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Midwest ISO
Energizing the Heartland

MTEP08

The Midwest ISO Transmission Expansion Plan

Growing the Grid Across the Heartland

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Section 1: Executive Summary

1.1 Introduction and Highlights

This Midwest ISO Transmission Expansion Plan 2008 (MTEP08) presents the Midwest ISO recommended regional transmission expansion plan, which includes identification of projects required to maintain reliability for the ten year period through the year 2018, as well as a preliminary evaluation of projects which may be required for economic benefit up to twenty years in the future. The 2008 plan adds to Appendix A 332 newly recommended expansion projects totaling $2.4 billion. Four projects account for $1.75 billion of the incremental $2.4 billion in new projects recommended in this year's plan. This brings Appendix A to 475 projects totaling $4.2 billion. Appendix A projects are those projects which are recommended for approval by the Midwest ISO Board of Directors and for implementation under the terms of the Midwest ISO Transmission Owners Agreement and Tariff.

Since its inception in 2003, the MTEP08 brings the total cost of projects recommended for implementation to $6.2 billion of which $2.2 billion is associated with projects already in operation. Other projects still in development are listed in Appendices B and C.

Once implemented, the $4.2 billion in Appendix A projects together with the $1.6 billion of proposed projects in Appendix B (provided that they continue to be demonstrated to be prudent) will provide for:

- Reliable and efficient transmission service for existing and new load growth through the ten year planning horizon
- More than $1 billion in annual benefits, including an estimated $ 0.95 billion annual adjusted production cost savings and $60 to 111 million in deferral of new unit construction due to reduction in capacity losses[1]
- 1951 MW of new generator interconnections since MTEP07, including 1048 MW of wind and 880 MW of gas fired

Although the majority of projects in Appendix A and B are targeted primarily at addressing reliability needs on the system, the $1 billion in annual benefits reflects the ability of reliability based projects to provide collateral economic benefits. That benefit is also a reflection of the direct efforts of the Midwest ISO Transmission Owners, Midwest ISO planning staff and other Midwest ISO stakeholders to specifically identify projects which address market efficiency and reliability, such as through identification of projects which eliminate Narrowly Constrained Areas. Other targeted studies underway seek to address transmission to meet renewable standards or to evaluate higher voltage transmission projects that are premised on a broad range of benefits.

[1] All benefit values calculated for the year 2013

In 2008, 31 projects totaling $1.36 billion are eligible for sharing, with $257 million of those costs being shared within the Midwest ISO but outside of the project sponsoring zone, including $15 million paid by generation developers for generator interconnection projects. Through 2007, approximately $1 billion of total projects were eligible for sharing, with $183 million shared outside the zone in which the project originated (including $63 million paid by generation developers). Cost sharing continues to be a contentious issue, particularly as the level of shared costs increases. Concerns about cost sharing are exacerbated due to expected future radical changes in energy policies, such as the desire to reduce carbon emissions. While the exact outcome of these policy shifts is uncertain, all appear to drive the need for significant increases in both generation and transmission infrastructure investment which in turn is expected to increase cost sharing levels and will likely expose some unintended consequences of the current cost sharing methodology.

New to the planning process in the MTEP 2008 report is an attempt to model this uncertainty around energy policy through future scenarios which provide reasonable bounds around expected policy outcomes, such as renewable portfolio standards or a carbon tax, while also incorporating base requirements such as load growth. Although transmission projects and generation requirements to support these futures are at a preliminary point in the analysis stage, initial estimates show potential rate increases of 27 to 43 percent, with 6 to 7 percent attributable to estimated transmission rate increases.

The uncertainty around policy causes a reluctance to invest overall. Long-term resource assessments indicate that the Midwest ISO footprint would fall below the target 14.5% reserve margin in 2014. However, any number of factors, from continued delay in increasing capacity to acceleration of retirements in an aging generating fleet could bring that date even closer. Even a prediction of a capacity shortfall in 2014 requires attention and action now to avoid that outcome.

Despite these concerns, the Midwest ISO and its stakeholders are committed to working together to meet future needs in the coming years through planning activities such as:

- Development of additional future scenarios to reflect changing expectations and inform policy makers in the choices they face
- Additional value-based planning, focused on addressing long-term needs from a strategic perspective by providing an integrated energy and reliability view
- Executing targeted studies focused on specific outcomes, such as the Regional Generation Outlet Study underway to address Renewable Portfolio Standards in the western portion of the Midwest ISO
- Evaluation of additional or modified cost allocation methods that better reflect changes in energy policy and its impact on Midwest ISO customers
- Ensuring compliance with the recently revised Module E compliance requirements.

1.2 Cost Sharing

MTEP08 includes 31 projects totaling $1.36 billion that are eligible for regional cost sharing under the reliability cost sharing (Regional Expansion Criteria and Benefits (RECB) I) provisions of the tariff. After applying the tariff based cost sharing provisions to these projects, 12 of the 31 projects result in actual costs being allocated outside of the constructing zone. This is because for projects of voltages below 345kV, cost sharing is based exclusively on the Line Outage Distribution Factor (LODF) calculation, with no postage-stamp component. The costs allocated away from the constructing zones for these 12 projects amounts to about $257 million of the $1.36 billion in eligible costs. Three large 345kV projects (described below) account for $235 million of the $257 million allocated. About $182 million of the $257 million in allocated costs is due to postage stamp treatment on 345kV class projects, and the remaining $75 million is due to LODF treatment. In summary then, about 9% of the $3 billion in estimated total new Appendix A project investment will be allocated to zones other than the constructing zones. Table 1.2-1 summarized the projects in MTEP08 that are eligible for cost sharing, and their total estimated investment. Additional detailed tabulations of cumulative cost sharing impacts on each pricing zone are contained in Appendices A-1 and A-2.

Table 1.2-1: Cost Shared Project Investment by Transmission Owner for MTEP08

Region	Transmission Owner	Baseline Reliability Projects	Generator Interconnection Projects	Total
Central	AmerenIL	$32,639,400	$4,271,957	$36,911,357
	AmerenMO	$19,000,000		$19,000,000
	Vectren (SIGE)	$7,680,032		$7,680,032
Central Total		$59,319,432	$4,271,957	$63,591,389
East	FE	$15,759,634		$15,759,634
	ITC		$10,181,368	$10,181,368
	METC	$126,400,000		$126,400,000
	NIPS	$5,050,000		$5,050,000
	WPSC		$1,983,200	$1,983,200
East Total		$147,209,634	$12,164,568	$159,374,202
West	ATC LLC	$230,056,311		$230,056,311
	GRE		$4,482,923	$4482,923
	GRE, XEL, OTP, MP, MRES	$490,000,000		$490,000,000
	ITCM	$16,450,000	$8,993,716	$25,443,716
	XEL	$24,064,000	$293,200	$24,357,200
	XEL, DPC, RPU, SMP, WPPI	$360,000,000		$360,000,000
West Total		$1,120,570,311	$13,769,839	$1,134,340,150
Grand Total		**$1,327,099,377**	**$30,206,364**	**$1,357,305,741**

1.3 Major New Projects

Three of the 332 Appendix A projects account for about $1.08 billion of the total $2.4 billion of estimated total recommended new investment in MTEP08. An additional major project that remains in Appendix B pending final design determination is expected to go forward and when recommended will add an additional currently estimated $665 million. These four projects are 345kV transmission lines totaling about 607 miles of new transmission and associated transformation to support the underlying systems. Three of these projects are in Minnesota and are known as the Capacity Expansion (CapX) 2020 Group I Projects, and the fourth is in Wisconsin and supports the load growth and reliability in the Dane County area. These four projects are summarized below and the three Appendix A projects in detail in Appendix D1 for West planning region.

CapX Projects

Fargo to Twin Cities 345kV Line

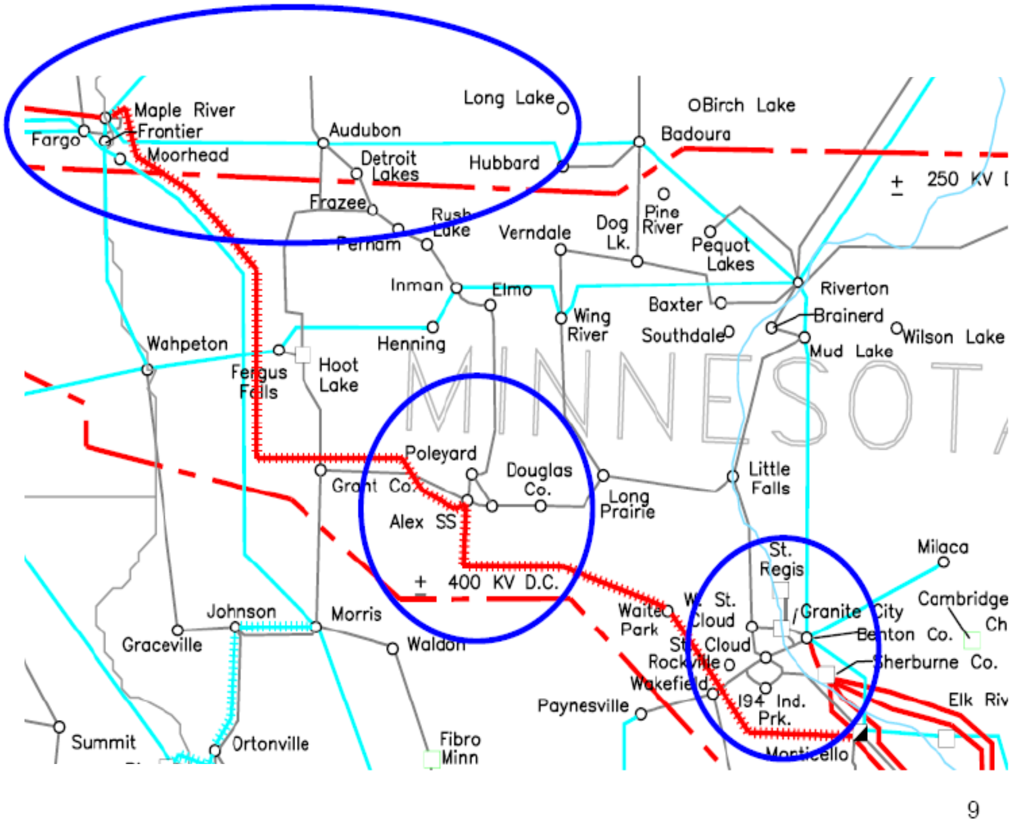


Figure 1.3-1: Fargo to Twin Cities 345kV Line

This 225 mile transmission line connects the Fargo, ND area to the Monticello substation in the Twin Cities area and has a currently estimated cost of about $490 million, which is eligible for cost sharing as a Baseline Reliability Project. The line will provide a connection between the existing 345kV systems in the Minneapolis area to the 345kV line from the west that now terminates at Maple River near Fargo. The project also includes transformation at points along the route to strengthen the underlying systems for local reliability. The project is an efficient means of resolving multiple reliability issues occurring in three separate areas along the route when testing the system against the North American Electric Reliability Corp. (NERC) reliability standards. More specifically, the project addresses reliability issues, including voltage instability potential under certain conditions, in the Red River Valley at the north end, in the Alexandria area near mid-line, and in the St. Cloud area near the southern terminal of the line. In addition to its near term reliability benefits, the project, combined with two other related projects described below that make up the CapX Group I projects, will also provide for flexibility to access supplies over the long term to serve the Western Region of the Midwest ISO market, as well as to deliver wind resources from the area to the Twin Cities and to other parts of the market.

Twin Cities to La Crosse 345kV line

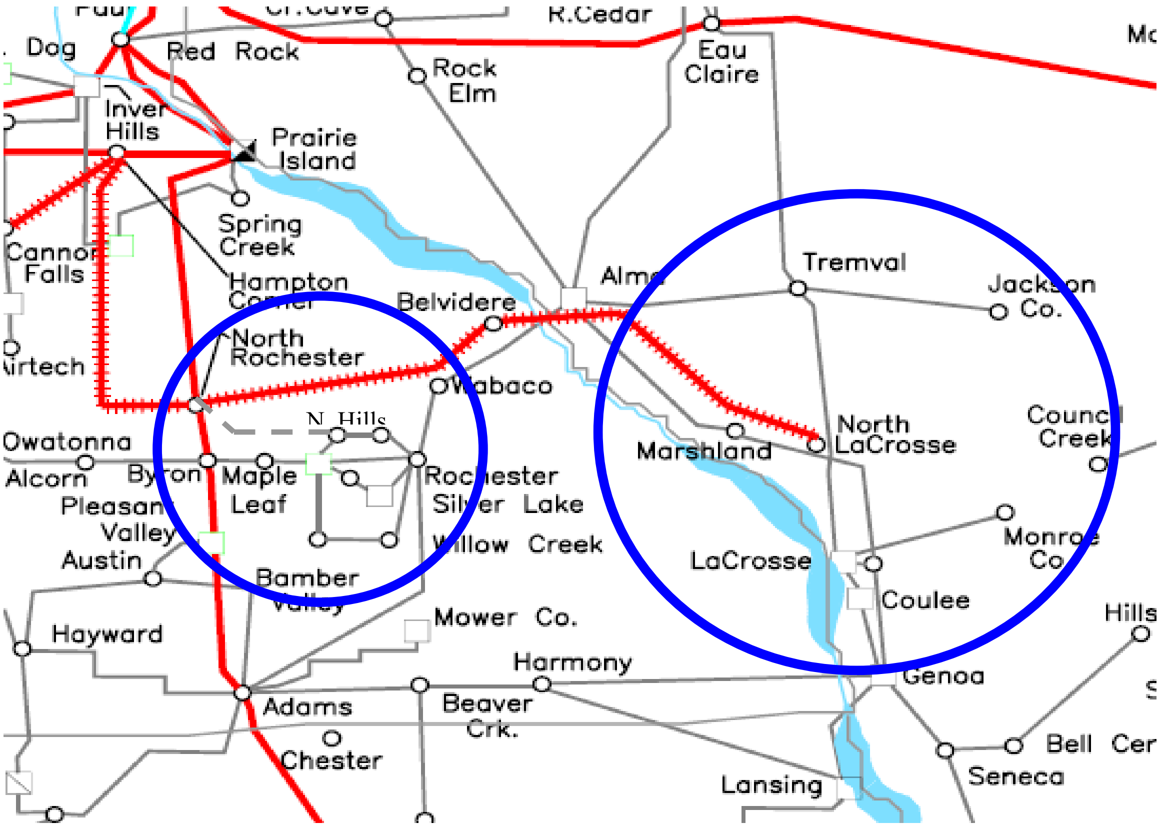


Figure 1.3-2: Twin Cities to La Crosse 345kV Line

This project has an estimated cost of $360 million, which is eligible for cost sharing as a Baseline Reliability Project, and extends 345kV transmission system support to growing load areas of Rochester Minnesota and La Crosse Wisconsin. Each of these areas has been experiencing load growth that will outstrip the ability of the existing lower voltage systems to reliably supply the loads. The proposed project resolves these reliability issues by providing additional transformation in the Rochester area and by introducing 345kV supply into the La Crosse area, reliving heavily loaded 161kV class lines in each area. Similar to the issues driving the Fargo line described above, this line is needed to resolve a lengthy list of NERC contingency based violations that, without this project will result in severe overloads in some cases within the five year planning horizon.

Brookings County SD to Twin Cities 345kV line

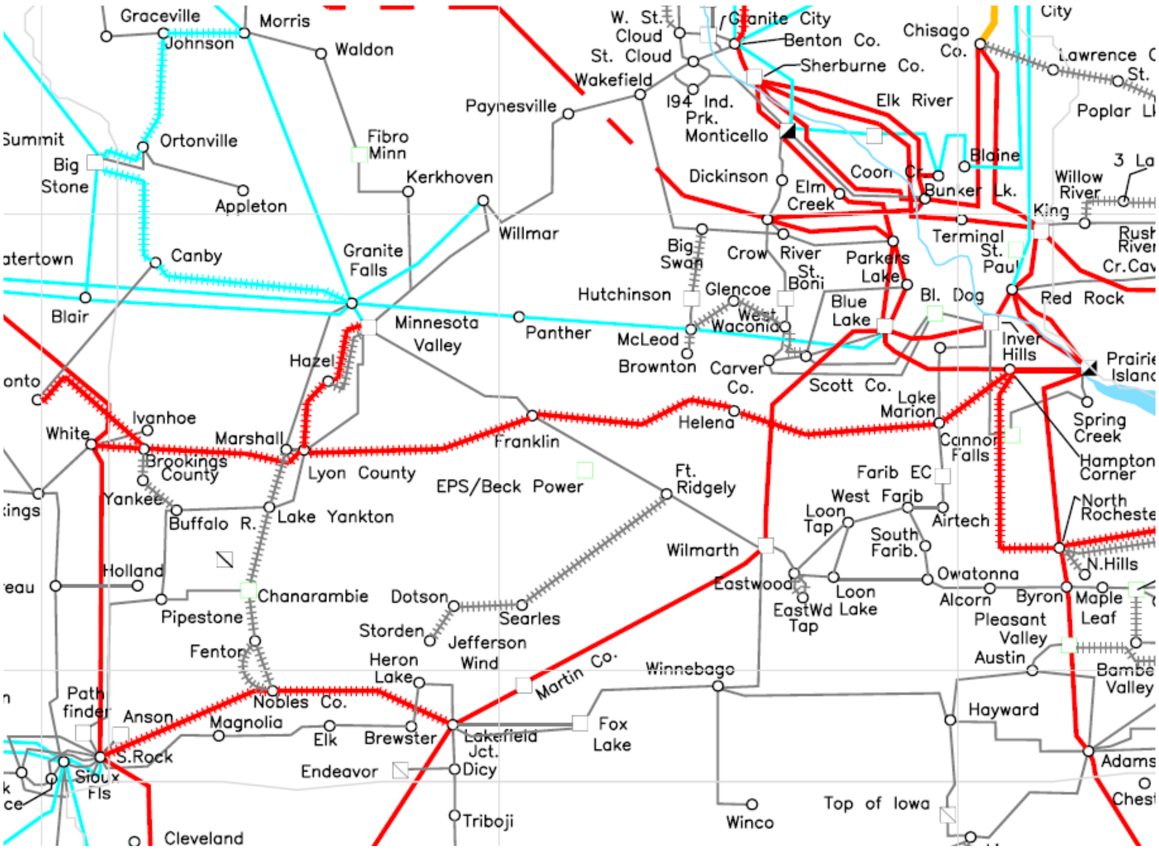


Figure 1.3-3: Brookings County SD to Twin Cities 345kV line

The Brookings, SD to Twin Cities line shown in Figure 1.3-3, with an estimated cost of $665 million, is designed to provide outlet for some of the large volume of wind generation seeking interconnection in the vicinity of the line. Integration of this generation will provide for reliable delivery of generation to meet forecast load growth and will support Minnesota state Renewable Energy Standards (RES) requiring 25% of the energy in the state to be generated by renewable resources by 2025. Nearly 7500 MW of new wind generation requests are in vicinity of this line and could benefit from this line addition. The project is estimated to enable about 13% of state mandated RES. As this project is required primarily for the delivery of new wind energy resources, it is not a Baseline Reliability Project. This project is currently in Appendix B pending final design determination to ensure the line is designed to appropriate capacity. The configuration will be finalized based on studies currently underway by the CapX utilities and by Midwest ISO in its Regional Generation Outlet Study (RGOS).

Madison, Wisconsin Area Project

Rockdale to W. Middleton 345kV line

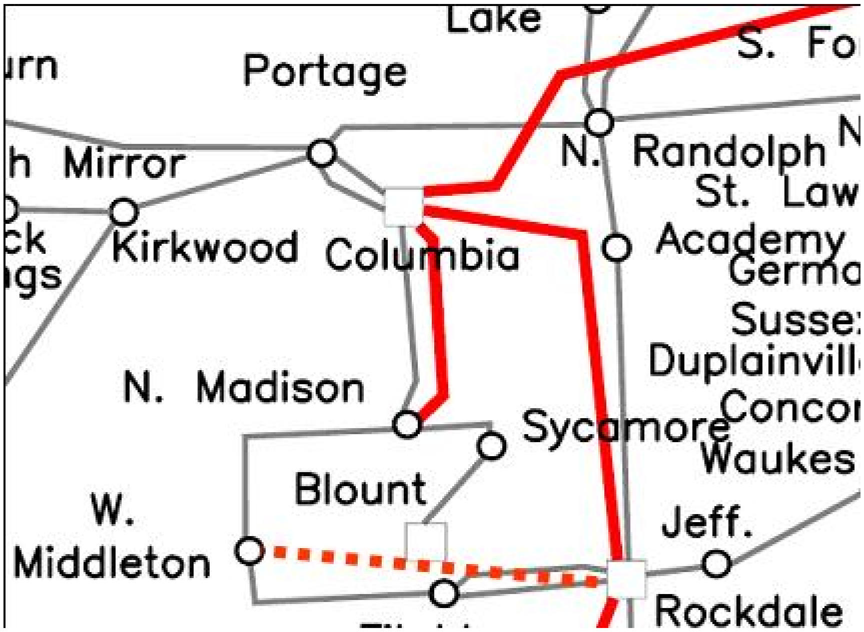


Figure 1.3-4: Rockdale to W. Middleton 345kV line

The $230 million Rockdale Middleton project, which is eligible for cost sharing as a Baseline Reliability Project, installs 47.9 miles of new 345kV line, a new West Middleton 345/138kV 500 MVA transformer, and modifications at Rockdale and West Middleton 345kV subs to accommodate these additions. The project is needed to resolve thermal overload under first contingency conditions and potential voltage collapse under multiple element outages by 2013 in the Dane County area of Wisconsin. For load growth beyond 2013, increasing numbers of thermal and low voltage violations would occur under single contingencies and more multiple facility outage combinations would result in potential voltage collapse. Voltage collapse can cause uncontrolled widespread loss of load on the system.

More details on the needs for all of the projects recommended for approval in this MTEP08 are contained in Appendix D1 West.

1.4 Key Findings

1.4.1 Reliability Needs – Transmission Capacity

Global reliability testing against the NERC Standards for the 5 and 10 year planning horizons was performed as a part of MTEP07. Additional reliability studies were performed on a project by project basis in MTEP08 in determining those Appendix B projects from MTEP07 (or newly identified) that need to move forward to mitigate reliability risks. This combined reliability analyses performed in MTEP07 and MTEP08 included simulation of over 79,000 multiple facility outage events, and 11,000 single facility outage events over all areas of the system. The projects recommended in Appendix A, together with those proposed in Appendix B will provide for full compliance with the NERC Transmission Planning Standards (TPL- 001, -002, -003, -004)

1.4.2 Reliability Needs – Generation Reserves

Resource Assessment in terms of Loss of Load Expectation (LOLE) was performed for the 2008 through 2017 period in MTEP08. This assessment indicates that the Midwest ISO has a LOLE of greater than 1 day in 10 years beginning in 2014 under base-case assumptions. Based on historical queue statistics, the base case assumes that 80% of queued generation with executed Interconnection Agreements will come to fruition, and that 20% of all other queued generation will come on-line. Additional details on the generation resource assessment can be found in Section 3.3.

Sensitivity analysis around some of the key drivers of reserve margin was performed and indicates the downside risk around that estimate, as shown in Table 1.4-1.

Table 1.4-1

Case	Year LOLE Exceeds 0.1
Base Case	2014
2 Year All Queue Project Delay	2014
Increase in Retirements	2013
Increase in Forced Outage Rate	2011
Wind Capacity Credit reduced to 0%	2014
No External Support (i.e. Firm Imports)	2009
Reduction in Demand Side Management	2012

In each of the tabulated cases, base and sensitivities, LOLE exceeded the one day in ten years benchmark by 2014 or earlier. Each of the cases from Table 1.4.1 can be brought to a level below one day in ten years LOLE not only in 2014 but through 2017, if the confidence factor (amount of queued generation that can be expected to come to fruition) could be increased from the current 20% to a range of 34% for base case assumptions. Depending on other variables such as higher than typical load growth, unit retirements, forced outage rates, external support and others, even higher confidence factors, near 60% for some cases, would be needed to ensure reliability meets expectation guidelines.

Historically, 20% of the queued capacity within the Midwest ISO (signed Interconnection Agreement (IA) plus non-signed IA) has gone into service. All of the sensitivities addressed require capacity to be added at percentages well above what has historically been experienced. As more capacity is proposed for areas that have over constrained transmission, confidence factors can be expected to shrink or remain relatively the same. The initiation of demand side management and conservation programs can lessen out-year LOLE; however, transmission upgrades are required to interconnect the queued capacity that will be necessary in the next ten years. Given the amount of time required to build both new units and transmission lines, action is needed soon in order to ensure resource adequacy for the next ten years.

1.4.3 Market Efficiency and Economic Transmission Planning Congestion

Congestion charges in the Midwest ISO are relatively low. There are however opportunities to relieve congested flowgates on the system. Section 3.4 of this report provides an analysis of flowgate congestion and trends since start of market operations. We have found that of the 45 most congested flowgates in terms of binding hours, 29 are within the Midwest ISO footprint. When we compare the planned reliability projects to these flowgates, we can see that reliability drivers will resolve 20 of these flowgates. This leaves opportunities to resolve nine of the most congested flowgates, listed in Table 1.4-2, with transmission expansions, if merited, based on economic criteria.

Table 1.4-2

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	3nd Year Market Congestion FG-Hr/YR Apr 07 to Apr 08	BA	MTEP Map Grid
5, 3270	State Line-Wolf Lake 138kV (flo) Burnham-Sheffield 345kV	21	151	481	847	NIPS	L8
13, 2463	Kokomo HP 230/138kV XFMR (flo) Jefferson-Greentown 765kV	0	132	750	0	CIN	K9
21, 3102	Bland-Franks 345kV	51	347	206	0	AMRN	I11
30, 2980	Dune Acres -Michigan City 138kV ckts 1&2 (flo) Wilton Center-Dumont 765kV	261	241	107	59	NIPS	L8
32, 3532	Ellington_Hintz_138_flo _NAppleton_WernerWest_345	0	0	86	286	WEC	
33, 3108	Overton-Sibley 345kV	0	160	189	20	AMRN	H10
36, 111	Sammis-Wylie Ridge 345kV line l/o Perry-Ashtabula-Erie West	2	58	92	172	PJM	P9
42, 3167	St. Francois-Lutesville 345kV	6	39	18	217	AMRN	K11
45, 3168	St. Francis-Lutesville 345kV (flo) Bland-Franks 345kV	37	151	113	0	AMRN	K11

Seeking resolution to these constrained flowgates would be consistent with the Midwest ISO regional transmission expansion planning process that has as its goal the development of a comprehensive expansion plan that meets both reliability and economic expansion needs, as well as energy policy objectives. Past planning processes have tended to focus on safeguarding reliability with accommodation for the principal of supporting regulatory mandates through the Energy Markets Tariff (EMT). In large part, this focus has been a result of appropriately high threshold questions of need within state regulatory processes and the implicit assumption that minimizing the cost of new transmission infrastructure has the effect of maximizing value to the consumer. With the advent of the Midwest ISO energy market in 2005, infrastructure planning began a shift toward a more comprehensive planning approach which ensures that, in addition to safeguarding reliability, sufficient transmission capacity is constructed so that a competitive wholesale energy market can flourish, and so that energy policy objectives are not impeded for lack of transmission capacity.

A key component of this more comprehensive planning process has been the development of criteria and equitable cost sharing arrangements that would apply to expansions needed not strictly for reliability benefit, but that are focused on improving market efficiency. This is the context in which the economic planning criteria and cost allocation provisions of the tariff known as RECB II were developed. Focused on market efficiency, the RECB II metrics keyed on improvements in generator production costs and load Locational Marginal Pricing (LMPs) that may be gained from a transmission expansion. Uncertainty about the experience with this kind of planning caused many stakeholders to support filing provisions only if sufficient benefit to cost ratios were achieved as a hurdle to administrative development by the Regional Transmission Organization (RTO) of projects to improve market efficiency. As a consequence, a Benefit/Cost (B/C) ratio of 2.0 is needed for projects to be completed in five years and 3.0 for those with 10 year out in service dates. Finding market efficiency projects that meet these high B/C ratios has proven challenging, though at this juncture, specific projects to address the constraints tabulated above have not been developed and tested due to other planning priorities. This work remains as an objective for MTEP09.

The fact that most of the heaviest constrained flowgates are eventually being addressed by reliability based upgrades points to the linked nature of reliability and congestion or economic issues: it’s often a matter of timing. For example, a transmission solution which is driven solely by perceived economic benefits in the short term, may be required to address reliability concerns over time.

Narrow Constrained Areas (NCAs)

A Technical Review Group (TRG) of stakeholders was formed in 2008 to evaluate the potential for mitigating three areas of the market that have been designated Narrow Contstrained Areas (NCAs) by the Independent Market Monitor (IMM). An NCA is defined as "An electrical area that has been identified by the IMM that is defined by one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours during a given year and within which one or more suppliers are pivotal." Historical Congestion has been tracked in all MTEP reports, as in Section 3.4 of this report. Concurrently the IMM has listed sets of Flowgates to define NCAs. There are currently three NCAs defined by the IMM in Midwest ISO footprint:

- Wisconsin Upper Michigan System (WUMS),
- Northern WUMS,
- SE_MN/N_IA/SW_WI which includes portions of southeast Minnesota, northern Iowa, and southwestern Wisconsin.

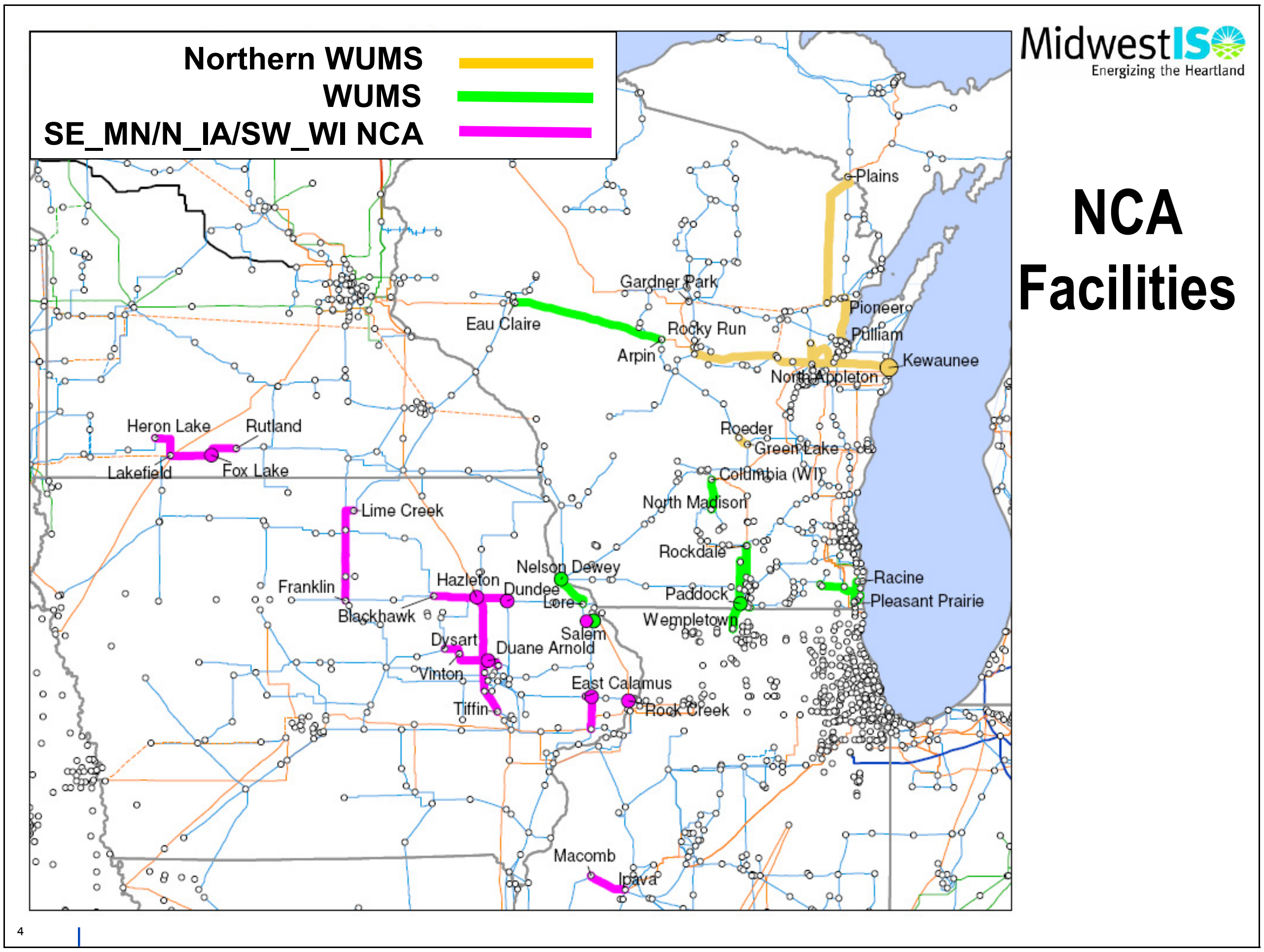


Figure 1.4-1: Facilities Comprising Each of the Three NCAs

Production cost models were prepared and evaluated with approved projects included in the models in order to evaluate the effect of planned projects on the constraints defining the NCAs. This analysis is described in detail in Section 8.1 of this report. The analysis found that:

- The WUMS and Northern WUMS NCAs are mitigated by existing plans already approved in Appendix A, therefore, no new transmission plans are required to mitigate those NCAs. The NCA TRG recommended that the projects to address the NCAs and their implementation schedule will be sent to the Independent Market Monitor to make him aware of when NCA is expected to be mitigated. After these upgrades are constructed, a request to remove the NCA will be formally made. More information on the specific projects identified as mitigating these NCAs is available in Section 8.1. The mitigating plans relative to each NCA are shown in Table 8.1-1.
- The 161kV portion of project P1746 is not currently required or scheduled until 2015 based on NERC planning criteria. However, the study clearly shows that the SE Minnesota NCA can be expected to no-longer qualify as a NCA by 2015 when P1746 is expected to be in service. Further study is recommended to determine whether the project provides additional non-reliability benefits sufficient to accelerate the project. The remaining projects which address this NCA are in Appendix A of the MTEP 08 report.

1.4.4 Economic Impact of Proposed Portfolio

The projects in Appendix A and B of the MTEP08 report have been evaluated based on reliability criteria and have been proven to be able to relieve potential reliability problems in Midwest ISO. However, these projects provide additional value such as:

- Adjusted production cost savings
- Load cost savings
- Energy loss benefit
- Capacity loss benefit

PROMOD® cases were run to evaluate the annual impacts in 2013. Table 1.4-3 shows the adjusted production cost savings, Load Cost Savings and RECBII benefit for the MTEP Appendix A/B projects. At a total portfolio cost of $4.8 billion and the current average fixed charge rate of 20%, this represents just over a 1:1 benefit cost ratio for these projects.

Table 1.4-3: Economic Indices

	Load Cost Savings	Adjusted Production Cost Savings	RECB II Benefits
Midwest ISO East	$714 million	$293 million	$419 million
Midwest ISO Central	$78 million	$386 million	$293 million
Midwest ISO West	$268 million	$272 million	$ 271 million
Midwest ISO	$1,060 million	$951 million	$983 million

Energy and capacity loss savings provide additional benefits of $138-$139 million. Table 1.4-4 provides a summary of the loss benefits in 2013.[2]

Table 1.4-4: MIDWEST ISO Loss Benefits with Appendix A/B Project

	Energy Loss Benefit	Value of Energy Loss Benefit	Capacity of Loss Benefit	Value of Capacity Loss Benefit	Maximum Hourly Loss Decrease
Midwest ISO	383,913	$78 million	93 MW	$60~111 million	568 MW

[2] Energy losses are priced utilizing hourly weighted average LMP; capacity losses are priced using a range of $650/kW – $1200/kW (the range of construction cost of different type units)

1.5 Value-Based Planning

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. Key issues and questions facing transmission planning go beyond defining what is needed to maintain reliability and market efficiency in the short term, but also how to most effectively meet these same needs in the long run, coupled with considerations of how to enable emerging renewable energy policies. Proper evaluation of the longer term needs require not only a suitably longer planning horizon for study than has been typically applied in recent years, but also a more hypothesis based approached to planning which is bounded by likely outcomes which address all the underlying issues.

Over the last couple of years, the Midwest ISO has been taking the steps needed to begin making the shift to a value-based transmission expansion planning model. The new approach better reflects appropriate (i.e. longer) project time scales, identifies and communicates the comprehensive value of a transmission project or portfolio of projects, seeks to develop political consensus on value attributes, identifies transmission infrastructure which maximizes this value within the Midwest ISO footprint, and provides for balanced cost sharing under the tariff. Initial implementation of this approach commenced in 2006 and has reached fruition in the MTEP 2008 report cycle with the appearance of the first preliminary transmission expansion plans developed under those methodologies, and discussed further in Section 4.2. Additional support for this value based planning approach arrived in 2007, as FERC issued Order 890 to further the openness and completeness of transmission planning. One of the nine planning principles specifically required Economic Planning Studies.

The transmission cost revealed by the preliminary transmission overlays, designed to deliver future generation to load under a range of energy policies in the next 15 to 20 year timeframe, under all scenarios is daunting. Transmission capital investment costs to the Eastern Interconnect over the next 20 years could exceed $20 billion (in 2008 dollars) with as much as a third of the cost falling to Midwest ISO stakeholders to support potential policy initiatives within the Midwest ISO footprint.[3] Transmission, however, is only the enabler, rather than the driver of future energy costs in the footprint. Continued expected increases in load growth, combined with energy policies such as Renewable Portfolio Standards (RPS) which drive an increase in wind technology (which will not, due to its intermittent nature, supplant on a 1:1 MW basis the need for additional generation of alternate types), drive a forecast for future generation needs where generation capital cost is expected to be at least seven times the transmission cost, and the incremental production cost[4] required to run the generation over the twenty year analysis far exceeds the capital cost of either generation or transmission. Figure 1.5-1 shows the total estimated costs in the Midwest ISO footprint for generation and transmission under each of the four Future scenarios considered as part of the MTEP 2008 report cycle:

- **Reference**: Status Quo, including current Renewable Mandates
- **Renewable:** Assume a 20% renewable mandate across the Midwest ISO Footprint
- **Environmental**: Assume a $25 carbon tax
- **Fuel:** Assume natural gas supply limitations

3 All dollars in 2008 dollars unless otherwise noted; assumes that transmission investment occurs over a 20 year period with an 8% discount rate applied.

4 Production costs include fuel, operating and maintenance, and emission costs.

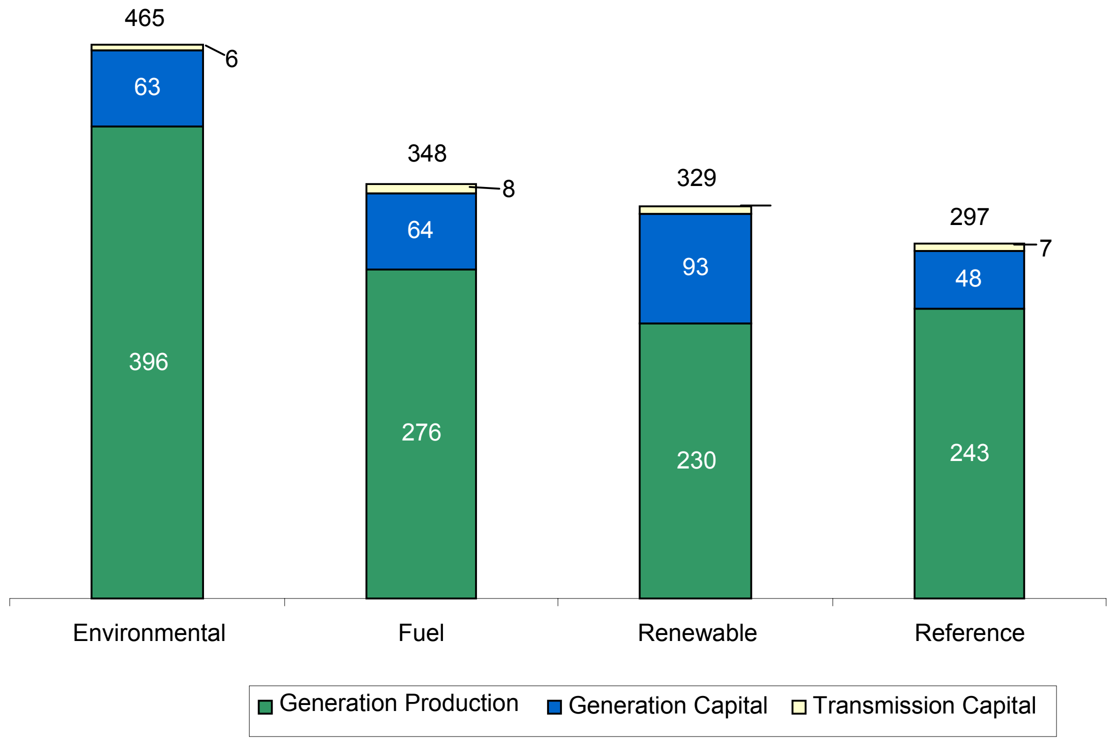


Figure 1.5-1: Future Scenarios Total Cost Comparison for 2008-2027 (billions 2008$)[5]

[5] Transmission Capital represents present value of only those capital costs expected to be assigned to the Midwest ISO; assumed implementation of costs over 20 years, with a discount rate of 8% applied

Figure 1.5-2 reflects the estimated rate impacts, in 2008 dollars of the generation and transmission expenditures predicted by the Future based scenario analysis. The total rate increase is a 38% to 62% increase over current total rates[6], assuming the distribution component remains constant at 27.5% of total per kwh rates, which, assuming current load levels[7], represents an annual increase for the average Midwest ISO residential rate payer of $216 to $346 only $16 to $22 of which is attributable to transmission.

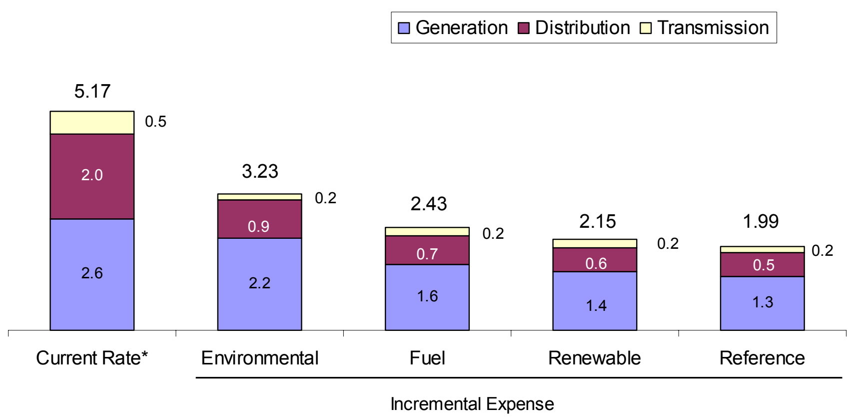


Figure 1.5-2: Comparison of Current Total Electricity Rate to Incremental Rate from Future Scenarios (¢/kwh in 2008$)

Under these scenarios it appears rate increases are unavoidable.[8] The scenarios utilized are based on the hypothesis that transmission is the enabler of an efficient system by which the total future cost to ratepayers is reduced. In the current report, all scenarios reflect an expectation that significant transmission expansion is possible. Certainly, there are a number of conditions precedent to increasing transmission build out which, if not achieved, could limit the ability to significantly build out the transmission infrastructure. Scenarios under development for inclusion in the MTEP 2009 report include a limited transmission investment future. The hypothesized outcome of the case is that the incremental cost of generation required to support the necessary reserve margins will far outweigh the transmission cost savings. Although value-based planning is intended to identify the most efficient and beneficial scenarios for a given energy policy outcome, ultimately success (or lack thereof) in resolving the conditions precedent to transmission build will drive selection of the ultimate solution.

Despite the increased efficiency which well-planned transmission can bring, a number of barriers constrain increasing transmission build. The difficulty with procuring the necessary right of way, combined

[6] The current total rate is based on the load weighted average for the reliability areas in the Midwest ISO footprint in 2008 dollars. The generation fuel component of the electric rate was escalated at a 3% inflation rate for 20 years and then discounted back to 2008 dollars using a discount of 8%. This modification to the generation fuel costs allows for a more accurate comparison between the incremental costs of the four Future scenarios and the current rate.

[7] The use of current load levels is a simplifying assumption to keep the comparison between current and future rates on a similar basis; in fact future load growth such as that which drives the need for some additional transmission and generation would reduce the absolute value of the rates stated here for both the current and future rates. Thus, all rates and rate increases shown should be considered directional rather than a prediction of actual rates

[8] The rate analysis assumes all costs are incremental and do not supplant in part the ongoing replacement of outdated equipment; the analysis also assumes that replacement of the aging transmission infrastructure is largely addressed by the ongoing reliability based projects proposed in the annual MTEP report.

with the potential for transmission built in one state to provide as much benefit beyond state, or even a Regional Transmission Organization (RTO), borders as it does within the states building the line has caused widespread concern about the ability 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.

- 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, exist.
- 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, such as around Renewable Portfolio Standards, exacerbate this divide, which can be a barrier to the development of large scale transmission projects which provide benefits of various types to users across multiple states or other entities.
- A regional tariff that matches who benefits with who pays over time – Over time those paying for the increased transmission must derive benefits proportional to the cost to feel satisfied with the investment.
- 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. A further discussion of the conditions precedent to increasing transmission build can be found in Section 2.4

1.6 Targeted Planning Initiatives

Long-term value-based planning provides the blueprint within which planning commitments in nearer timeframes can be more optimally made. Short term reliability planning for the five to ten year planning horizon is needed to ensure adequate capacity is committed. Between these bookend planning analyses the Midwest ISO undertakes what we have referred to as "Targeted Studies". Targeted Studies, typically using a version of the long-term value based planning process, usually 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. Targeted Studies presently underway include:

- Regional Generation Outlet Study
- NCA Study
- Southern Indiana Planning Study
- ITC 765kV Study

These studies are detailed in Section 8 of the report, along with an additional targeted study already identified for 2009, the Top 4 Constraint (2013) Portfolio Analysis Study which focuses on evaluating the benefits from a number of projects considered in combination as a solution to minimize the economic impact of the top four constraints which are to date unmitigated by current transmission plans.

1.6.1 Regional Generation Outlet Study (RGOS)

The RGOS seeks to address the physics[9] component of generator interconnection queue reform[10] by driving greater integration between longer term (MTEP) and shorter term (generator interconnection queue) planning processes. The objective is the development of a regional collector system(s) to support existing renewable portfolio standards. This will be accomplished with the identification of renewable energy zones within the region and by developing necessary transmission to move the energy from those zones on to the transmission grid and load centers. The study commenced in 2008, and study work is ongoing as of the MTEP 2008 report. Projects identified in this study are expected to be included in the MTEP09 report and appendices.

