4061	8/1/2018	St. Francois	Rockport	1	765		2904	new line	MO/IL/IN		186	Conceptual	$599,000,000			Y	C
C	Central	MISO	2198	4066	8/1/2018	Pontiac	Transformer	1	765	345	2767.5	new transformer	IL			Conceptual	$15,000,000			Y	C
C	Central	MISO	2198	4038	8/1/2018	Rock Creek	Pontiac	1	765		3768	new line	IA/IL		108	Conceptual	$348,000,000			Y	C
C	West	MISO	2198	4065	8/1/2018	Rock Creek	Transformer	1	765	345	2767.5	new transformer	IA			Conceptual	$15,000,000			Y	C
C	Central	MISO	2199	4039	8/1/2018	Pontiac	Dequine	1	765		4368	new line	IL/IN		87	Conceptual	$265,000,000			Y	C
C	Central	MISO	2200	4050	8/1/2018	Dequine	South Chicago	1	765		5376	new line	IN		64	Conceptual	$161,000,000			Y	C
C	Central	MISO	2201	4072	8/1/2018	Dequine	Sullivan	1	765		4008	new line	IN		90.3	Conceptual	$294,000,000			Y	C
C	Central	MISO	2201	4073	8/1/2018	Dequine	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$15,000,000			Y	C
C	Central	MISO	2202	4074	8/1/2018	Dequine	Greentown	1	765		3576	new line	IN		117	Conceptual	$281,000,000			Y	C
C	East	MISO	2203	4069	8/1/2018	Blue Creek	Greentown	1	765		6000	new line	IN		59	Conceptual	$191,000,000			Y	C
C	East	MISO	2204	4067	8/1/2018	Cook	Evans	1	765		4008	new line	MI		99	Conceptual	$299,000,000			Y	C
C	East	MISO	2204	4070	8/1/2018	Evans	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$20,000,000			Y	C
C	East	MISO	2205	4045	8/1/2018	Evans	Spreague	1	765		4008	new line	MI		95	Conceptual	$304,000,000			Y	C
C	East	MISO	2206	4048	8/1/2018	Spreague	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$15,000,000			Y	C
C	East	MISO	2206	4046	8/1/2018	Spreague	Bridgewater	1	765		6000	new line	MI		42	Conceptual	$120,000,000			Y	C
C	East	MISO	2207	4047	8/1/2018	Bridgewater	Blue Creek	1	765		3288	new line	MI		134	Conceptual	$432,000,000			Y	C
C	East	MISO	2207	4049	8/1/2018	Bridgewater	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$15,000,000			Y	C
C	East	MISO	2208	4082	8/1/2018	Livingston	Dead River	1	345		488	new line	MI		232	Conceptual	$329,000,000			Y	C
C	East	MISO	2209	4068	8/1/2018	Bridgewater	South Canton	1	765		3024	new line	MI/OH		167	Conceptual	$538,000,000			Y	C
C	West	MISO	2210	4060	8/1/2018	Longwood	Chisago County	1	345		692	new line	MN/WI		116	Conceptual	$165,000,000			Y	C
C	West	MISO	2211	4037	8/1/2018	Longwood	Greenwood	1	345		1000	new line	WI		14	Conceptual	$200,000,000			Y	C
C	West	MISO	2212	4044	8/1/2018	Adams	Rock Creek	1	765		2808	new line	MN/IA		204	Conceptual	$627,000,000			Y	C
C	Central	MISO	2213	4087	8/1/2018	Buffington	Ghent	1	345		1000	new line	KY		33.2	Conceptual	$47,000,000			Y	C
C	West	MISO	2214	4080	8/1/2018	Glenham	Ellendale	1	345		872	new line	SD/ND		86	Conceptual	$37,000,000			Y	C

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C	West	MISO	2214	4081	8/1/2018	Glenham	Transformer	1	345	230	336	new transformer	SD			Conceptual	$10,000,000			Y	C
C	Central	MISO	2215	4064	8/1/2018	Coffeen	Sullivan	1	765		3768	new line	IL/IN		100	Conceptual	$322,000,000			Y	C
C	West	MISO	2217	4088	8/1/2018	West Waconia	Hazel	1	345		800	new line	MN		92.3	Conceptual	$112,000,000			Y	C