[9] Three P's of queue reform: Process, Physics, Policy

[10] See Queue Reform at:

http://www.midwestmarket.org/publish/Folder/67519_1178907f00c_-7fff0a48324a

There are several problem statements to be addressed by this study, including:

- The level of requests in the Midwest ISO generation interconnection queue, driven in large part, by renewable mandates has risen dramatically over the past two years. As of summer 2008, there were over 70 GW of wind generation requests out of approximately 80 GW total in the Midwest ISO queue.
- As well, the queue is a less than optimal method of performing transmission planning as it is based on individual projects rather than a collective system, leading to higher capital costs and less efficiency.
- A determination of generation size and location that should drive the 5-15 year transmission build-out is needed to establish a base-line for prudent transmission investment.
- Laws at the state and federal level reflect different energy and economic policies and thus regulatory processes; however a concerted collaborative effort can find improvements and solutions to enable the integration of this resource.
- Geographic areas that support wind typically to not support large communities of energy consumers and thus only a small fraction of the available wind resource can be used in the location it can be developed. Transmission to connect renewable resource areas to load centers needs to be constructed to meet state's energy policy.

The RGOS study is following the Midwest ISO transmission planning process described in Section 2 of this report. This is a multi-step process that utilizes various generation scenarios, known as Futures[11], to represent plausible long-term generation expansions. As these Futures are analyzed, necessary transmission is developed to resolve any issues. Transmission developed in the analysis is then tested for robustness. Robustness looks for common transmission projects that provide benefit in all scenarios analyzed. The premise is that a particular transmission project that benefits all scenarios is a strong candidate for prudent future investment under a wide range of public policy direction.

The RGOS is scheduled to be completed in the first quarter of 2009 with results included in the MTEP09 process and report. Upon completion of this study, a second study will commence for the eastern half of the Midwest ISO footprint, anticipated to include Ohio, Michigan and Indiana.

Stakeholder involvement is being accomplished with the use of a Technical Review Group (TRG). The objective of the TRG approach is to receive stakeholder involvement as early as possible in study efforts. The role of the TRG is to provide input and feedback on study scope, methodology, assumptions, and results. With the help of the TRG, results are being coordinated with utilities, states, and other efforts that the Midwest ISO supports such that they have merit/credibility and regulatory support gained from stakeholder involvement. The TRG is open to all interested stakeholders and for the RGOS is presently comprised of over 100 participants representing regulatory entities, transmission owners, load serving entities, wind developers, and others.

A dedicated email exploder exists for RGOS members and is used for all communications related to the study. All that is needed to become a member of the TRG is to subscribe to the exploder. This can be done by establishing a Midwest ISO extranet account (http://extranet.midwestiso.org) and editing the account settings. As well, further information about the study can be obtained on the Midwest ISO website, under the Planning tab. This is located at: http://www.midwestmarket.org/page/Planning

[11] See Joint Coordinated System Plan at: http://www.midwestmarket.org/publish/Folder/5d42c1_1165e2e15f2_-7efc0a48324a

1.6.2 Southern Indiana Planning Study

A series of economic studies have been performed to evaluate the potential for the development of economically beneficial transmission expansion in Southern Indiana. Project proposals and study input and review has been provided by a group of interested transmission owners that include IPL, DUKE, Vectren, Hoosier Energy, NISPCO, and ATC. A large number of transmission portfolios at both 345kV and 765kV have been evaluated to date against the Midwest ISO Regionally Beneficial Project economic criteria, which is a blend of production cost and load LMP payment benefits. In addition, system loss benefits have been compared among the portfolios.

In this study, Midwest ISO performed two rounds of PROMOD® runs, and evaluated 18 portfolios in total (12-345kV Portfolios and 6-765kV Portfolios).

For the 765kV portfolios, though they show benefits larger than the 345kV portfolios, because of their high project costs, the B/C ratio is small. The study shows that only adding 765kV lines in Indiana area will not bring enough benefits to cover its cost. The larger benefit of the added 765kV line is not from relieving the binding constraints in local area, but from delivering power from cheap source area to expensive sink area. The group decided to defer the 765kV portfolio study to some future time after we have a better idea of the 765kV overlay that is being evaluated in the in other areas/regions in the Joint Coordinated System Plan and other work planned in the MTEP 09 report cycle.

The 345kV Portfolios showed varying economic benefits (load cost savings, adjusted production cost savings, net generation revenue increases) to different companies. When we use the RECB II criterion, only 345kV Portfolio 10 (Bloomington-Pritchard-Frank Twp-Hanna single circuit 345kV line) passes the B/C ratio threshold. But this calculation is based on the assumption of 14% fixed charge rate, 10% discount rate, and 3% inflation rate. Benefit to cost results vary if these assumptions are varied. The portfolios are under further evaluation based on each Transmission Owner’s actual fixed charge rate and discount rate, and to determine which if any of the portfolios may move forward as Regionally Beneficial Projects under the tariff. More details on the analyses are contained in Section 8 of the report.

1.6.3 ITC 765kV Study

On November 6, 2006, ITC Holdings, Inc. (ITC) and American Electric Power (AEP) announced plans to perform a joint technical study to evaluate the feasibility and benefits of building a 765kV transmission network in Michigan's Lower Peninsula and connecting to AEP's existing 765kV transmission network in Michigan and Ohio. This proposed transmission infrastructure would span approximately 700 miles and would expect to significantly improve Michigan import capability and enhance overall system reliability. ITC and AEP are committed to working with Midwest ISO and Pennsylvania, New Jersey, Maryland Interconnect (PJM) to have this proposed 765kV transmission infrastructure expansion evaluated under the Midwest ISO MTEP and PJM RTEP planning processes. Section 8.4 includes the preliminary draft results of the initial study work that MIDWEST ISO has conducted and a study team has been formed to ensure coordinated planning. The study team includes Detroit Edison, Consumers Energy, ITC, AEP, DUKE, First Energy, IPL, PJM, MIDWEST ISO, ABATE, NIPSCO, Michigan PSC and Michigan Public Power Agency.

The purpose of this study is to evaluate the economic benefits of the proposed 765kV transmission project under various future generation scenarios and transmission portfolio options. This study is also to explore and determine the need justifications for the project, longer term reliability, capacity or regionally economic beneficial. Currently this proposed project is a conceptual solution in MTEP Appendix C without needs proven. To fully capture the value of the proposed long-term project, a broader set of value metrics should be under consideration for justification.

Based on the economic benefit analysis preliminary results, the proposed project does not meet the 3:1 RECB II benefit/cost ratio for Regionally Beneficial Project categorization, under the present tariff. It is recognized that such large scale projects may meet multiple planning objectives beyond basic congestion relief which the RECBII metrics are designed to capture. Further analyses would be needed to explore additional value metrics such as import capability, deferred generation capacity, loss reduction, constraint relief etc. to reveal the full benefit potential of this and similarly large expansion proposals. Currently several value measures are under development with the ongoing Midwest ISO Value Measures workshops, as described further in Section 10 of this report

1.7 Other Planning Activities for the MTEP 2009 report cycle and beyond

1.7.1 Advancement of Value Based Planning Methodology

The introduction and implementation of value based planning methodologies for the Midwest ISO and its stakeholders is an ongoing process. In the latter part of 2008 and into 2009, the Midwest ISO will continue work through the ongoing implementation of the value based methodology. The next phase of work will focus on the development of methodologies to identify and evaluate portfolios of projects.

Additionally, the Midwest ISO will continue to work with its stakeholders in the development of additional future scenarios to evaluate the impacts of projects or portfolios of projects under a wide range of outcomes. One scenario under development for inclusion in the MTEP 2009 report is a limited transmission investment future

Finally, over time, it is expected that the portions of the currently conceptual high voltage transmission overlays will evolve into subsets of projects or portfolios of projects for further evaluation of the business case. This will occur over the next several MTEP cycles as the analytical methodologies mature and Transmission Owners have the opportunity to evaluate the projects more fully. As the technical analysis and business case are completed and shown to be appropriate, these projects will then begin to move into Appendix B and ultimately Appendix A.

1.7.2 Joint Coordinated System Plan

Formally initiated on November 1, 2007, the Joint Coordinated System Plan (JCSP08) study began as collaboration between the Midwest ISO, Pennsylvania, New Jersey, Maryland Interconnect (PJM), Southwest Power Pool (SPP) and the Tennessee Valley Authority (TVA) to meet the requirements of the Joint Operating Agreements each organization has with Midwest ISO. Subsequent to the initial four parties the ISO New England, New York ISO and the Mid-Continent Area Power Pool (MAPP) all joined the study as formal participants. On an informal basis, the Southeast Inter Regional group has been formed within the South-Eastern Reliability Corp. (SERC) – both the TVA and Entergy are part of this group and Entergy is participating in the JCSP primarily through the SPP. Therefore, TVA and SPP can act as a liaison between the JCSP and this group.

While comprised of both a reliability assessment focused on 2018 and a separate economic assessment with a 2024 focus, the main focus of the JCSP08 is the economic assessment. To leverage staff resources and also produce an extensive policy level study, the economic study is also being performed in collaboration with the Department of Energy (DOE) and their Eastern Wind Integration Transmission Study (EWITS). The DOE EWITS had an objective to investigate both 20% and 30% wind energy penetration scenarios in the bulk of the Eastern Interconnection and the transmission required to effectuate that level of penetration. The JCSP study adopted the DOE assumptions and added them to a Reference Future that acts as a baseline for comparison.

This Reference Future is based on meeting the existing state mandates for Renewable Portfolio Standards (RPS) in existence as of January 1, 2008. Many of the existing standards allow for a variety of resources, such as hydro, biomass and solar to be used in addition to wind, although wind is the predominant renewable being advocated in the Eastern Interconnect. As with the 20% wind energy Future and 30% wind energy Future, a key assumption for this study is that all of the renewable portfolio standards are assumed to be met with wind energy.

In 2009, JCSP efforts will increase focus on the reliability assessment as well as the development of additional Future scenarios to support the analysis.

1.7.3 Project and Portfolio Valuation

While assessment of the RECB methodology is largely outside the scope of this report, it is worth noting that ongoing planning activities will include continued evaluation of the existing methodology for inclusion and cost allocation of projects and portfolios of projects. In August of 2008, the Midwest ISO filed an assessment of the RECB methodology (available at: http://www.midwestmarket.org/publish/Document/25f0a7_11c1022c619_-7bd50a48324a) which reflected a number of potential unintended outcomes from the current RECB methodology which require further evaluation and consideration.

One of the potential issues identified was the narrow nature of the economic criteria used to evaluate projects. This notion is of particular concern under the value based planning approach, where large-scale projects may provide widespread benefits beyond the market efficiency metrics currently reflected in the economic RECB criteria. The RECB discussion in the report is focused on the usage of these metrics to qualify projects for cost sharing. However, even in the absence of the cost sharing concerns the Midwest ISO believes there is value in continuing the work on Valuation Measures described in Section 10 if only to build a more robust standard business case for projects included in Appendix A of the MTEP report. Thus, that work will continue into 2009 in conjunction with the ongoing RECB evaluation efforts.

Section 2: Impact of Value Based Planning

2.1 Midwest ISO Planning Approach

The Midwest ISO regional transmission expansion planning process has as its goal the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The Midwest ISO planning process has (and the majority of incumbent transmission owner processes have) historically focused on the principal of safeguarding reliability, with accommodation for the principal of supporting regulatory mandates, through the Energy Markets Tariff (EMT). In large part, this focus has been a result of extraordinarily high threshold questions of need within state regulatory processes and the implicit assumption that minimizing the cost of new transmission infrastructure has the effect of maximizing value to the consumer. With the advent of the Midwest ISO energy market in 2005, infrastructure planning began the shift to a more comprehensive planning approach which ensures that, in addition to safeguarding reliability, sufficient transmission capacity is constructed so that a competitive wholesale energy market can flourish.

To further understand the drivers for this continued evolution of the planning process, consider the overall role of the Midwest ISO in the transmission expansion process. The annual MTEP report, and the underlying regional transmission expansion planning processes, provide a valuable platform to develop and publish information to be considered by siting authorities, regulatory bodies which grant the authorizations to construct new facilities, and other interested stakeholders. However, the role of the Midwest ISO is not to (and the Midwest ISO is not authorized to) construct transmission facilities. That responsibility 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 is 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.

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 early 2006, provided to the Midwest ISO community and staff in an effort to improve the transmission investment in our region and guide the Midwest ISO annual transmission plan.

- **Guiding Principle 1 –** Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs
- **Guiding Principle 2** – Provide a transmission infrastructure that safeguards local and regional reliability
- **Guiding Principle 3** – Support existing state and federal renewable objectives by planning for access to all such resources (e.g. wind, biomass, demand side management
- **Guiding Principle 4** – Creates a mechanism to ensure investment implementation occurs in a timely manner
- **Guiding Principle 5** – Develop a transmission system scenario model and make it available to state and federal energy policy context and inform the choices they face

[1] Transmission Owners Agreement Section VI of Appendix B

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. Key issues and questions facing transmission planning include new renewable energy policies, reducing congestion on the grid, 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?
- Are we reflecting all the primary value drivers in our cost sharing methodology?
- Are we accurately capturing the value of benefits which may flow across borders?

By revealing answers to these questions and others, the Midwest ISO is able to provide support to the policy and other decision makers about the impacts of those decisions. By focusing on value, rather than solely reliability analysis, this approach seeks to ensure that no matter the outcome, the most efficient approaches are considered.

Over the last couple of years, the Midwest ISO has been taking the steps needed to make this shift to a value-based transmission expansion planning model. The new approach better reflects appropriate (i.e. longer) project time scales, identifies and communicates the comprehensive value of a transmission project or portfolio of projects, seeks to develop political consensus on value attributes, identifies transmission infrastructure which maximizes this value within the Midwest ISO footprint, and provides for balanced cost sharing under the tariff. Initial implementation of this approach commenced in 2006 and has reached fruition in the MTEP 2008 report cycle with the appearance of the first preliminary transmission expansion plans developed under those methodologies. Additional support for this value based planning approach arrived in 2007, as FERC issued Order 890 to further the openness and completeness of transmission planning. One of the nine planning principles specifically required Economic Planning Studies.

For the Midwest ISO to support these efforts from an analytical perspective, new tools and methods needed to be 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 not 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. 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.

Figure 2-1 illustrates how the various transmission planning tools, from short-term NERC reliability studies to long-term economic studies and Targeted Studies to address specific topics of concern, all interrelate and fall under the umbrella of the MTEP planning cycle. Note that the MTEP report itself is a snapshot of all of these planning activities.

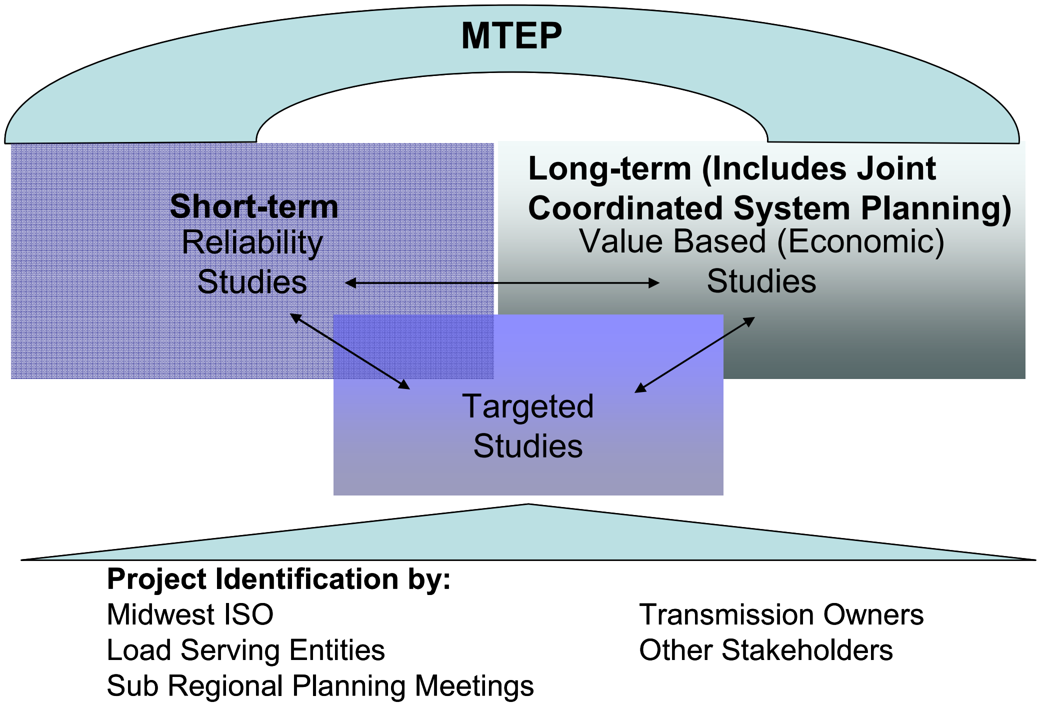


Figure 2-1: Midwest ISO Planning Approach

2.2 Value-Based Planning Process

Beginning in 2006, the Midwest ISO worked with the Planning Advisory Committee (PAC) and other interested parties to develop a revised methodology to develop top-down, value-based transmission plans to support economic and reliable energy delivery under a wide range of potential energy policy outcomes. This methodology is represented in Figure 2-1 as the Long-Term Economic/Value methodology.

The following broad steps outline the process undertaken to develop transmission to support economic energy delivery:

- **Step 1:** Forecast Multi-Future regional resources
- **Step 2:** Site generation and place in Powerflow Model
- **Step 3:** Design preliminary transmission plans for each future
- **Step 4:** Test preliminary transmission plans for robustness
- **Step 5:** Consolidate alternatives into a single transmission plan
- **Step 6:** Perform Reliability Assessment and integration; make final design modifications
- **Step 7:** MTEP Cost Allocation and Delivery to Board of Directors

The flow of the process is outlined in Figure 2-2 and subsequently described in greater detail below.

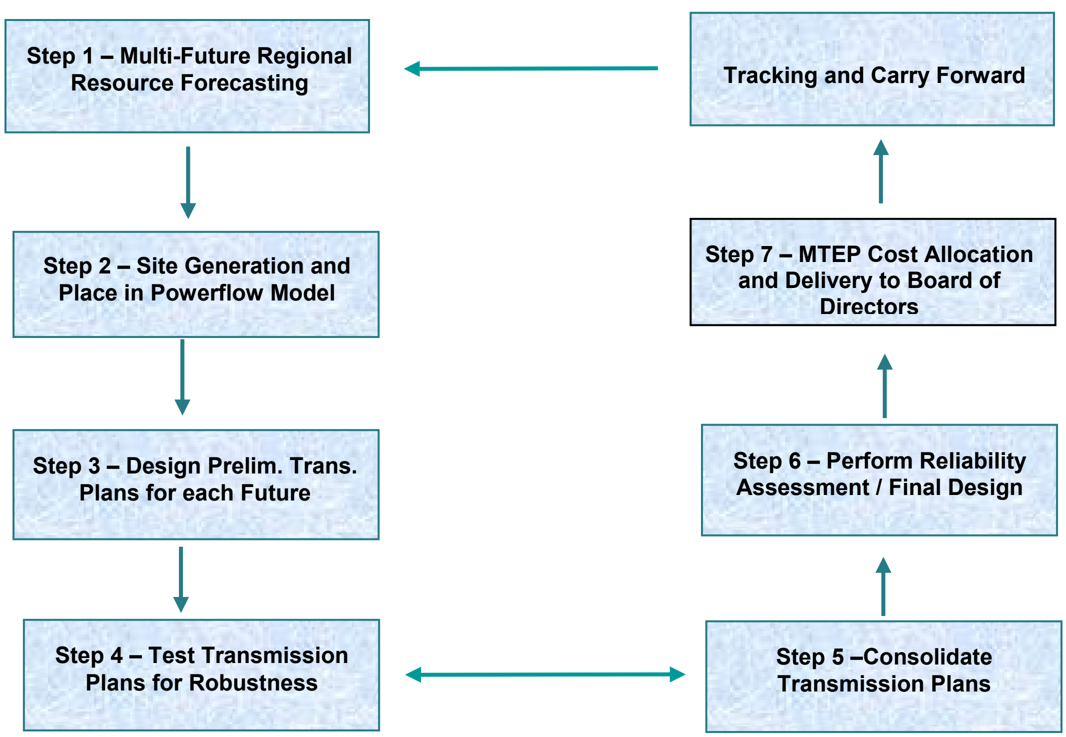


Figure 2-2: Seven step value based process flow

As part of the MTEP 2008 report cycle, steps 1 through 4 were completed. The results are in the form of four conceptual overlays addressing four generation Futures. The impacts are further discussed in Section 2.3. The Midwest ISO will continue to work with stakeholders to evolve the value based planning methodology and execute the remaining steps of the process.

- **Step 1: Forecast Multi-Future Regional Resources** – Four generation Futures were created for the analysis included in the MTEP08 report. The Futures are used to bracket the uncertainty around future public policy and economic drivers by providing multiple alternatives of the future state. The process to create the Futures, and the detailed assumptions underlying them, are discussed further in Section 4.1. At a summary level, these four Futures are:
    - **Reference**: Status Quo, including current Renewable Mandates
    - **Renewable:** Assume a 20% renewable mandate across the Midwest ISO Footprint
    - **Environmental**: Assume a $25 carbon tax
    - **Fuel:** Assume gas supply limitations

- **Step 2: Site Generation and Place In PowerFlow Models** - Once the future generation from the portfolio assessment 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 indicative siting of generation is required as the tariff driven queuing system hasn't provided generation information over the time horizons required. Absent the generation assumption transmission line benefits analysis 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.

    Fifteen-year out transmission models were developed to support this new process. Transmission Owners supply known system upgrades while the generation additions are incorporated from the Generator Interconnection Queue and the portfolio assessment process. With the development of the long-term power flow models, the corresponding PROMOD® models, which are used for economic analysis, are then developed.

- **Step 3: Design Preliminary Transmission Plans for Each Future -** To accomplish this task for each of the Futures analyzed as part of the previous steps the following methodology is used.

    First, we use the power flow and PROMOD® models developed in Step 2 and run PROMOD® using the same assumptions used in the development of the portfolio assessment. For example, if we have four Futures from the portfolio assessment process we would develop four 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 transmission plan.

    This process was collaboratively performed with stakeholders in an open planning process.

- **Step 4: Test Preliminary Transmission Plans for Robustness -** The outcome of the process in Step 3 is the development of preliminary transmission plans for each Future being studied. Up to this point the preliminary plans are developed in isolation of each of the other Futures. Our ultimate goal is to develop one transmission plan that performs the best under all Futures. The planning process is fraught with uncertainty; our objective is to manage the uncertainty as best we can. 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 Future then potential adjustments to the transmission plan will need to be evaluated.

  For the robustness tests executed as part of the 2008 MTEP process, projects were evaluated for benefits utilizing the current criteria for economic project inclusion: production cost and locational marginal price. In the future, each plan will be tested under a variety of attributes to make the value comparisons. These attributes, and the associated testing process, are described further in the Section 10 review of Valuation Measure Development.

- **Step 5: Consolidate Transmission Plans** – Once the initial robustness test has been executed, it is necessary to develop the appropriate portfolio of transmission projects which will make up the overall plan. There are two key considerations in consolidating the preliminary transmission plans into a single comprehensive plan. First, is the need to maintain options for future changes in energy policy. The Futures represent a wide range of outcomes of future generation needs. By selecting preliminary plan components into a comprehensive plan which provides the most benefit under all outcomes, the transmission infrastructure will support changes to generation and market requirements with the least incremental investment and rework. Second, is the notion that the value of a whole may be greater than the value of the sum of the parts. By selecting the appropriate transmission plan components as a group, or portfolio of outcomes, Midwest ISO customers may see benefits well beyond what may be achieved if only a subset of the projects were executed.

- **Step 6: Perform MTEP Reliability Assessment and Make Final Design Modifications–** Over the first three MTEPs the reliability assessment component of the study has evolved to its current state. It is a well-defined stakeholder driven process performed on a regional basis through the west, central and east regional study groups. This process will continue in parallel with the overlay process of prior steps, to ensure that reliability is maintained while more regionally effective transmission can be developed. As value driven regional expansions are justified, traditionally developed reliability plans will be displaced by the more economic regional plans where appropriate. Final adjustments to the integrated plan may be required based on the reliability assessment.

- **Step 7: MTEP Cost Allocation and Delivery to the Board of Directors** – After completing the final design, the remaining efforts focus on determining the proper cost allocation and taking the project through any final approval steps, including delivery to the Board of Directors. Note that as the project is developed, and moved from Appendix C forward, it will follow the standard approval and review process including evaluation through the Technical Review Group (TRG), Subregional Planning Meetings (SPM), Planning Subcommittee (PS) and Planning Advisory Committee (PAC).

2.3 Estimated Impacts of Future Scenarios

The only certainty in projecting future energy policy is that it is certain to change, but uncertain as to how that policy will look in its ultimate form. Given the advent of wind energy, Renewable Portfolio Standards (RPS) and a national focus on climate change impacts, it is expected that the future will look quite different from recent history. The Future scenarios recognize this uncertainty and attempt to bookend the different outcomes. However, there are common threads among the Futures.

Before discussing the impact of the Future scenarios, consider the current cost of electricity to the retail customer. The current average retail electricity rate for Midwest ISO residential, commercial, and industrial sectors is approximately 7.38 ¢/kwh, which is 28% lower than the national average of 9.44 ¢/kwh.[2] Figure 2-3 provides the average retail rate in ¢/kwh by state, excluding those states where the Midwest ISO footprint only encompasses a small part of that state. Based on information provided in the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2008 the generation, transmission, and distribution cost components of the retail electricity rate in 2006 were on average 65.5%, 7.0%, and 27.5%, respectively.[3] This equates to approximately 4.8 ¢/kwh for generation, 0.5 ¢/kwh for transmission, and 2.0 ¢/kwh for distribution. The average residential customer in the Midwest ISO footprint uses 900 kwh of electricity each month, which is equal to approximately $800 per year in electricity costs, based on a 7.38 ¢/kwh rate.[4]

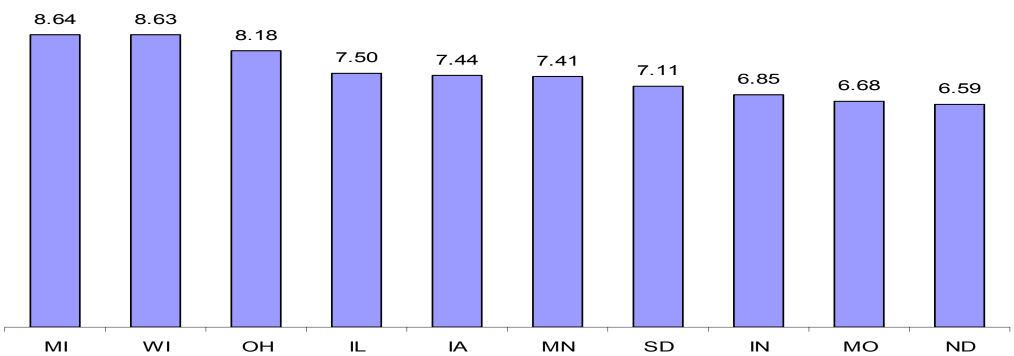


Figure 2-3: State Average Retail Rate for all Sectors in ¢/kwh (2008 dollars)

[2] Data courtesy of the Energy Information Administration (EIA) Annual Energy Outlook 2008 report released April 2008. The Midwest ISO rate was calculated by taking the load weighted average of the East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP) reliability regions, including only those balancing authorities that are currently Midwest ISO members, 2006 per kwh rate and adjusting that rate from 2006 to 2008 dollars assuming a 3% inflation rate.

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

[4] Residential Electricity usage numbers for the Midwest ISO footprint courtesy of the EIA at the following link: http://www.eia.doe.gov/cneaf/electricity/esr/table5.html.

The transmission cost revealed by the preliminary transmission overlays under all scenarios is daunting. Although cost estimates are preliminary, they reveal that transmission capital investment costs to the Eastern Interconnect over the next 20 years could exceed $20 billion (in 2008 dollars) with as much as a third of the cost falling to Midwest ISO stakeholders to support potential policy initiatives within the Midwest ISO footprint.[5] As demonstrated in Figure 2-4, that represents to Midwest ISO stakeholders a 29% to 38% increase over the current average transmission rate component in the footprint. Thus, assuming current load levels,[6] the average residential customer in the Midwest ISO footprint could expect to pay approximately $16 to $22 more each year due to transmission expansion from the various Future scenarios. Note that this estimated rate increase also assumes that all costs from the transmission overlay are incremental, although in fact some of the new build out may supplant the need for replacement of the aging infrastructure currently reflected in the rates.

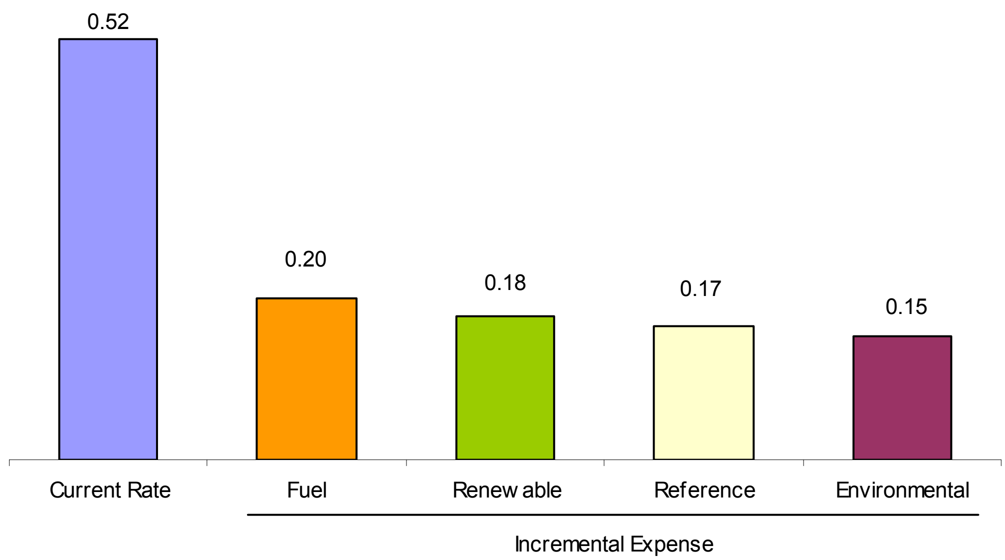


Figure 2-4: Comparison of Estimated Transmission Rate[7] under Future Scenarios (¢/kwh in 2008$)

Transmission, however, is primarily the enabler of generation required to meet load and congestion mitigation, rather than the primary driver of future energy costs in the footprint. Continued expected increases in load growth, combined with energy policies such as RPS, which drive an increase in wind technology, and will not, due to its intermittent nature, supplant on a 1:1 MW basis the need for additional generation of alternate types. This drives a forecast for future generation needs where generation capital

[5] All dollars in 2008 dollars unless otherwise noted; assumes that transmission investment occurs over a 20 year period with an 8% discount rate applied.

[6] The use of current load levels in the Future scenarios per kwh rate calculation for the transmission and generation component is a simplifying assumption to keep the comparison between current and future rates on a similar basis; in fact future load growth such as that which drives the need for some additional transmission and generation would reduce the absolute value of the rates stated here for both the current and future rates. Thus, all rates and rate increases shown should be considered directional rather than a prediction of actual rates.

[7] Transmission costs included in each Future scenario rate calculation are based on the present value of the expected annual revenue requirement after 20 years divided by the 2007 12 month average coincident peak for the Midwest ISO.

cost is expected to be at least seven times the transmission cost, and the incremental production cost[8] required to run the generation over the twenty year analysis timeframe is approximately thirty-six times the transmission cost in all scenarios except the Environmental Future where estimated production cost is nearly seventy times the transmission cost due to the assumed imposition of a twenty-five dollar per ton carbon tax.

Figures 2-5 and 2-6 provide comparisons of generation costs to existing rates and as part of the total energy cost to the consumer, respectively. Note that to achieve consistency in the comparison, all rate values have been shown in 2008 dollars and based on 2008 load values. Thus, although the absolute dollar values shown here, including the current rate, are not the expected nominal future values, and should be considered directional. To keep the current rate on the same basis as the future rate, the fuel component was also inflation adjusted, then discounted to 2008 dollars. Thus, the value of the current rate as shown in the remainder of this section will also differ from the current nominal rate of 7.38 ¢ per kwh due to the effects of discounting on the generation component of the rate..

The generation component, including generation production and capital costs for each of the Future scenarios represents a 49% to 84% increase over the current generation costs, see Figure 2-5. For a residential consumer who uses on average 900 kwh per month this increase in generation costs would increase their annual electricity expenditures by $140 to $238, assuming current load levels. The total rate increase is a 38% to 62% increase over current total rates, assuming the distribution component remains constant at 27.5% of total per kwh rates, which represents an annual increase for the average Midwest ISO residential rate payer of $216 to $346 only $16 to $22 of which is attributable to transmission.

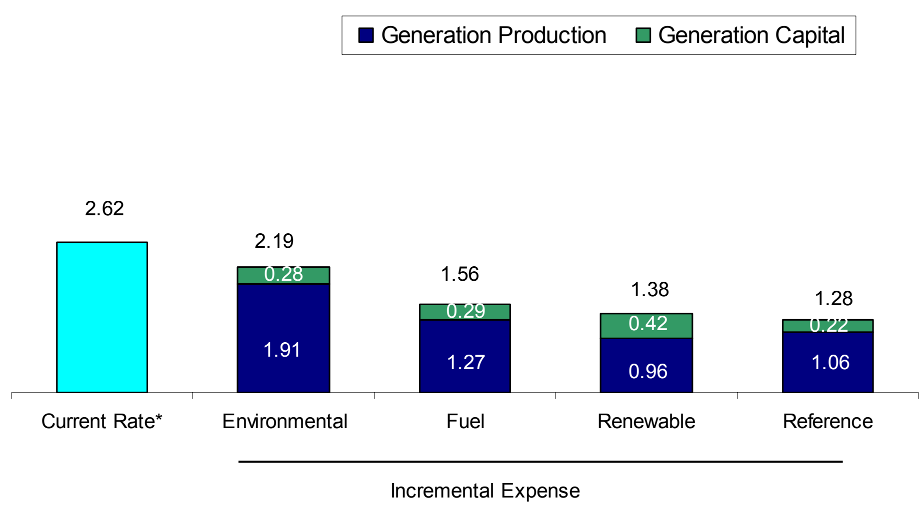


Figure 2-5: Comparison of Estimated Generation Rate under Future Scenarios (¢/kwh in 2008$)[9]

[8] Production costs include fuel, O&M and emission costs.

[9] Generation production costs included in the Future scenarios rate calculation are based on present value of the expected production costs in 2027 divided by the 2007 12 month average coincident peak for the Midwest ISO. The generation capital

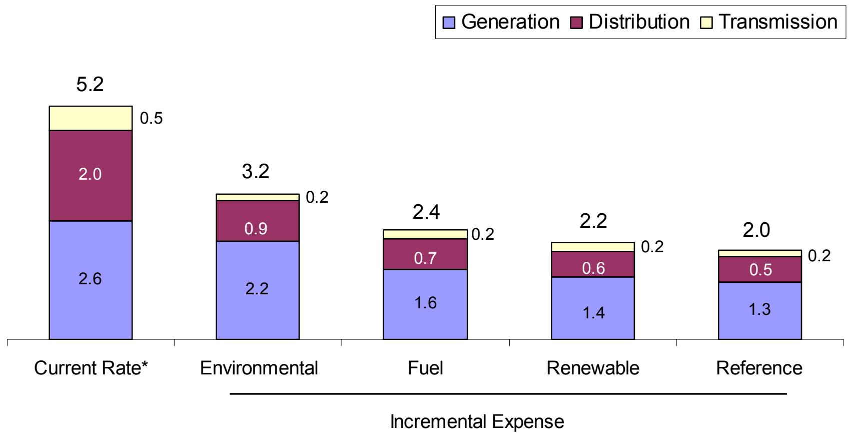


Figure 2-6: Comparison of Current Total Electricity Rate to Incremental Rate from Future Scenarios (¢/kwh in 2008$)[10]

Under these generation scenarios it appears rate increases are unavoidable.[11] The scenarios utilized are based on the hypothesis that transmission is the enabler of an efficient system by which the total future cost to ratepayers is reduced. In the current report, all scenarios reflect an expectation that significant transmission expansion is possible. Certainly, there are a number of conditions precedent to increasing transmission build out which, if not achieved, could limit the ability to significantly build out the transmission infrastructure. Scenarios under development for inclusion in the MTEP 2009 report include a limited transmission investment future. The hypothesized outcome of the case is that the incremental cost of generation required to support the necessary reserve margins will far outweigh the transmission cost savings. Although value-based planning is intended to identify the most efficient and beneficial scenarios for a given energy policy outcome, ultimately success (or lack thereof) in resolving the conditions precedent to transmission build will drive selection of the ultimate solution.

costs used in the rate calculation are based on the present value of the annual generation capital investments divded over an assumed thirty-year life of the plant, which is then divided by the 2007 12 month average coincident peak load for the Midwest ISO.

[10] The distribution component for each Future scenario's total rate was estimated based on the assumption that the generation and transmission component will equal 72.5% of the total per kwh rate.

[11] The current scenarios also assume that replacement of the aging transmission infrastructure is largely addressed by the ongoing reliability based projects proposed in the annual MTEP report.

2.4 Conditions Precedent

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 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, exist. 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 which 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. And 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. Increased certainty of cost recovery, through a pass-through rate mechanism for the transmission provider, in three of the states in the Midwest ISO footprint may be one of the drivers for the transmission build in those three states representing over 75% of the total Appendix A project dollars in MTEP 2007.

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 3: Midwest ISO System Information

3.1 Midwest ISO System Overview

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 our 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 15 states and one Canadian province. Our members' systems cover 920,000 square miles with 93,600 miles of transmission operated at 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, and 69kV. The geographic location of the Midwest ISO and the other Independent System Operators (ISO) and Regional Transmission Organizations (RTO) in US and Canada is shown in Figure 3.1-1.

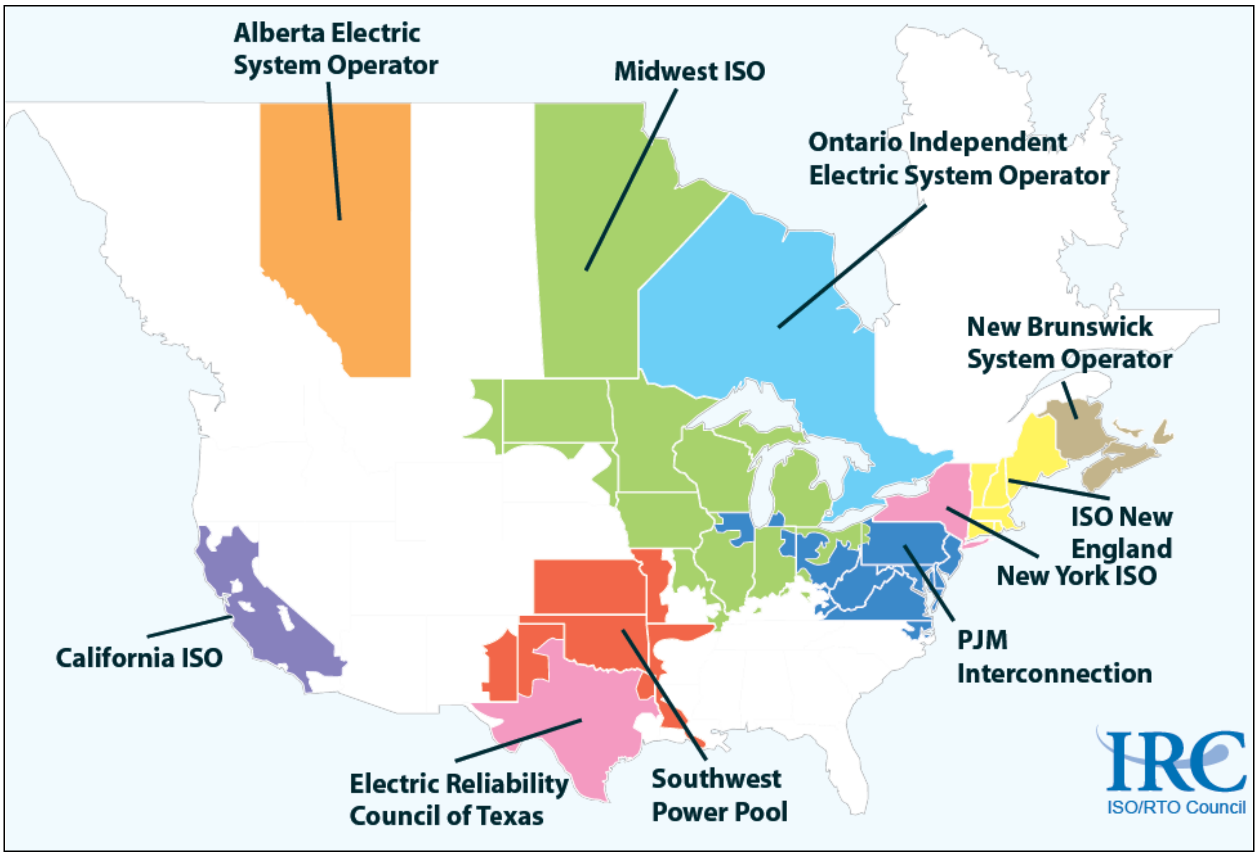


Figure 3.1-1 Midwest ISO Geographical Footprint

The following Transmission Owners are Midwest ISO members:

West Planning Region

- 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)
- Wabasha Valley Power Association

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 3.1-2 below shows 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.

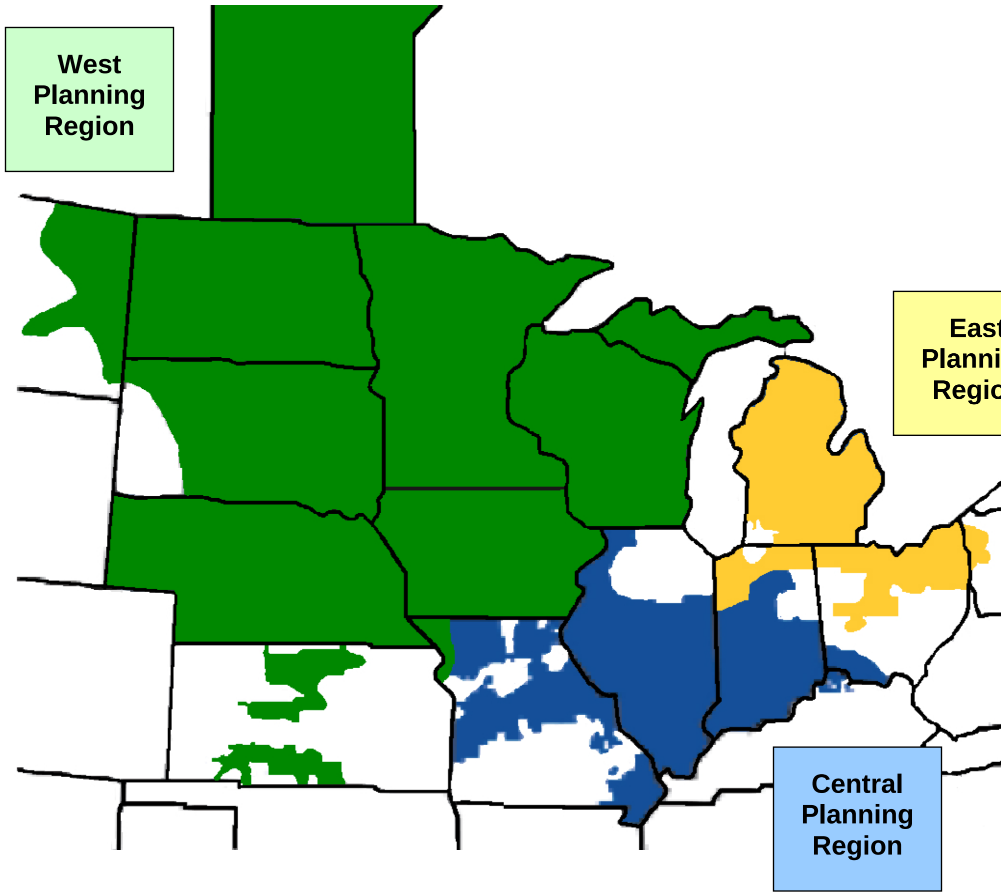


Figure 3.1-2 Midwest ISO Planning Regions

3.2 Load and Generation

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

3.2.1 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.

3.2.1.1 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 3.2-1 compares the non-coincident peak gross demand forecasts collected in the 2008 data request to the forecast collected through the 2007 data request. The 2008 data collection non-coincident peak forecast is organized by Midwest ISO Planning Regions.

Table 3.2-1: Non-Coincident Peak Demand Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
West	34,357	35,588	36,053	36,699	37,329	37,968	38,615	39,298	39,964	40,673
East	39,268	39,489	40,866	41,309	41,657	41,996	42,368	42,737	43,125	43,516
Central	39,084	39,754	40,248	40,766	41,205	41,682	42,148	42,623	43,085	43,591
Midwest ISO	***112,709***	***114,831***	***117,167***	***118,774***	***120,191***	***121,646***	***123,131***	***124,658***	***126,174***	***127,780***
2007 Forecast	114,949	116,722	118,744	120,174	122,041	123,617	125,230	127,027	128,645	

Historically, the Midwest ISO has experienced between a 1.5% and 2.0% load growth rate; however, the slowing economy has had a significant effect on the load forecast for 2008. Since 2007, some large industrial customers were forced to shut down or cut back production. There was a 0.43% reduction in the gross demand forecast from 2007 (not displayed in Table 3.2-1). Although the forecasted growth rates remained relatively unchanged between the 2008 and 2007 data request, the slowing economy has caused forecasted gross demand levels to shift forward by one year - i.e. the 2010 gross demand forecast level in the 2007 data request is approximately the same as the 2011 level in the 2008 data request forecast.

Using three 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 3.2-2, the gross coincident demand forecast ranges from 108,255 MW in 2008 to 122,730 MW in 2017, which is approximately 3.7% lower than the 2007 forecasted peak coincident demand levels for the same year.

Table 3.2-2: Coincident Peak Demand Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Midwest ISO	***108,255***	***110,293***	***112,537***	***114,080***	***115,441***	***116,839***	***118,265***	***119,732***	***121,188***	***122,730***
2007 Forecast	112,261	113,993	115,967	117,364	119,187	120,726	122,302	124,057	125,637	

The methodology used in determining the load diversity factor was changed in 2008. This change in methodology resulted in a shift of the calculated diversity factor, which caused the coincident peak to fall by 2% rather than 0.4%. In 2007, a 0.977 load diversity factor was calculated by observing the 2002 load profile which is considered a typical year without abnormalities. Three years of historical Market data was used to calculate the load diversity factor for 2008. With this limited amount of data, the trend contains some deviation; however it still gives a more accurate representation of the Midwest ISO's large geographic size, differing time zones and recently observed peak conditions.

3.2.1.2 Demand Response Programs

Recently, there has been an increased awareness in demand side management and conservation programs. Compared to last year, there has been a 17%, 705 MW, increase in the reported demand response capability. Many Market Participants have discussed their intention to initiate new programs or expand their existing to meet growing demands and State Renewable Portfolio Standards; however, reported forecasts fail to show demand side management programs increasing at rates that will significantly affect out-year resource adequacy. All demand side management totals and Net Internal Demands use only the currently reported penetrations, and do not assume additional demand side management growth. Across the Midwest Market footprint approximately 4,800 MW of demand side management is reported through 2017, which is an increase of roughly 800 MW from the 2007 data request.

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 3.2-3 details the reported 2008 data request DCLM forecast by Planning Region and compares it to the total 2007 data request forecast.

Table 3.2-3: Direct Controlled Load Management Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
West	1,228	1,256	1,284	1,303	1,316	1,329	1,336	1,344	1,352	1,354
East	271	273	275	277	279	279	279	279	279	279
Central	239	246	252	254	254	254	254	254	254	254
Midwest ISO	***1,738***	***1,775***	***1,811***	***1,834***	***1,849***	***1,862***	***1,869***	***1,877***	***1,885***	***1,887***
2007 Forecast	1,570	1,601	1,624	1,642	1,654	1,664	1,669	1,679	1,687	

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 3.2-4, there has been a roughly 600 MW increase in the amount of reported interruptible load from the 2007 data request. The majority of the increase in IL is within the East Planning Region and is attributed to a change in reporting rather than the initiation of new programs. The decreases in the amount of IL in years after 2008 are caused by IL programs with contracts that do not extend beyond the specific Planning Year. Many of these programs will continue into the next Planning Year and beyond; however, only the currently reported levels were included as a conservative estimate.

Table 3.2-4: Interruptible Load Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
West	1,437	1,428	1,284	1,290	1,275	1,284	1,254	1,301	1,310	1,318
East	1,033	936	988	1,018	1,018	1,018	1,018	1,018	1,018	1,018
Central	596	535	542	553	565	573	582	589	597	605
Midwest ISO	***3,066***	***2,899***	***2,814***	***2,861***	***2,858***	***2,875***	***2,854***	***2,908***	***2,925***	***2,941***
2007 Forecast	2,510	2,357	2,169	2,204	2,224	2,249	2,274	2,299	2,326	

3.2.1.3 Behind-the-Meter Generation

In the Midwest ISO, there is approximately 4 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 and acts as a load reduction at the applicable commercial node when in operation. Distributed generation capacity is included as a subset of BTM Generation. Table 3.2-5 details the amount of BTM Generation designated on summer peak from 2008 to 2017.

Table 3.2-5: Behind-the-Meter Generation

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
West	730	736	738	739	740	729	730	727	732	733
East	1,743	1,685	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697
Central	969	960	950	960	962	965	968	970	972	975
Midwest ISO	***3,442***	***3,381***	***3,385***	***3,396***	***3,399***	***3,391***	***3,395***	***3,394***	***3,401***	***3,405***
2007 Forecast	3,192	3,171	3,175	3,202	3,210	3,215	3,218	3,219	3,201	

Because BTM Generation can not be offered into the market, for the purposes of Midwest ISO Resource Adequacy it is only counted to the extent that it offsets load from the same point-of interconnection.

3.2.1.4 Net Internal Demand

Net Internal Demand is the coincident gross demand forecast less demand response programs and BTM Generation, as seen in the Figure 3.2-1 formula. On peak, it is this value that is expected to be metered in real-time. When calculating Net Internal Demand 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 Net Internal Demand forecast. 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 - BTM Generation

Figure 3.2-1: Coincident Net Internal Demand Formula

The projected Net Internal Demand for the Midwest ISO Market ranges from 100,009 MW for the summer of 2008 to 114,497 MW in 2017. A lower gross forecast, increased amount of demand side programs, and change in diversity factor have caused the Net Internal Demand forecast in the 2008 data request to drop by approximately 4.7%, essentially shifting the 2007 data request Net Internal Demand levels forward by two years in the 2008 data request. Table 3.2-6 details the 2008 and 2007 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 1.5%.

Table 3.2-6: Coincident Net Internal Demand Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Midwest ISO	***100,009***	***102,238***	***104,527***	***105,989***	***107,335***	***108,711***	***110,147***	***111,553***	***112,977***	***114,497***
Growth Rate		2.2%	2.2%	1.4%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%
2007 Forecast	104,989	106,864	108,999	110,316	112,099	113,598	115,141	116,860	118,423	

The Midwest ISO Market's adjusted all-time peak demand of 109,157 MW occurred on 7/31/2006. The slow economy coupled with an increase in demand side management levels, has resulted in the Midwest ISO forecast not reaching those same levels until the 2013-2014 timeframe. Figure 3.2-2 shows the actual peak load levels from 2005 through 2007 and the forecasted coincident Net Internal Demand levels from 2008 to 2017. 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 accounts for volatility in load forecasts.

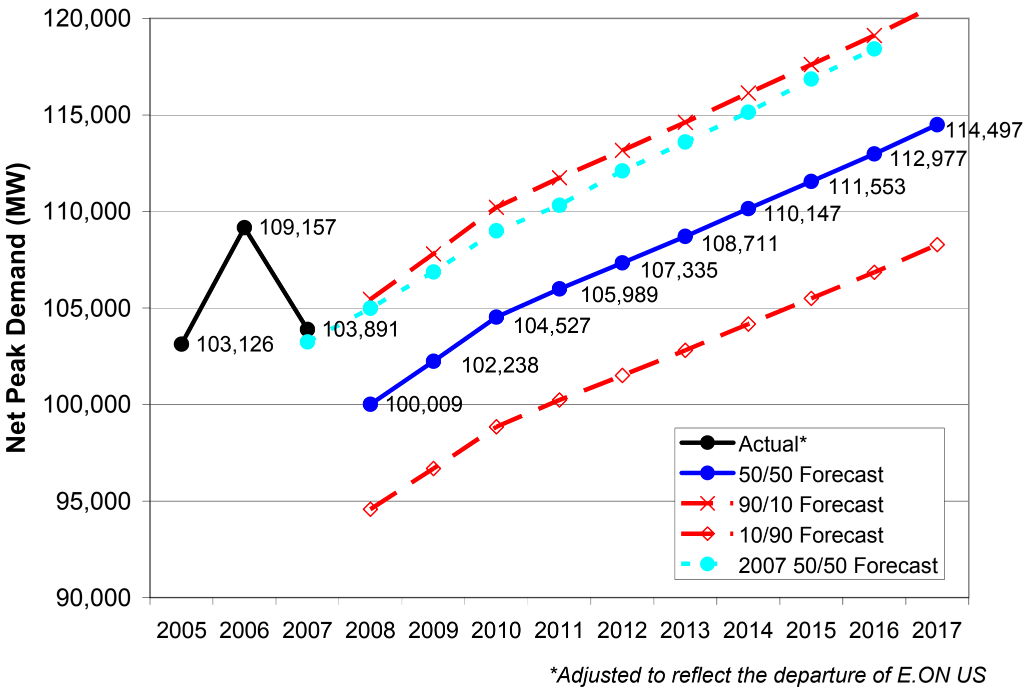


Figure 3.2-2: Historical and Forecasted Peak Demands

3.2.1.5 Contingency Reserves

Starting in 2007, a collaborative effort was initiated outside the Midwest ISO Tariff to lower the minimum required amount of Contingency Reserves (CR) through pooling. Signatories of the Contingency Reserve Sharing Group (CRSG) agreement include a set of systems slightly larger than the Midwest ISO Market. The total amount of CR required was determined by increasing the single largest contingency within the CRSG by 150%, totaling 2,250 MW. Coordination over the large area results in the Midwest ISO Market resources having a CR obligation equal to 1,662 MW on peak. Prior to the CRSG, Midwest ISO Market resources had a CR obligation of 2,635 MW.

Contingency Reserves must be held unless load curtailment is imminent. In the operating horizon, generation must be online to meet not only load requirements but also CR requirements. When establishing minimum planning reserve margins, CR requirements are not included; therefore, to reflect the current CR obligation, a 1,662 MW net load addition will be used throughout this assessment. The expected net summer peaks with CR are displayed in Table 3.2-7.

Table 3.2-7: Net Coincident Demand Plus Contingency Reserves Forecasts

Region	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Midwest ISO	***101,671***	***103,900***	***106,189***	***107,651***	***108,997***	***110,373***	***111,809***	***113,215***	***114,639***	***116,159***
2007 Forecast	106,651	108,526	110,661	111,978	113,761	115,260	116,803	118,522	120,085	

3.2.1.6 Load Forecast Uncertainty Calculations

The Load Forecast Uncertainty (LFU) value is derived from variance analysis to determine how likely monthly peak forecasts will deviate from actual monthly peak load. In order to establish an LFU value for the summer period, three years of real-time load data was compared to forecasts for those same periods. Load forecasts for the months of June, July and August were adjusted for the reported demand side management programs to arrive at coincident Net Internal Demand forecast values. Those monthly forecasts were compared to the actual monthly peak loads of the same period and the differences compiled into a sample space from which to derive a standard deviation. A load forecast uncertainty of approximately 4% was calculated using this methodology, which accounts for roughly 4,245 MW in 2008 and up to 4,849 MW in 2017 of load variability applied to peak projections. The 2008 uncertainty was used to form the normal distribution seen in Figure 3.2-3. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a value by finding the area under the curve to the right or left of that point. The 2007 actual coincident peak plus 1,622 MW of Contingency Reserves was 105,553 MW, the area to the left of this value represents a 82% chance that the 2008 peak will be less than 2007's and the area to the right represents a 18% chance the 2008 peak will exceed that of 2007.

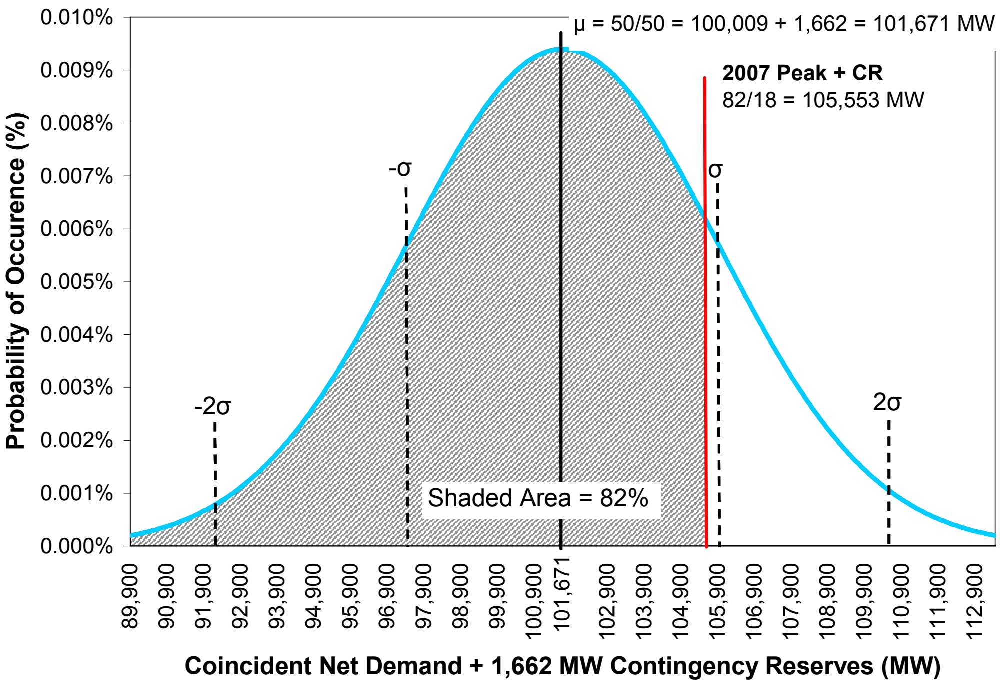


Figure 3.2-3: Net Coincident Demand Probability Distribution

3.2.2 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 2008 baseline capacity levels. The Midwest ISO Generator Interconnection Queue is used to identify future unit expansions.

3.2.2.1 2008 Baseline Capacity Levels

To create an accurate capacity projection, a reliable first year baseline capacity must be established. The following sections detail the derates, outages, and import capability expected during the 2008 peak.

3.2.2.1.1 Midwest ISO Generation

Nameplate capacity of 127,204 MW is expected to be available in 2008 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 1,418 MW or 96% growth in the amount of nameplate wind capacity from 2007, and a 24 MW or 0.6% growth in the amount of hydro capacity. A breakdown of the 2008 nameplate rated capacity can be seen in Figure 3.2-4. The waste units listed in Figure 3.2-4 are composed of four refuse derived fuel plants, two wood waste burners, and one turkey waste plant.

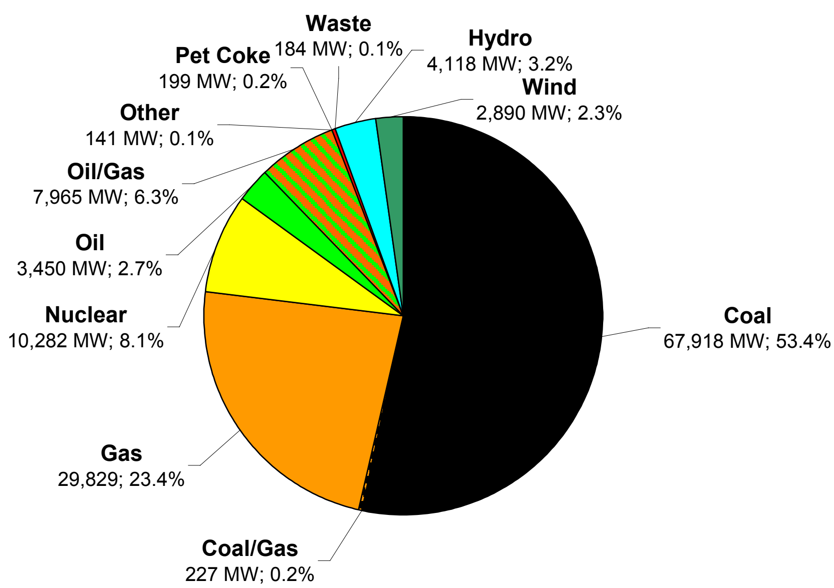


Figure 3.2-4: 2008 Nameplate Capacity by Fuel Type

Based on the nameplate values of generation capacity, 127,204 MW are available in 2008 within the Midwest ISO. This amount is reflected in the first (left-most) column of Figure 3.2-5. Experience indicates that this number is not a reasonable expectation when it comes to the actual operating day. A number of items contribute to the actual available capacity on the operating day being less than the nameplate capacity, including: planned or forced outages, operational derates, external commitments, and other factors. The remaining columns in Figure 3.2-5 illustrate how the 127,204 MW of nameplate capacity was progressively adjusted to reflect known operational performance, market requirements, and additional contracted or imported resources to arrive at a value that can be expected on the operating day.

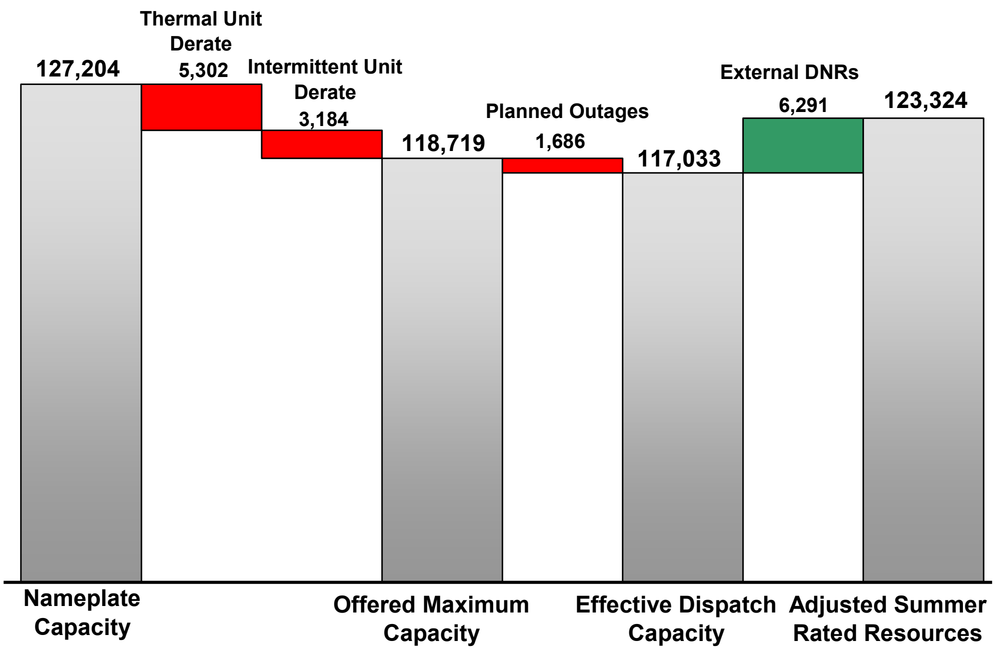


Figure 3.2-5: 2008 Capacity/Resource Overview

The *Nameplate Capacity* mentioned in Figure 3.2-5 refers to the manufacturer's projected output of a given unit. A study was undertaken to derive historical performance values for individual units during the summer period; the sum of these values is the *Offered Maximum Capacity*. The difference between the Nameplate Capacity and the *Offered Maximum Capacity* is split into two pieces as *Thermal Unit Derate* and *Intermittent Unit Derate*. Sections 3.2.2.1.2 and 3.2.2.1.3 respectively detail the study process for determining unit derates based on historic performance values.

Units on outage for the entire summer of 2008 are represented as *Planned Outages* and are subtracted from the *Offered Maximum Capacity* to arrive at an *Effective Dispatch Capacity*. The *Effective Dispatch Capacity* represents the amount of generation which could be available within the footprint for dispatch during the summer peak.

Another portion of expected capacity is comprised of resources external to the Midwest ISO Market and represented as *External Designated Network Resources (DNRs)*. Historically, the Midwest ISO imports roughly 8 GW during peak; however, a conservative approach was taken to include only those external resources that have a contractual obligation to exclusively serve load within the Midwest ISO on peak. The contractual obligation with External DNRs for summer 2008 is 6.3 GW.

The total internal capacity that has historically been available during peak conditions as well as the external resources that are obligated to serve Midwest ISO load is represented by the *Adjusted Summer Rated Resources total*. Figure 3.2-6 illustrates the fuel/resource distribution for the *Adjusted Summer Rated Resources total.* The *Adjusted Summer Rated Resource total* will be the baseline capacity that will be expanded upon throughout this section.

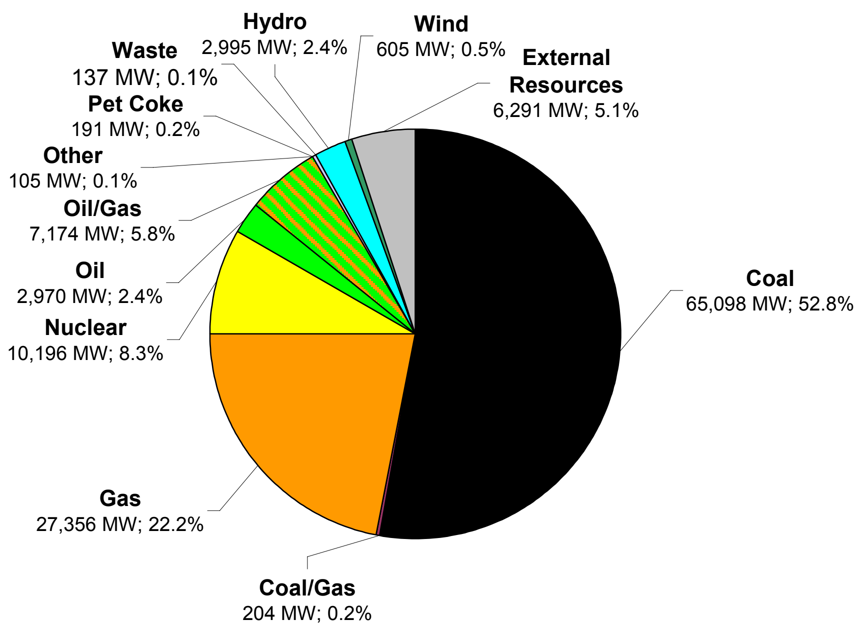


Figure 3.2-6: 2008 Adjusted Summer Rated Resources by Fuel Type

3.2.2.1.2 Thermal Unit Derate

Unit derating refers to the lowering of the rated electrical capability of generation resources. Generating units within the Midwest ISO footprint submit hourly offers to the Midwest ISO stating their availability for the following day. To obtain a better indication of thermal unit maximum capability, an extensive review of the offered emergency maximums during the 2007 summer was conducted. Emergency maximum output offers represent the highest stable MW level at which a unit can operate; therefore, with each offer the operating Market Participant is reporting a maximum capacity rating for that hour. Hourly Day-Ahead emergency output offers were queried to find the highest offered emergency maximum over the 2007 summer for each unit. New thermal units without historical offer information were assigned their nameplate rating for the purposes of this study.

Because not all units are committed through the Day-Ahead process, utilizing real-time performance does not give a valid indication of potential performance for all thermal units. All designated network resources have a requirement to make an offer in Day-Ahead Market; therefore, the Midwest ISO was able to assign a market measured maximum capacity for all network resources.

The Midwest ISO has 120,195 MW of nameplate rated thermal capacity resources in its Market. The aggregation of the maximum offered emergency maximum for each thermal unit over the 2007 summer was 114,893 MW. This 5,302 MW difference is reflected as a derate in Figure 3.2-5.

3.2.2.1.3 Intermittent Unit Derate

In order to determine a capacity value for intermittent units that could be reliably expected to operate on peak a study was conducted using historical outputs. A unit capacity value was calculated by obtaining a three-year average of actual output during the summer weekday peak periods consisting of the hours between 3:00 p.m. and 6:00 p.m during June, July and August. This historic capacity value, when compared to the nameplate capacity available during peak, was used to determine peak capacity credit factors. Through this study, it was determined that wind units within Midwest ISO had an average peak capacity credit of roughly 20%. The same study provided that run-of-river hydro units averaged a capacity credit of approximately 50%. Wind units without sufficient historical data were assigned this 20% capability while run-of-river hydro units were assigned 50% capability. The summation of this study amounted to 2,286 MW of wind capacity derate and 898 MW of hydro derate. **Due to the limited amount and irregular distribution of performance data available, the methodology used in this assessment will not necessarily be used for future analyses or intermittent resource accreditation.**

The intermittent nature of wind capacity allows for no guarantee in the amount available on peak. As wind begins to comprise a greater portion of footprint capacity, this variability becomes a significant issue. In order to account for this variability, wind production during peak conditions was examined. Table 3.2-8 details the wind performance **during the peak hour** for the previous three years.

Table 3.2-8: Wind Production at Peak

	2005		2006		2007		2008	
	MW	% of NP	MW	% of NP	MW	% of NP	MW	% of NP
Nameplate Capacity (NP)	871		1,032		1,462		2,890	
Nameplate less Intermittent Derate [4]	174	20.0%	217	21.0%	307	21.0%	604	20.9%
Designated Network Resources [4]	92	10.6%	148	14.3%	147	10.1%	224	7.8%
Actual Metered at Peak	103 [1]	11.8% [1]	686 [2]	66.5% [2]	24 [3]	1.6% [3]		

[1] Midwest ISO Peak Hour - August 3, 2005 16:00

[2] Midwest ISO Peak Hour - July 31, 2006 16:00

[3] Midwest ISO Peak Hour - August 8, 2007 16:00

[4] Due to the limited amount and irregular distribution of data available, this methodology may not be used for future analyses or wind resource accreditation.

The *Nameplate Less Intermittent Derate* portion of the table utilizes the aforementioned analysis. Designated Network Resources represents units designated by Load Serving Entities to meet their Resource Adequacy requirements. Load Serving Entities can designate up to 20% of the unit's nameplate capacity. *Actual Metered at Peak* represents the amount of generation actually produced during the yearly peak hour.

The majority of wind generation within the Midwest ISO is located within the Western Planning Region; the output is therefore contingent on weather conditions within that region of the footprint. Accordingly, a weather system which moves across the footprint could cause wind to be nearly unavailable during times which certain regions are experiencing peak conditions. As wind generation continues to be developed across the entire Midwest ISO footprint, thus increasing diversity, there is a greater possibility of wind being available on peak.

3.2.2.1.4 Unit Outages

Planned unit outages were accounted for only if the unit was reported out for the entire 2008 summer period (June 1, 2008 through August 31, 2008). These outages amounted to 1,686 MW of capacity that will not be available during the 2008 peak period. Generally, planned unit outages tend to be minimal during the summer peak and the majority of these planned outages have been out for an extended period, though they have not been formally retired.

Although outages are only planned for the 2008 summer, historically the Midwest ISO has experienced roughly the same amount of "all summer" outages in past years. To represent these expected out-year outages 1,686 MW of planned outages will be carried through 2017.

3.2.2.1.5 Designated External Resources

6,291 MW of capacity from outside of the Midwest ISO footprint is utilized during the 2008 summer. This capacity is designated to serve load within the Midwest ISO and cannot be recalled by the source Transmission Provider. Examining historical data, this designated capacity does not account for the entirety of external support that the Midwest ISO is capable of receiving. Typically the Midwest ISO imports over 8 GW of energy during the system peak; however, the 6,291 MW is being used as a conservative estimate.

In the Midwest ISO, resources are only designated through the 2008 Planning Year. Since Market Start, the amount of external unit designations has remained relatively constant. To reflect the consistent commitment of external resources in future years, the 6,291 MW of external resources will be carried through 2017.

3.2.2.2 Out-Year Proposed Generation

During the past five years the number of active generator interconnection queue entries has continued to rise. There has also been a considerable shift in the types of requests. Driven by Renewable Portfolio Standards, there has been a vast increase in the number of active wind projects in the queue. From 2005 to 2006, the number of queued wind projects has doubled. With more states considering renewable energy mandates the number of queued wind projects is expected to continue to increase. Figure 3.2-7 details the current capacity and types of generator interconnection queue requests with an active status.

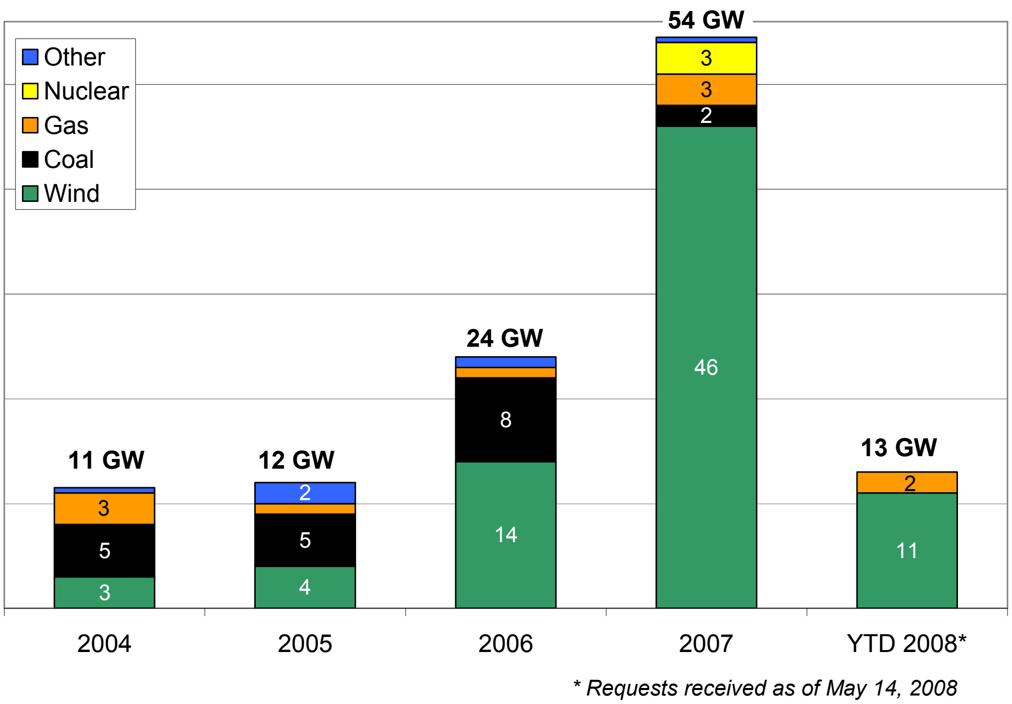


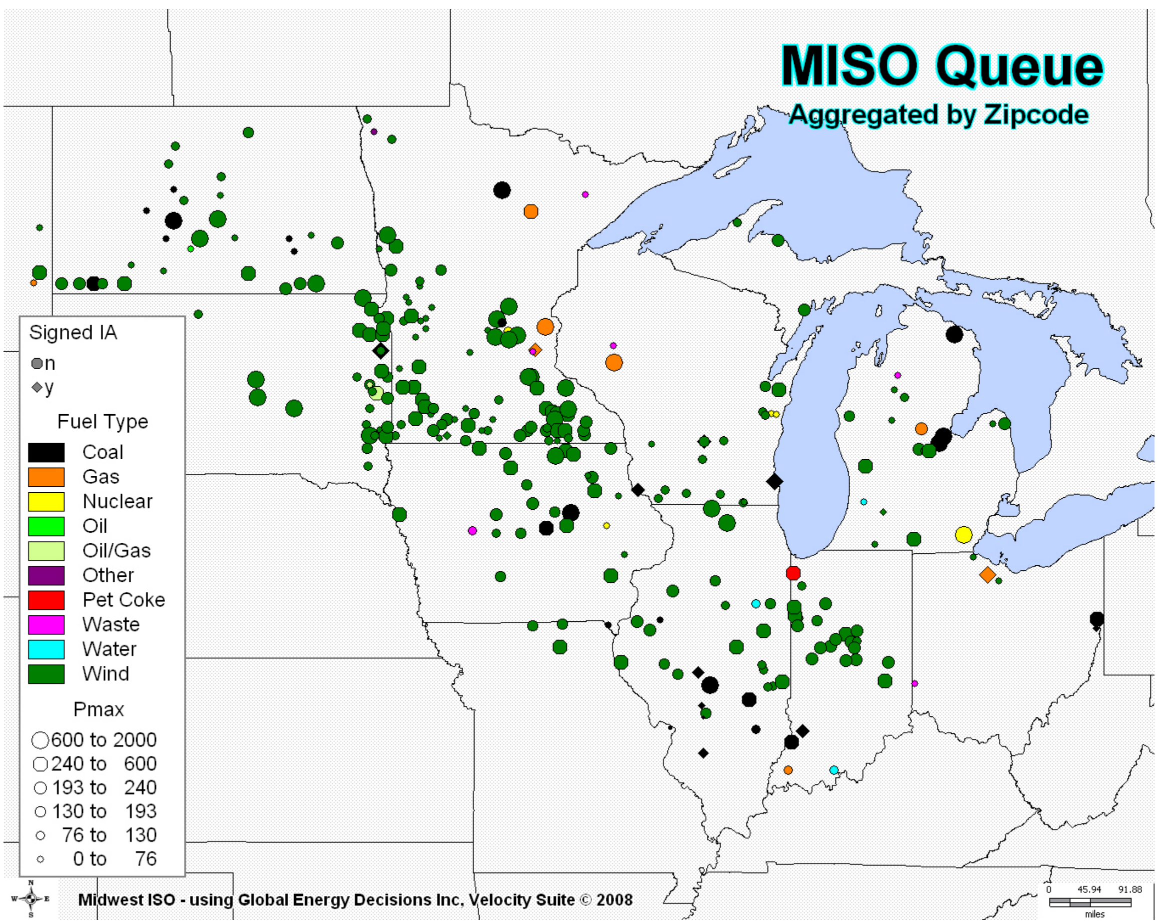
Figure 3.2-7: Giga-Watts of Queue Requests by Year and Fuel Type

Figure 3.2-8 displays the location of active queue projects. Numerous relatively large generation projects are located in remote areas a great distance from load centers, requiring significant transmission upgrades. The bulk of the active queue projects are concentrated in the southwestern portion of Minnesota, eastern South and North Dakota, and northern Iowa where wind is most prevalent. Several large non-wind projects are located in northern Minnesota, central and southern Michigan, and northern Ohio. Note that Figure 3.2-8 shows both requests with a signed Interconnection Agreement (IA) (*diamond shaped*) and those requests without a signed IA (*circular shaped*).

Throughout this assessment "active queued capacity" includes those units with:

- An active or done status and not already included in the Midwest ISO Commercial Model;
- A location inside the Midwest ISO system (non-coordinated); and
- An expected online date prior to 2017 and after May 31, 2008.

Unit information in the Midwest ISO Interconnection Queue was updated with Market Participant supplied information wherever applicable. Unless updated, in-service dates were directly referenced from the Midwest ISO Interconnection Queue, even though many dates are optimistic.



*Callaway Nuclear 2 has a Queue in-service date of 12/31/2017 and is not included in this assessment

Figure 3.2-8: Map of "Active Queued Capacity" Aggregated by Zip Code

Currently, there are 367 active Midwest ISO projects in the Generator Interconnection Queue totaling 83.5 GW; however, only 306 projects (80.5 GW) meet the "active queued capacity" criteria for use in this assessment. Of the 306 projects, 242 of them are proposed wind plants which total 62.8 GW (nameplate capacity).

Because of the intermittent nature of proposed wind and run-of-river hydro units, a summer capacity credit was applied consistent with Section 3.2.2.1.3. 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.

Figure 3.2-9 provides a timeline of cumulative active queued capacity additions for the Midwest ISO.

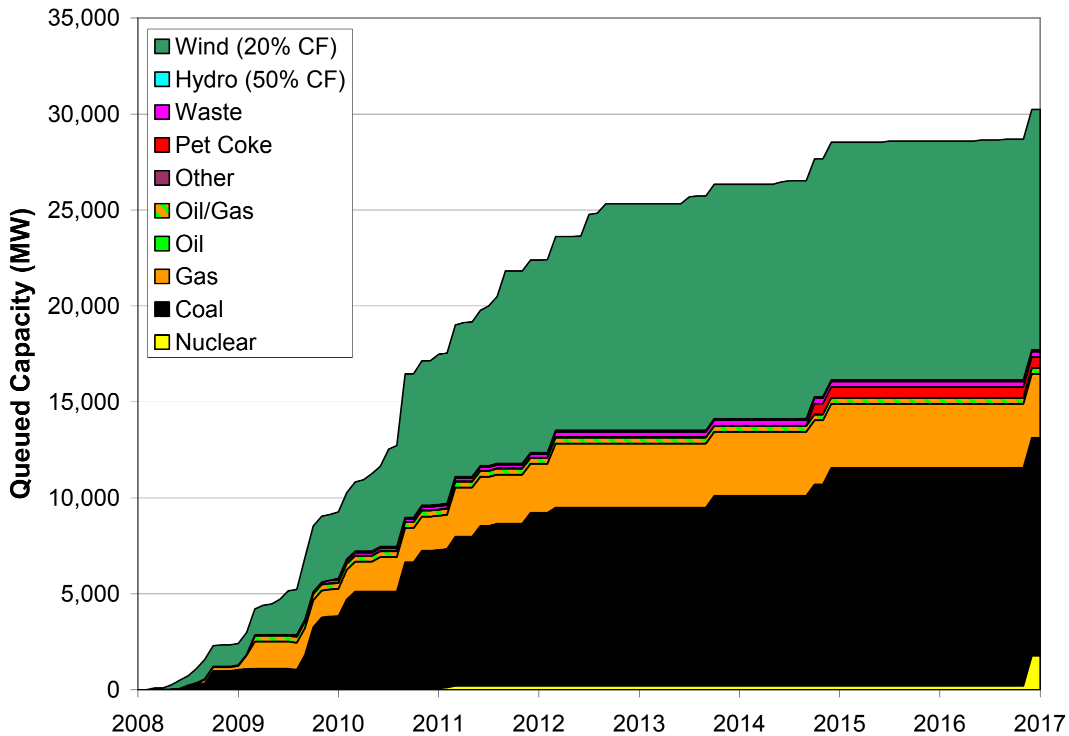


Figure 3.2-9: Midwest ISO Total Cumulative Queued Capacity

Of the 306 active queued capacity projects, there are 18 projects with a signed Interconnection Agreement (IA) and an expected in-service date prior to 2017. These projects are expected to add 5,105 MW of additional capacity to the Midwest Market footprint. The expected capacity additions are primarily composed of coal projects totaling 3,775 MW. Gas fueled combined cycle projects amount to 1,210 MW and proposed signed IA wind units total 118 MW.

Queued capacity with a signed IA is primarily concentrated in the West Planning Region, where several large coal facilities are under construction or being discussed. The large combined cycle plant in the East Planning Region is currently under construction and expected to be online during the 2009 summer.

Figure 3.2-10 provides a timeline of cumulative active queued capacity additions with a signed IA for the Midwest ISO.

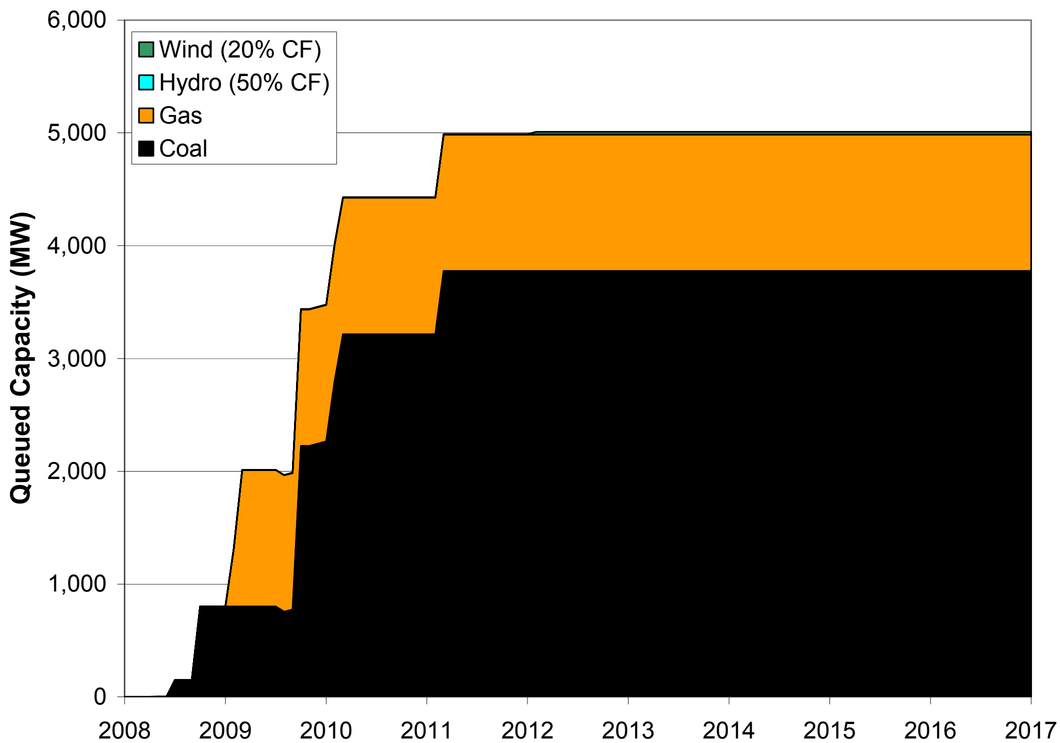


Figure 3.2-10: Midwest ISO Signed IA Cumulative Queued Capacity

3.2.2.3 Projected Capacity

Currently, there is 123,324 MW of capacity that is expected provide energy to the Midwest ISO during summer peak conditions. 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 3.2-9 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 IA have a total confidence factor of 80% and all queued units (signed IA plus non-signed IA) have an equivalent 20% confidence factor.

Table 3.2-9: 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%**

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 2017. Applying those two confidence factors to the appropriate queued statuses and fuel types yields generation expansions totaling 4,132 MW using the 80% confidence factor on signed IA queued capacity and 5,866 MW using the 20% confidence factor on all queued capacity over the ten-year horizon.

Since the 2007 summer period, 972 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. There are 561 MW of known units that are scheduled to retire in the next ten years. 70% of these retirements are existing coal-powered plants that are being converted to gas-fueled facilities.

Figures 3.2-11 and 3.2-12 break-down the forecasted 2017 capacity by fuel type. Figure 3.2-11 includes signed IA queued units with an applied 80% confidence factor and totals 126,895 MW. Figure 3.2-12 utilizes all queued capacity units with a 20% confidence factor applied and totals 128,697 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.

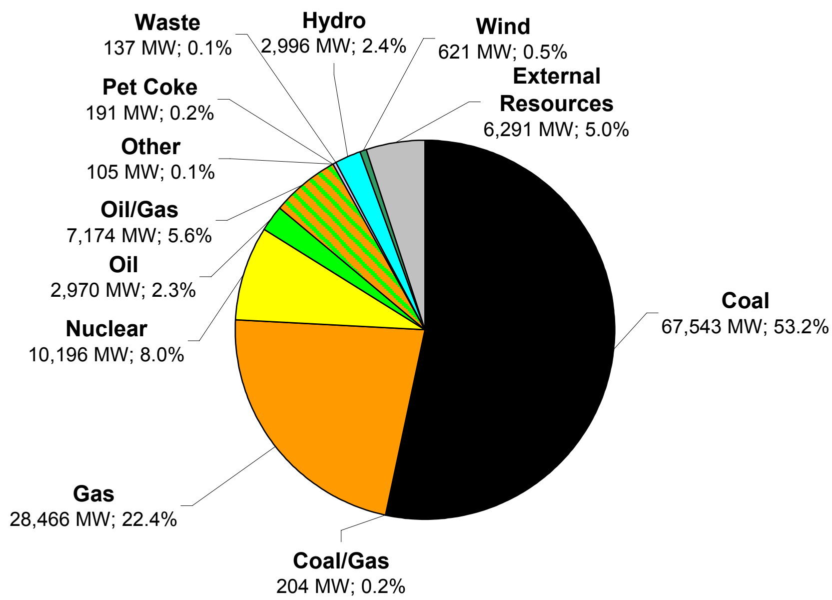


Figure 3.2-11: 2017 Projected Capacity by Fuel Type – 80% Signed IA

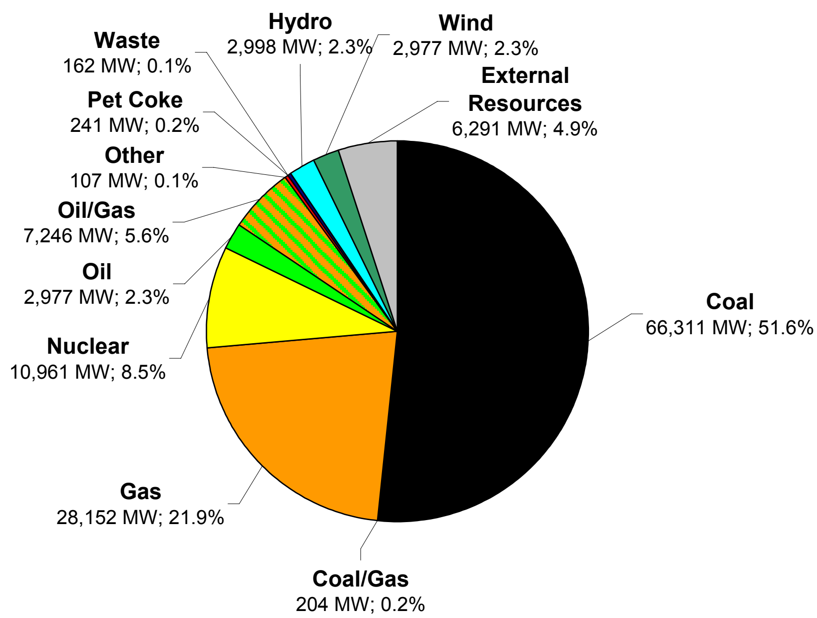


Figure 3.2-12: 2017 Projected Capacity by Fuel Type – 20% All Queue Entries

3.3 Resource Adequacy

The determination for Resource Adequacy within the Midwest ISO is split into two parts, the Reliability Assessment and Risk Assessment. The Reliability Assessment focuses on comparing the forecasted reserve margin against the minimum requirement determined by State Authorities and Planning Reserve Sharing Groups. The Risk Assessment considers a wider range of possible forecasts and explores associated effects on Loss of Load Expectation (LOLE). Both parts are 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

3.3.1 Reliability Assessment

The Reliability Assessment relies on the current year's minimum reserve margin requirements determined by State Authorities and Planning Reserve Sharing Groups as a benchmark. For the current Planning Year, each LSE is required to provide capacity resources to meet their total reserve requirement. Load Serving Entities' (LSE) individual reserve requirements may be derived from numerous State and Planning Reserve Sharing Group requirements. Because most resources within the Midwest ISO are deliverable to the aggregate and can be designated to serve any Network Load, specific source-to-sink combinations are not appropriate. Therefore, it is not possible to calculate the projected reserve margins for each requirement. When the total aggregated reserve requirement has been satisfied, the Midwest ISO can be considered to have sufficient resources.

Under the current Resource Adequacy section of the Midwest ISO's Energy Markets Tariff (Module E) reserve requirement standards are governed by the States and NERC Regional Entities. Presently, Wisconsin is the only state to have a defined reserve requirement. Three NERC Regional Entities within the Midwest ISO have established standards to govern the methodology used in the determination of reserve requirements. There are two Planning Reserve Sharing Groups within the Midwest ISO that have reserve requirements consistent with the Regional Entity standards.

The Midwest Planning Reserve Sharing Group (MPRSG) has approved planning reserve targets for three zones within the Midwest ISO Market Footprint. The MPRSG's approval was based on its review of numerous LOLE analyses and represents the group's consensus of the reserve margins necessary to maintain a resource adequacy criterion of one day in ten years LOLE. The report for the MPRSG is located at:

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

Mid-Continent Area Power Pool (MAPP) has a long-standing reserve requirement necessary to maintain a resource adequacy criterion of one day in ten years LOLE. The same reserve requirement applies to all MAPP members within the Midwest ISO Market. Many MPRSG West members are also MAPP members; however, because MAPP has a higher reserve requirement they have a contractual obligation to follow the MAPP reserve requirements.

A 12% default requirement is applicable for demand that is not within Wisconsin or included in MAPP or the MPRSG. The six applicable reserve margins in the Midwest ISO for the 2008 summer are provided in Table 3.3-1. Although, the reserve margin in Table 3.3-1 is only applicable for the 2008 summer, it will be used as a benchmark to assess adequacy levels in out-year capacity projections.

Table 3.3-1: 2008 Midwest ISO Reserve Requirements

Region	% of Total Demand	Reserve Requirement
MPRSG WEST	6.1%	14.2%
MPRSG CENTRAL	35.5%	14.3%
MPRSG EAST	29.8%	13.7%
MAPP	12.7%	15.0%
WISCONSIN	11.8%	18.0%
MISO DEFAULT	4.2%	12.0%
TOTALS	***100.0%***	***14.5%***

MPRSG = Midwest Planning Reserve Sharing Group

The reserve margin used in this assessment was calculated from both the Net Internal Demand in Table 3.2-6 and the Net Internal Demand plus Contingency Reserves in Table 3.2-7. The Adjusted Summer Rated Resource total in Figure 3.2-5 was used as the base (2008) capacity total. To assure a highly probable capacity expansion an equivalent 80% confidence factor was applied to capacity in the Midwest ISO Generator Interconnection Queue with a signed Interconnection Agreement and known retirements were removed. The projected reserve margins for the Midwest ISO range from 23,315 MW in 2008 to 12,397 MW in 2017 - 23.3% to 10.8% of the Net Internal Demand. When Contingency Reserve are added the projected reserve margins drop to 21,653 MW in 2008 and 10,735 MW in 2017. Table 3.3-2 displays the projected reserve margins through 2017.

The projected reserve margins exceed the minimum reserve requirement benchmark of 14.5% through 2013; however, in 2014 the reserve margin with Contingency Reserves drops to 13.4% and in 2015 the reserve margin without Contingency Reserves drops below the threshold.