C	West	MISO	2217	4109	8/1/2018	West Waconia	Blue Lake	1	345		2066	new line	MN		20	Conceptual	$25,000,000			Y	C
C	West	MISO	2217	4110	8/1/2018	West Waconia	Blue Lake	2	345		2066	new line	MN		20	Conceptual	$25,000,000			Y	C
C	West	MISO	2219	4091	8/1/2018	Ellendale	Maple River	1	345		740	new line	ND		103	Conceptual	$229,000,000			Y	C
C	West	MISO	2219	4115	8/1/2018	Ellendale	Transformer	1	345	230	336	new transformer	ND			Conceptual	$10,000,000			Y	C
C	West	MISO	2220	4092	8/1/2018	Big Stone	Ellendale	1	345		692	new line	ND\SD		114	Conceptual	$255,000,000			Y	C
C	West	MISO	2220	4116	8/1/2018	Big Stone	Transformer	1	345	230	336	new transformer	SD			Conceptual	$10,000,000			Y	C
C	West	MISO	2221	4117	8/1/2018	Big Stone	Watertown	1	345		1000	new line	SD		60	Conceptual	$140,000,000			Y	C
C	West	MISO	2222	4121	8/1/2018	West Waconia	Transformer	2	345	230	448	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2222	4093	8/1/2018	West Waconia	McLeod	1	230		600	new line	MN		26	Conceptual	$78,000,000			Y	C
C	West	MISO	2222	4118	8/1/2018	Minnesota Valley	Panther	1	230		600	Rebuild Line	MN	30.4		Conceptual	$91,000,000			Y	C
C	West	MISO	2222	4119	8/1/2018	McLeod	Panther	1	230		600	Rebuild Line	MN	28.2		Conceptual	$85,000,000			Y	C
C	West	MISO	2222	4120	8/1/2018	West Waconia	Transformer	1	345	230	448	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2223	4127	8/1/2018	Adams	Transformer	2	345	161	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2223	4126	8/1/2018	Hayward	Transformer	1	345	161	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2223	4125	8/1/2018	Winnebago	Transformer	1	345	161	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2223	4124	8/1/2018	Hayward	Adams	2	345		1000	new line	MN		37	Conceptual	$40,000,000			Y	C
C	West	MISO	2223	4122	8/1/2018	Winnebago	Lakefield	2	345		1000	new line	MN		55	Conceptual	$59,000,000			Y	C
C	West	MISO	2223	4094	8/1/2018	Winnebago	Lakefield	1	345		1000	new line	MN		55	Conceptual	$59,000,000			Y	C
C	West	MISO	2223	4095	8/1/2018	Hayward	Winnebago	1	345		1000	new line	MN		50	Conceptual	$53,000,000			Y	C
C	West	MISO	2223	4096	8/1/2018	Hayward	Adams	1	345		1000	new line	MN		37	Conceptual	$40,000,000			Y	C
C	West	MISO	2223	4123	8/1/2018	Hayward	Winnebago	2	345		1000	new line	MN		50	Conceptual	$53,000,000			Y	C
C	West	MISO	2224	4098	8/1/2018	Morris	Johnson Junction	1	345		1000	new line	MN		16	Conceptual	$34,000,000			Y	C
C	West	MISO	2224	4128	8/1/2018	Morris	Alexandria	1	345		1000	new line	MN		44	Conceptual	$93,000,000			Y	C
C	West	MISO	2224	4129	8/1/2018	Morris	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2224	4130	8/1/2018	Johnson Junction	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2224	4097	8/1/2018	Johnson Junction	Big Stone	1	345		1000	new line	SD\MN		32	Conceptual	$68,000,000			Y	C
C	West	MISO	2225	4132	8/1/2018	Big Swan	Transformer	1	345	115	448	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2225	4133	8/1/2018	Crow River	Transformer	1	345	115	448	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2225	4131	8/1/2018	Willmar	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000			Y	C