Table 3.3-2: Reserve Margin Forecasts

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Reserve Margin (MW)	23,315	21,795	21,663	20,446	19,561	18,184	16,748	15,343	13,919	12,397
Reserve Margin (%)	23.3%	21.3%	20.7%	19.3%	18.2%	16.7%	15.2%	13.8%	12.3%	10.8%
Reserve Margin + CR (MW)	21,653	20,133	20,001	18,784	17,899	16,522	15,086	13,681	12,257	10,735
Reserve Margin + CR (%)	21.3%	19.4%	18.8%	17.4%	16.4%	15.0%	13.5%	12.1%	10.7%	9.2%

CR = Contingency Reserves

3.3.2 Risk Assessment

Using the various levels of capacity and demand established in this report, LOLE study was performed over the summer months for each of the out-looking ten years. This study established risk levels associated with the yearly declining reserve margin. This study goes much farther to quantify the effects altering the load forecast, confidence factor, external commitments, wind capacity credit, forced outage rates have on LOLE. 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 operating conditions on LOLE so that future risk can be managed.

3.3.2.1 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 a study with an unconstrained transmission system there are three primary variables that affect LOLE, capacity ratings, Forced Outage Rates (FOR), and demand levels.

The base case utilizes the capacity forecast used in the reserve margin calculations in Section 3.3.1 – the Adjusted Summer Rated Capacity plus an 80% confidence factor applied to the Signed IA Queue Projects. In addition, the base case, and all subsequent cases, will separately employ the capacity projected when a 20% confidence factor is applied to all queued projects.

The average FOR used in the base case is the statistical mode of the system forced outage rates experienced during the last two summers – 6.4%. Section 3.3.2.2.1.3 further describes the average system FOR calculations.

The 50/50 Net Demand forecast used in Section 3.3.1 is the base case demand forecast. All demand forecasts include consideration for Contingency Reserves.

The base case provides the "best guess" case; 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. The Load Forecast Uncertainty (LFU) analysis described in Section 3.2.1.6 results in the formation of a normal distribution of 2008 load levels as seen in Figure 3.3-1. 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. These values are represented for 2008 in Figure 3.3-1 as the Low and High Load with the Base Load representing the reported coincident Net Internal Demand around which the normal distribution is constructed. A similar distribution is available for years 2009-2017.

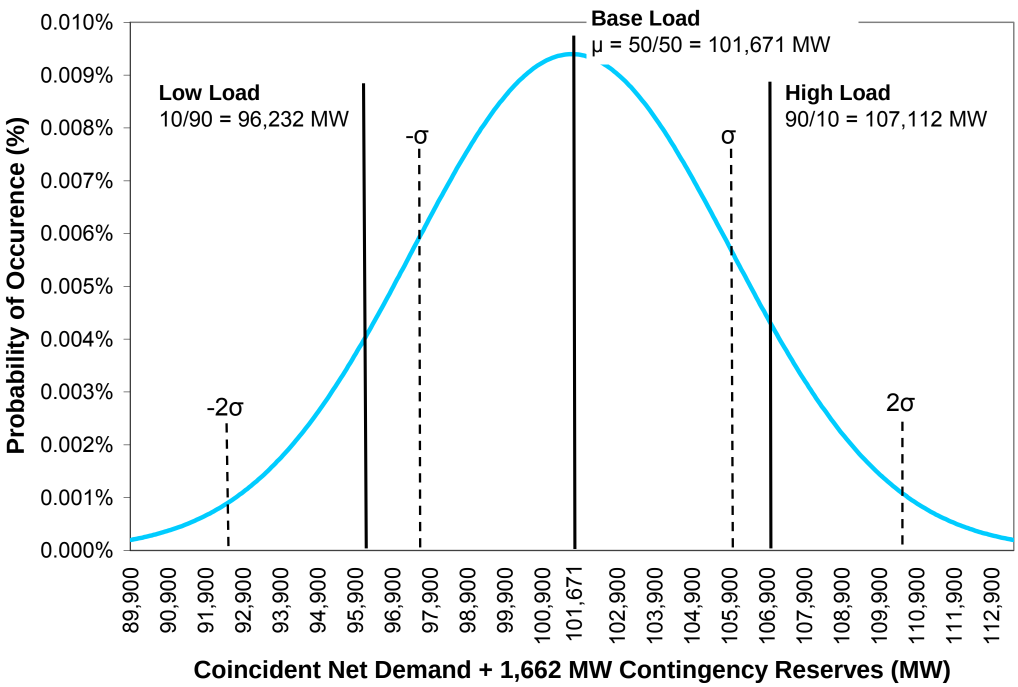


Figure 3.3-1: Case Summary of Net Demand

Table 3.3-3 summarizes the inputs for the base case as well as the high and low demand cases.

Table 3.3-3: Base and High/Low Load Case Set-Up Summary

Case Name	Demand	Year 2008 Capacity	Forced Outage Rate
Base	Net 50/50 + CR	Adjusted Sum. Rtd. Resources	6.40%
High Load	Net 90/10 + CR	Adjusted Sum. Rtd. Resources	6.40%
Low Load	Net 10/90 + CR	Adjusted Sum. Rtd. Resources	6.40%

Figure 3.3-2 provides a projected reserve margin timeline for the base case and high and low demand cases utilizing the projected capacity when an 80% confidence factor is applied to queued units with a signed IA.

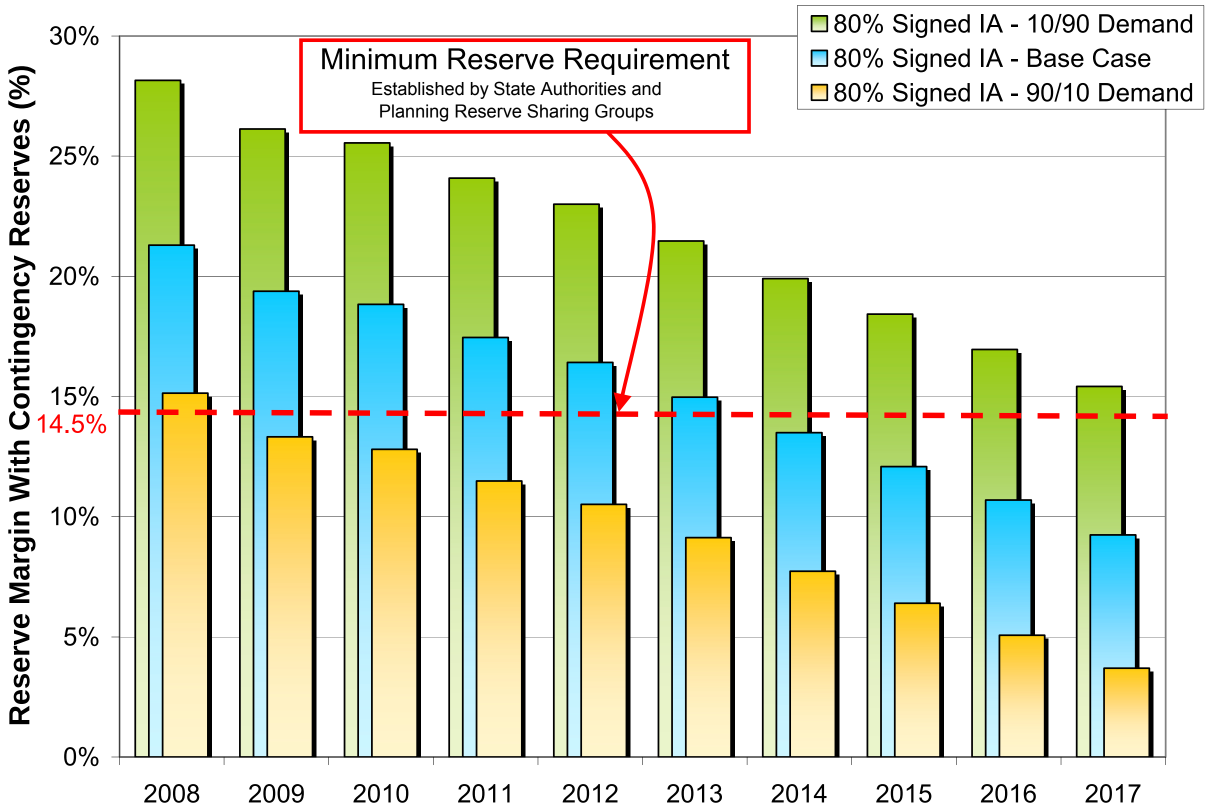


Figure 3.3-2: 2008 – 2017 Reserve Margin Forecast

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.

Figure 3.3-3 displays the projected LOLE levels for the base case and high and low demand cases utilizing the projected capacity when an 80% confidence factor is applied to queued units with a signed IA. The reserve margins are plotted on the same chart to show as reserve levels erode, risk increases at an exponential rate.

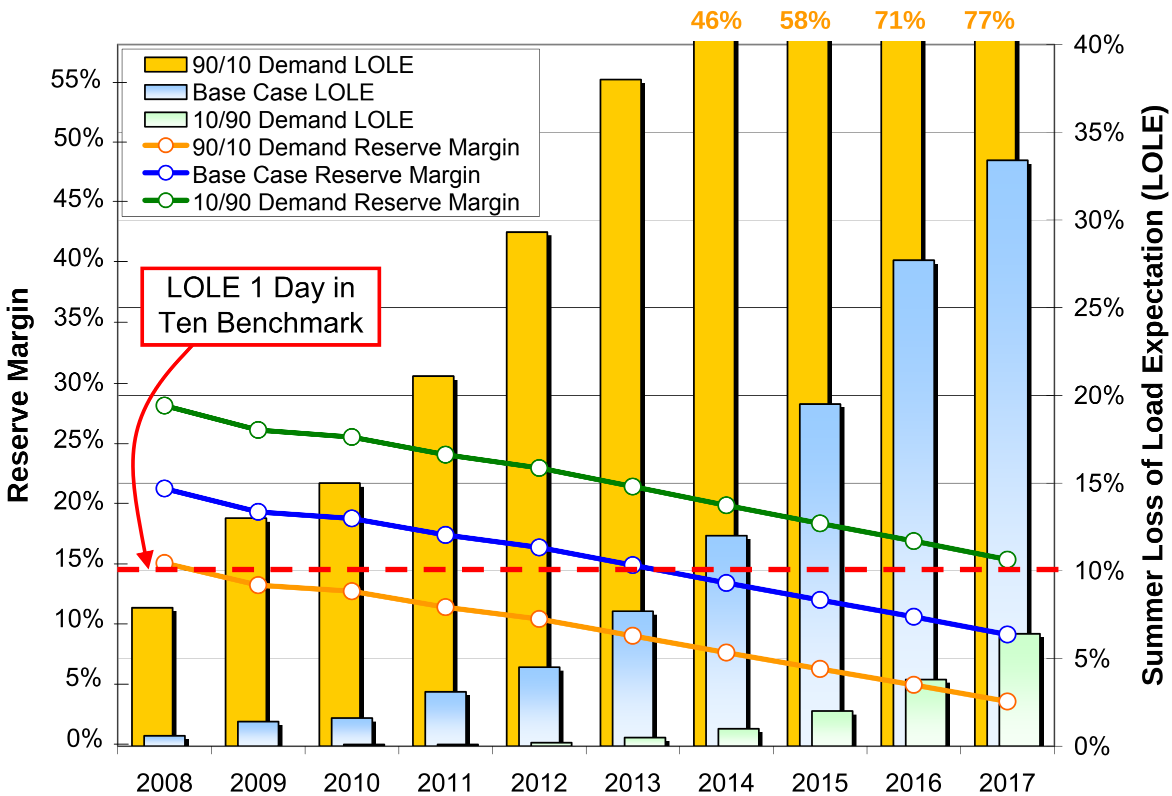


Figure 3.3-3: 2008 – 2017 Loss of Load Expectation Forecast

From Figure 3.3-3, it can be seen that LOLE exceeds the minimum 0.1 day LOLE criteria in 2014. Table 3.3-4 summaries when each case's LOLE exceeds 0.1 day per year.

Table 3.3-4: Base Case LOLE Summary

Base Case	Year LOLE Exceeds .1	
	80% Signed IA	20% All Queue
Base - 50/50 Demand	***2014***	***2015***
High Load - 90/10 Demand	2009	2009
Low Load - 10/90 Demand	> 2017	> 2017

3.3.2.2 Future Uncertainties – Sensitivity Analysis

Section 3.3.2.1 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 make it more probable that actual conditions will be worse than forecasted in the base case; meaning system conditions could exceed the 0.1 day LOLE criteria sooner than 2014. Factors contributing to this probability include:

- An increasing number of queue requests coupled with regulatory delays could push proposed units’ in-service dates into the future
- The aging generation fleet carries an increased risk of retirement and higher forced outage rates
- The initiation of significant greenhouse gas regulations would increase the probability for retirement of older baseload units
- 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 case shown in Table 3.3-5 was run over the ten year planning horizon using both of the projected capacities from Section 3.2.2.3. In each case only a single variable was changed to observe the effects that particular variable had on LOLE. A full description for each uncertainty as well as the case set-up is provided in Section 3.3.2.2.1.

Table 3.3-5: Case Sensitivities Set-Up Summary

Case Name	Demand	Year 2008 Capacity	Queued Capacity	FOR
2 Year Queue Project Delay	Net 50/50 + CR	Ad. Sum. Rtd. Resources	Base - In-Service Date + 2 yrs	6.40%
Increased Retirements	Net 50/50 + CR	Ad. Sum. Rtd. Resources	Base & Units >65 yrs Retired	6.40%
Increased Forced Outage Rate	Net 50/50 + CR	Ad. Sum. Rtd. Resources	Base	9.26%
0% Wind Capacity Credit	Net 50/50 + CR	Ad. Sum. Rtd. Resources - Wind	Base - Wind Units	6.40%
No External Support	Net 50/50 + CR	Ad. Sum. Rtd. Resources - Externals	Base	6.40%
Reduced Demand Side Mgmt	Gross 50/50 - ? DSM + CR	Ad. Sum. Rtd. Resources	Base	6.40%

As determined in the base case analysis in Section 3.3.2.1, LOLE exceeded the one day in ten years benchmark in 2014, when each uncertainty is individually realized the effects on LOLE ranged from having nearly no effect to causing LOLE to exceed 0.1 days in 2009. Table 3.3-6 provides the year LOLE exceeded 0.1 days for each of the sensitivities listed in Table 3.3-5. The complete LOLE and reserve margin results for these runs can be found in Appendix F1.2.

Table 3.3-6: LOLE Summary for Sensitivities

Case	Year LOLE Exceeds .1	
	80% Signed IA	**20% All Queue**
Base - 50/50 Demand	***2014***	***2015***
2 Year All Queue Project Delay	2014	2014
Increase in Retirements	2013	2014
Increase in Forced Outage Rate	2011	2010
Wind Capacity Credit reduced to 0%	2014	2013
No External Support	2009	2009
Reduction in Demand Side Management	2012	2010

Using the base case as a benchmark, it was possible to derive the impact that each variable has on LOLE for a single year – 2015. 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. Project delay had little to no effect on LOLE because the last signed IA project was added in 2012. Figure 3.3-4 shows the effect each variable has on LOLE in 2015 when projected capacity includes an 80% confidence factor applied to signed IA queue projects and Figure 3.3-5 shows the affects when a 20% confidence factor is applied to all queue projects.

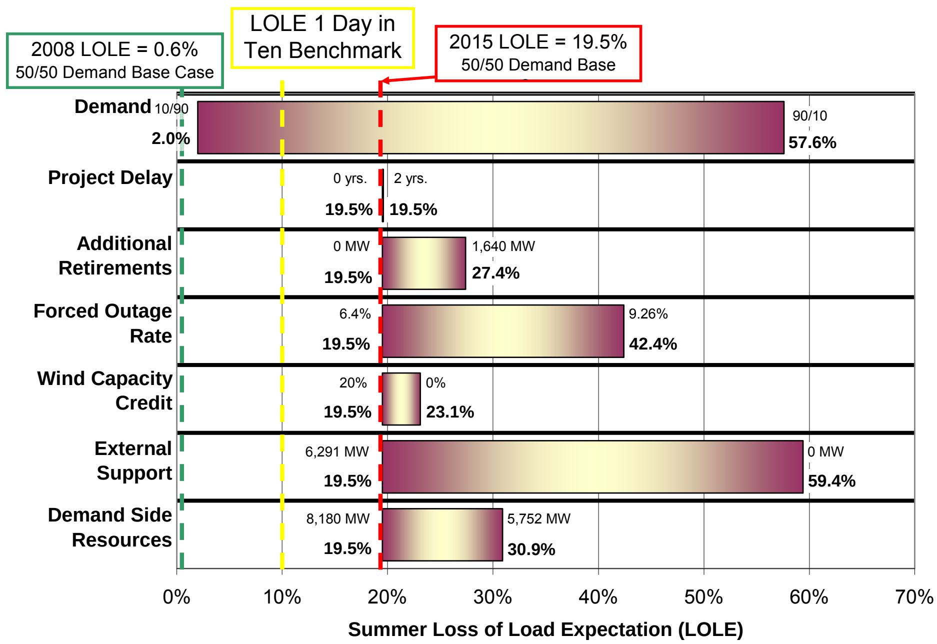


Figure 3.3-4: Year 2015 LOLE Sensitivity to Variable Adjustment – 80% Signed IA

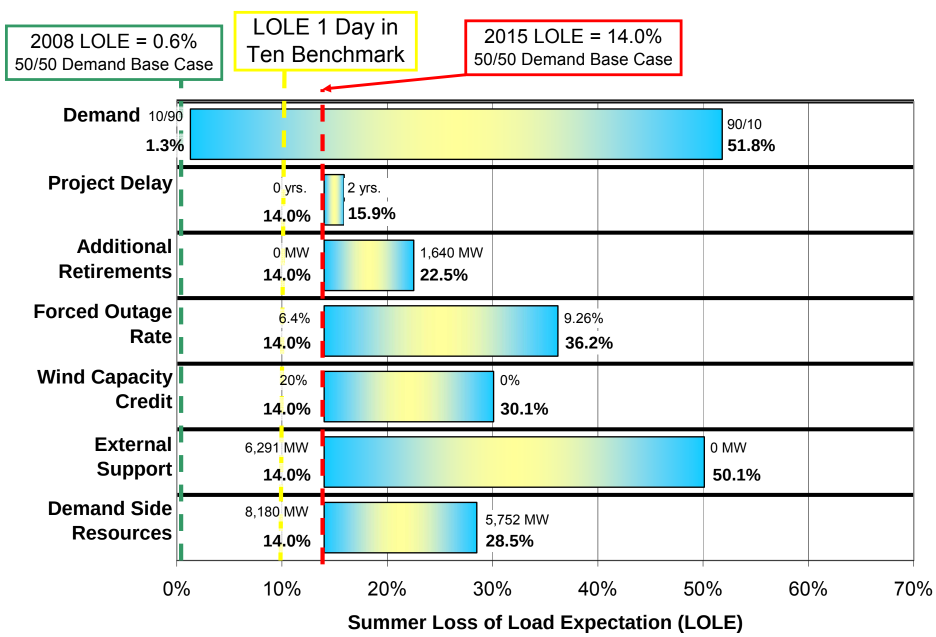


Figure 3.3-5: Year 2015 LOLE Sensitivity to Variable Adjustment – 20% All Queue

In all previous cases only a single uncertainty has been realized and it effects observed; however, in all actuality it is more probable that a combination of the uncertainties would be experienced simultaneously. To examine these effects, every possible combination of uncertainties was analyzed to obtain a range of possible LOLE for a single year – 192 combinations. Figure 3.3-6 is a scatter plot of every combination of uncertainties using the projected capacity with a 20% confidence factor on all queued capacity for the year 2015. Each single variable adjustment case from Figure 3.3-5 is marked with a blue triangle in Figure 3.3-6.

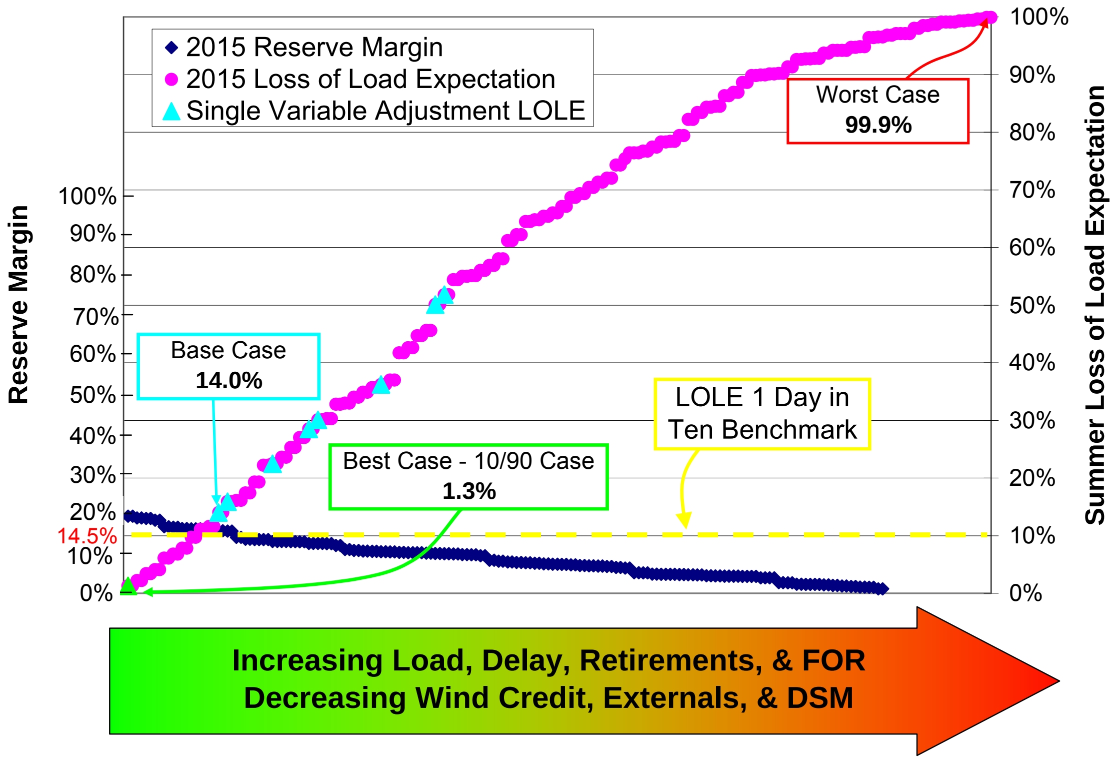


Figure 3.3-6: 2015 LOLE Forecast – All 192 Sensitivity Combinations

When a combination of variables is realized there are only few combinations that allow for LOLE to be less than that of the base case. LOLE trends in the chart do not display the familiar exponential growth as seen in previous charts, because LOLE is already beyond the exponential range – LOLE levels are already so high, that even the addition of another high LOLE event doesn't have as much affect. The highest volume of LOLE values is in the 95% to 100% range, followed next by the 90% to 95% range. The complete results from the 192 uncertainty combinations can be found in Appendix F1.3.

3.3.2.2.1 Sensitivity Descriptions

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

3.3.2.2.1.1 Project Delay

During the past six years the number of active generator interconnection queue requests has continued to rise. Driven by Renewable Portfolio Standards, there has been a shift in the types of requests primarily towards wind. Many of these wind requests are in areas where transmission is most constrained – i.e. Buffalo Ridge currently has ten times the amount of generation requests as planned transmission availability. With more States considering Renewable Portfolio Standards, the number of queue requests is only expected to grow. Throughout this section, queued units were added on their in-service date listed in the Midwest ISO Generator Interconnection Queue, unless updated information was provided by a Market Participant. However, given the amount of time necessary to study each queue request and the extremely high numbers of requests the probability that a unit will be in-service on its listed date is diminishing. Uncertainty around future regulations adds to the probability of project delays, especially for baseload units.

To examine the effects of regulatory and queue delays, the in-service date for queued units was moved into the future by two years.

3.3.2.2.1.2 Additional Retirements

The aging generation fleet within the Midwest ISO carries the risk of decreasing availability as components reach the end of their useful life and asset owners are forced to take additional outages, increase the duration of planned maintenance schedules, or ultimately retire the unit. Currently, the majority of baseload units within the Midwest ISO are 30 to 40 years old. By the year 2017, 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 46 years in 2017. As this capacity continues to age, the probability of retirement and higher forced outage rates increases. Only currently announced retirements were included in reserve margin calculations and other LOLE runs.

Figure 3.3-7 displays the age of the generation fleet within the Midwest ISO Market by fuel type.

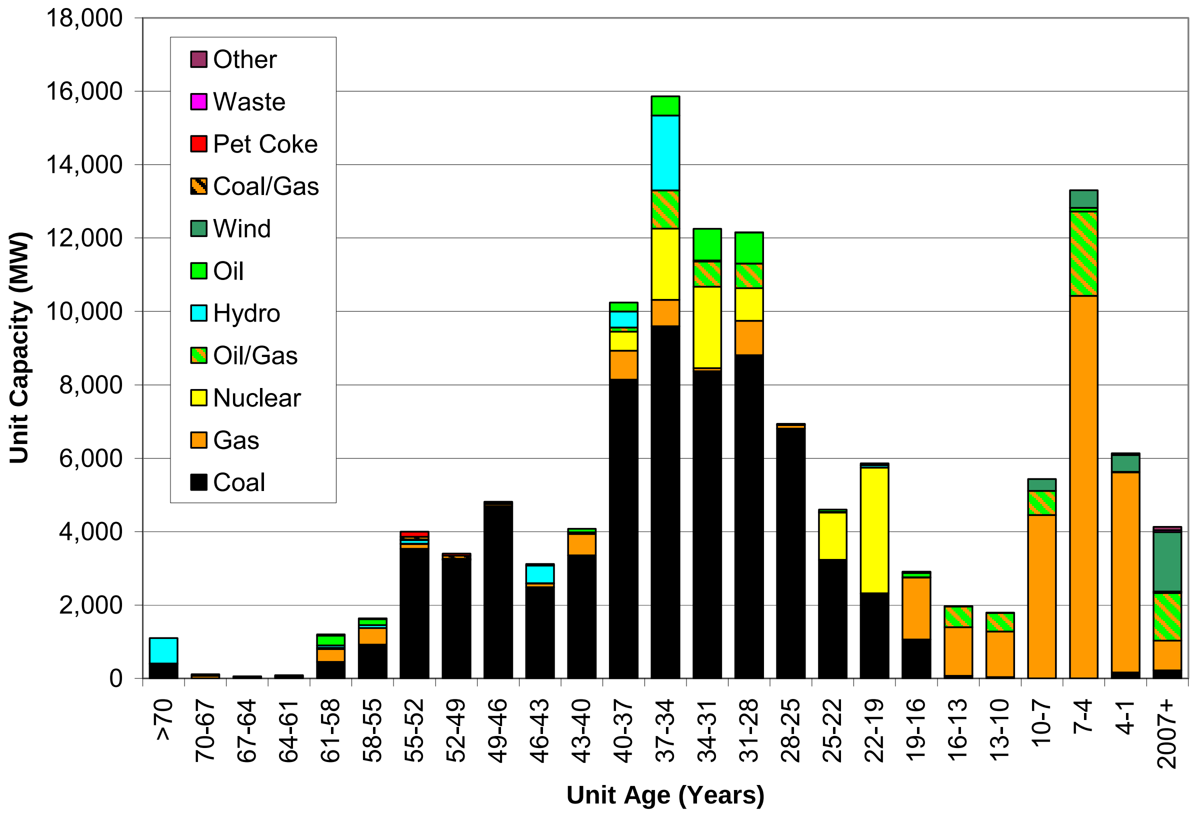


Figure 3.3-7: Age of Generation Fleet by Fuel Type

Concurrent with an aging generation fleet, there is also an increased awareness in greenhouse gas emissions and a greater probability for greenhouse gas regulations. The onset of CO_2 regulations as well as a requirement to reduce Critical Air Contaminants such as SO_2 and NO_x could cause restrictions to high emitting technologies. Such restrictions would increase desire for emission free resources such as wind, nuclear, and demand response/energy efficiency programs. Regulations may make operating existing older baseload coal units non-economical, and therefore there is an increased probability that older baseload units would be retired. A study on the affects of greenhouse gas regulations is included in Appendix F1.1.

To model additional retirements resulting from an aging generation fleet or possible carbon regulations, non-hydro units greater than 65 years old were retired – these retirements were in addition to the 561 MW of known retirements. The resulting additional yearly retirements are shown in Table 3.3-7.

Table 3.3-7: Additional Retirements Timeline for Risk Analysis (Non-Cumulative)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Retirements (MW)	*502*	*0*	*40*	*10*	*28*	*144*	*338.3*	*577.5*	*506*	*534*

3.3.2.2.1.3 Forced Outage Rate

As detailed in Section 3.3.2.2.1.2, the aging generation fleet carries an increased probability that forced outage rates will rise. To establish an elevated Average System Forced Outage Rate (FOR) for analysis system outages for the previous two summers were examined to determine the average amount of capacity unavailable throughout the summer months relative to the capacity in service during that same period. The percent of generation unavailable from June 15 through August 15 from the past two summers is displayed below in Figure 3.3-8 as a histogram. These outages are not included in planned outages already subtracted from the capacity totals.

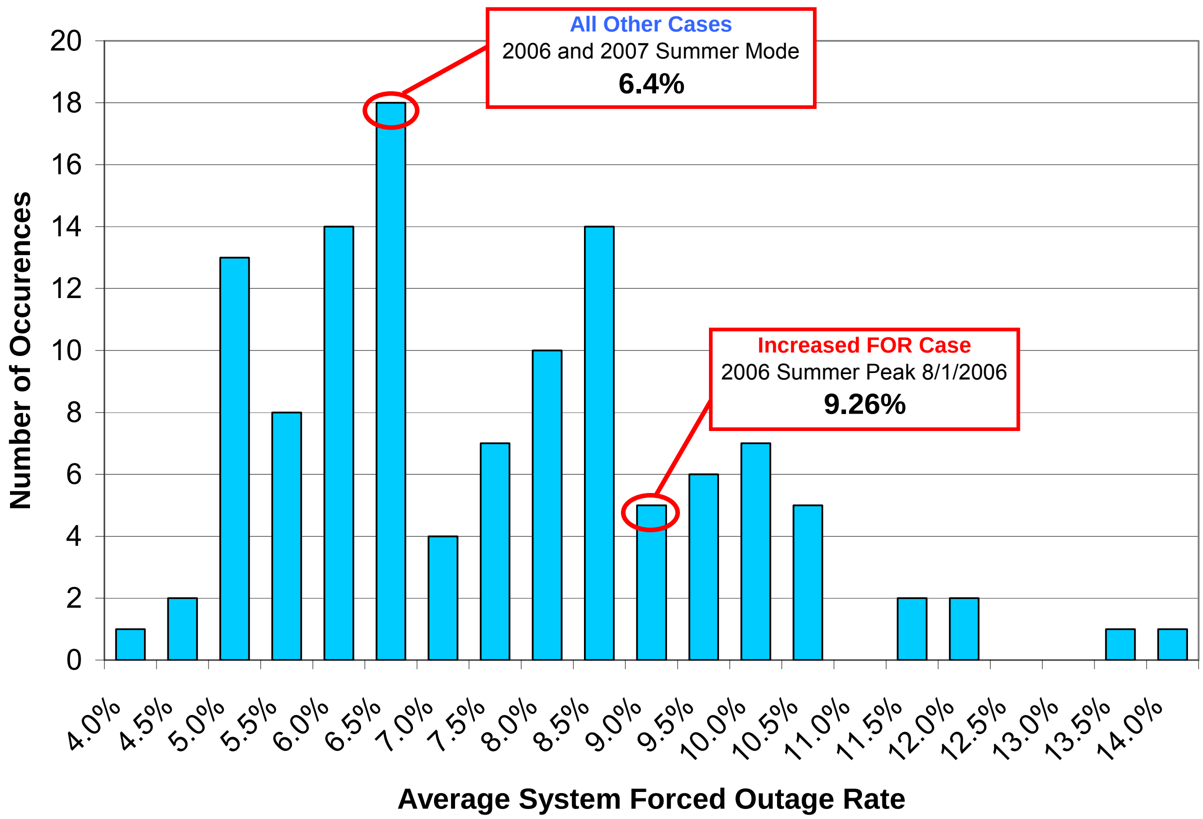


Figure 3.3-8: Case Summary of Average System Forced Outage Rates

This distribution of Average System FOR was analyzed to determine values appropriate for an increased FOR case as well as all other cases. The statistically most frequently occurring range or mode of the available data was 6.0% to 6.5%. The average of that range is 6.4% and was used as the Average System FOR in all other LOLE runs. The increased FOR for use in sensitivity analysis was determined to be the rate experienced during the 2006 summer peak – 9.26%.

Outlying data points can be seen on the histogram in the 11.5% to 14% outage rate range. These outlying points represent an outage of three large coal facilities during the 2007 summer period, thus causing an outage rate statistically above the average.

Total outages experienced throughout the two previous summer periods can be seen in Figure 3.3-9, which shows the MW total of all units that were experiencing an outage (whether planned or forced). As evident in the figure, the variability on the amount of outage around peak is less than that of the entire summer period.

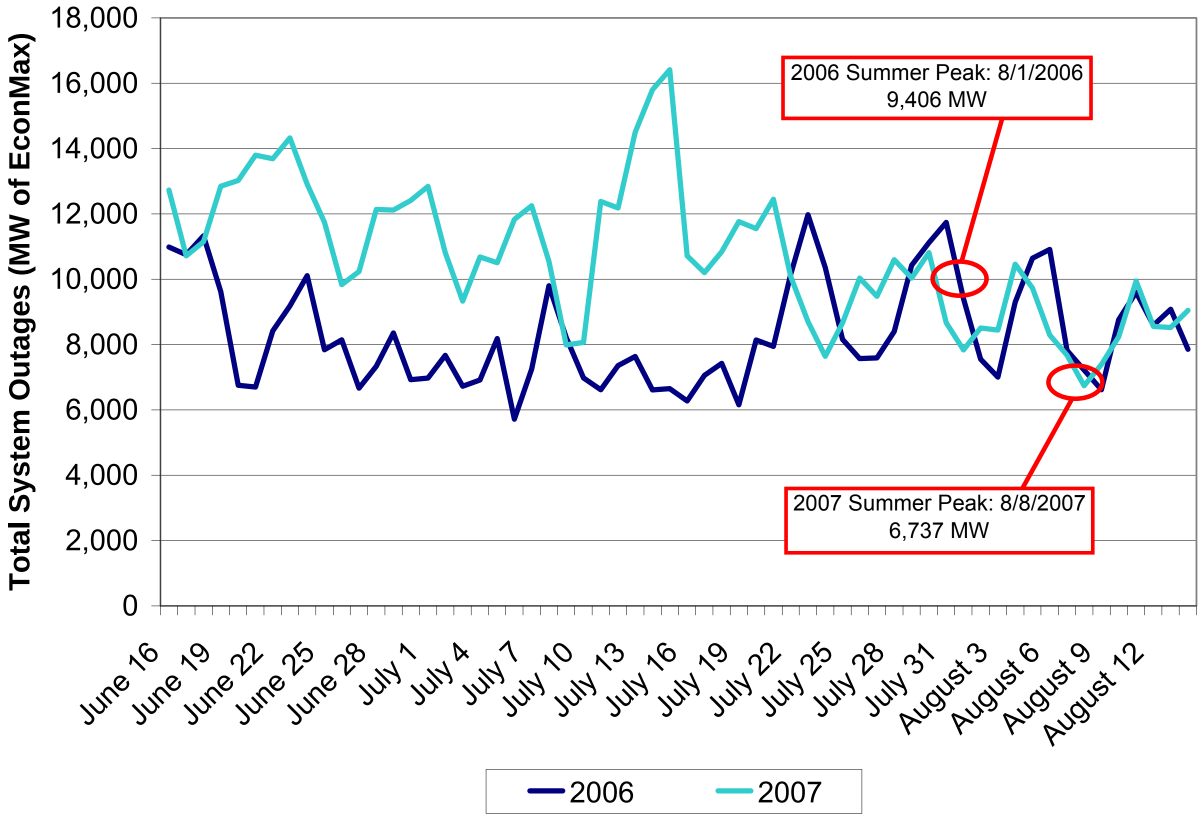


Figure 3.3-9 Total System Outages During Summer Peak Periods

3.3.2.2.1.4 Wind Capacity Credit

The intermittent nature of wind capacity allows for no guarantee in the amount available on peak, as detailed in Section 3.2.2.1.3. 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 Risk Assessment and in other runs, wind units were assigned a 20% peak capacity credit, which is the average wind capacity production experienced during peak hours over the summer months. However, during the annual peaks for two of the three 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 Capacity Credit Case.

3.3.2.2.1.5 External Commitments

Currently there is 6,291 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 two years' 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 maintained at 0 MW.

3.3.2.2.1.6 Demand Side Resources

Recently, there has been an increased emphasis on demand side resources. Many Market Participants have discussed their intention to initiate new programs or expand their existing to meet growing demands and State Renewable Portfolio Standards; however, reported forecasts fail to show demand side management programs increasing at rates that will significantly affect out-year resource adequacy.

In order to establish the risk associated with the incomplete realization of demand side resources a sensitivity was run utilizing the demand reduction experienced during the all time peak. This amounted to 3,047 MW of demand side management and 2,705 MW of load offset by behind-the-meter generation. Total demand side resources have increased since the 2006 peak making this estimate conservative for out year studies. The same amount of demand side resources was assumed for all ten years of the study.

3.3.2.3 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. Although various factors played a part in the risk analysis, 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.

In almost all cases, base and sensitivities, LOLE exceeded the one day in ten years benchmark. Each of the cases from Table 3.3-5 can be brought to a level below one day in ten years LOLE not only in 2015 but through 2017, if the following conditions are met:

- **Base Case:** Currently there is a total of 30,246 MW of summer rated capacity in the Midwest ISO Generator Interconnection Queue. If 10,240 MW of that capacity is added in the next ten years there will be sufficient capacity to bring the Base Case LOLE to a level below one day in ten years in 2017. This would require a confidence factor of 34%.
- **High Load Case:** The presence of the 90/10 load projection would require 17,356 MW of addition capacity for LOLE to be below one day in ten years for all years. To meet a capacity level of that magnitude a 57% confidence factor would have to be utilized.
- **Regulatory/Queue Delay Case:** The affects of delaying the in-service date by two years for queued units varies drastically by which year one is observing. Because most of the queued capacity with associated high confidence factors has an expected in-service date in the near-term, the affects are greatest during the next few years. To maintain a 0.1 day LOLE in 2017 10,240 MW of capacity with an in-service date prior to 2015 is required, 36% of the pre-2015 capacity in the queue.
- **Increased Retirements:** Increasing the amount of retirements by 2,680 MW through 2017 requires 12,920 MW of capacity to be added to maintain a 0.1 day LOLE through 2017 – a 43% confidence factor.
- **Increased Forced Outage Rate:** When the average system FOR is increased from 6.4% to 9.26% an additional 1,792 MW of capacity is required over the base case. To achieve 12,032 MW of queue additions a 40% confidence factor would have to be realized.
- **0% Wind Capacity Credit:** Currently, there is 2,890 MW of nameplate rated capacity which accounts for 2.3% of the fleet. This small amount of capacity has little effect on LOLE when it produces 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. If wind capacity is given a 0% capacity credit it would require 10,845 MW of non-wind capacity to be installed in the next ten years to maintain an LOLE below 0.1 days – 61% of the non-wind capacity that's currently in the Midwest ISO Generator Interconnection Queue.
- **No External Support Case:** When the 6,291 MW of external support is omitted in all years from the risk analysis, even the LOLE for year 2009 exceeds the one day in ten years benchmark. For all years' LOLE to be reduced below the benchmark 16,531 MW of resources would have to be integrated into the system - a 55% confidence factor. To maintain a 0.1 day LOLE in 2009 2,330 MW would have to be added.
- **Reduced Demand Side Resources Case:** Because demand side resources are netted from the demand, when demand side resource levels are reduced the effects on LOLE are much more drastic than the loss of a capacity unit. To achieve an LOLE of one day in ten years 13,020 MW of capacity would have to be added by the year 2017 – a 43% confidence factor.

Historically, 20% of the queued capacity within the Midwest ISO (signed IA plus non-signed IA) has gone into service. All of the aforementioned sensitivities require capacity to be added at percentages well above what has historically been experienced. As more capacity is proposed for areas that have over constrained transmission, confidence factors can be expected to shrink or remain relatively the same. The initiation of demand side management and conservation programs can lessen out-year LOLE; however, transmission upgrades are required to interconnect the queued capacity that will be necessary in the next ten years. Given the amount of time required to build both new units and transmission lines, action is needed soon in order to ensure resource adequacy for the next ten years.

3.4 Historical Constraint Data

Congestion has followed an increasing trend in the Midwest RA footprint since the year 2001 and after peaking three years ago during the 1st Market year, has leveled off the last two years at a level reduced somewhat from the maximum 27,842 Flow Gate (FG)-Hours experienced during the 1st Market year. Congestion analyzed here reflects the combined quantification from Real-Time operations and NERC Transmission Loading Relief (TLR). Congestion is an ongoing dynamic experience from year to year or even month to month. The historical analysis is just one of several inputs utilized in determining if particular expansion to reduce congestion is warranted. Table 3.4-1 illustrates both increased utilization of congested flowgates and also shows the number of flowgates that were congested annually. Some flowgates that were used in the past are not utilized going forward or become inactive for a period of time. Also, new flowgates or flowgates not used since January 1, 2001 can become active. For example: of the 798 flowgates used in the April 2007 to April 2008 period only 257 had a previous history of congestion since January 1, 2001. This transient aspect 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 has leveled off at about 800, and the overall average hours that flowgates are congested is leveling off around 25 hours per flowgate as shown by the right hand column in Table 3.4-1. While the overview summary in Table 3.4-1 utilizes averages to reveal the general trend that congestion is becoming spread over more FG, more detailed discussion follows in this section and in Appendix F2.. Appendix F2, page 9 also contains a full distribution of the post market hours on the 2,213 FG, and a spread sheet summarizes the history on each FG annually.

Table 3.4-1 Number of Flowgates Utilized and Annual FG-Hours Since January 1, 2001

	Number of Flowgates Utilized			
Time Period	Utilized In The Period	Cumulative Utilized Since January 2001	Congestion FG-Hours In Period	Average Hours/FG Utilized In The Period
April 2007 – April 2008	798	2,213	20,748	26
April 2006-April 2007	829	1,672	20,329	25
April 2005-April 2006	841	1,105	27,842	33
April 2004-April 2005	200	358	11,050	55
April 2003-April 2004	174	316	11,094	64
April 2002-April 2003	89	116	10,172	114
January 2001-April 2002	64	64	6,432	101

The column second from the right in Table 3.4.1 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. Since the exceptional high level of congestion in the 1st Market year, the annual congestion has leveled off between 20,000 and 21,000 in the 2nd and 3rd Market years, or just under twice the pre Market level. The increased annual FG-Hour metric after April 1, 2005 speaks to the point that the Locational Marginal Pricing (LMP) market more fully utilizes and effectively exploits use of the available transmission system up to reliability limits.

As one moves forward in expansion planning, careful consideration will be necessary to identify transmission investments that may address congestion, and at the same time avoid transmission investment to mitigate congestion when the benefit to do so would be short lived. Most of the congestion observed in the Midwest ISO has some associated reliability based projects that will mitigate the hours of congestion observed historically. A few congested locations have no current associated mitigating project driven from reliability analysis of the system. Beyond reliability needs, plans are for study in MTEP09 to investigate the cost effectiveness of future projects to reduce congestion.

Transmission system constraints that limit the availability of transmission service reservations or that limit the flow of scheduled transmission service reservations; generally represent limitations to the commercial use of the system, rather than limitations to the reliability of the system. This review will focus on real-time operations in the three 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. Midwest ISO implemented a 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 system conditions are other than planned. 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 expanding 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 is the situation for a great 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. The following discussion provides information about constraints that have been most frequently involved in limiting transactions via TLR or have been bound in the Midwest ISO market dispatch. Both TLR and Midwest ISO market re-dispatch measures are used to maintain system reliability.

The primary value in summarizing the congestion history is that this provides one metric of system performance. This summary does not include tracking the individual impacts among flowgates or of new flowgates being introduced or other dynamics as the physically installed generation or transmission system itself changes over time. While no particular attempt has been made in MTEP to dissect specific historical data or merge commonly impacted flowgates, this summary (particularly the individual flowgate charts in Appendix F2) 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 is the subject of Narrow Constrained Areas (NCA) in Section 8.1.

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.

As was first done in MTEP07 this MTEP08 report puts particular emphasis on the post market timeframe, which is now the first 36 months of the Midwest ISO market operations (April 1, 2005 through March 31, 2008). 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. It is intended that the charts in Appendix F2 will provide a basis for further insight. On occasions 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 beyond an MTEP report.

3.4.1 History of Congestion

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 MTEP06 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) 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 3.4-1 illustrates the sum of monthly flowgate hours of congestion and the relative method of managing congestion since from January 2001 through March 2008. 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 redispatch by adjusting LMP prices. 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 redispatch were utilized concurrently.

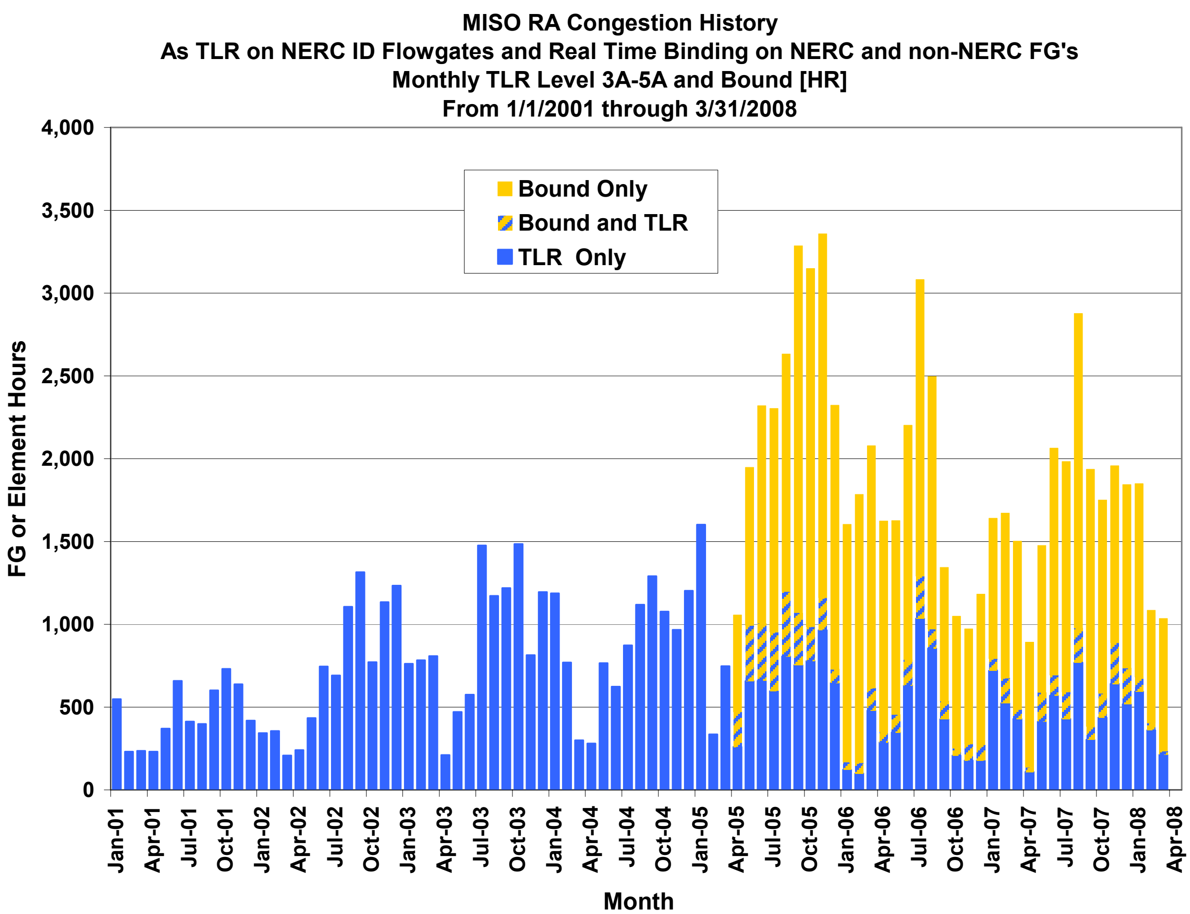


Figure 3.4-1 Overview History of Midwest ISO Congestion and Method

Similarly, Figure 3.4-2 shows the itemization by TLR Level for hours that were affected exclusively or in part by TLR. The "Bound Only" portions in Figure 3.4-2 is the same as the "Bound Only" portions plotted in Figure 3.4-1. As shown by Figures 3.4.1 and 3.4-2, 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.

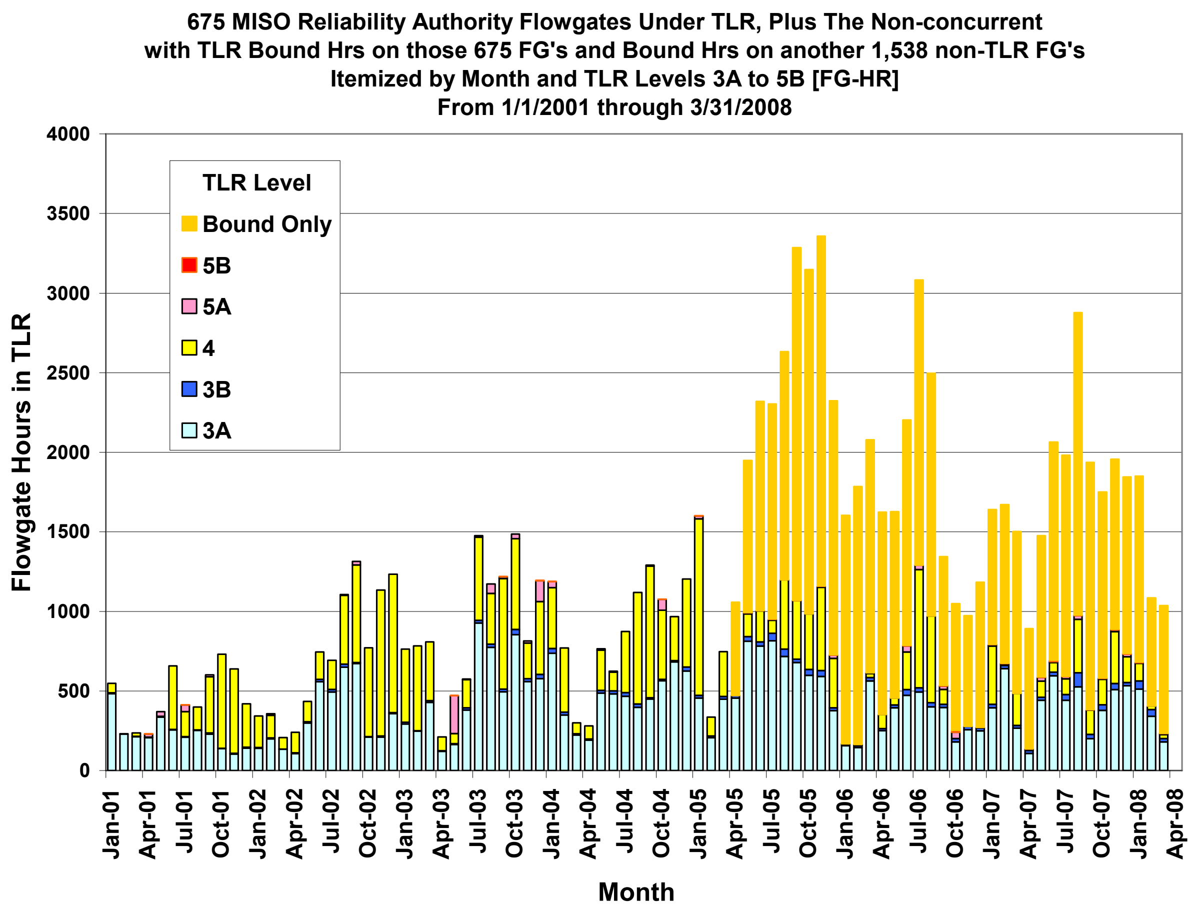


Figure 3.4-2 Overview History with TLR Affected Hours Itemized by TLR Level

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 elements 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 with 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 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 3.4-2 lists 45 flowgates that, on the average, were congested more than 1% of the time in the post-Midwest ISO market period (over 262 hours in the three year period). Table 3.4-2 also shows the average annual hours of congestion for the pre-Midwest ISO market period, the 1st Market year, the 2nd Market year, and the 3rd Market year. The yellow high lighted rows indicate eight flowgates among the top 25 most active FG shown in Figure 3.4-6 that had 3rd Market year congestion greater than the 1st or 2nd Market years, and are addressed later in discussion related to Figure 3.4-6. Figure 3.4-3 is a chart of the 45 flowgates that itemizes the total exclusive hours bound and hours at each TLR Level. Approximately half the congestion from the top 45 FG is due to FG's that are not under the direct influence of the Midwest ISO Planning Authority (PA).

Table 3.4-2 The 45 Post Market Flowgates that on the average were congested more than 1% of the time
(see Figure 3.4-3 for long-term Bound versus TLR breakdown of all 2,213 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	BA	MTEP Map Grid
1, 100	Kammer 765/500kV XFMR (flo) Belmont-Harrison 500kV	0	1,733	338	938	PJM	Q9
2, 2353	Black Oak-Bedington 500kV (flo) Pruntytown-Mt. Storm 500kV	0	914	1,157	909	PJM	Q10
3, 3006	Eau Claire-Arpin 345kV	145	1,529	245	794	WPS	J6
4, 2245	Blue Lick-Bullitt Co. 161kV (flo) Baker-Broadford 765kV	48	1,699	44	6	LGEE	N11
5, 3270	State Line-Wolf Lake 138kV (flo) Burnham-Sheffield 345kV	21	151	481	847	NIPS	L8
6, 3012	Paddock 345/138kV XFMR (flo) Paddock-Rockdale 345kV	161	405	420	477	ALTE	K7
7, 2872	Frankfort East-Tyrone 138kV (flo) Ghent-West Lexington 345kV	49	1,151	132	0	LGEE	M11
8, 6004	Minnesota Wisconsin Stability Interface (MWSI)	49	806	212	144	NSP	I6
9, none	Culley-Grandview 138kV (flo) Henderson 161/138kV XFMR	0	539	284	189	SIGE	L11
10, 6009	Cooper South Interface	15	696	234	76	NPPD	G9
11, 2352	Pruntytown-Mt. Storm 500kV (flo) Black Oak-Bedington 500kV	0	468	395	142	PJM, VAP	Q9
12, 122	Wylie Ridge 500/345kV XFMR #7 (flo) Wylie Ridge 500/345kV XFMR #5	0	573	375	31	PJM	Q9
13, 2463	Kokomo HP 230/138kV XFMR (flo) Jefferson-Greentown 765kV	0	132	750	0	CIN	K9
14, 3567	ATC LLC Flow South Interface	1,229	646	172	25	WEC	K5
15, 9159	Ontario-ITC Interface	8	79	251	475	DECO	O7
16, 6007	Gerald Gentleman-Red Willow 345kV	22	271	186	312	NPPD	D9
17, 6126	S1226-Tekamah 161kV flo S3451-Raun 345kV	76	36	0	714	OPPD	
18, 3706	Arnold-Hazleton 345kV	26	112	480	156	ALTW	I7
19, none	Culley-Grandview 138kV (flo) Henderson-A.B. Brown 138kV	0	586	84	30	SIGE	L11
20, 6164	Plymouth-Sioux City 161kV flo Raun-Sioux City 345kV	0	0	139	470	MEC, WAUE	G7
21, 3102	Bland-Franks 345kV	51	347	206	0	AMRN	I11
22, 2086	Newtonville 161/138kV Transformer #1	1	28	8	502	SIGE	
23, 6006	Gerald Gentleman Station	4	0	531	0	NPPD	D9
24, 6085	Genoa-Coulee 161kV (flo) Genoa-LaCrosse-Marshland 161kV	51	158	344	4	DPC	J7
25, 140	Elrama_Mitchell_138kV_flo_Ft_Martin_Ronco_500kV	0	72	12	382	AP, DLCO	
26, 3724	Arnold-Vinton 161kV (flo) Arnold-Hazelton 345kV	180	105	216	135	ALTW	I7

Table 3.4-2 The 45 Post Market Flowgates that on the average were congested more than 1% of the time (see Figure 3.4-3 for long-term Bound versus TLR breakdown of all 2,213 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**	**BA**	**MTEP Map Grid**
27, 291	Pierce B 345/138kV transformer l/o Pierce-Foster 345kV	0	4	31	393	OVEC	
28, 3145	Pana 345/138kV XFMR (flo) Coffeen-Coffeen North 345kV	0	24	164	230	AMRN	
29, 1649	Avon 345/138kV XFMR	0	147	260	1	EKPC	N11
30, 2980	Dune Acres-Michigan City 138kV ckts 1&2 (flo) Wilton Center-Dumont 765kV	261	241	107	59	NIPS	L8
31, 3745	Lime Creek-Emery 161kV (flo) Adams-Hazleton 345kV	1	30	291	70	ALTW	H7
32, 3532	Ellington_Hintz_138_flo_NAppleton_WernerWest_345	0	0	86	286	WEC	
33, 3108	Overton-Sibley 345kV	0	160	189	20	AMRN	H10
34, 2557	Northeast Kentucky Interface	0	249	111	7	LGEE	M11
35, 13746	Genoa-Lacrosse Tap 161kV (flo) JPM unit	0	0	325	0	DPC	J6
36, 111	Sammis-Wylie Ridge 345kV line l/o Perry-Ashtabula-Erie West	2	58	92	172	PJM	P9
37, 2295	A.B. Brown-Henderson 138kV (flo) Culley-Grandview 138kV	9	220	6	95	SIGE	L11
38, 3186	West Mt. Vernon-E W Frankfort 345kV	0	188	12	119	AMRN	L10
39, none	Kelly-Whitcomb 115kV (flo) Rocky Run-Werner West 345kV	0	264	34	0	WPS	K6
40, 3529	North Appleton-Werner West 345kV	14	8	225	49	WEC	K6
41, 2908	Miami Fort 345/138kV XFMR (flo) East Bend-Terminal 345kV	43	247	20	8	CIN	N10
42, 3167	St. Francois-Lutesville 345kV	6	39	18	217	AMRN	K11
43, 6124	Tiffin-Arnold 345kV	25	0	271	0	MEC	I8
44, 2375	Wylie Ridge 500/345kV XFMR #5 (flo) Belmont-Harrison 500kV	0	161	27	79	PJM	Q9
45, 3168	St. Francis-Lutesville 345kV (flo) Bland-Franks 345kV	37	151	113	0	AMRN	K11

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

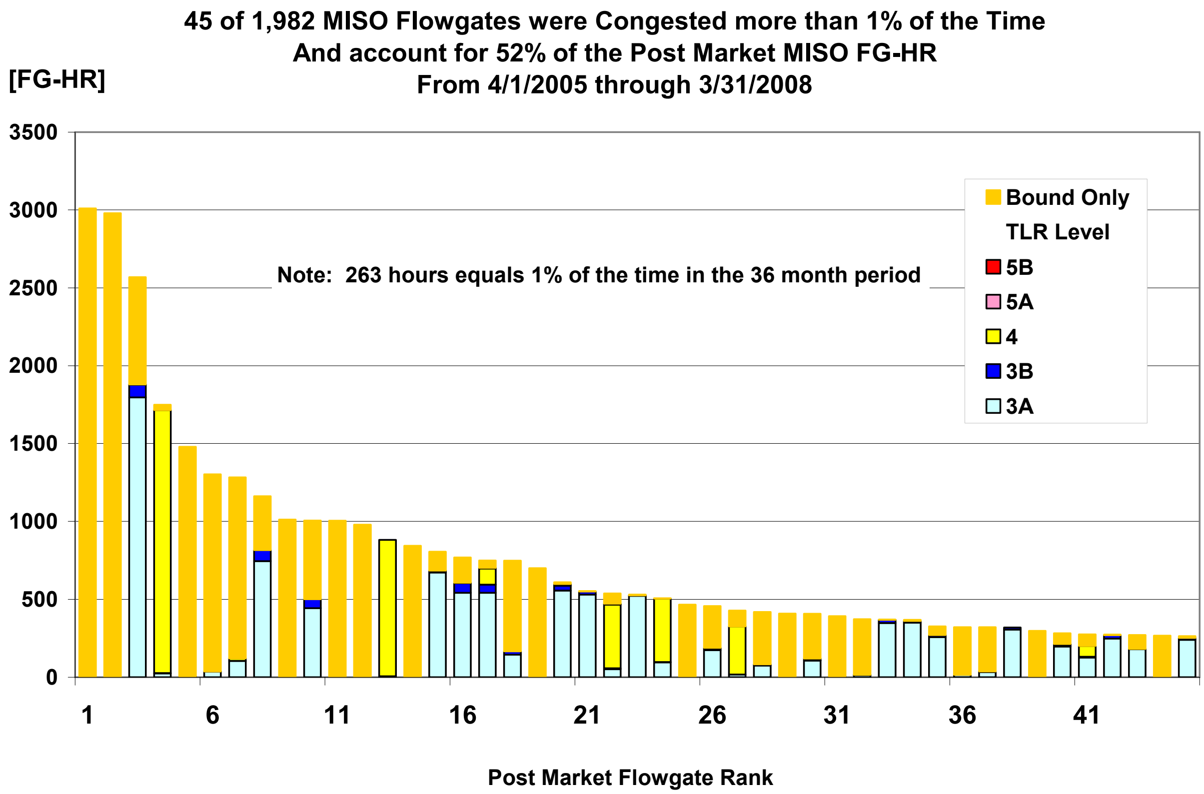


Figure 3.4-3 Top 45 Most Congested Post Market FGs
See Table 3.4-2 for Identification of a Specifically Ranked FG

Note: Since no FG's were tied on a total post market "Rank" basis, the X-axis label also represents FG count (number 0f FGs) or Rank number within the FGs as sorted on decreasing post market FG Hours. Rank positions and FG Identification associated with Figure 3.4-3 are reflected in Table 3.4-2.

As previously pointed out, 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 three Midwest ISO market years, and discuss the changes through the third year. For the 25 most congested post Midwest ISO market flowgates, Figure 3.4-4 illustrates the average annual congestion hours for four periods of time: the pre-Midwest ISO market period, 1st Market year, 2nd Market year, and 3rd Market year. Color coding of the legend font in Figure 3.4-4 identifies 12 of the 25 FG that are not within direct influence of the Midwest ISO PA. Also, Appendix F2 contains a geographic map of the top 10 most active post market Midwest ISO Reliability Authority flowgates with non-Midwest ISO PA flowgates depicted with blue font..

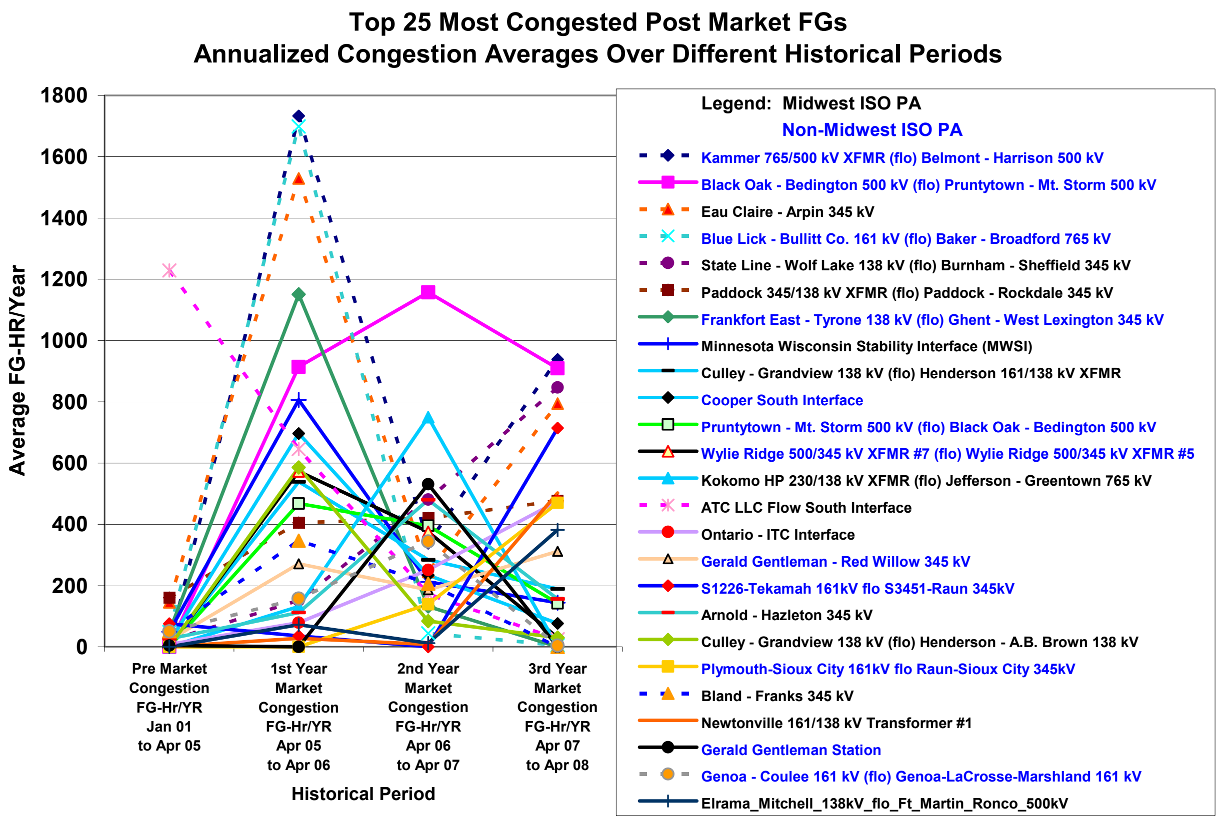


Figure 3.4-4 Top 25 Most Congested Post Market FGs
Annualized Congestion Averages Catagorized into Different Historical Periods

In spite of the elevated congestion activity for the first six months of the Midwest ISO market, some flowgates clearly showed increased activity form the 1st year to the 2nd year. Figure 3.4-5 shows ten of the top 25 most congested post Midwest ISO market flowgates that realized increased congestion in the second year, and also realize an annual rate of congestion higher than realized in the pre-Midwest ISO market period. Figure 3.4-6 shows eight of the top 25 most congested post Midwest ISO market flowgates that realized third year congestion equal to or greater than previous market years. Figure 3.4-7 illustrates the general location with post Midwest ISO market ranking, and NERC ID number noted for the eight 3rd year FG's that realized more congestion than in either the 1st or 2nd Market year. Some caution is in order because three years of data allows a perception of only three trend points. For example, longer term tracking of individual flowgates in the pre-Midwest ISO market time frame had shown that volatile congestion hours can occur for specific time frames. The itemized monthly congestion history for the eight flowgates that realized 3rd year congestion over the 1st and 2nd Market year levels are shown in Figures 3.4-8 through 3.4-15. A review of the data from these Figures and possible review of other aspects of operation would be needed before predicating specific expansion decisions upon congestion as a driver.

Appendix F2 "Appendix_F2_Congestion_History_090408.pdf" is a compendium of additional individual flowgate histories like Figures 3.4-8 through 3.4-15 and other charts, including a lookup table "Appendix_F2_Congestion_Summary_090808.xls" spread sheet for hours congested on each of 2,213 flowgates since January, 2001.

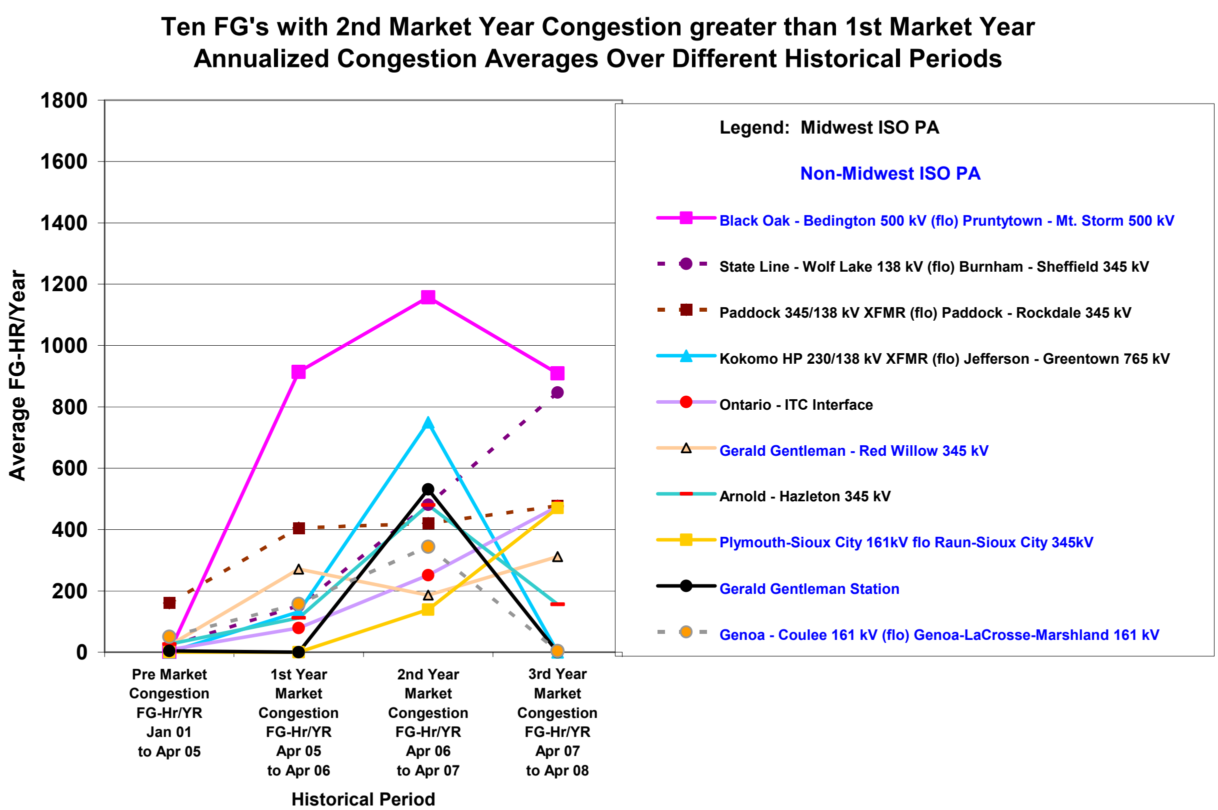


Figure 3.4-5 Ten of the Top 25 Most Congested Post Market FGs That were Congested More in the 2nd Market Year than in the 1st Year Annualized Congestion Averages Over Different Historical Periods

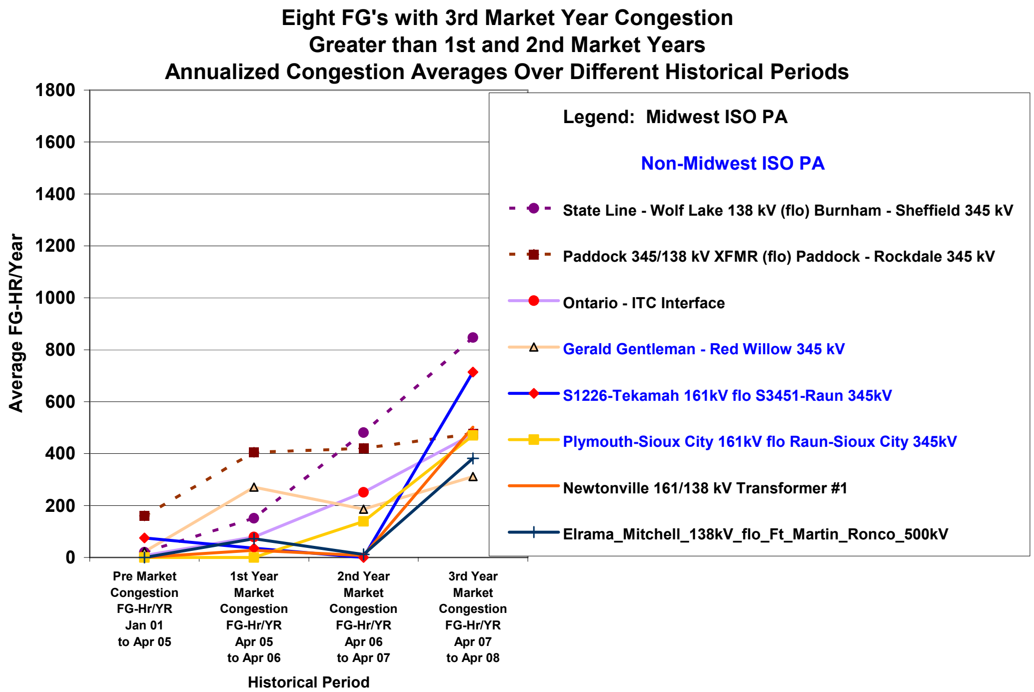


Figure 3.4-6 Of the Top 25 most congested Post Market FGs eight FG that were congested more in the 3rd Market Year than either of the previous Market Years annualized congestion averages over different historical periods

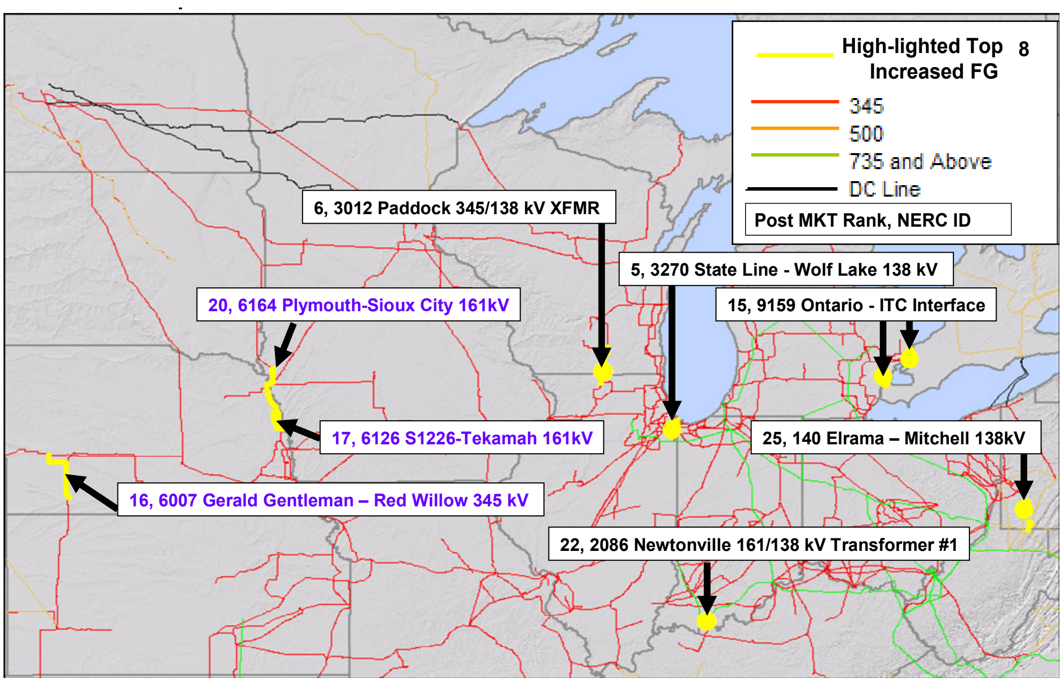


Figure 3.4-7 Location of Eight of the Top 25 Most Congested Post Market FG That Realized Increased 3rd year Congestion greater than either the 1st or 2nd Market Year

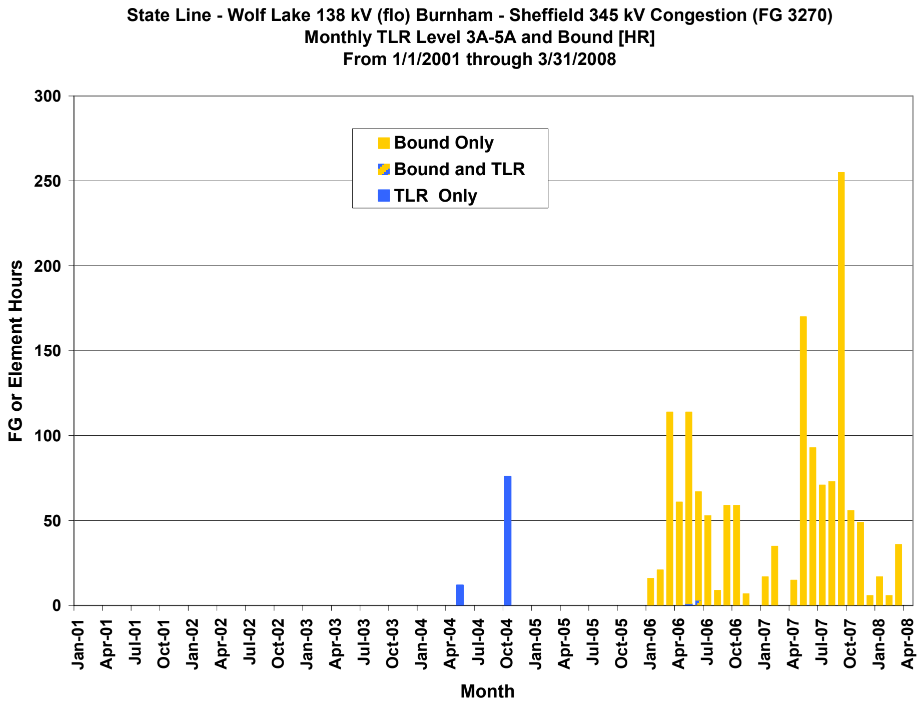


Figure 3.4-8 Itemization of State Line-Wolf Lake 138kV TLR versus Bound, Post Market Rank =5

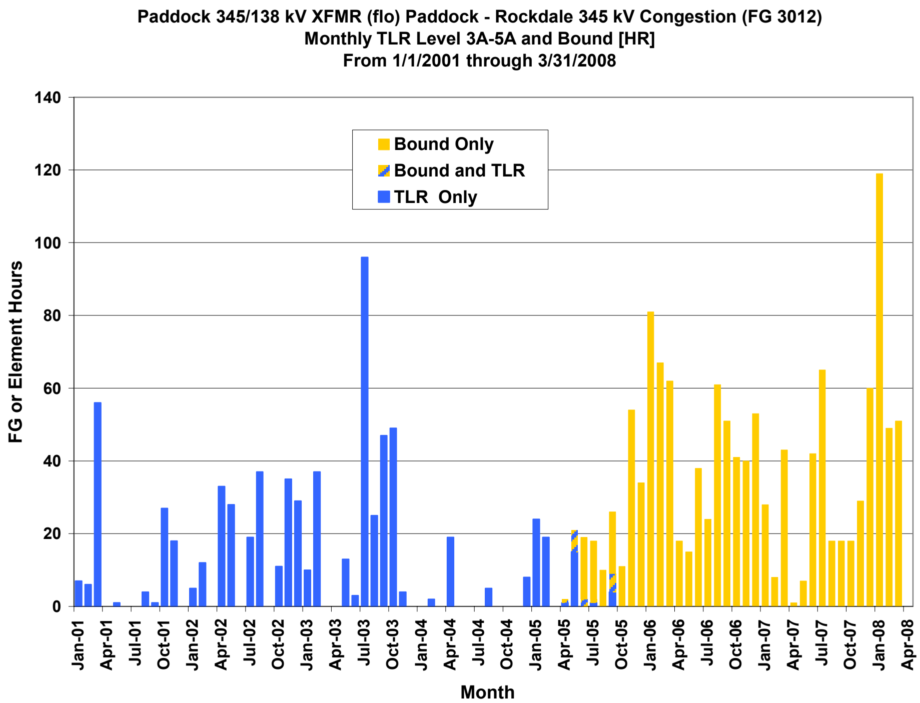


Figure 3.4-9 Itemization of Paddock 345/138kV XFMR TLR Versus Bound, Post Market Rank = 6

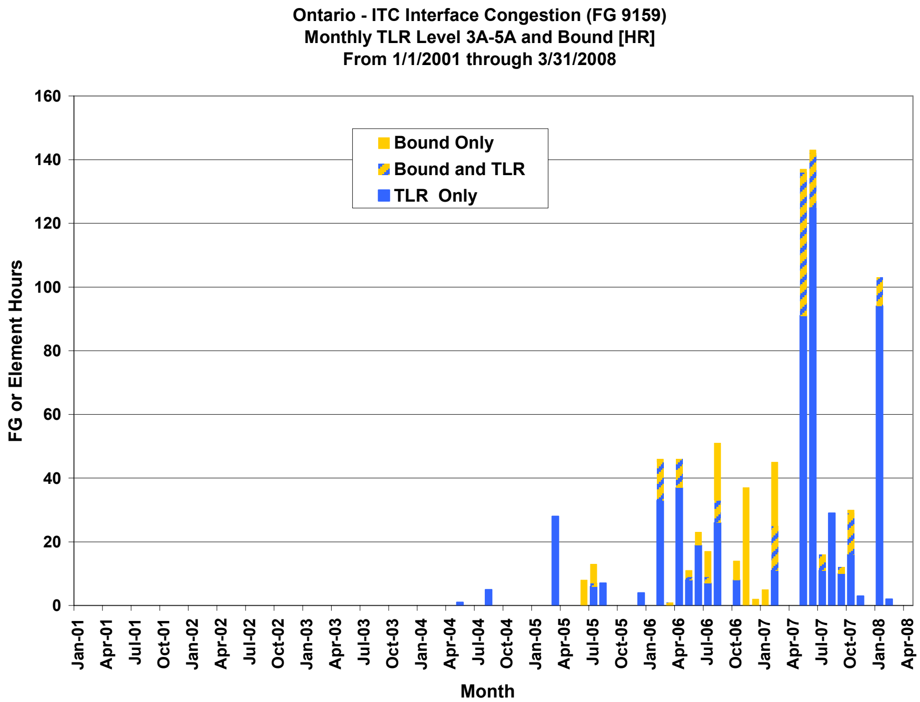


Figure 3.4-10 Itemization of Ontario-ITC Interface TLR versus Bound, Post Market Rank =15

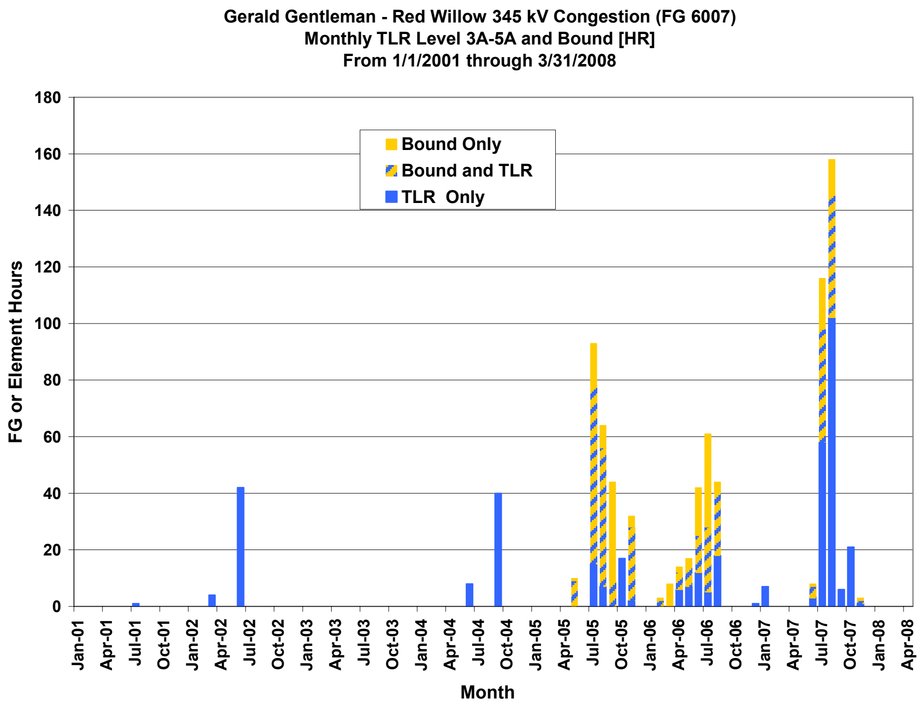


Figure 3.4-11 Itemization of Gerald Gentleman-Red Willow 345kV TLR Versus Bound, Post Market Rank = 16

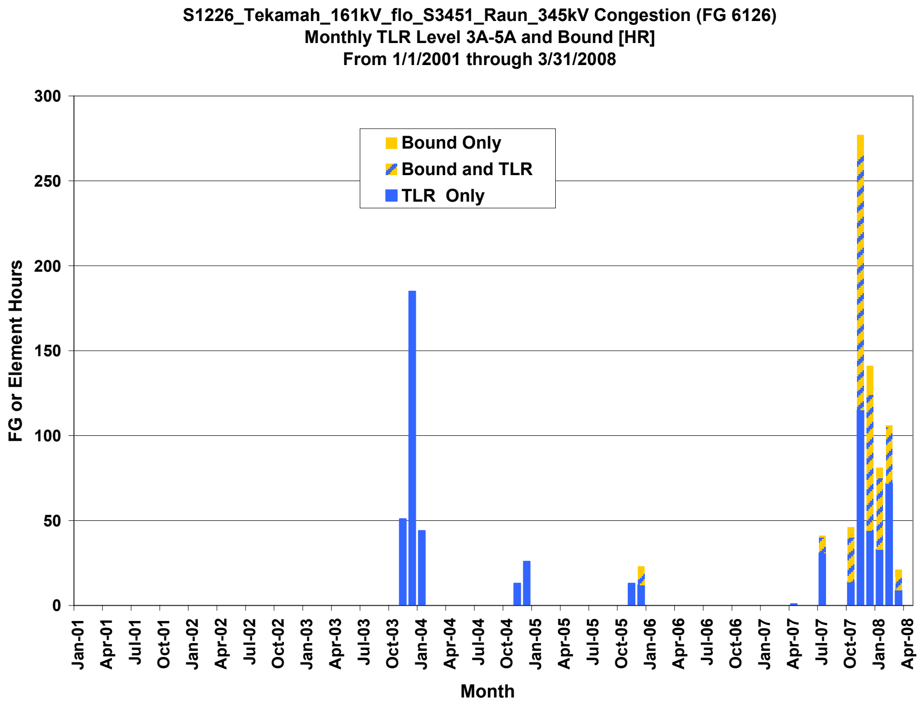


Figure 3.4-12 Itemization of Substation 1226 – Tekamah 161kV TLR versus Bound, Post Market Rank =17

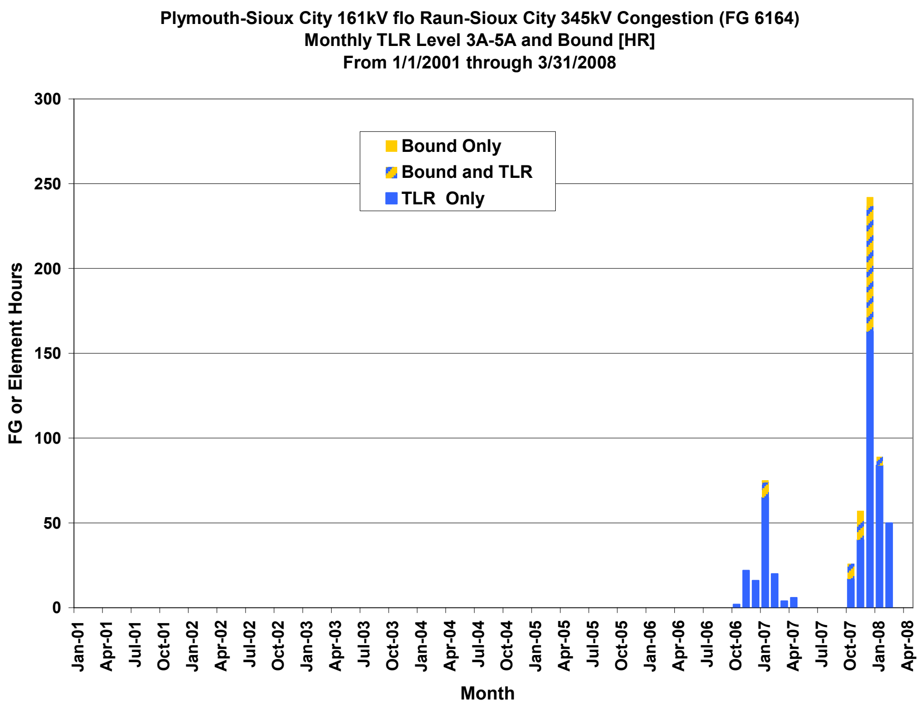


Figure 3.4-13 Itemization of Plymouth-Sioux City 161kV TLR Versus Bound, Post Market Rank = 20

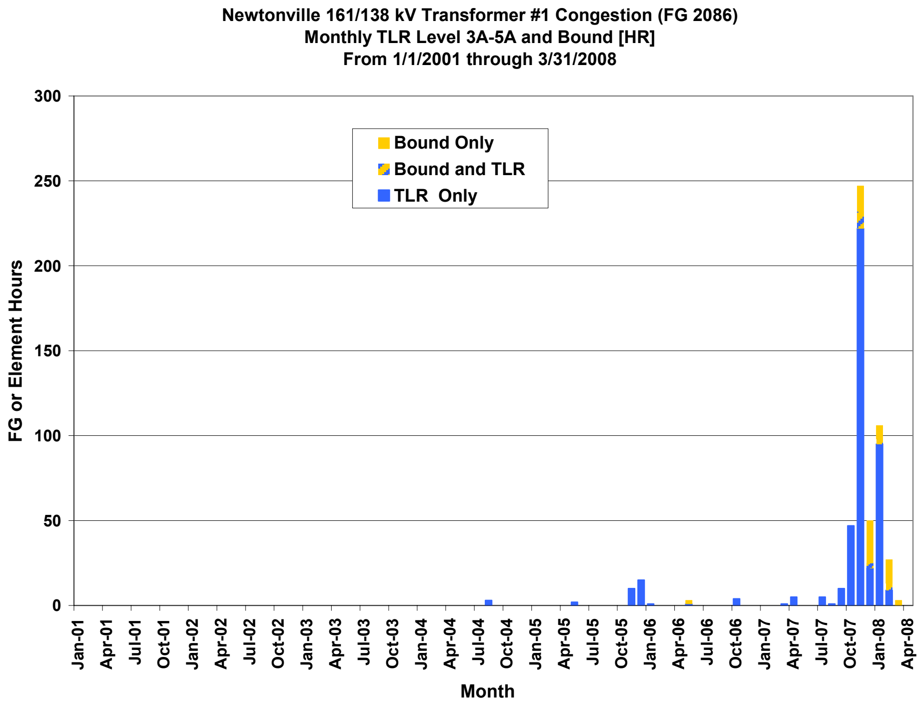


Figure 3.4-14 Itemization of Newtonville 161/138kV Transformer #1 TLR versus Bound, Post Market Rank =22

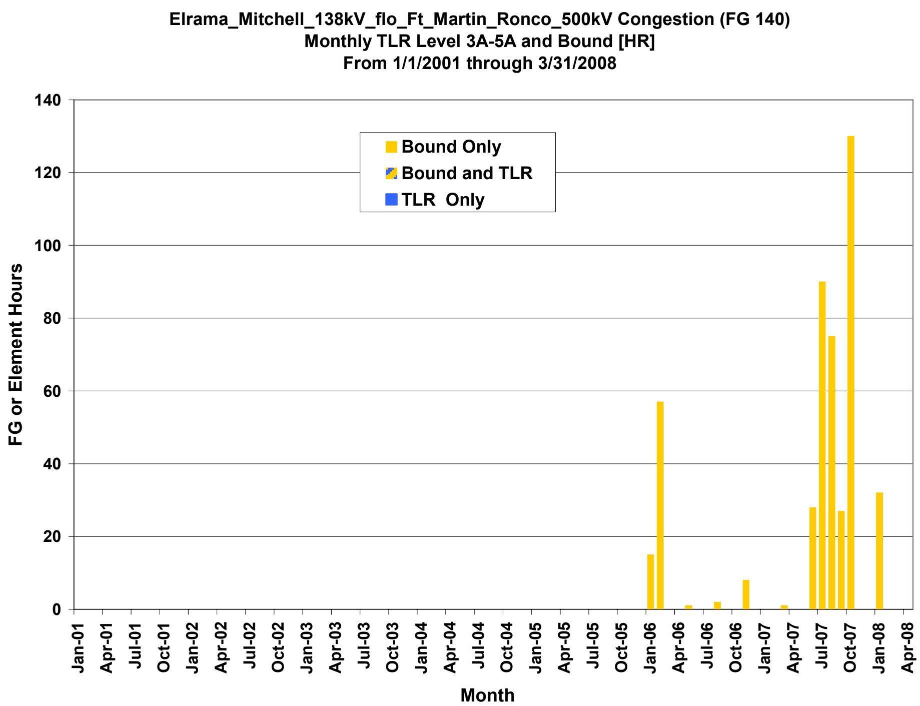


Figure 3.4-15 Itemization of Elrama – Mitchell 138kV TLR Versus Bound, Post Market Rank = 25

3.4.2 View of Future Congestion

The historical constraint overview in Section 3.4.1 demonstrates that there are opportunities for improving the performance of the energy market. Significant transmission system upgrades are planned, primarily to address baseline reliability concerns, in future years. Table 3.4-3 lists the future planned or proposed facilities that are expected to mitigate some of congestion on the top 45 historically most congested post-Midwest ISO market flowgates previously listed in Table 3.4-2.