C	West	MISO	2225	4099	8/1/2018	Willmar	Big Stone	1	345		972	new line	MN/SD		75	Conceptual	$159,000,000			Y	C
C	West	MISO	2225	4101	8/1/2018	Crow River	Big Swan	1	345		1000	new line	MN		25.3	Conceptual	$54,000,000			Y	C
C	West	MISO	2225	4100	8/1/2018	Big Swan	Willmar	1	345		1000	new line	MN		40	Conceptual	$85,000,000			Y	C
C	West	MISO	2226	4135	8/1/2018	Byron	Pleasant Valley	2	345		1000	new line	MN		16.3	Conceptual	$38,000,000			Y	C
C	West	MISO	2226	4136	8/1/2018	North Rochester	Byron	2	345		1000	new line	MN		10	Conceptual	$24,000,000			Y	C
C	West	MISO	2226	4134	8/1/2018	Adams	Pleasant Valley	2	345		1000	new line	MN		16.8	Conceptual	$39,000,000			Y	C
C	West	MISO	2227	4139	8/1/2018	Crow River	West Waconia	1	345		1000	new line	MN		23.9	Conceptual	$34,000,000			Y	C
C	West	MISO	2227	4140	8/1/2018	West Waconia	Helena	1	345		1000	new line	MN		26	Conceptual	$37,000,000			Y	C
C	West	MISO	2227	4138	8/1/2018	Dickinson	Crow River	1	345		1000	new line	MN		3.8	Conceptual	$6,000,000			Y	C
C	West	MISO	2227	4137	8/1/2018	Monticello	Dickinson	1	345		1000	new line	MN		17.4	Conceptual	$25,000,000			Y	C
C	West	MISO	2230	4144	8/1/2018	Spring Green	Transformer	1	345	138	336	new transformer	WI			Conceptual	$10,000,000			Y	C
C	West	MISO	2230	4105	8/1/2018	Spring Green	Salem	1	345		1412	new line	WI		54	Conceptual	$69,000,000			Y	C
C	West	MISO	2230	4143	8/1/2018	Spring Green	West Middleton	1	345		1412	new line	WI		18	Conceptual	$23,000,000			Y	C
C	West	MISO	2231	4107	8/1/2018	Hilltop	Transformer	1	345	138	500	new transformer	WI			Conceptual	$10,000,000			Y	C
C	West	MISO	2231	4106	8/1/2018	Hilltop	Columbia	1	345		1195	new line	WI		50	Conceptual	$68,000,000			Y	C
C	West	MISO	2231	4145	8/1/2018	Hilltop	LaCrosse	1	345		1195	new line	WI		80	Conceptual	$108,000,000			Y	C
C	East	MISO	2244	4158	8/1/2018	Stillwell	Burr Oak	1	345		1000	new line	IN		19.3	Conceptual	$28,000,000			Y	C
C	East	MISO	2245	4159	8/1/2018	Avon Lake	Fox	1	345		1000	new line	OH		16.4	Conceptual	$24,000,000			Y	C
C	Central	MISO	2246	4075	8/1/2018	Petersburg	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$20,000,000			Y	C
C	Central	MISO	2247	4076	8/1/2018	Gwynn	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$20,000,000			Y	C
C	East	NIPS	1983	2773	12/1/2013	Dekalb	Transformer	1	138	69	112	Upgrade 138-69 Transformer	IN			Conceptual	$1,700,000			Y	C
C	East	NIPS	1993	2783	12/1/2012	South Valparaiso	138/69 kV Substation	1	138	69	168	New 138/69 kV Substation	IN			Conceptual	$4,917,000			Y	C
C	East	NIPS	2321	4247	9/1/2011	Miller	Capacitor		138			Add one step of 100 MVAR capacitors on the Miller Substation 138 kV bus. Engineering only in 2010.	IN			Conceptual	$974,838			Y	C

Appendix C: Facility Table 10/16/2009

Target Appendix	Region	Geographic Location by TO	PrjID	Facility ID	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Summer Rate	Upgrade Description	State	Miles Upg.	Miles New	Plan Status	Estimated Cost	Cost Shared	Postage Stamp	MISO Facility	App ABC