Table 3.4-3 The 45 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	Sum of All Three Market Years Hours Congested	Related Upgrades/Comments
1, 100	Kammer 765/500kV XFMR (flo) Belmont-Harrison 500kV	3,009	Not Midwest ISO flowgate
2, 2353	Black Oak-Bedington 500kV (flo) Pruntytown-Mt. Storm 500kV	2,980	Not Midwest ISO flowgate
3, 3006	Eau Claire-Arpin 345kV	2,568	P1: Arrowhead-Gardner Park 345kV line (ISD January 2008)
4, 2245	Blue Lick-Bullitt Co. 161kV (flo) Baker-Broadford 765kV	1,749	Not Midwest ISO flowgate
5, 3270	State Line-Wolf Lake 138kV (flo) Burnham-Sheffield 345kV	1,479	No project identified
6, 3012	Paddock 345/138kV XFMR (flo) Paddock-Rockdale 345kV	1,302	2nd Wempletown-Padock 345kV line (in service in 2005) and P1256 (Paddock Rockdale 345kV circuit #2 ISD 4/1/2010)
7, 2872	Frankfort East-Tyrone 138kV (flo) Ghent-West Lexington 345kV	1,283	Not Midwest ISO flowgate
8, 6004	Minnesota Wisconsin Stability Interface (MWSI)	1,162	P1: Arrowhead-Gardner Park 345kV line, ISD January 2008, and P1024: SE Twin Cities-Rochester, MN-LaCrosse, WI 345kV project
9, none	Culley-Grandview 138kV (flo) Henderson 161/138kV XFMR	1,012	P1259: New transmission line Dubois to Newtonville, ISD June 2006.
10, 6009	Cooper South Interface	1,006	Not Midwest ISO flowgate
11, 2352	Pruntytown-Mt. Storm 500kV (flo) Black Oak-Bedington 500kV	1,005	Not Midwest ISO flowgate
12, 122	Wylie Ridge 500/345kV XFMR #7 (flo) Wylie Ridge 500/345kV XFMR #5	979	Not Midwest ISO flowgate
13, 2463	Kokomo HP 230/138kV XFMR (flo) Jefferson-Greentown 765kV	882	No project identified
14, 3567	ATC LLC Flow South Interface	843	Stiles-Plains 138kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park-Highway 22 345kV line projects) and P345 (Morgan-Werner West 345kV line) connect Morgan-Plains 345kV line to the pre-existing 345kV system, hence increase voltage stability. P352 (Cranberry-Conover 115kV and Conover-Plains conversion to 138kV) will also help increase the FG limit.
15, 9159	Ontario-ITC Interface	805	Congestion on the tie is caused by transactions beyond firm reservations between Michigan and IESO. Once Bunce Creek Phase Shifter (previously failed) is returned to service (Est. Summer 2009), all four ties on this interface (Currently normally operated with the existing three Phase Shifters by-

Table 3.4-3 The 45 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**	**Sum of All Three Market Years Hours Congested**	**Related Upgrades/Comments**
			passed) may be Phase Shifter controlled in order to help limit flows to limit congestion.
16, 6007	Gerald Gentleman-Red Willow 345kV	769	Coordinated Non-Midwest ISO flowgate
17, 6126	S1226-Tekamah 161kV flo S3451-Raun 345kV	750	Not Midwest ISO flowgate
18, 3706	Arnold-Hazleton 345kV	748	P1340: Build a new Hazleton-Lore-Salem 345kV line with a Lore 345/161kV 335/335 MVA transformer ISD: December 2011
19, none	Culley-Grandview 138kV (flo) Henderson-A.B. Brown 138kV	700	P1259: New transmission line Dubois to Newtonville,
20, 6164	Plymouth-Sioux City 161kV flo Raun-Sioux City 345kV	609	Not Midwest ISO flowgate
21, 3102	Bland-Franks 345kV	553	No congestion since Callaway-Franks line ISD 2006; See chart in Appendix F2
22, 2086	Newtonville 161/138kV Transformer #1	538	Coordinated Non-MISO flowgate. Driven by ice storm related damage in early 2007
23, 6006	Gerald Gentleman Station	531	Coordinated Non-MISO flowgate. Driven by ice storm related damage in early 2007
24, 6085	Genoa-Coulee 161kV (flo) Genoa-LaCrosse-Marshland 161kV	506	P584: Genoa-Coulee 161kV rebuild. In Service
25, 140	Elrama_Mitchell_138kV_flo_Ft_Martin_Ronco_500kV	466	Not Midwest ISO flowgate
26, 3724	Arnold-Vinton 161kV (flo) Arnold-Hazelton 345kV	456	P1340: Build a new Hazleton-Lore-Salem 345kV line with a Lore 345/161kV 335/335 MVA transformer ISD: December 2011and P1739: Reconductor the 161kV from Arnold-Vinton-Dysart-Washburn, sum rate 446 MVA
27, 291	Pierce B 345/138kV transformer l/o Pierce-Foster 345kV	428	P625: Add a third transformer rated 400 MVA
28, 3145	Pana 345/138kV XFMR (flo) Coffeen-Coffeen North 345kV	418	No project identified.
29, 1649	Avon 345/138kV XFMR	408	Non-MISO flowgate. Planned 2nd Avon 345/138kV transformer. Expected ISD: June 2009
30, 2980	Dune Acres-Michigan City 138kV ckts 1&2 (flo) Wilton Center-Dumont 765kV	407	Market Operational Issue during high West to East Transfers
31, 3745	Lime Creek-Emery 161kV (flo) Adams-Hazleton 345kV	391	P90: Emery-Lime Crk 161kV, Ckt 2
32, 3532	Ellington_Hintz_138_flo_NAppleton_WernerWest_345	372	Uprates of Ellington – Hintz 138kV 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 345kV line and P345: Morgan-Werner West 345kV line will assist.
33, 3108	Overton-Sibley 345kV	369	No project identified
34, 2557	Northeast Kentucky Interface	367	Not Midwest ISO flowgate
35, 13746	Genoa-Lacrosse Tap 161kV (flo) JPM unit	325	P1559: Genoa-La Crosse tap 161 rebuild. ISD 2011
36, 111	Sammis-Wylie Ridge 345kV line l/o	322	No project identified

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Sum of All Three Market Years Hours Congested	Related Upgrades/Comments
	Perry-Ashtabula-Erie West		
37, 2295	A.B. Brown-Henderson 138kV (flo) Culley-Grandview 138kV	321	P1257: New transmission line Gibson (Cinergy) to AB Brown to Reid (BREC). ISD is May 2011.
38, 3186	West Mt. Vernon-E W Frankfort 345kV	319	P739: The Franklin County plant interconnection includes a 345kV switchyard and "in and out" connection to the Mt. Vernon-E W Frankfort 345kV line. Detailed design changes that may mitigate impact on flowgate, are TBD
39, none	Kelly-Whitcomb 115kV (flo) Rocky Run-Werner West 345kV	298	P101: Kelly-Whitcomb 115kV upgrade
40, 3529	North Appleton-Werner West 345kV	282	P345: Morgan-Werner West 345kV line P177: Gardner Park-Highway 22 345kV line
41, 2908	Miami Fort 345/138kV XFMR (flo) East Bend-Terminal 345kV	275	P1248: Miami Fort 21.6MVAR 69kV capacitor. This project can reduce the reactive power flow through the transformer. ISD: June 2008
42, 3167	St. Francois-Lutesville 345kV	274	No project identified
43, 6124	Tiffin-Arnold 345kV	271	Non-MISO flowgate: P1340: Build a new Hazleton-Lore-Salem 345kV line with a Lore 345/161kV 335/335 MVA transformer ISD: December 2011
44, 2375	Wylie Ridge 500/345kV XFMR #5 (flo) Belmont-Harrison 500kV	267	Not Midwest ISO flowgate
45, 3168	St. Francis-Lutesville 345kV (flo) Bland-Franks 345kV	264	No project identified

Table 3.4-3 The 45 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

There are many flowgates listed above which are not on Midwest ISO system, yet they are listed to show the opportunity for coordinating with neighboring systems to improve energy market performance. Midwest ISO will work with neighboring systems to determine which flowgates may be cost effectively mitigated and provide value to the Midwest ISO market. Additionally, for some flowgates, no projects have yet been identified as required for reliability purposes that would also mitigate the constrained hours. This offers an opportunity in MTEP 09 to evaluate whether there is sufficient economic benefit to introduce new transmission projects which reduce congestion on those flowgates.

Section 4: Long-Term Plan: 10-20 Year Horizon

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.

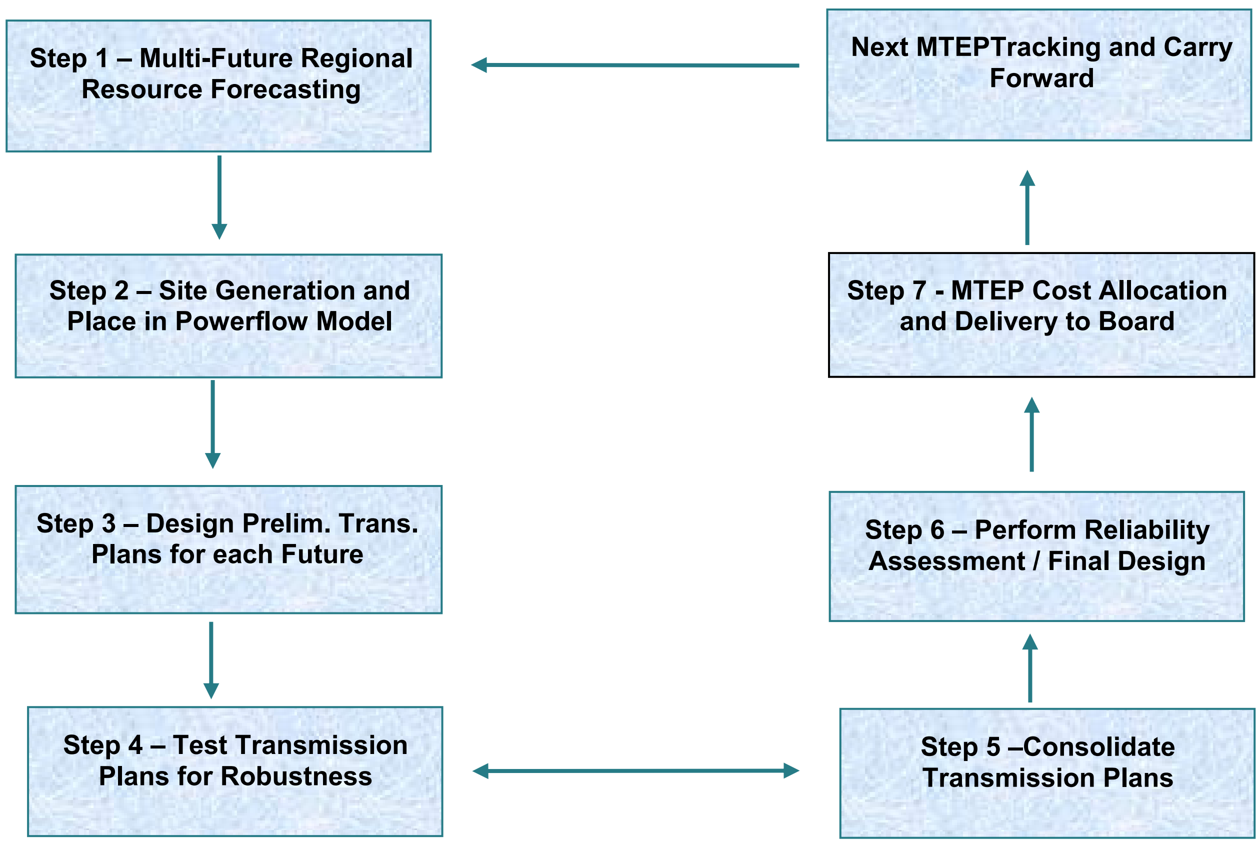


Figure 4.1-1: Best Models Integrated Process

4.1 Generation Futures Development

This section addresses 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 futures. Given how electricity is now provided, with the increasingly regional nature of existing organizations and federal interests, RRF greatly enhances the overall planning process for electricity infrastructure. Moreover, given that we are at the beginning of a major new investment cycle for generation and transmission, all with hefty price tags, consumers deserve a planning process which will maximize the use of new facilities and spread its cost over multiple beneficiaries. 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. 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.

The MTEP08 planning cycle is the first in which regional resource planning activities have been included in the enhanced MTEP process. The Future definitions and assumptions for the models for steps one and two were developed through numerous Planning Advisory Committee (PAC) meetings and stakeholder workshops from February 2006 to March 2007. 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. Since then, the MTEP09 Steps one and two process was completed in March of 2008, and reflects updates and additions to the assumptions, including the external review of other ISO's and stakeholders through the Joint Coordinated System Planning (JCSP) process. The assumptions and results can be viewed on the Midwest ISO website.

4.1.1 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 portfolio. The portfolios are the capacity expansion results from a "least cost" optimization of future generation requirements based on the specified resource adequacy criteria of 15% reserve margin. It identifies the optimal "least cost" generation required to meet reliability criteria based on the assumptions for each Future scenario. MTEP08 has four Futures:

- Reference Future
- Environmental Future
- Renewable Mandate Future
- Fuel Supply 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 existing standards for resource adequacy, renewable mandates and environmental legislation will remain unchanged. Included in the Future is the assumption of the existing wind energy credit which is set to expire in 2008 but will be extended through year 2015.

The Environmental Future models the uncertainties assuming environmentally friendly legislation including a mid-range carbon initiative. A Carbon price of $25 per ton is a midpoint within the range as reported by the National Commission on Energy Policy representing the McCain-Lieberman Stewardship Act of 2003-SA 2028 and the Energy Information Administration (EIA) analysis of the plan. The assumption guiding the uncertainty values are the inclusion of the standards which will push the non-coal related fuels and generators to be in higher demand, as well as force less than ideal economic conditions based on the increased cost of energy resulting in reduced demand growth. The carbon initiative will be indexed to inflation and begins 2010. A high mercury cost is also modeled in this Future. This Future also assumes retirement of uneconomic coal units. In this Future the price of gas and oil are 10% higher, and coal is 10% lower.

The Renewable Mandate Future requires 20% of the energy consumption within each Midwest ISO Region to come from a renewable energy source. Wind is the preferred generation alternative to meet the mandate. A 33% capacity factor for existing wind generators and 40% capacity factor for new wind generators counts toward the renewable mandate. Fifteen percent of the wind generators nameplate capacity will be used in reserve margin calculations. This Future will force Wind Generation to be constructed to meet 20% of the total energy served by 2020 and maintain the 20% mandate thereafter. Wind Generation will begin to be forced in the models starting in 2010. It is assumed the wind energy credit is not renewed beyond 2008 in this Future. This Future recognizes states that have specific RPS that may exceed the 20%, or have special siting conditions.

The Fuel Supply Future represents a limitation to the supply of Natural Gas as a fuel source. Either due to supply or pipeline availability, this Future models the inability to run a gas unit at full capacity by increasing the de-rate of all natural gas fired units' maximum capacities. The modelled de-ration will be 30% of the maximum capacity of each gas unit. The shortage of gas availability is also captured in the assumption scarcity pricing for natural gas.

4.1.2 Portfolio Development

A regional assessment was performed separately using Strategist on the Midwest ISO East, Central and West regions as indicated in Figure 4.1-2. Using the most recent projected demand and energy by each company and common assumptions for resource forecasting, models were developed to identify least cost portfolios of generation needed to meet the needs of each Future.

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. The siting methodology is explained in the appendix E of this report.

An example of the 20 year study for generation requirements for the Midwest ISO and the Reference Future is provided below. The complete assumptions and results can be viewed in Appendix E of this report.

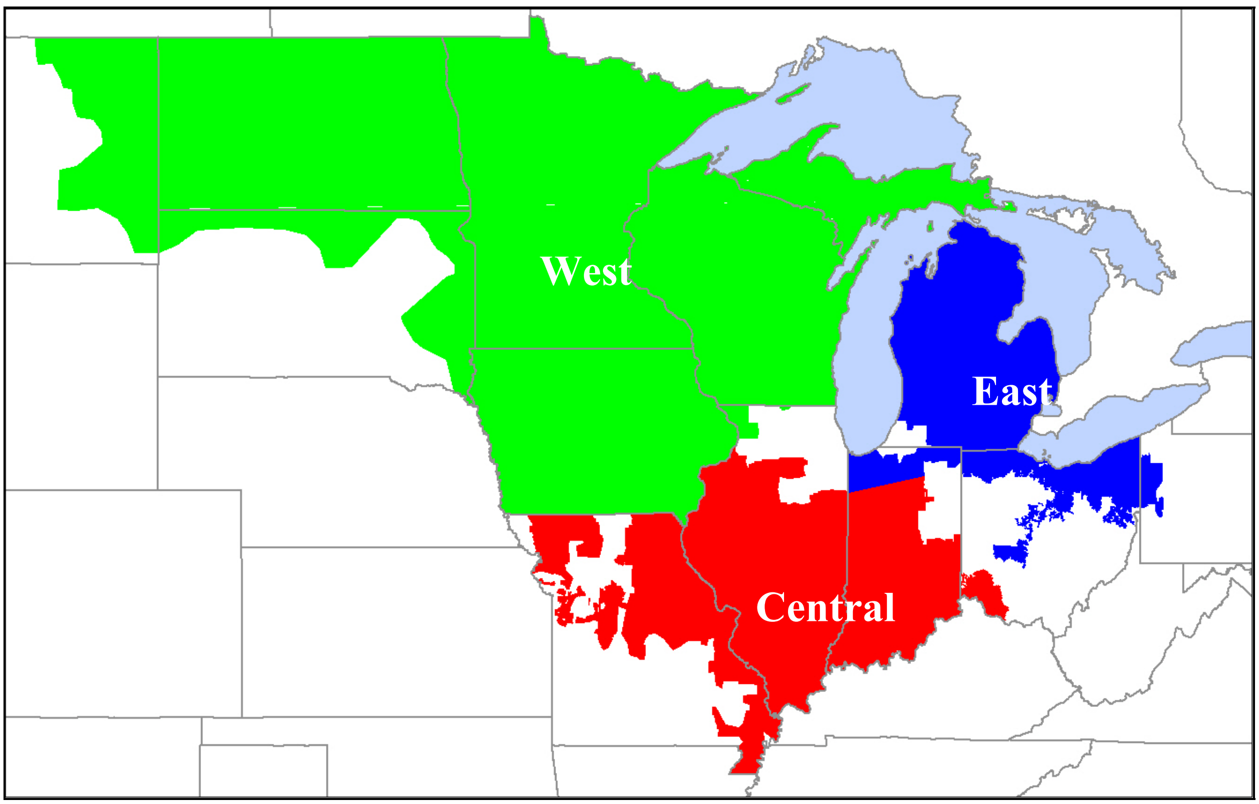


Figure 4.1-2: Midwest ISO Regions

Table 4.1-1: Summary of Midwest ISO Generation Additions by Future and Fuel Type 2008-2027

Future	Queue (MW)	Nuclear (MW)	Coal (MW)	CC (MW)	CT (MW)	Wind (MW)	BTM (MW)	DR (MW)	Total (MW)	Costs (Millions)
Reference	6,326	0	20,400	3,600	3,520	12,600	1,425	1,235	49,106	290,640
Environmental	6,326	12,000	6,000	3,600	2,880	13,800	1,425	1,235	47,266	458,858
Fuel	6,326	0	26,400	6,000	4,160	12,600	1,425	1,235	58,146	339,989
Renewable	6,326	0	16,800	6,000	1,600	40,500	1,425	1,235	73,886	322,904

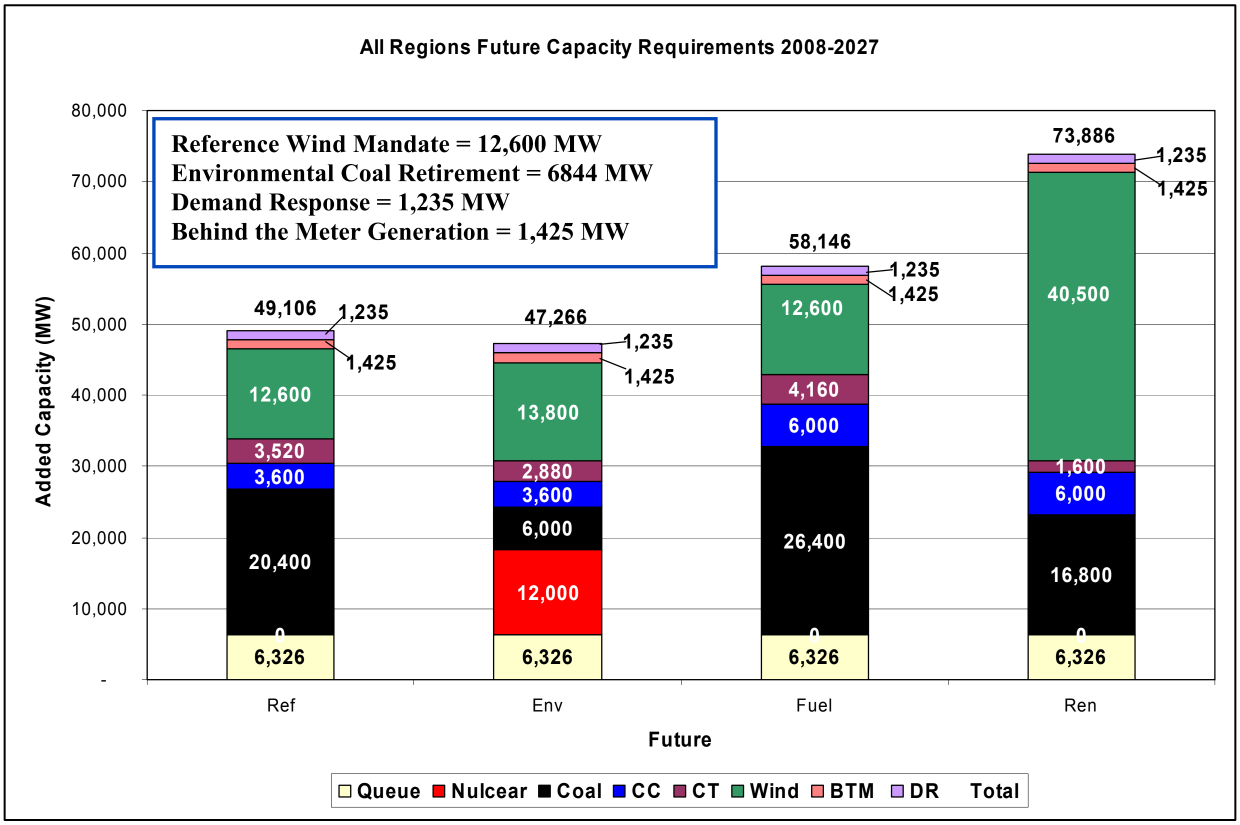


Figure 4.1-3: MTEP 2008 Total Midwest ISO Generation Additions By Future

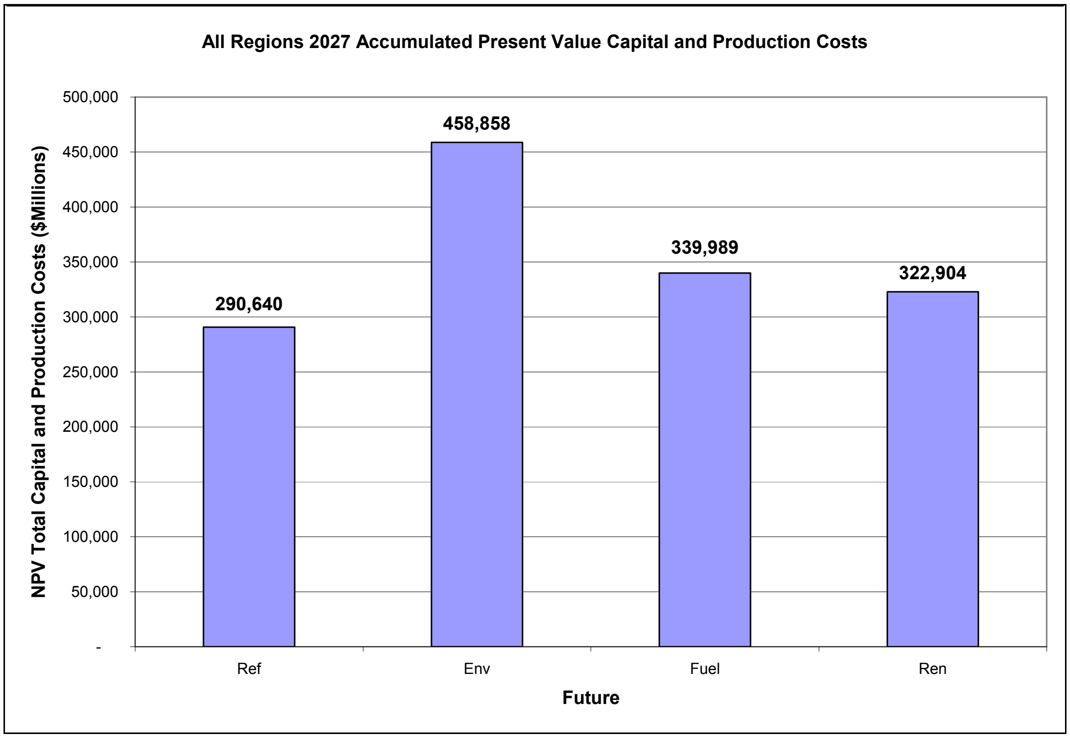


Figure 4.1-4: 2027 Accumulated Present Value of Incremental Capital and Production Costs

Table 4.1-2: Total Midwest ISO Reference Capacity Additions

	COAL	CC	Queue	CT	WIND	BTM	INT	Total
2008	-	-	1,633	-	-	-	-	1,633
2009	-	-	2,661	-	-	75	65	2,801
2010	-	-	732	320	1,200	75	65	2,392
2011	-	-	-	-	900	75	65	1,040
2012	-	-	-	-	1,500	75	65	1,640
2013	-	1,200	1,300	320	1,500	75	65	4,460
2014	2,400	-	-	-	1,200	75	65	3,740
2015	1,200	-	-	320	1,500	75	65	3,160
2016	1,200	-	-	320	600	75	65	2,260
2017	-	-	-	320	-	75	65	460
2018	2,400	-	-	320	300	75	65	3,160
2019	2,400	1,200	-	320	600	75	65	4,660
2020	1,200	-	-	-	900	75	65	2,240
2021	1,200	-	-	320	-	75	65	1,660
2022	1,200	-	-	-	600	75	65	1,940
2023	1,200	-	-	320	300	75	65	1,960
2024	3,600	1,200	-	320	300	75	65	5,560
2025	-	-	-	320	300	75	65	760
2026	2,400	-	-	-	600	75	65	3,140
2027	-	-	-	-	300	75	65	440
Total Units:	20,400	3,600	6,326	3,520	12,600	1,425	1,235	49,106

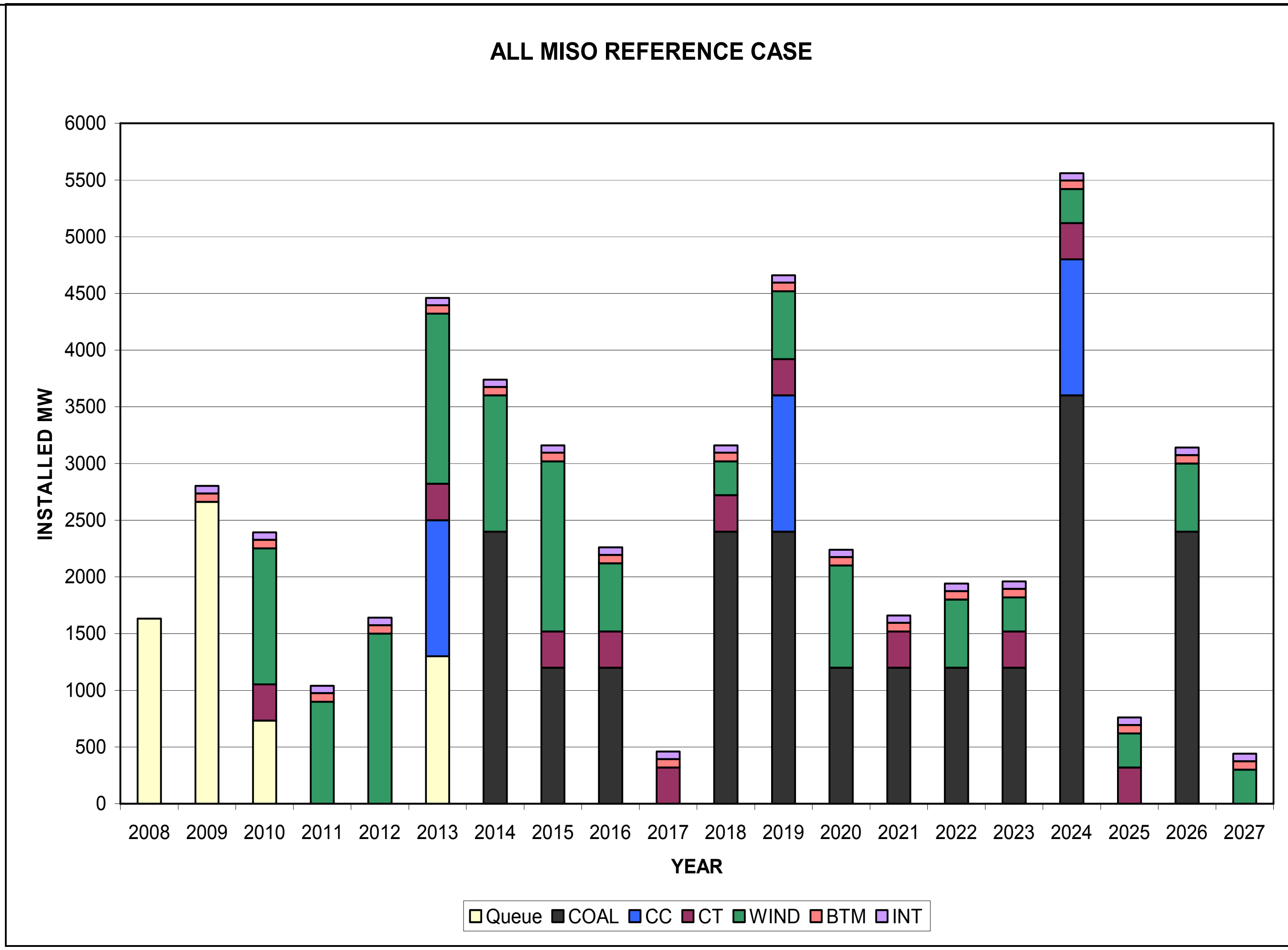


Figure 4.1-5: Reference Future Capacity Additions by Year and Fuel Type

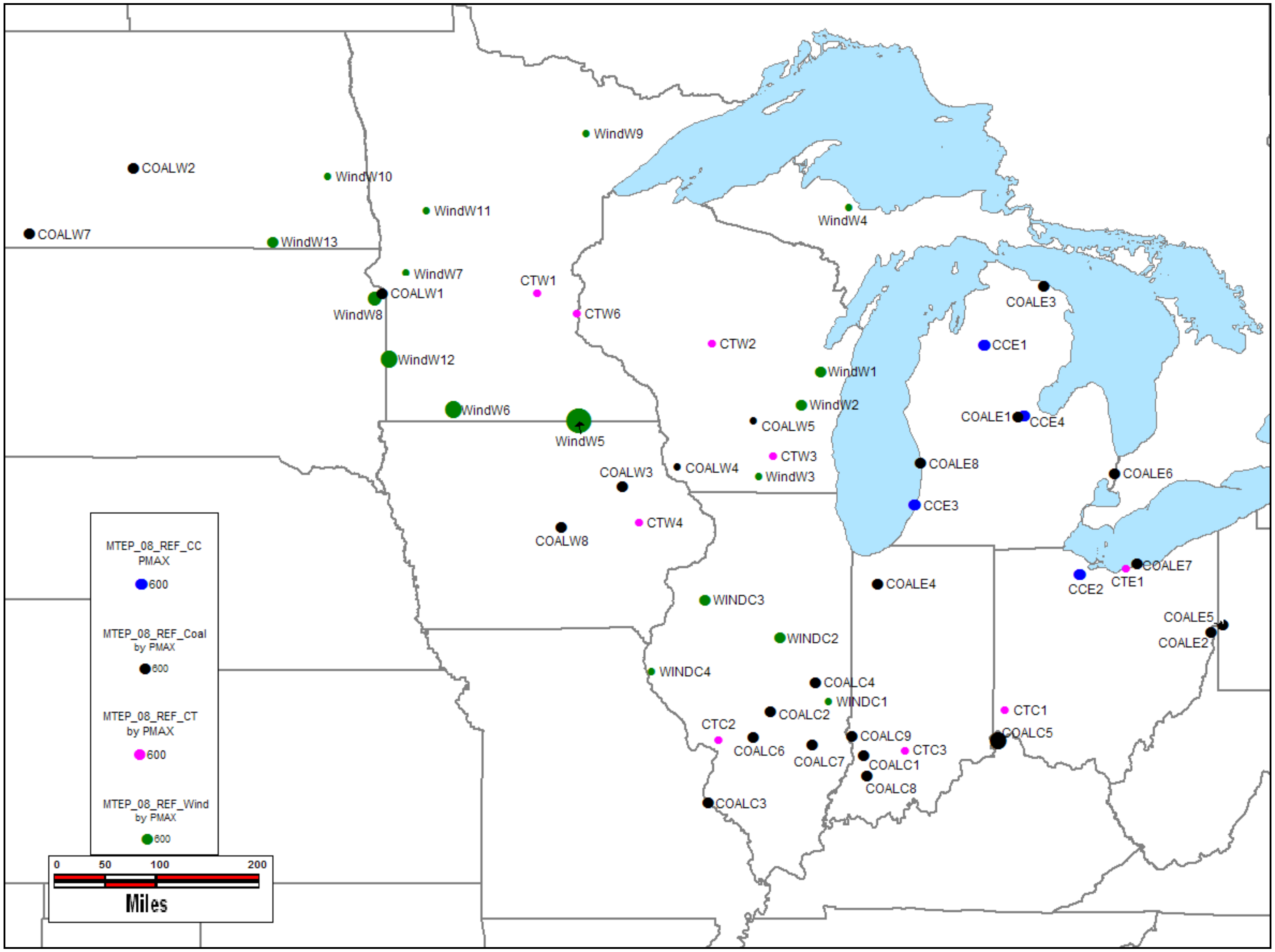


Figure 4.1-6: Reference Future Generation Siting

4.2 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 4 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 MTEP08 value-based (economic) planning process, as described in Section 2, 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 MTEP08. Section 4.1 provides more information on how the generation portfolio futures were developed for MTEP08.

In summary, the four generation Futures defined by Planning Advisory Committee for MTEP08 are:

- **The Reference Future -** mandated wind and the future generation expansion alternative list.
- **The Renewable Future -** 20% wind energy from the Midwest ISO foot print and future generation expansion from the alternative list. Wind mandates are included in the 20% wind energy model.
- **The Environmental Future -** $25/ton carbon dioxide tax, mandated wind generation and the future generation expansion from the alternative expansion alternative list.
- **The Fuel Restriction Future -** natural gas supply limitation for both future and expansion gas fired generation, mandated wind and generation expansion from the alternative expansion list.

This section describes Steps 3 and 4 of the value-based planning process Step 3 focuses on development of conceptual 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. Step 4 performs the economic studies to understand how the EHV overlays perform against a specific set of economic metrics. A robustness test is also used to determine how the overlays perform against other future outcomes than the Future for which the transmission was specifically designed.

Two economic studies were performed against each of the four futures. The first developed conceptual EHV transmission expansion within the Midwest ISO footprint and also modeled transmission in the neighboring PJM region to provide more complete information about some of the impacts to and from the Midwest ISO from potential transmission expansion in neighboring regions. This study is referred to as the Eastern Interconnection (EI) study. The second study focused solely on conceptual EHV transmission expansion within the Midwest ISO footprint, without regard to impacts from and on neighboring systems. This study is referred to as the Midwest ISO Centric.

4.2.1 Summary of Conceptual EHV Transmission Study Results

The general observations result from the MTEP08 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. The Midwest ISO and the Pennsylvania – New Jersey - Maryland Interconnect (PJM) have a Joint and Common Market and a Joint Operating Agreement which includes transmission planning. See Section 4.2.3 for results of Eastern Interconnection conceptual transmission overlay.

- If Midwest ISO does not include the conceptual EHV transmission development and associated benefits beyond its borders, little additional transmission is needed for economic purposes. See Section 4.2.4 for results of Midwest ISO Centric conceptual transmission overlay.

- Inputs from neighboring RTOs and utilities are needed to accurately study the impacts of conceptual EHV transmission overlays. The JCSP study described in Section 4.4 is a result of the experiences in the MTEP08 report cycle, where the Eastern Interconnection study was modeled solely with input from the Midwest ISO and its stakeholders.

4.2.2 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.

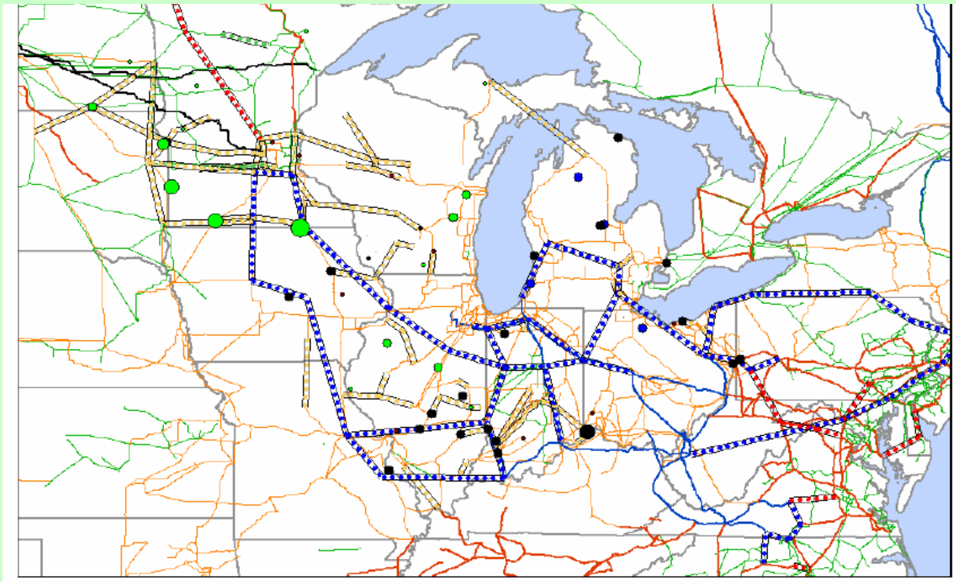
The following process is used to develop the conceptual transmission overlays in Step 3. First, we use the power flow and PROMOD® models developed in Step 2 (Section 4.1) and run PROMOD® using the same assumptions used in the development of the generation portfolio assessment. For example, if we have four Futures from the portfolio assessment process we would develop four 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 and Midwest ISO only benefit area. The sections also present economic results from Step 4 of the process.

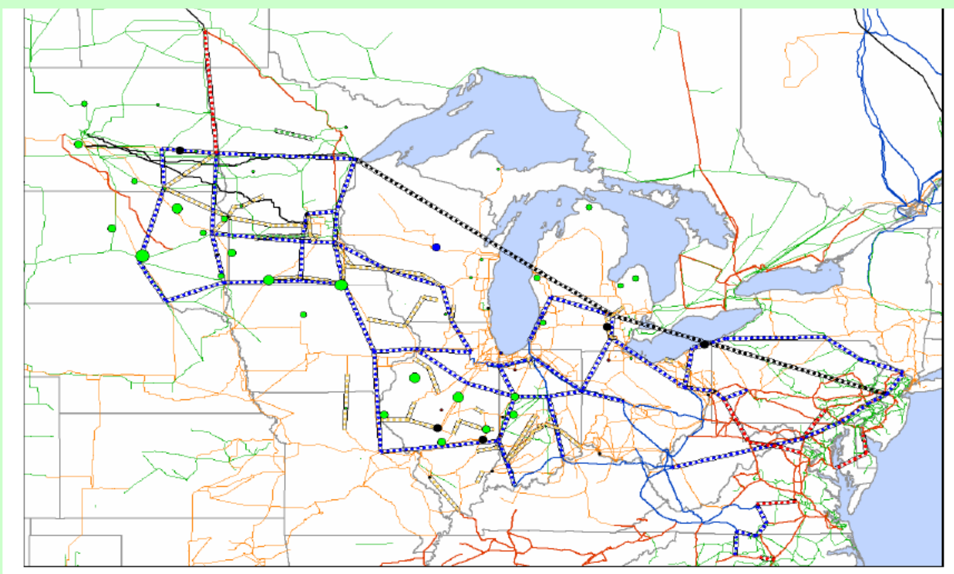
4.2.3 Conceptual Transmission Design EI

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. Maps 4.2-1 to 4.2-4 are the conceptual transmission expansion maps for each Future for the Eastern Interconnection (EI) part of the MTEP08 value-based studies. Conceptual transmission was modeled for the Midwest ISO, PJM and part of Duke Carolinas. The dashed lines are expansion lines. The solid lines are existing lines. Black lines are DC, Blue lines are 765kV, Red lines are 500kV, and Tan lines are 345kV. The colored dots indicate the location of forecasted generation expansion or generation with signed interconnection agreements from the Generation Interconnection Queue.

Map 4.2-1: EI Conceptual Transmission for Reference Future



Map 4.2-2: EI Conceptual Transmission for Renewable Future



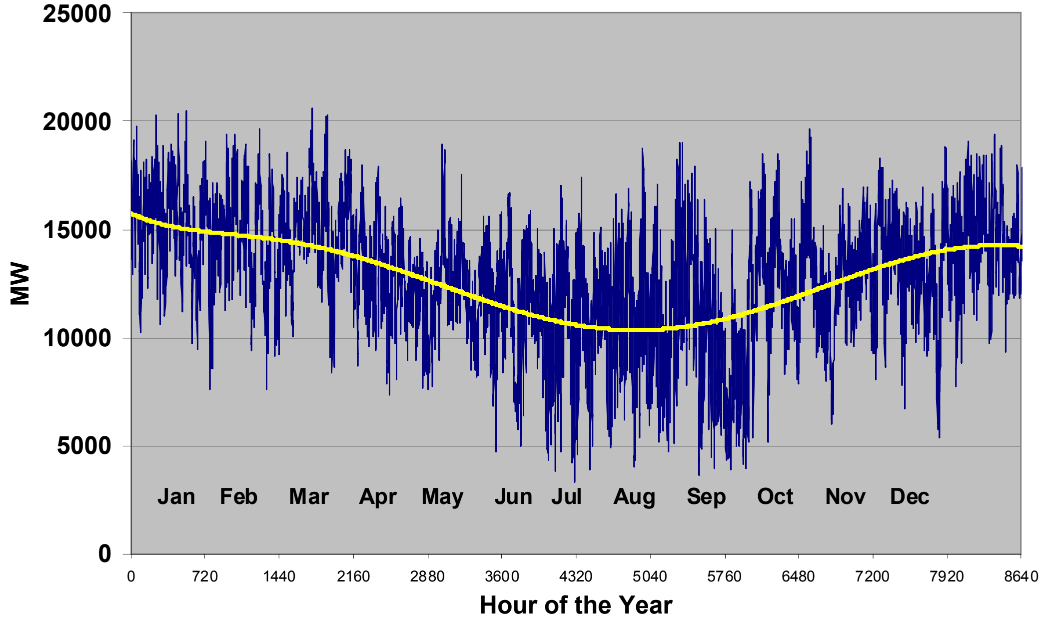
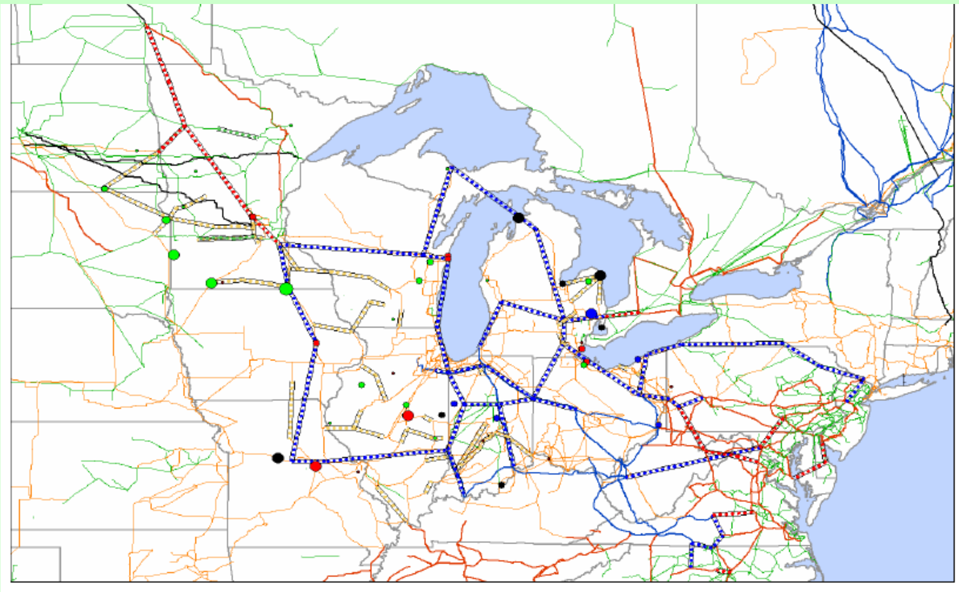


Figure 4.2-1: West to East Flow on OH-PA Interface

Figure 4.2-1 is the summation of all the hourly energy flows across the Ohio-Pennsylvania and south interface for the Renewable Future. The transmission across the interfaces is sized to supply about 80% of the energy as a first estimate of the economic transmission required. The dip in the middle is due to the pattern of wind energy not being available on peak. The peak loading of the transmission system is off peak.

Map 4.2-3: EI Conceptual Transmission for Environmental Future



Not as much transmission is required from the Midwest ISO to the East Coast under the Environmental Future with a carbon tax policy.

Map 4.2-4: EI Conceptual Transmission for Fuel Future

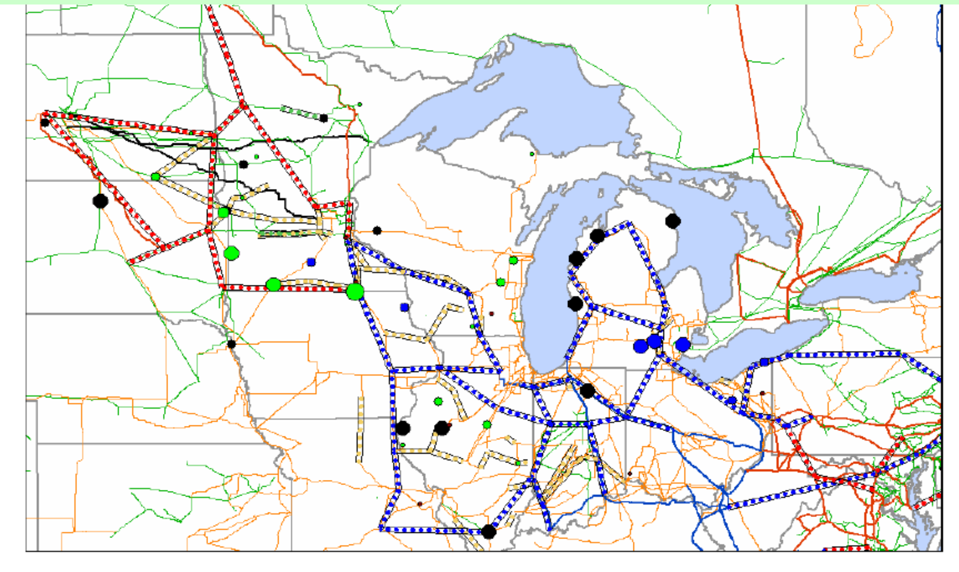


Table 4.2-1: EI Conceptual Transmission Cost Estimates

		345	(2) - 345	500	765	DC-800kV
Cost/Mile	(2007$)	1,100,000	1,800,000	1,400,000	2,500,000	5,000,000

		345	(2) - 345	500	765	DC-800kV	Total
Line Mileage	Reference	3,374	997	855	3,860	0	9,086
	Renewable	2,213	997	723	5,309	1,192	10,434
	Environmental	2,403	997	1,074	4,613	0	9,087
	Fuel	2,213	997	2,346	4,108	0	9,664

		345	(2) - 345	500	765	DC-800kV	Total
Total Line Cost (M$)	Reference	3,712	1,795	1,198	9,649	0	16,353
	Renewable	2,434	1,795	1,012	13,274	5,960	24,474
	Environmental	2,644	1,795	1,503	11,533	0	17,474
	Fuel	2,434	1,795	3,284	10,270	0	17,783

(In Millions of Dollars)	Cost Including Stations (2007$)	ARR at 15% (2007$)	ARR at 15% (2021$)
Reference	20,441	3,066	4,777
Renewable	30,593	4,589	7,149
Environmental	21,843	3,276	5,105
Fuel	22,229	3,334	5,195

Table 4.2-1 contains the assumptions on the cost per mile for each voltage. A 25% multiplier was added to approximate the inclusion of substation costs. HVDC used cost of the terminals and line divided by the mileage as a proxy cost per mile.

An annual revenue requirement of 15% of the total cost was used to calculate the annual cost of the lines. The annual revenue requirement includes the cost of money for equity and borrowed funds, taxes, insurance, depreciation and estimated operation and maintenance cost.

A typical Benefit/Cost (B/C) ratio for a transmission line built for reliability purposes may be 0.3. Generally, transmission is a cost and does not pay for itself with the exception of lines that are supported with generation transactions.

The B/C ratios are included in Table 4.2-2. A net present value calculation was used to calculate the costs from one PROMOD® run for the year 2021. A 3% escalation rate on the benefits and an 8% discount factor were used. The difference in the price of natural gas versus the price of coal is one of the primary factors in the escalation rate. The price of wind energy is essentially a constant.

Table 4.2-2: EI Conceptual Transmission Benefit/Cost

Cost and Benefit Comparison (All in 2021 $) EI Overlay			
		EI	B/C Ratio
	10 year NPV costs (M$)	APC 10 year NPV Savings (M$)	
Reference	34,102	40,167	1.18
Renewable	51,039	56,280	1.10
Environmental	36,441	32,094	0.88
Fuel	37,086	60,525	1.63

Note:

1. 10 year NPV costs calculated using ARR at 15% of total line and station costs with a discount rate of 8%
2. APC 10 year NPV savings include 3% benefit growth per year from 2021 with a discount rate of 8%
3. B/C ratio is calculated using the NPV of the Adjusted Production Cost benefit for the ten year period following 2021 divided by the NPV of the ARR costs for the 10 year period following 2021

Three of the four Futures' conceptual transmission overlays developed under the EI study have a B/C ratio greater than one. The B/C ratio of the Environmental Future being less than 1.0 may indicate that the amount of transmission in overlay may have to be reduced. Only adjusted production cost (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.

Using the adjusted production cost alone as the measure of the benefits is conservative. Several additional evaluation measurement components could be:

- Lowering the capital cost of future interconnections of generation.
- Lowering the transmission capital costs associated with providing energy and capacity deliverability for future generation.
- Transmission capital cost reductions by reducing or mitigating constraints or adding transmission capacity that possibly could be used to serve future load.
- Reduction of losses for both the energy and the deferred capital of generation capacity.
- Capital costs of generation capacity deferment due to lower capacity requirements for planning reserves.
- Transmission revenue sources for economic purposes may be derived from other loads than the areas of the energy supply. The conceptual EHV transmission overlay benefits indicate that the typical assumptions associated with transmission cost allocation and business models to build transmission may require revision.

Including the evaluation of more components would require more study resources than were available for MTEP08. A stakeholder process is investigating what valuation metrics should be used in future MTEP studies, and is discussed further in Section 10.

Table 4.2-3 contains lists by area of the total annual value of the transmission constraints (Achievable Target) and the total annual value of the transmission constraints relieved (Achieved). The MTEP08 studies sought to capture no more than 80% of the Achievable Value as a practical limit.

Table 4.2-3: EI Transmission Overlay APC Savings by Region

			Adjusted Production Cost Saving			
			Reference	Renewable	Environmental	Fuel
MISO	Achieved	(M$)	1,793	3,642	2,425	3,226
	Achievable	(M$)	3,016	5,808	3,636	5,265
	Achieved/Achievable	(%)	59%	63%	67%	61%
PJM	Achieved	(M$)	1,905	2,027	649	2,377
	Achievable	(M$)	6,434	6,679	5,798	7,233
	Achieved/Achievable	(%)	30%	30%	11%	33%
MAPP non-MISO	Achieved	(M$)	268	21	253	319
	Achievable	(M$)	1,292	1,131	1,271	1,829
	Achieved/Achievable	(%)	21%	2%	20%	17%
NYISO	Achieved	(M$)	132	96	81	344
	Achievable	(M$)	2,628	2,906	2,633	3,126
	Achieved/Achievable	(%)	5%	3%	3%	11%
SPP	Achieved	(M$)	22	71	-6	36
	Achievable	(M$)	1,028	1,162	1,001	1,997
	Achieved/Achievable	(%)	2%	6%	-1%	2%
SETRANS	Achieved	(M$)	557	652	569	786
	Achievable	(M$)	3,825	4,288	3,692	5,771
	Achieved/Achievable	(%)	15%	15%	15%	14%
IMO	Achieved	(M$)	266	416	-22	360
	Achievable	(M$)	936	1,143	1,044	989
	Achieved/Achievable	(%)	28%	36%	-2%	36%
Whole East Interconnection	Achieved	(M$)	4,943	6,925	3,949	7,448
	Achievable	(M$)	19,161	23,117	19,075	26,211
	Achieved/Achievable	(%)	26%	30%	21%	28%

While the results for the Midwest ISO were in the 60% plus range, the results in the PJM area were only in the 30% range. The need for the PJM input to the study process is evident. This was one driver for the Joint Coordinated System Planning (JCSP) study.

The benefits to the regions besides the Midwest ISO and PJM are free rider benefits from being connected to an interconnected AC power system.. Table 4.2-3 shows that the benefits achieved by the conceptual EHV transmission expansion are to the Eastern Interconnection and not just to the Midwest ISO and PJM.

Table 4.2-4: Relief Of Binding Constraints – El Overlay

With EI Overlay				
	Reference	Renewable	Environmental	Fuel
Total Shadow Hour Decrease (Hour)	64,924	73,561	52,523	73,808
Total Shadow Price Decrease (K$/MW)	23,531	61,217	22,601	27,895
Removed Binding Constraints	127	144	117	131
Shadow Price Decreased (k$/MW)	19,322	54,206	22,115	25,618
New Binding Constraints	37	31	21	25
Shadow Price Decreased (k$/MW)	-268	-966	-88	-650
Worsened Binding Constraints	119	149	146	135
Shadow Price Decreased (k$/MW)	-5,305	-9,302	-7,207	-7,034
Improved Binding Constraints	206	177	163	193
Shadow Price Decreased (k$/MW)	9,781	17,279	7,781	9,962

Table 4.2-4 lists the categories of constraints that were changed by hour and by price. While the conceptual overlays are large, the transmission to resolve or mitigate the number of constraints that were affected by the conceptual overlays would also result in a large financial cost. The transmission design process used in MTEP to design transmission overlays is effective in resolving a high number of constraints in areas outside of the Midwest ISO.

The disadvantage of resolving constraints in a serial fashion (traditional process) is that constraints only occur where there are transmission lines. The resultant power flows would probably be in directions other than the indication by the market price signals. The market signals are from west to east and require power transfers of a magnitude that could not be supported by just constraint relief as there is very little power transfer capability in the west to east direction. Northern Pennsylvania is one example. The Minnesota border is another example.

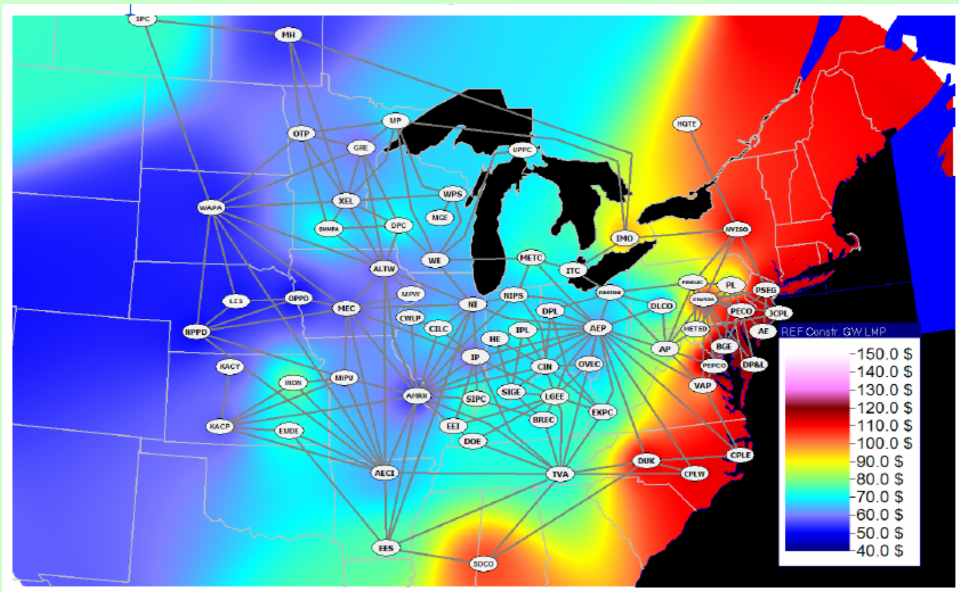
Table 4.2-5: Top Binding Constraints – EI Overlay

Top 10 Binding Constraints Outside MISO	Total Binding Hours	Total Shadow Price (k$/MW)	Area
01DOUBS 20459 01AQUEDT 20456 330	3,327	2,087	PJM
NEWROAD6 50403 6W.NROAD 98414 1	4,837	2,018	SPP
01DOUBS 20105 01DOUBS 20459 1	712	1,492	PJM
MED-LDG3 58773 MED-LDG4 58774 1	3,256	1,409	SPP
PLAT T#1 79593 WILLIS E 79595 1	7,960	1,384	NYISO
MANOR 3071 MILLWOOD 3104 363	1,135	1,317	PJM
WHITPAIN 15 WHITPAN3 4601 1	1,097	1,280	PJM
CRAIGJT4 54015 ASHWEST4 53226 19	4,577	859	SPP
INTERFACE ISONE - CAPITAL 1	8,522	769	NYISO
CARLISLE 205 ROXBURY 221 362	2,230	718	PJM

Top 10 Binding Constraints in MISO	Total Binding Hours	Total Shadow Price (k$/MW)	Area
PR ISLD3 60105 REDROCK3 60236 209	3334	351.91	NSP
MT VRNON 32328 ASHLEY 32334 216	608	254.91	AMREN
19WTRMN 28883 J5D PS 82590 1	1764	171.41	ITC-IMO
17LESBRG 28047 17NRTHES 28063 139	312	148.5	NIPS
DUCK CRK 33161 IPAVA 30788 1	335	99.86	AMRN
PLS PR2 38849 ZION ; R 36421 53	2958	95.36	ComED-WEP
LANSVLAM 33200 LANVL AM 33201 76	195	91.48	AMREN
GENOA 5 69523 COULEE 5 60302 250	382	58.51	NSP-DPC
HENNEPIN 32418 LTV TP E 32420 227	83	50.45	AMREN
QUAD ; 36382 ROCK CK3 34036 44	1490	48.74	ALWST-ComED

Table 4.2-5 lists the top constraints outside of the Midwest ISO and inside the Midwest ISO sorted by the summation of shadow prices for the year after the Renewable Overlay was applied. The more significant constraints are outside of the Midwest ISO. These lists are used to resolve constraint issues with the conceptual transmission overlays along with the interchange tables.

Map 4.2-5: Reference Average Annual LMP without Transmission Overlay



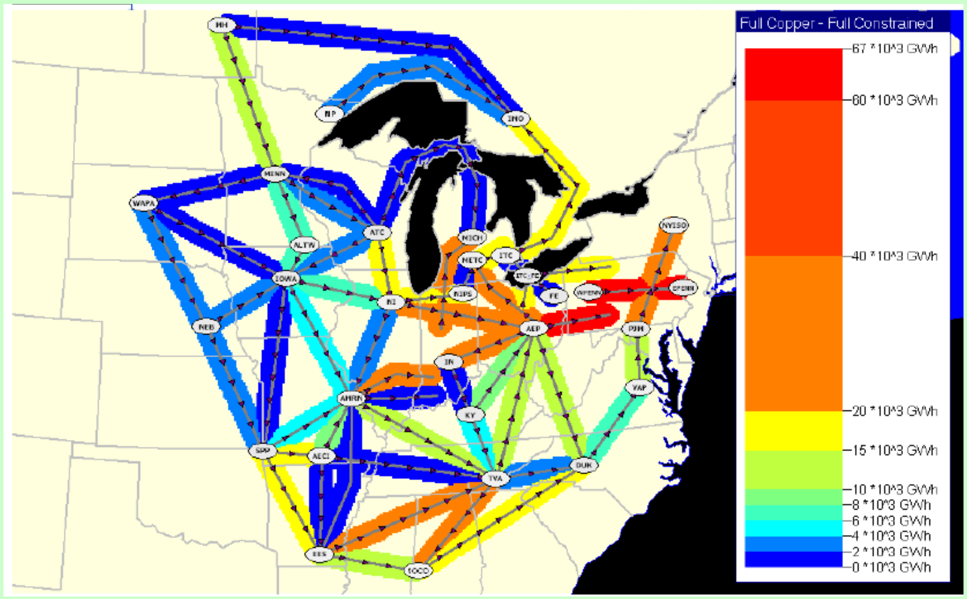
Map 4.2-5 shows the generator average annual Locational Marginal Pricing (LMP) prices across the system studied in MTEP08 for the Reference Future without any transmission overlays. The highest prices are on the east coast. Changes in color indicate areas of constraint.

Transmission has a value if energy is delivered across a price differential (change in color).

For transmission to be able to pay for itself, a price differential has to be maintained after the transmission is constructed. Generation in the low priced areas bid into the high priced areas as price takers. The difference in the clearing price of the two markets is used to pay for the transmission plus provide an incentive to the generator to participate in the market (contribution margin). Building transmission from one blue area to another almost blue area in the Midwest ISO will not pay for transmission. The MTEP06 and MTEP08 studies show that it may be possible to construct transmission that may be self supporting.

Price is not enough to design a transmission overlay. To pay for a transmission system price and the energy volume at that price need to be considered. The potential volume of energy flow is determined from the difference between an unconstrained case and a constrained case. A "Copper Sheet Analysis" is the name used for unconstrained case. Two PROMOD® simulations are run. One with constraints and one with all ratings removed, losses not calculated and interchanges not maintained. The difference provides information as to where the energy is generated, where the energy displaces other generation, and the quantity of flow hourly across geographic interfaces.

Map 4.2-6: Interface Contour: Annual Energy Difference Full Copper Sheet to Full Constrained Case



Map 4.2-6 provides the information about the sources of generation, the location of areas receiving energy and the quantities across the geographical interfaces.

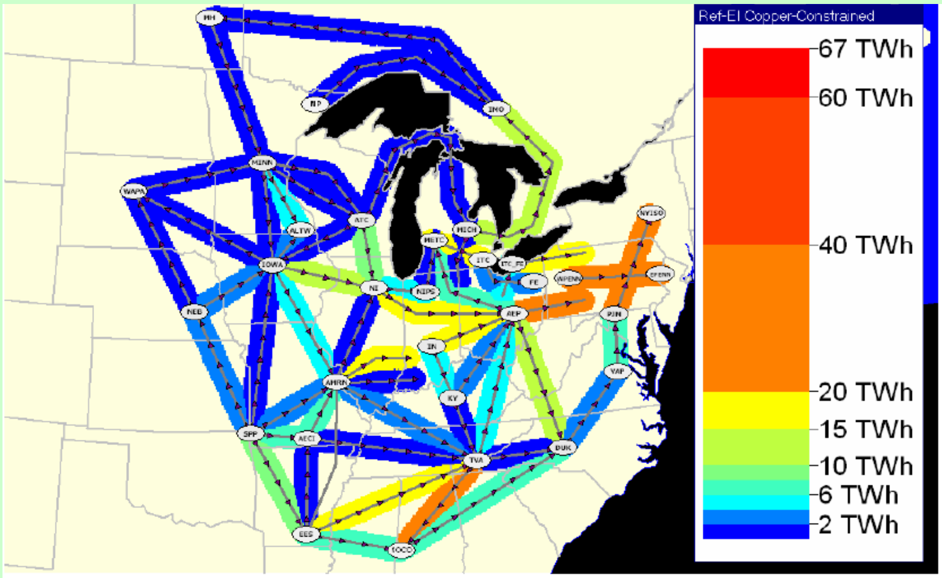
The red lines indicate the heaviest incremental power flow. The blue lines the lightest incremental power flow. Hourly power flows across the interfaces are examined and the transmission capacity to deliver about 80% of the energy is calculated. Table 4.2-6 is a list of interface flows that is derived from the information that is presented from an interface flow diagram similar to the one in Map 4.2-6.

Table 4.2-6: Top Interfaces Need More Transfer Capability – EI Overlay

INTERFACE	Total Positive Energy (MWh)	Total Negative Energy (MWh)	Addition Capacity Needed to Deliver 80% Energy (MW)
AEP-EAST	33,007,341	-675,836	5,008
WPENN-EPENN	37,370,128	0	4,860
SOCO-TVA	11,053	-21,664,531	3,404
PJM-NYISO	29,839,960	-49,197	3,279
TVA-EES	279,463	-17,363,280	2,866
AMRN-EAST	19,451,425	-334,211	2,764
DUK-SOCO	3,642,931	-7,787,024	2,427
AEP-COMED	79,712	-18,411,865	2,205
DUK-AEP	3,029	-12,375,443	2,126
METC-ITC	16,576,393	-29,450	2,022

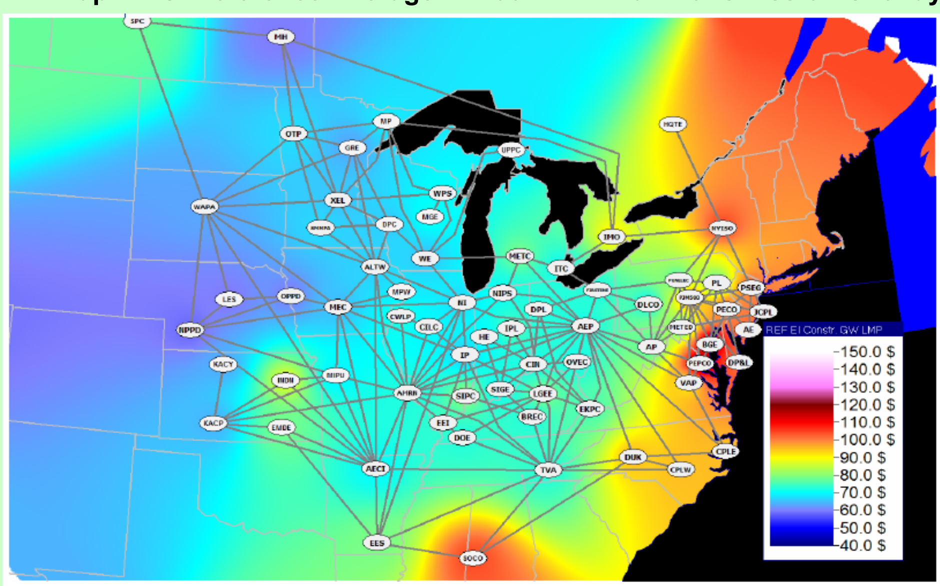
Table 4.2-6 is a list of the interface flows that could be served by additional transmission to supply 80% of the energy from the "Copper Sheet Analysis".

Map 4.2-7: Interface Contour: Annual Energy Difference Full Copper Sheet to Full Constrained Case



Map 4.2-7 shows the interface flow diagram after the application of the transmission overlay. Note the change in color. Also note the change in loop flow indicated by the color and direction of the arrows through the areas not in the Midwest ISO and PJM.

Map 4.2-8: Reference Average Annual LMP with Transmission Overlay

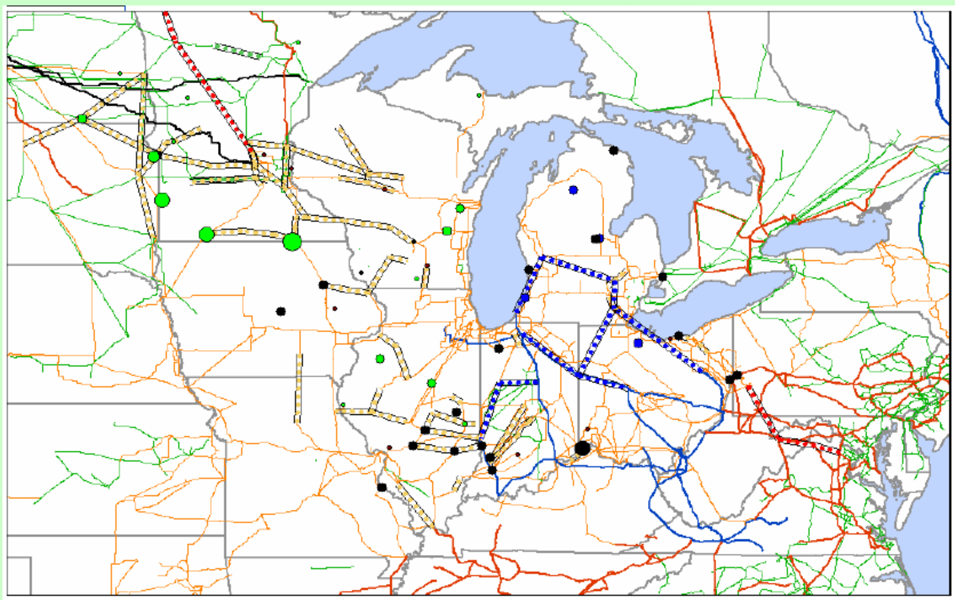


Map 4.2-8 shows the generation annual average LMP pricing with the Reference transmission overlay. A comparison with Map 4.2-5 (without transmission overlay) demonstrates ability of conceptual transmission overlay in providing a more competitive market within Midwest ISO and reduction in costs to the east.

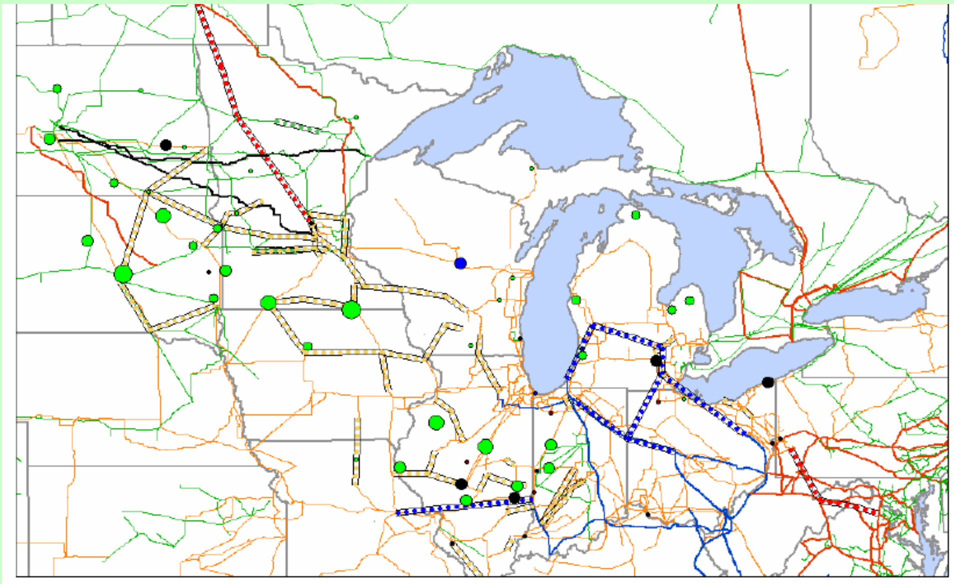
4.2.4 Conceptual Transmission Design for Midwest ISO

The same types of analyses that were executed to develop the Eastern Interconnect Conceptual EHV Transmission Designs were also executed to develop conceptual EHV Transmission designs which only capture benefits to Midwest ISO market. These are called Midwest ISO Centric designs. Maps 4.2-9 to 4.2-12 are the conceptual transmission overlays that were constructed for the four Futures with no transmission expansion outside the Midwest ISO borders. Present transmission ties were allowed to export or import energy. As with the EI conceptual EHV overlay maps, the dashed lines are expansion lines. The solid lines are existing lines. Black lines are DC, Blue lines are 765kV, Red lines are 500kV, and Tan lines are 345kV. The colored dots indicate the location of forecasted generation expansion or generation with signed interconnection agreements from the Generation Interconnection Queue.

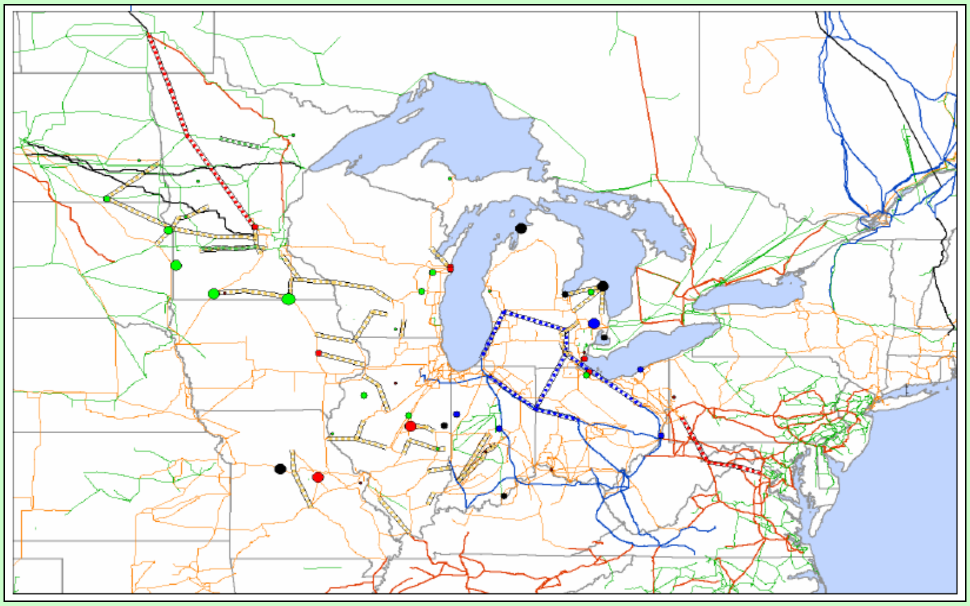
Map 4.2-9: Midwest ISO Centric – Reference Future



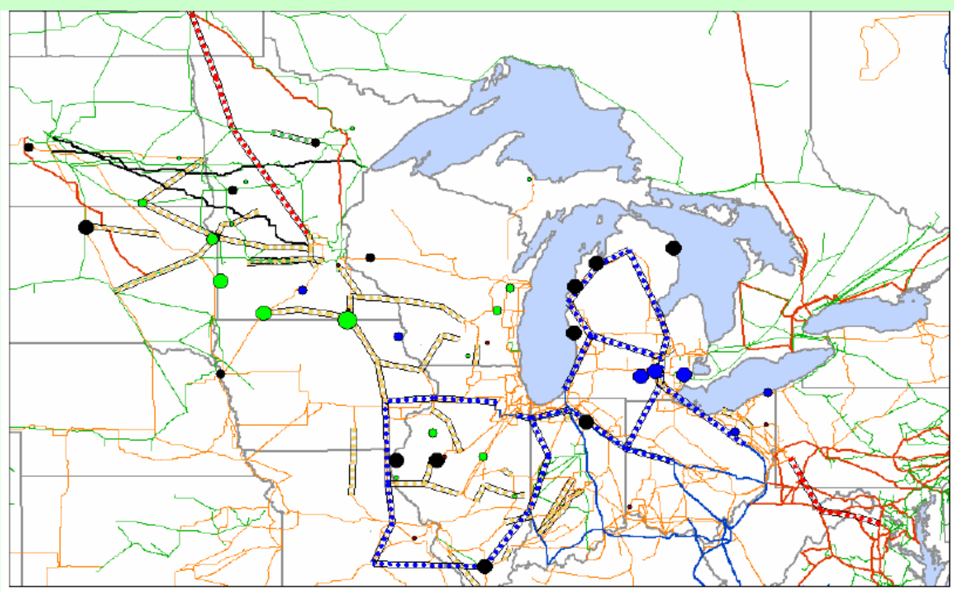
Map 4.2-10: Midwest ISO Centric – Renewable Future



MAP 4.2-11: Midwest ISO Centric – Environmental Future



Map 4.2-12: Midwest ISO Centric – Fuel Future



A comparison of Table 4.2-7 to Table 4.2-1 highlights the differences between Midwest ISO only benefit area versus a larger benefit area including others in Eastern Interconnection. Table 4.2-7 requires significantly less transmission than Table 4.2-1. This is largely due to the additional transmission required in the Eastern portion of the footprint, although close examination of the maps also reveals less transmission with the Midwest ISO footprint itself.

Table 4.2-7: Line Miles, Total Cost, Annual Cost Calculation

		345	(2) - 345	500	765	DC-800kV
Cost/Mile	(2007$)	1,100,000	1,800,000	1,400,000	2,500,000	5,000,000

		345	(2) - 345	500	765	DC-800kV	Total
Line Mileage	Reference	3,181	997	538	815	0	5,531
	Renewable	3,497	997	538	930	0	5,962
	Environmental	2,692	997	538	682	0	4,909
	Fuel	2,554	997	571	1,884	0	6,006

		345	(2) - 345	500	765	DC-800kV	Total
Total Line Cost (M$)	Reference	3,499	1,795	753	2,037	0	8,083
	Renewable	3,847	1,795	753	2,325	0	8,719
	Environmental	2,962	1,795	753	1,705	0	7,213
	Fuel	2,809	1,795	800	4,711	0	10,114

	Cost Including Stations (2007$)	ARR at 15% (2007$)	ARR at 15% (2021$)
Reference	10,104	1,516	2,361
Renewable	10,899	1,635	2,547
Environmental	9,017	1,353	2,107
Fuel	12,643	1,896	2,955

\

Table 4.2-8: B/C Ratio – Midwest ISO Overlay

Cost and Benefit Comparison (All in 2021 $) MISO Overlay			
		MISO	B/C Ratio
	10 year NPV costs (M$)	APC 10 year NPV Savings (M$)	
Reference	16,855	11,645	0.69
Renewable	18,183	10,865	0.52
Environmental	15,042	15,928	1.06
Fuel	21,096	19,772	0.94

Note:

1. 10 year NPV costs calculated using ARR at 15% of total line and station costs with a discount rate of 8%
2. APC 10 year NPV savings include 3% benefit growth per year from 2021 with a discount rate of 8%
3. B/C ratio is calculated using the NPV of the Adjusted Production Cost benefit for the ten year period following 2021 divided by the NPV of the ARR costs for the 10 year period following 2021

Table 4.2-8 shows lower B/C ratios than those calculated for the EI study which are shown in Table 4.2-2. The B/C ratios below 1.0 indicate that the Midwest ISO only conceptual EHV transmission overlays are not economic, but the information may be used for other uses such as coordination of future transmission proposals with neighbors.

Transmission projects built to address the Top 4 footprint constraints (further discussed in Section 8.5) would probably represent most of the transmission that would be constructed between areas within the Midwest ISO if transmission expansion was limited to within the Midwest ISO borders under the RECB II criteria.

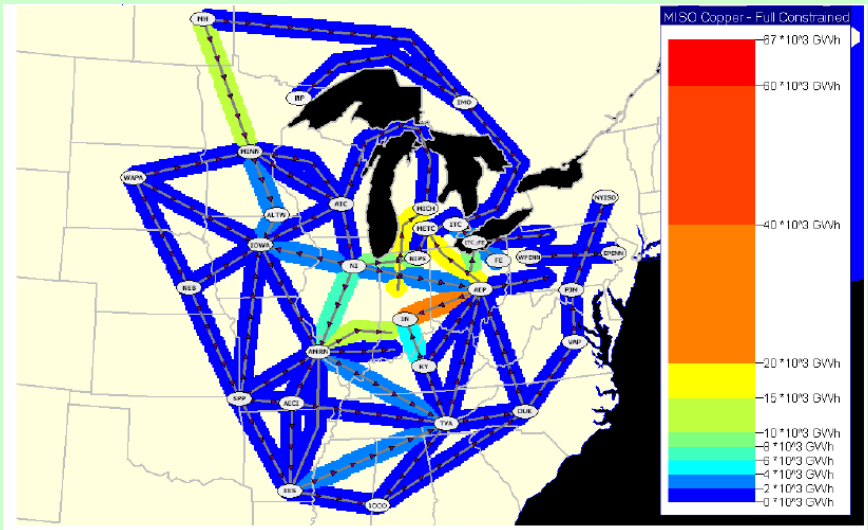
Table 4.2-9: APC Savings for Midwest ISO Conceptual Transmission Overlay

Achievable Benefits are based on the difference between
Full Copper Sheet Case and Full Constrained Case

Adjusted Production Cost Savings						
			Reference	Renewable	Environmental	Fuel
MISO	Achieved	(M$)	1,433	1,337	1,960	2,433
	Achievable	(M$)	3,016	5,808	3,636	5,265
	Achieved/Achievable	(%)	47.53%	23.01%	53.91%	46.21%
PJM	Achieved	(M$)	1,028	936	719	924
	Achievable	(M$)	6,434	6,679	5,798	7,233
	Achieved/Achievable	(%)	15.98%	14.02%	12.40%	12.77%
MAPP non-MISO	Achieved	(M$)	144	-111	137	129
	Achievable	(M$)	1,292	1,131	1,271	1,829
	Achieved/Achievable	(%)	11.13%	-9.79%	10.78%	7.04%
NYISO	Achieved	(M$)	19	17	7	13
	Achievable	(M$)	2,628	2,906	2,633	3,126
	Achieved/Achievable	(%)	0.71%	0.58%	0.26%	0.43%
SPP	Achieved	(M$)	-13	-48	-18	-28
	Achievable	(M$)	1,028	1,162	1,001	1,997
	Achieved/Achievable	(%)	-1.24%	-4.10%	-1.76%	-1.42%
SETRANS	Achieved	(M$)	-21	-43	-63	10
	Achievable	(M$)	3,825	4,288	3,692	5,771
	Achieved/Achievable	(%)	-0.56%	-1.00%	-1.70%	0.18%
IMO	Achieved	(M$)	48	63	-20	105
	Achievable	(M$)	936	1,143	1,044	989
	Achieved/Achievable	(%)	5.17%	5.55%	-1.93%	10.63%
Whole East Interconnection	Achieved	(M$)	2,638	2,152	2,722	3,586
	Achievable	(M$)	19,161	23,117	19,075	26,211
	Achieved/Achievable	(%)	13.77%	9.31%	14.27%	13.68%

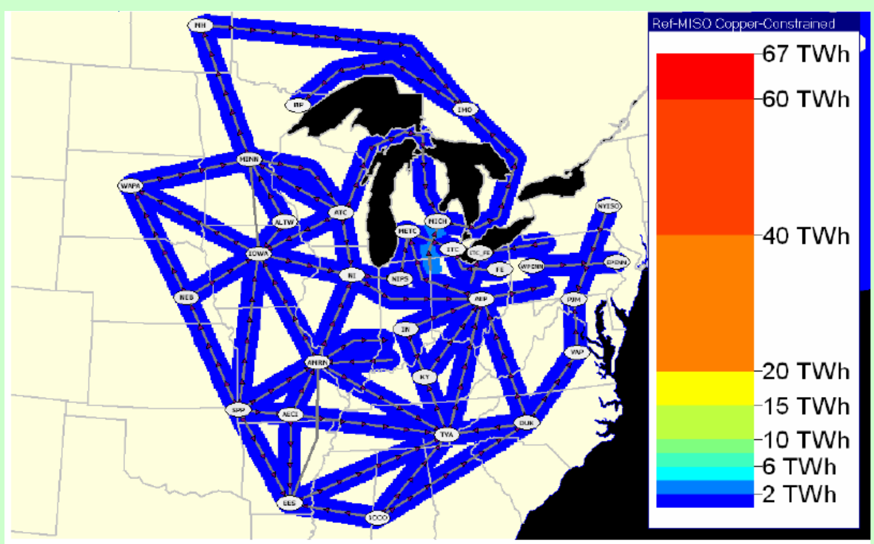
Table 4.2-9 shows that some benefits still occur to entities outside the Midwest ISO even without additional transmission. The benefits within Midwest ISO and elsewhere would probably be reduced since some of the transmission in the conceptual design would not be economical and would not qualify for cost sharing under Regional Expansion Criteria and Benefits (RECB) II.

Map 4.2-13: Interface Contour: Annual Energy Difference Midwest ISO Copper Sheet to Full Constrained Case



Map 4.2-13 shows that the areas with transmission potential are mainly from Manitoba to Minnesota and from the Central area of Ameren and Indiana to Michigan. The Top 4 and the ITC Target study lines are in these areas.

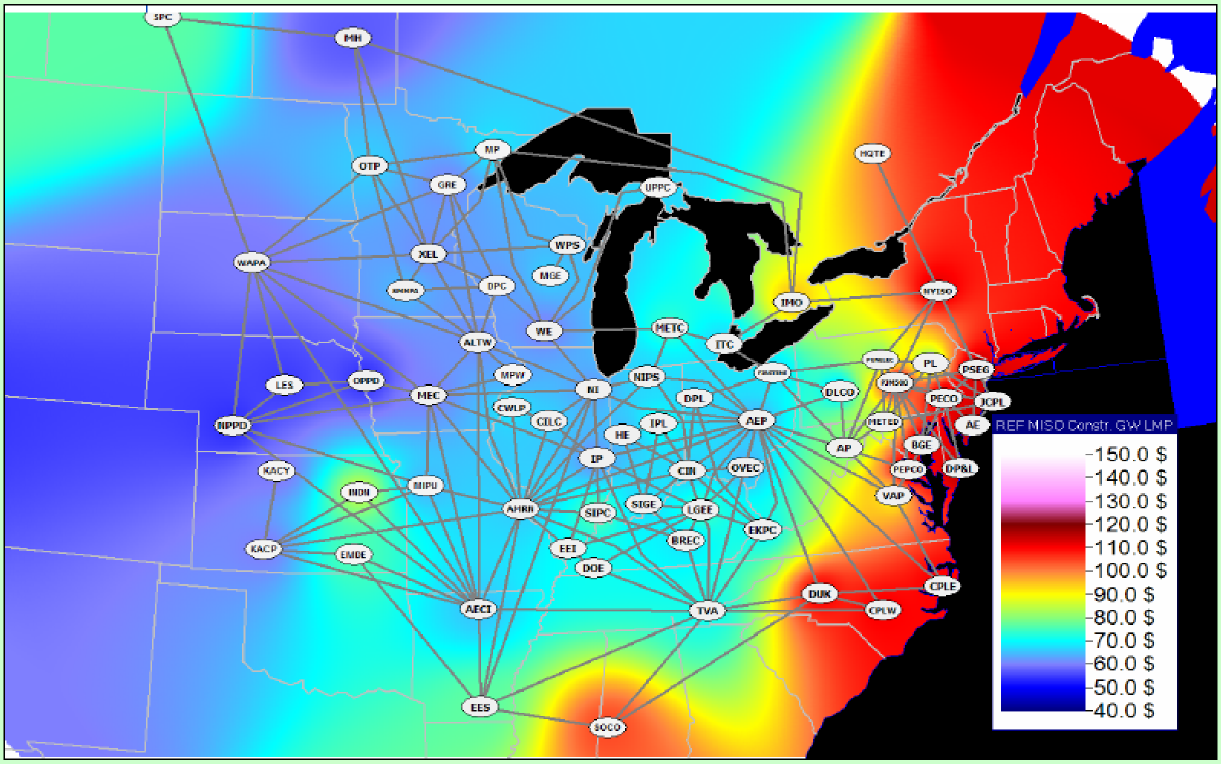
Map 4.2-14: Interface Contour: Annual Energy Difference Midwest ISO Copper Sheet to Full Constrained Case



Map 4.2-14 shows that there is little need for additional transmission with the Reference overlay for Midwest ISO limited development.

The MISO Centric conceptual EHV transmission overlay would limit the amount of wind generation that could be operated in the Midwest ISO footprint to about half of that with the EI conceptual EHV transmission overlay. Generation curtailment would be required to manage this mode of operation.

Map 4.2-15: Reference with Midwest ISO Centric Skelton Overlay Generation Weighted LMP



Map 4.2-15 is the Midwest ISO Reference future transmission overlay of the generation annual average LMP. This should be compared with Map 4.2-5 for the Eastern Interconnection overlay.

4.2.5 Overlay Generation and Transmission Economics

To understand the future costs of the electric grid we must look at all components of cost. The accumulated present value cost of the Future (generation and transmission) for a 20 year period, are included in Figure 4.2-2. The costs for the overlay for both the Midwest ISO and the PJM areas are included. Notice that transmission is a small part of the total Future projected costs of generating and delivering electricity. The transmission costs are for the entire overlays. The capital costs are the summation of the annual capital requirements of the expansion forecast generation, and the production costs include the fuel and Operations & Maintenance (O&M) for both the existing and expansion forecast generation for Midwest ISO. See Section 2 for costs in rate terms.

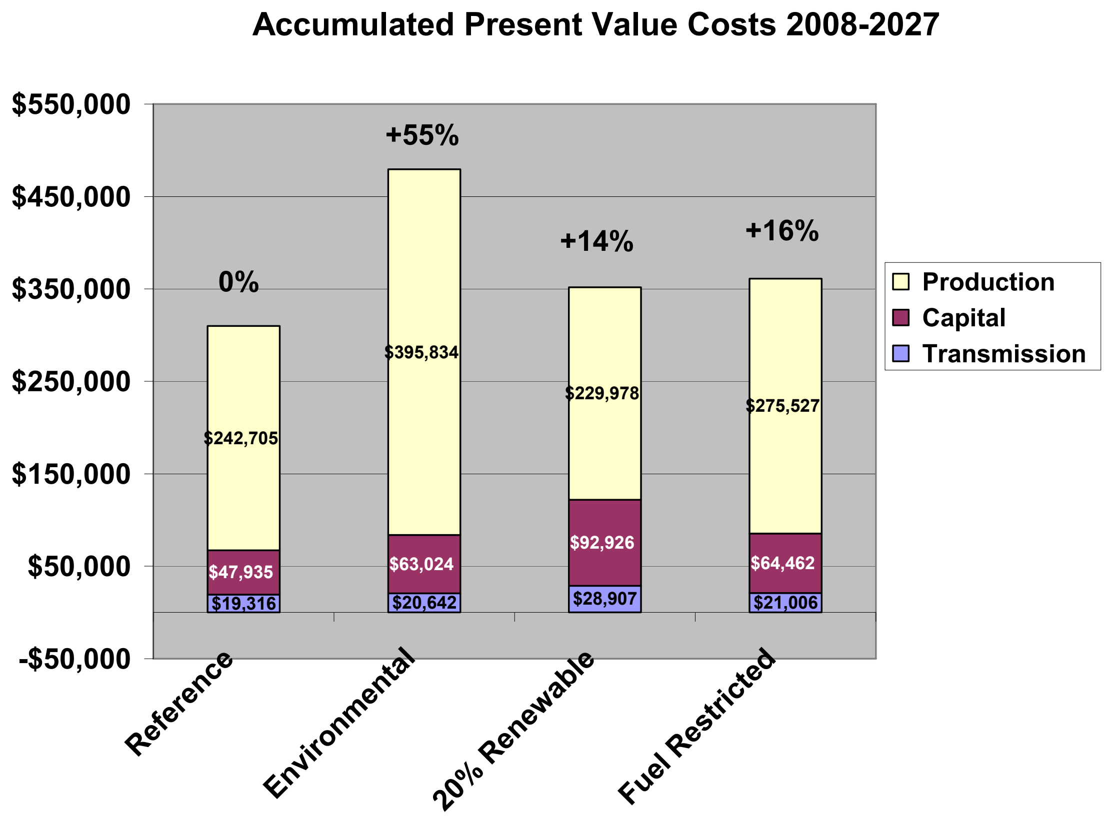


Figure 4.2-2: Futures Cost for 20 Years (Millions)

The percentages at the top of the columns are the increases versus the Reference future costs. Production costs are the dominant component. Some of the capital costs associated with generation may occur as production cost due to power purchase agreements as with wind generation.

MTEP08 value-base planning studies indicate that there can be significant interaction with the neighbors and other energy markets depending on scope of conceptual EHV transmission design. Therefore, it would be prudent to understand those interactions before making decisions on long term transmission investments within the Midwest ISO footprint.

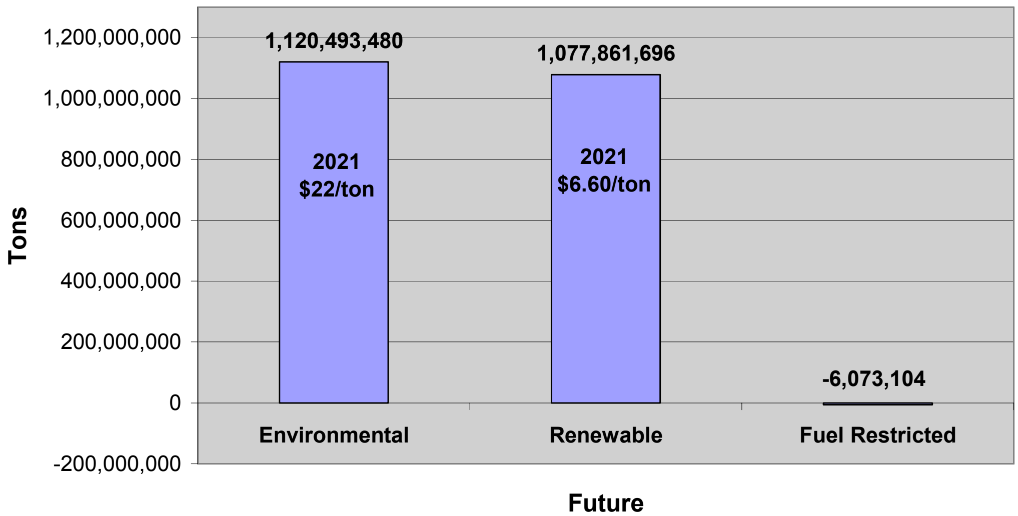


Figure 4.2-3: Carbon Dioxide Reduction 2021

The carbon dioxide reduction for the simulated year 2021, shown in Figure 4.2.3, is slightly less for the Renewable Future than the Environmental Future. The reduction of carbon dioxide for the Environmental Future to the Reference Future is 10.3%. The reduction of carbon dioxide for the Renewable Future to the Reference Future is 9.9%. The Fuel Restricted Future increased the carbon dioxide production slightly. Figure 4.2.3 is a 20% wind energy for the Midwest ISO footprint. Figure 4.4-7 contains the results for the JCSP study and most of the U.S. Eastern Interconnection footprint.

The Environmental Future has a cost of 335% higher per ton of carbon dioxide reduced than the Renewable Future for the year 2021. The Environmental value is reduced by the mix of mandated wind energy from the $25/ton study assumption.

Figure 4.2.4 is the sulfur dioxide reduction for the simulated year 2021.

Figure 4.2.5 is the nitrogen oxide reduction for the simulated year 2021.

Figure 4.2.6 is the mercury reduction for the simulated year 2021.