C	East	NIPS	2323	4249	12/1/2016	Hiple	Northport	1	138		316	Add new 138 kV terminals at Hiple and Northport Substations, and construct a new 10 mile 954 KCM ACSR 138 kV line between these two substations. Engineering only on 2008.	IN		10	Conceptual	$5,770,000			Y	C
C	East	NIPS	2324	4252	5/1/2016	East Plymouth - (2) 138kV Line Extensions	Plymouth and Leesburg-Kosciusko	1	138			Split existing Plymouth-Leesburg-Kosciusko 138kV circuit and tie into new East Plymouth substation	IN			Conceptual	$3,519,080			Y	C
C	East	NIPS	2324	4251	5/1/2016	East Plymouth - (2) 345kV Line Extensions	Burr Oak and Leesburg	1	345			Split existing Burr Oak to Leesburg 345kV circuit and tie into new East Plymouth substation	IN			Conceptual	$2,638,409			Y	C
C	East	NIPS	2324	4250	5/1/2016	East Plymouth 345/138 kV			345	138		Add East Plymouth 345/138 kV, 1-560 MVA Transformer Sub - New	IN			Conceptual	$12,726,528			Y	C
C	West	Non-MISO	2773	4851	12/31/2020	Plano	Line tap and terminal equipment	1	765	345	2640/3040 MV	Construct a new 765kV tap & associated 765kV terminal equipment into the Plano substation in IL	IL			Conceptual	$5,000,000			Y	C
C	West	Non-MISO	2773	4842	12/31/2020	Fort Thompson	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new two TRF 765/345kV substation in SD. Substation will have two 765/345kV TRFs tying to the Fort Thompson 345kV system and three 765kV line terminals.	SD			Conceptual	$205,000,000			Y	C
C	West	Non-MISO	2773	4863	12/31/2020	Fort Thompson	New North Dakota	1	765		3975/4570 MV	Build 245 miles of new 765kV from the new North Dakota substation in ND to the Fort Thompson substation in SD.	SD/ND		245	Conceptual	$882,000,000			Y	C
C	West	Non-MISO	2773	4840	12/31/2020	Antelope Valley	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in ND. Substation will have a single 765/345kV TRF tying to the Antelope Valley 345kV system and a single 765kV line terminal.	ND			Conceptual	$85,000,000			Y	C
C	West	Non-MISO	2773	4852	12/31/2020	Sullivan	Line tap and terminal equipment	1	765	345	2640/3040 MV	Construct a new 765kV tap & associated 765kV terminal equipment into the AEP Sullivan substation in IN.	IN			Conceptual	$5,000,000			Y	C
C	West	OTP	2773	4841	12/31/2020	North Dakota new substation	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in ND. Substation will have a single 765/345kV TRF and three 765kV line terminals.	ND			Conceptual	$120,000,000			Y	C
C	West	XEL	2773	4846	12/31/2020	Adams	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in MN. Substation will have a single 765/345kV TRF tying to the Adams 345kV system and a four 765kV line terminals.	MN			Conceptual	$135,000,000			Y	C
C	West	XEL	2773	4843	12/31/2020	Chisago	New 765/345 kV substation	1	765	345	2640/3040 MV	Construct a new 765/345kV substation in MN. Substation will have a single 765/345kV TRF tying to the Chisago Co. 345kV system and two 765kV line terminals.	MN			Conceptual	$110,000,000			Y	C