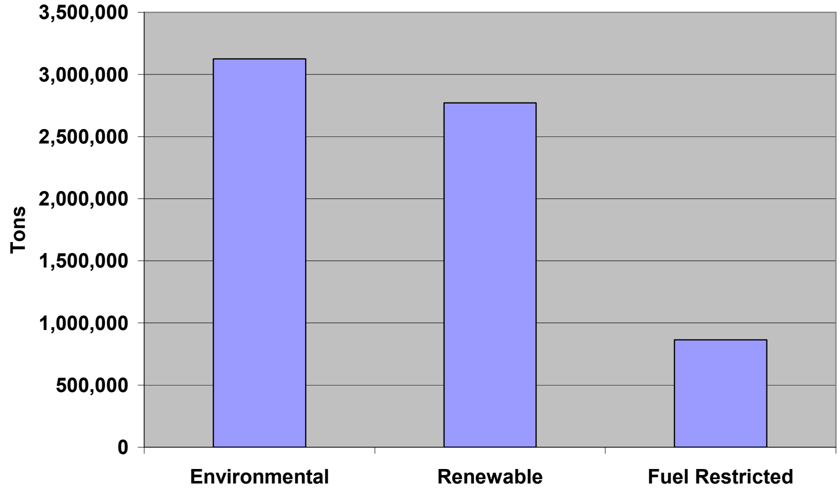


Figure 4.2-4: Sulfur Dioxide Reduction 2021

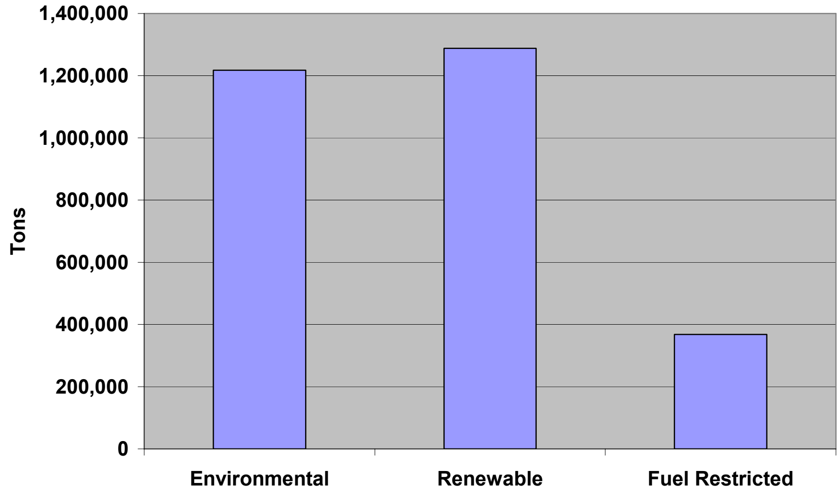


Figure 4.2-5: Nitrogen Oxide Reduction 2021

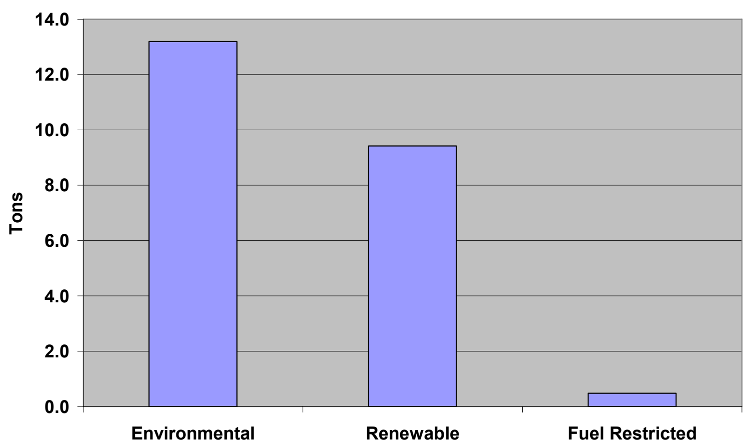


Figure 4.2-6: Mercury Reduction 2021

4.2-6 Transmission Design Considerations for EHV Overlay

Economics aside, there are other engineering reasons for an EHV transmission overlay. Consider that the cost of higher voltage, higher power transfer lines cost less per MW-mile than lower voltage lines, Figure 4.2-7. If lines can be loaded economically near their power transfer limit, then the cost to deliver energy is lower with the higher voltage lines. Wind energy helps load lines as it displaces low cost base load generation as well as higher priced gas fired generation.

If a higher voltage system of lines can be loaded economically and the benefit to cost ratio is sufficient to pay for the higher voltage lines in the early years, then it may be beneficial to build the overlay.

For example, if a transmission system is sized initially to export energy in the early years of service, then later the local loads grow to consume the capacity of the transmission system within a smaller footprint, the price of transmission to serve the new load is the depreciated price of the higher voltage transmission that was initially constructed. Historically, 115kV, 138kV and 161kV were the highest transmission voltages used to transmit power from generation to load. Today, these voltages are used to serve load by step downs from higher voltage lines and are not the primary long distance transmission. As load continues to grow, the 345kV transmission of the Midwest ISO is encountering a similar fate. Where in the 1960's and early 1970's 345kV lines had spare capacity and a year's load growth would not consume a lines capacity for many years. Today, a 345kV line may only serve an area for a few years or may be fully loaded to capacity when it is built as in the case of areas with wind generation.

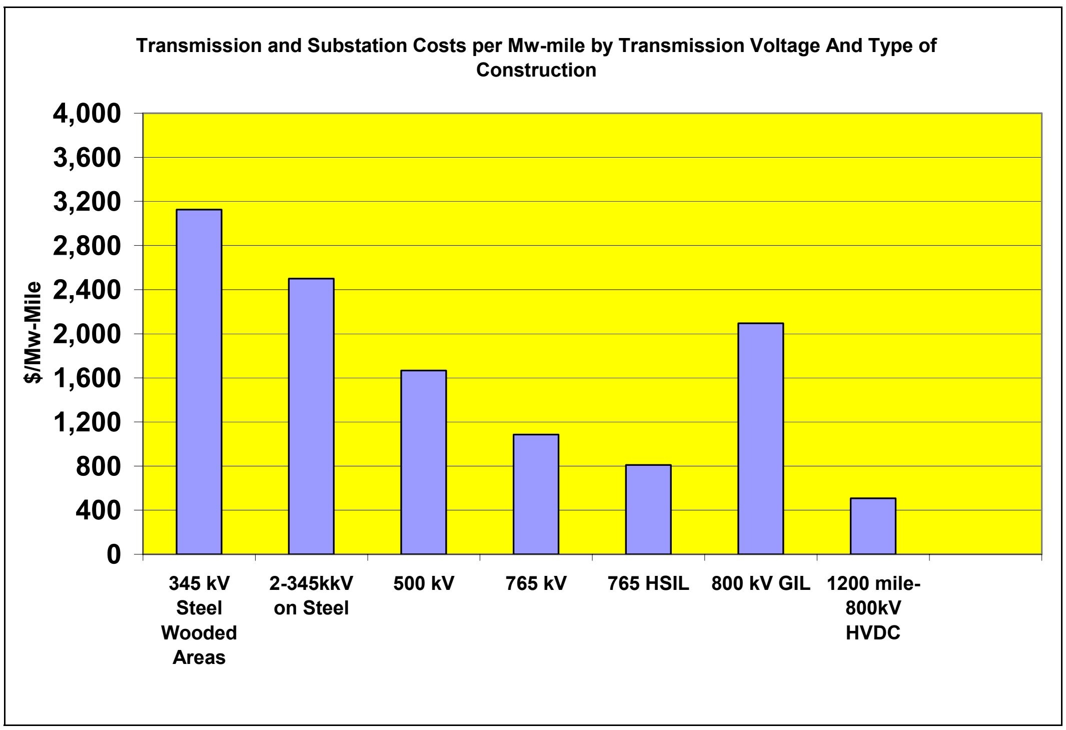


Figure 4.2-7: Transmission Line Costs per MW-Mile by Voltage and Design

The power transfers that are expected to occur with the conceptual EHV transmission overlays for the four generation Futures in MTEP08 are not for capacity purposes, but for energy purposes. Most of the energy is transferred off peak, leaving the peak capacity available for load growth. As the load grows the use of the energy that is sold over the high voltage overlays initially will be assimilated into the local load growth unless new base load generation is built.

The construction of an EHV transmission overlay requires that at least three lines of the same voltage or capacity be constructed at the same time to be economical. The Rule of Three is:

1. If a transmission system is expanded by one line, generally the most economical line will be of the present voltages. Processes that approve one line at a time almost guarantee the selection of the present voltages.
2. If a transmission system is expanded by two lines, generally two higher voltage lines will be competitive with the lower voltage lines if they can be loaded to economic levels.
3. If a transmission system is expanded by three lines, generally the higher voltage lines will be the superior choice and for all expansions after that time.

Choosing too small of a period for a study will also limit the choices in “Item 2” to lower voltage choices. The corollary to the Rule of Three is that if you have three lines of the same voltage in an area it may be time to consider a higher voltage overlay.

The Reference, Renewable and Fuel Restricted Futures have heavy enough power flows to support a higher voltage overlay. With other considerations for future generation outlet, load growth, the future cost of transmission and Rights of Way (ROW) and the use of the transmission to deliver wind energy for load growth beyond the Renewable Portfolio Standard (RPS) stated years, a higher voltage overlay may be justified as a business case. The 1.10:1 B/C ratio in MTEP08 EI studies indicate this. The power transfer level from the Midwest ISO to PJM was increased by about 12,000 MW in the MTEP08 EI study. The Reference future produced a ration of 1.18:1 with a 12,600 MW wind mandate level. The Midwest ISO mandate level has increased since the inception of the MTEP08 study to 15,000 MW. Higher levels of wind mandates increase the amount of energy for sale to the east coast from the Midwest ISO and further load the transmission. More detailed studies are required, but there may be a business case to support the construction of a higher voltage transmission overlay to provide for multi-uses of the overlay over its lifetime.

A transmission overlay of three 800kV HVDC lines is estimated to have a capacity to deliver about 14,300 MW of energy. Typically wind generation produces about 80% of the rated capacity at its peak output. One would expect some planned curtailment of the wind energy for short periods of time for economic reasons. Assume 10% curtailment. The amount of wind generation that might be able to be connected and economically delivered to an overlay of three 800kV HVDC lines and the appropriate AC contingency backup system would be about 20,000 MW. A 20,000 MW wind generation development would serve the Midwest ISO footprint to about a 10% wind energy penetration.

4.3 Reference Future EHV Overlay Reliability Screening

The Extra High Voltage (EHV) transmission overlays developed in 2007 for MTEP08 are conceptual. While the conceptual transmission overlays have various levels of economic merit, they have been analyzed primarily using PROMOD® which is a linear analysis which does not consider system voltages and which has an economic focus. The actual power system is non-linear. Transmission planners need to understand how the conceptual transmission overlay will perform using traditional AC steady-state contingency analysis (reliability) study techniques in order for the conceptual transmission overlay to be refined. The reliability analysis monitors the entire transmission system compared to a small select group of branches in the economic analysis. The AC performance of an EHV conceptual overlay provides an understanding of the reliability benefits and impacts of conceptual overlay. This provides transmission planners with insights on what reliability issues may be resolved with the conceptual overlay and facilitates the long-term planning process. This reliability screening is part of Step 6 of the value-based planning process described in Section 2.2.

The objectives of performing reliability screening of EHV conceptual transmission overlay for the Reference generation portfolio future are:

- To determine reliability benefits and impacts caused by EHV conceptual overlay;
- To refine conceptual overlay to maximize reliability benefits and minimize reliability impacts;
- To understand real and reactive power requirements associated with EHV conceptual overlay;
- To provide input in MTEP09 long-term economic analysis in the form of additional constraints monitor and recommended changes to transmission overlay;
- To provide insights to long-term transmission planning process.

Complete details of this reliability screening are located in Appendix E3.

4.3.1 Reference Generation Portfolio Future and EHV Overlay

For the Reference Generation Portfolio Future, there are 22,200 MW of future generation proposed to be sited in the Midwest ISO footprint by 2018 in the regional resource forecast study. Among all the regional resource forecasted units, there are 3000 MW wind generation and 3600 MW Combustion Gas Turbine generation in the Central Region, there are 2400 MW Coal Steam Turbine generation and 3600 MW Combustion Gas Turbine generation in the East Region, and there are 6000 MW wind generation, 2400 MW Coal Steam Turbine generation and 1200 MW Combustion Gas Turbine generation in the West Region (see Table 4.3-1).

Table 4.3-1: Regional Resource Forecasted Generation in Reference Future

Region	Category	MW
Central	CT Gas	3,600
Central	Wind	3,000
Central Total		**6,600**
East	CT Gas	3,600
East	ST Coal	2,400
East Total		**6,000**
West	CT Gas	1,200
West	ST Coal	2,400
West	Wind	6,000
West Total		**9,600**

The Reference Generation Portfolio Future (Reference Future) EHV conceptual overlay was originally developed by Midwest ISO in 2007 for MTEP08, mainly based on PROMOD® economic analysis and Midwest ISO stakeholders' input and feedback. In addition, there were a couple of sub-regional economic/congestion studies ongoing, including the Southwestern Indiana Economic study and the AEP-ITC 765kV targeted study. Based on the feedback from Stakeholders and the sub-regional economic studies, a couple of updates have been made from the original EHV conceptual overlays, these changes are:

- The original conceptual overlay had a Manitoba Hydro Dorsey-Karlstad-Wingerne-Sherburne County 500kV line. The new EHV overlay has a Dorsey-Riel-Maple River-Blue Lake 500kV line.
- AEP-ITC Cook-Kenowa-Spreague-Bridgewater 765kV transmission line was in the original overlay. This analysis updated the line to a Cook-Evans-Spreague-Bridgewater 765kV line.

There are 215 transmission lines and transformers in the Midwest ISO Reference Future EHV conceptual transmission overlay. Some transmission lines are 345kV may be under investigation by transmission owning companies. these 345kV lines are called short-term projects, as they may become real projects prior to more conceptual components of EHV overlay.

4.3.2 System Conditions Analyzed

For the Reference Future EHV overlay reliability screening study, two sets of power flow models are created: the 2018 summer peak model and the 2018 off peak model. The regional resource forecasted units developed for the Reference Generation Portfolio future are sited in the models. The 2018 off peak model has 70% of summer peak load level in Midwest ISO footprint and has the same transmission topology as the 2018 summer peak model.

Generation dispatch in Midwest ISO footprint was based on Security Constrained Economic Dispatch (SCED) to mitigate all possible N-1 constraints in Midwest ISO 200kV and above systems. Wind generation in the Midwest ISO footprint was dispatched at 15% of its capacity in 2018 summer peak model and 100% of its capacity in 2018 off peak model. Run-of-river hydro generation dispatch was not changed from typical values. For other generation with energy cost, the pre-existing baseload Network Resources (NR) were dispatched before the Regional Resource Forecasted baseload Generation was dispatched, assuming there was no constraint created in 200kV and above system. Same dispatch rule was applied to the peaking generation with pre-existing peaking generation dispatched first.

For both the 2018 summer peak model and the 2018 off peak model, two transmission scenarios are created: without EHV transmission overlay and with EHV transmission overlay. Generation dispatch was the same in summer peak cases and the same in off-peak cases. This was to determine the reliability benefits and issues caused by the EHV transmission overlay with AC contingency analysis.

To keep the bus voltages within the acceptable operating range after the 765kV EHV overlay was added, line reactors are assumed to be connected to the conceptual 765kV lines.

Transmission systems 100kV and above in all Midwest ISO companies and their first-tier non-Midwest ISO companies are monitored in AC contingency analysis. Monitoring of all transmission system branches over 100 kV is significant difference between economic analysis and reliability analysis. Therefore, reliability analysis finds more limiting elements than economic analysis and can provide additional monitored elements to be included in next iteration of the economic EHV overlay development process. Thermal results used emergency rating and voltage results used Transmission Owner thresholds.

All single contingencies (line, transformer) in 200kV and above systems of Midwest ISO footprint and its first-ties non-Midwest ISO companies are analyzed. Single unit contingencies for all generation units in the systems are also analyzed. Besides these, about 1100 significant NERC category C contingencies are also selected for the ACCC analysis. See contingency files:

4.3.3 Reliability Screening for Reference Future EHV Overlay

Power Loss Reduction with EHV Overlay

With EHV overlay added in 2018 summer peak model, the total real power losses of Eastern Interconnection (EI) are reduced by 884.1 MW, and the total reactive power losses are reduced by 8499.5 Mvar. In the 2018 off peak model, the EHV overlay will reduce the real power losses of EI by 1819.6 MW and the reactive power losses by 16028 Mvar. The Reference Future EHV overlay would significantly reduce the power losses in the Eastern Interconnection (Table 4.3-2). This reduction in losses provides a huge savings in cost of generation capacity as one large or a couple medium power plants would not have to be constructed because 884 MW of demand caused by losses was eliminated.

In the 2018 summer peak model with EHV overlay added, the top seven Balancing Authorities (BA), which are represented by control areas in model, with largest reduction of real power losses are:

- Michigan Electric Transmission Co. (METC)
- American Electric Power (AEP)
- Duke Energy Midwest (DEM)
- Commonwealth Edison (CE)
- FirstEnergy (FE)
- Xcel Energy-North (Xcel)
- Ameren Illinois (AMIL)

See Table 4.3-3.

In the 2018 off peak model with EHV overlay added, the top seven BAs with most reduction of real power losses are:

- Commonwealth Edison (CE)
- American Electric Power (AEP)
- Michigan Electric Transmission Co. (METC)
- Xcel Energy-North (XEL)
- FirstEnergy (FE)
- Ameren Illinois (AMIL)
- Alliant East (ALTE)

See Table 4.3-4.

Table 4.3-2: Changes of Power Losses with EHV Overlay in EI System

Model	Before EHV Overlay		After EHV Overlay		Loss Change	
	Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss Change (MW)	Reactive Power Loss Change (Mvar)
2018 Summer Peak	21764.8	314726.8	20880.7	306227.3	-884.1	-8499.5
2018 Off Peak	21950.7	311517.9	20131.1	295489.9	-1819.6	-16028

Table 4.3-3: Top Seven BAs with Most Reduction of Real Power Losses with EHV Overlay in 2018 Summer Peak

Area #	Area Name	Before EHV Overlay		After EHV Overlay		Loss Change	
		Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss Change (MW)	Reactive Power Loss Change (Mvar)
218	METC	599.4	6329.4	487	5055.3	-112.4	-1274.1
205	AEP	987.2	12522.5	876.2	11980.9	-111	-541.6
208	DEM	625.5	6853.2	531.8	6049.4	-93.7	-803.8
222	CE	704.5	12243.6	632.5	11227.1	-72	-1016.5
202	FE	468.7	6009.9	397.5	5372.8	-71.2	-637.1
600	XEL	394.3	4361.5	332.2	3618.5	-62.1	-743
357	AMIL	271	3539	229.4	3195.8	-41.6	-343.2

Table 4.3-4: Top Seven BAs with Most Reduction of Real Power Losses with EHV Overlay in 2018 Off Peak

Area #	Area Name	Before EHV Overlay		After EHV Overlay		Loss Change	
		Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss (MW)	Reactive Power Loss (Mvar)	Real Power Loss Change (MW)	Reactive Power Loss Change (Mvar)
222	CE	914.7	14954.5	689.5	12019.4	-225.2	-2935.1
205	AEP	1156.5	14320.3	952.6	13343.4	-203.9	-976.9
218	METC	461.5	5010.3	293.5	3111.5	-168	-1898.8
600	XEL	488	5105	355.2	3804.6	-132.8	-1300.4
202	FE	353.7	4198.8	237.4	3202.3	-116.3	-996.5
357	AMIL	273.1	3359.1	162.4	2347.8	-110.7	-1011.3
694	ALTE	243.4	1539.5	141.3	1198.2	-102.1	-341.3

Reliability Benefits and Issues Caused by EHV Overlay

To determine the reliability benefits and impacts caused by the EHV overlay, AC contingency analysis has been performed for the scenario with EHV transmission overlay and the scenario without EHV transmission overlay. Branch loadings and bus voltages under system intact and contingencies are compared between with and without EHV conceptual overlay scenarios. All bus voltage deviations beyond 0.02 (p.u.) and branch loading changes more than 5% of their ratings between two scenarios are reported and analyzed. Loadings in without EHV overlay case were flagged at 70% of rating to capture line capacity freed up by power flowing on EHV conceptual overlay. Therefore, many of lines with reduced loadings are not overloaded in either scenario. However, this freed capacity is available for use and should defer upgrades to the off-loaded facilities. See Appendix E3 for the additional details.

Table 4.3-5 Thermal Overloads Relieved or Caused by Reference EHV Transmission Overlay

System Condition	Relieved	Caused
2018 Summer Peak	111	16
2018 Off Peak	114	8

4.3.4 Conclusions

Overall, the proposed Reference Future EHV conceptual transmission overlay has many reliability benefits and relieves loading on many existing transmission lines and transformers. The EHV conceptual transmission overlay also provides a significant reduction in real power losses with 880 MW in peak case and 1820 MW in off-peak case. The EHV conceptual overlay also enables delivery of renewable resources around the system. Not all facilities in the EHV conceptual overlay have associated reliability benefits. Some sub-regions may have overlapping facilities with the EHV conceptual overlay which should be addressed if those portions of EHV conceptual overlay advance in the planning process. There are some reliability issues caused by the EHV conceptual overlay which should be addressed in subsequent MTEP futures transmission overlay development by monitoring those limiting facilities in economic analysis. Additional studies need to be performed to continue to refine the EHV conceptual transmission overlay with long-term goal of using the insights provided to shape future transmission development.

4.4 Joint Coordinated System Plan

Formally initiated on November 1, 2007, the Joint Coordinated System Plan (JCSP08) study began as collaboration between the Midwest ISO, Pennsylvania, New Jersey, Maryland Interconnection (PJM), Southwest Power Pool (SPP) and the Tennessee Valley Authority (TVA) to meet the requirements of the Joint Operating Agreements each organization has with Midwest ISO. Subsequent to the initial four parties the ISO New England, New York ISO and the Mid-Continent Area Power Pool (MAPP) all joined the study as formal participants. On an informal basis, the Southeast Inter Regional group has been formed within the South-Eastern Reliability Corp. (SERC) – both the TVA and Entergy are part of this group and Entergy is participating in the JCSP primarily through the SPP. Therefore, TVA and SPP can act as a liaison between the JCSP and this group.

While comprised of both a reliability assessment focused on 2018 and a separate economic assessment with a 2024 focus, the main focus of the JCSP08 is the economic assessment. To leverage staff resources and also produce an extensive policy level study, the economic study is also being performed in collaboration with the Department of Energy (DOE) and their Eastern Wind Integration Transmission Study (EWITS). The DOE EWITS had an objective to investigate both 20% and 30% wind energy penetration scenarios in the bulk of the Eastern Interconnection and the transmission required to effectuate that level of penetration. The JCSP study adopted the DOE assumptions and added them to a Reference Future that acts as a baseline for comparison.

This Reference Future is based on meeting the existing state mandates for Renewable Portfolio Standards (RPS) in existence as of January 1, 2008. Many of the existing standards allow for a variety of resources, such as hydro, biomass and solar to be used in addition to wind, although wind is the predominant renewable being advocated in the Eastern Interconnect. As with the 20% wind energy Future and 30% wind energy Future, a key assumption for this study is that all of the renewable portfolio standards are assumed to be met with wind energy.

The remainder of Section 4.4 is organized to address the process and results from the three main phases of the economic assessment:

- model development
- resource development and siting
- transmission design of the high voltage overlays

Phase I: Develop Power Flow Models

The development of the power flow models was lead by the Southwest Power Pool. The starting point for the models is the 2007 series NERC Multi-Regional Modeling Work Group (MMWG) 2018 summer peak case which is based on the new six digit format being used within the NERC community. All study participants submitted updated cases with interchange information to SPP based on their internal model development processes. For example, the Midwest ISO uses an economic dispatch while the other organizations use contractual dispatch for setting generator levels. SPP took all of the information and produced a solved power flow for the Eastern Interconnect. Given the timing considerations associated with the new six digit bus numbers and the magnitude of the task, the model development phase lasted for five months and was completed in April, 2008. The delivered cases for 2018 contains approximately:

- 57,300 buses
- 7,900 generators
- 884,000MW of generation
- 788,000MW generating in the case
- 765,900MW load
- 21,300MW losses

This power flow model is used for the reliability assessment phase of the study; however, for the economic assessment in 2024, a greatly expanded model is needed. The 2024 economic assessment model needed to include forecasted loads and the inclusion of new generating capacity through 2024. The generating capacity is comprised of all of the wind resources needed to meet the wind energy requirement for each case (i.e. Reference and 20%) plus all of the thermal generation needed to maintain an adequate reserve margin. The development of the resource forecasts for the majority of regions within the Eastern Interconnect for the Reference and 20% Wind Futures was undertaken as a separate phase of the JCSP study which was performed in parallel to the power flow model development.

The model is available to Stakeholders and other parties with a need to access; however, availability to the model is subject to meeting the Non Disclosure and Critical Energy Infrastructure Information (CEII) requirements of Midwest ISO, PJM and SPP. Table 4.4-1 outlines the requirements:

Table 4.4-1: Non Disclosure Requirements

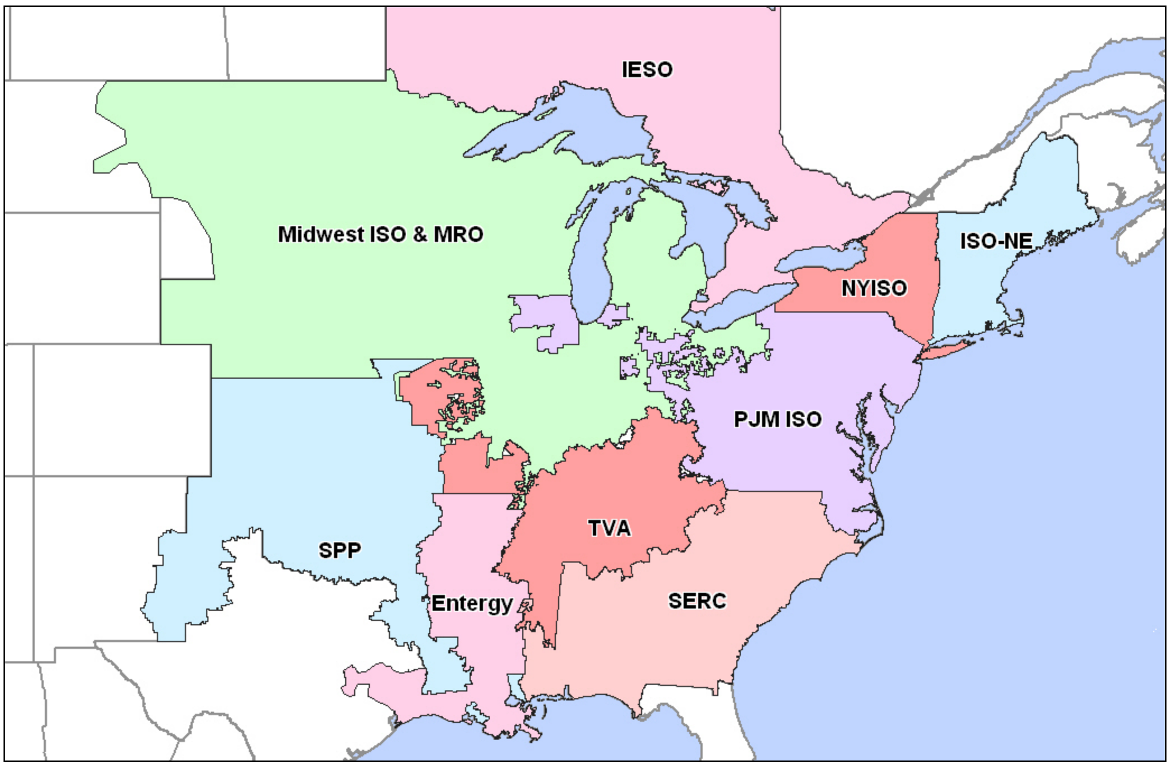
	Midwest ISO requirements			PJM requirements			SPP requirements	
Employee of	Midwest ISO Universal NDA	Midwest ISO CEII NDA	FERC CEII Clearance	PJM Request Form	PJM CEII NDA	FERC CEII Clearance	SPP CEII NDA	FERC CEII Clearance
Midwest ISO Member*	SN	SI	N/A	SI	SI	FD	S	FD
PJM Member**	SA	SI	FD	SI	SI	N/A	S	FD
SPP Member ***	SA	SI	FD	SI	SI	FD	S	N/A
Consultants/Others	SA	SI	FD	SI	SI	FD	SP	FD

*Midwest ISO Member	Transmission Owning or Load Serving Entity members of Midwest ISO
**PJM Member	PJM member, PJM generation or transmission interconnection customer
***SPP Member	SPP member, SPP transmission customer, SPP generation interconnection customer or their consultant
S	Need to sign one per company
SA	Need to sign a company-wide Universal NDA if Midwest ISO doesn't have one already. Need updated Appendix A
SN	Need to sign a company-wide Universal NDA if Midwest ISO doesn't have one already. Need updated Appendix A
SI	Need individually signed CEII NDA from each employee
SP	The party represented by a consultant needs to sign a company-wide NDA (the consultant is covered under this NDA) and designate in writing any consultant(s)requiring access to SPP highly sensitive information in the performance of their contract(s).
FD	Apply directly at FERC to obtain FERC CEII clearance for Access to Form No. 715 CEII data of all relevant RTOs. http://www.ferc.gov/legal/ceii-foia.asp
N/A	Not applicable or not needed

Phase II: Develop Regional Resource Forecasts and Site New Generation

A series of regional workshops were held to gather initial input on the assumptions and then subsequently to provide feedback on the results of the resource forecasts and siting of those resources. Future generation must be incorporated into the out years in both the power flow and economic assessment models. These workshops outlined the process, discussed the assumptions and provided initial results for discussion and analysis. Based on participant feedback, the regional resource models were updated in an iterative fashion.

The first regional Stakeholder Workshop took place December 11-12 in Nashville to outline the requirements for the regional resource planning model and discuss how those results are used in the model development and study processes. The Electric Power Research Institutes' Electric Generation and Expansion Analysis System (EGEAS) model was used for the development of the regional resource forecasts for each of the regions shown in Figure 4.4-1:



Midwest ISO - using Global Energy Decisions Inc, Velocity Suite © 2008

Figure 4.4-1: Regions

Due to its size, the Midwest ISO and Midwest Reliability Organization (MRO) region was broken into four sub regions for the regional resource forecast. These sub regions correspond to the east, central and west planning areas within the Midwest ISO with the non-Midwest ISO portion of the MRO constituting the fourth area.

A second Stakeholder workshop was held in New Orleans on January 9-10 to provide additional regional coverage to the Nashville Stakeholder workshop. This workshop covered the same material and was held specifically to enable greater stakeholder participation. Key findings from the workshops based on the regional resource forecast models and work performed by study staff is illustrated in Figures 4.4-2 – 4.4.4. Figure 4.4-2 shows the make-up of the forecasted capacity resources needed between 2008 and 2024 to maintain reserve margins at 15% for all areas except PJM. The PJM reserve requirement is 15.5%.

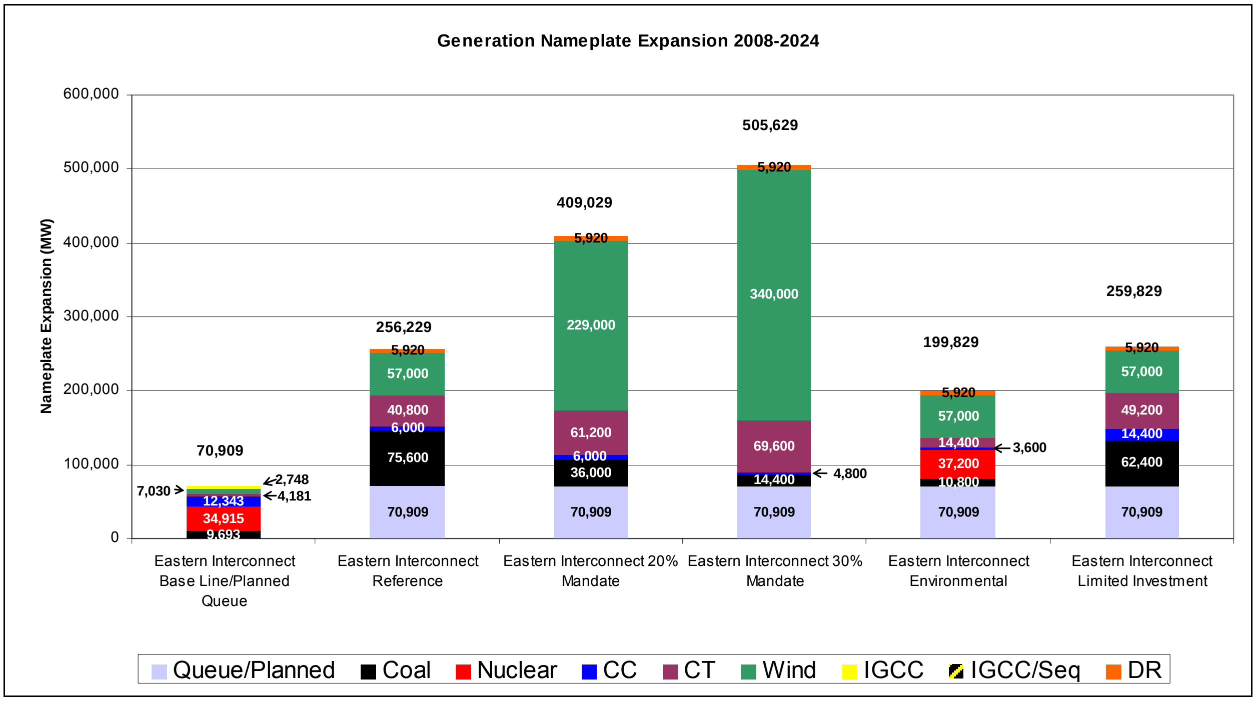
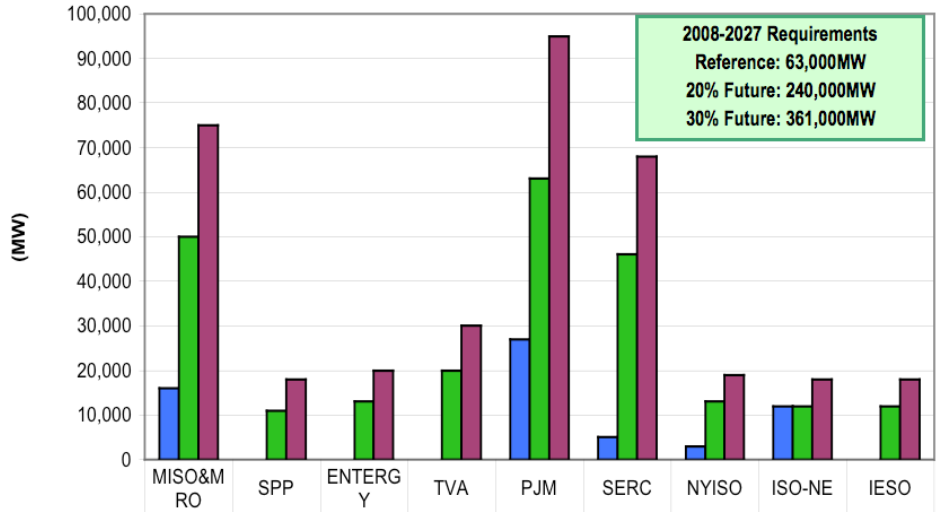


Figure 4.4-2: Generation Nameplate Expansion 2008-2024

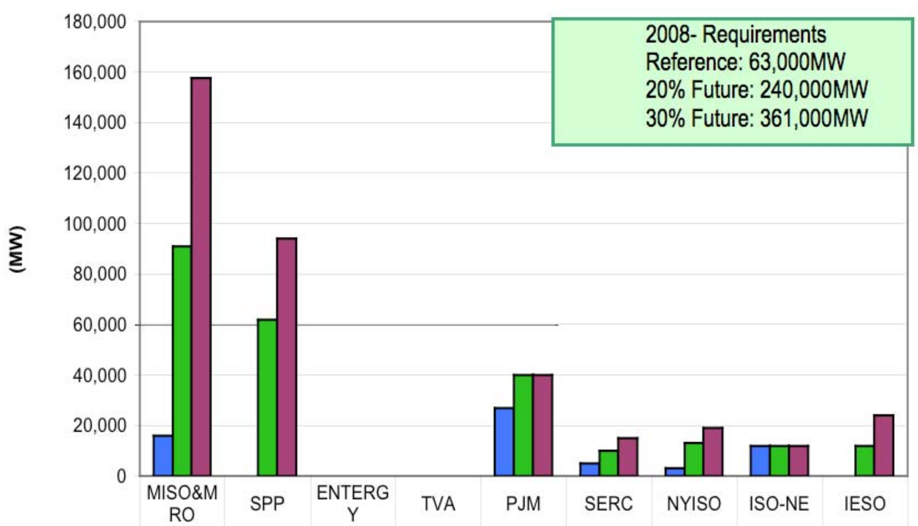
Figure 4.4-3 shows the detailed wind capacity requirements to meet the energy mandates (assuming all renewable energy portfolio standards were met with wind) in each of the Futures:



	MISO&MRO	SPP	ENTERGY	TVA	PJM	SERC	NYISO	ISO-NE	IESO
Reference	16,000	0	0	0	27,000	5,000	3,000	12,000	0
20%	50,000	11,000	13,000	20,000	63,000	46,000	13,000	12,000	12,000
30%	75,000	18,000	20,000	30,000	95,000	68,000	19,000	18,000	18,000

Figure 4.4-3: Detailed Wind Capacity Requirements

Based on discussions with NREL staff, the siting of all of the wind capacity requirements within the region where needed did not appear feasible given the wind quality information available at the time the siting analysis was performed. Therefore, Figure 4.4-4 shows the redistribution of the wind requirements to those geographic areas most suitable to meet the requirements. Essentially, the Midwest ISO and SPP see a shift in wind being sited into those footprints for the energy needs of SERC, TVA and to a lesser extent PJM.



	MISO&MRO	SPP	ENTERGY	TVA	PJM	SERC	NYISO	ISO-NE	IESO
Reference	16,000	0	0	0	27,000	5,000	3,000	12,000	0
20%	91,000	62,000	0	0	40,000	10,000	13,000	12,000	12,000
30%	157,667	94,000	0	0	40,000	15,000	19,000	12,000	24,000

Figure 4.4-4: Wind Requirement Redistribution

Based on these results, specifically the amount of wind needed in the Midwest ISO and SPP areas for the 30% wind energy Future, a determination was made by the JCSP study team and DOE to put this Future on hold until better wind siting information was available. It should be noted that at the time the decision was made to not carry the 30% Wind Energy Future forward for JCSP08 that a significant of information from the resource forecasting model had already been developed and was still valid. Information relative to the 30% Wind Energy Future from the resource forecasting work will be discussed later on in this section.

As part of the DOE's Eastern Wind Integration Study the DOE has a separate initiative to develop the hourly time synchronized wind speed and wind power values (in two kilometer square zones) for much of the Eastern Interconnect. The results of this 'Mesoscale' analysis were not expected until June 2008 and therefore could not be incorporated into the JCSP08 analysis[1].

[1] The Mesoscale data was received in late June and is being incorporated into ongoing Midwest ISO study work, but could not be used for the JSCP08 work

The third Stakeholder workshop was held on February 5, 2008 in St. Paul to discuss the siting of the generation developed from the Nashville and New Orleans Stakeholder workshop process. The following general methodology made up the rule set by which generation was sited:

- Transmission is not an initial siting factor, but may be used as a weighting factor if all other factors are equal
- Site by region with the exception of wind. Therefore, for example, the regional resource forecast developed for the Midwest ISO west region would be sited wholly in the Midwest ISO west region
- 'Share the Pain' mentality. Not all generation in a given region can be placed in one state and one state cannot be excluded from having generation sited.
- Avoid greenfield sites for gas units(CT's and CC's) if possible by giving preference to brownfield sites
- Site baseload units in 600MW increments except nuclear which are sited in 1200MW units
- Limit the total amount of expansion at an existing site to no more than an additional 2,400MW
- Restrict greenfield sites to a total size of 2,400MW

Study staff worked closely with the staff from the National Renewable Energy Laboratory in the siting of the wind facilities. The results from the siting analysis are illustrated below in Figures 4.4-5 for the Reference Future and Figure 4.4-6 for the 20% Wind Energy Future:

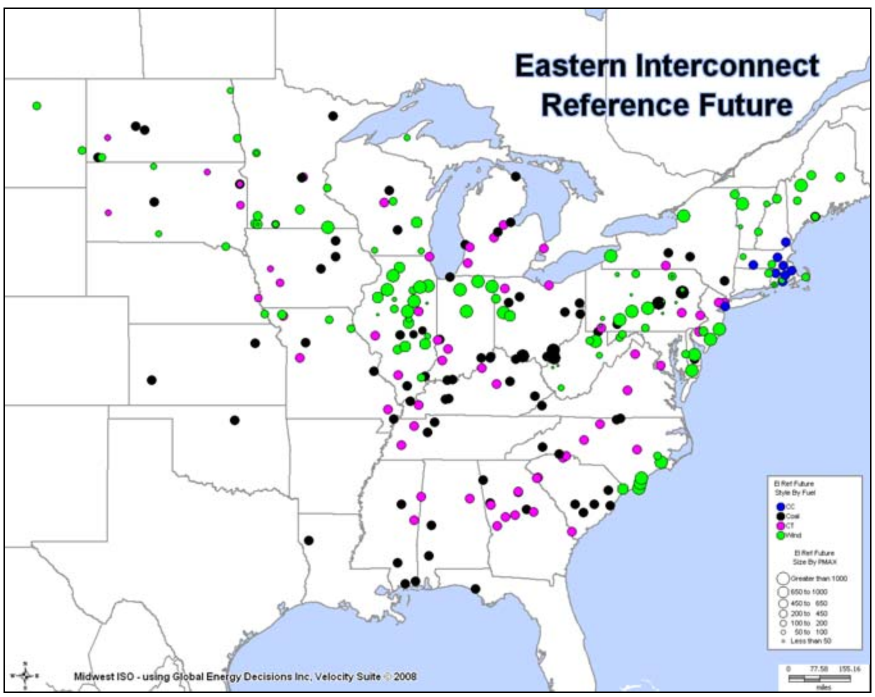


Figure 4.4-5: Wind Facilities Siting for the Reference Future

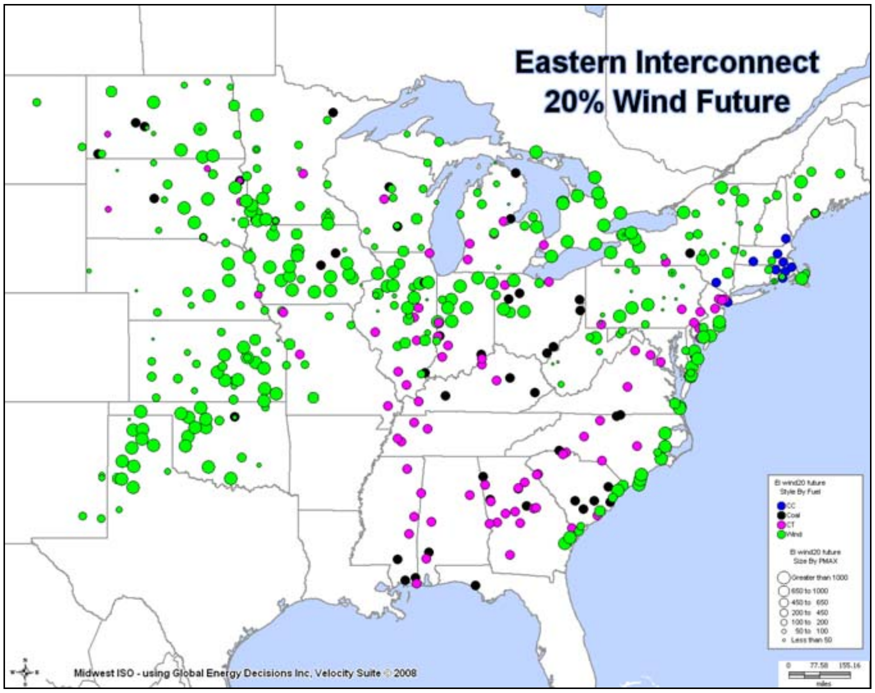


Figure 4.4-6: Wind Facilities Siting for the 20% Wind Energy Future

The regional resource forecast of new generation and the location of that new generation is a critical component of the study scope. In addition to providing the out year resources needed in the power flow and economic models, the resource forecasting models also produce significant strategic information. This additional information produced from the resource forecasting models is helpful for the ongoing policy debate surrounding several key issues such as various strategies for mitigating climate change. One such example is that the EGEAS model captures the CO_2 emissions component for each Future. Figure 4.4-7 combines comparable results from the Reference, 20% Wind Energy and 30% Wind Energy Futures from the JCSP along with the Environmental Future from Midwest ISO Transmission Expansion Plan for 2008 (MTEP08) to illustrate the amount of CO_2 emissions:

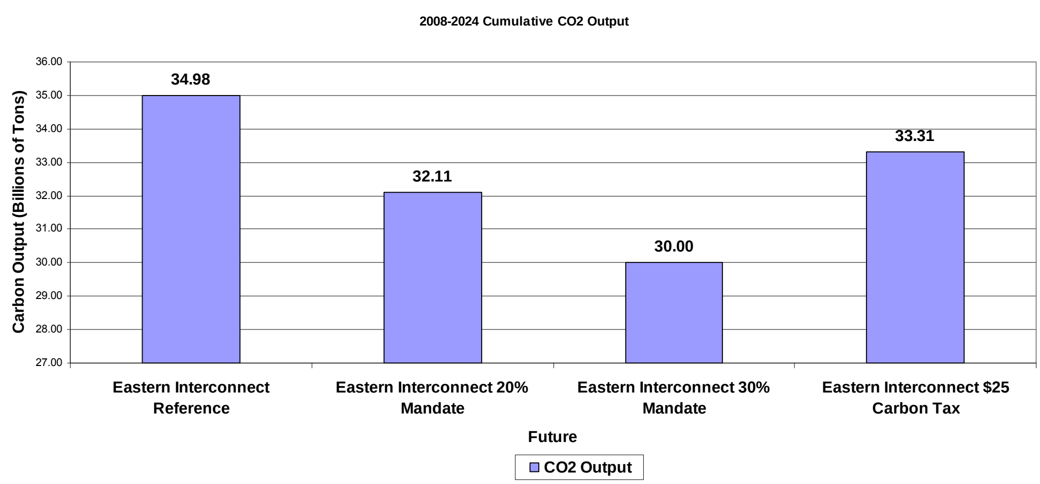


Figure 4.4-7: CO_2 Emissions

With the regional resource forecast developed and sited in both the power flow and PROMOD® models the analysis phase of the study began.

Phase III: Analysis for Reliability and Economic Studies

PJM staff is leading the reliability study with support from all formal participants. The study focus is on 200kV and above using region specific criteria to determine reliability issues that may exist at seams boundaries. The reliability study is currently performing an N-1 branch thermal analysis, an N-1 voltage analysis, a loss of thermal source analysis and a NERC multi-facility contingency (category C) analysis. The initial study results are expected in early September.

Midwest ISO staff is leading the economic study with support from all formal participants. The analytical phase of the JCSP08 economic study will require a six month intensive effort to be conducted during the timeframe of May through November. To facilitate the development of the high voltage overlay for both the Reference Future and the 20% Wind Energy Future, workshops on the basic fundamentals of transmission design in addition to regional design took place from the end of April through June. These workshops were held at various regional locations to obtain input from a broad cross section of participants and are described in more detail below:

A Transmission Fundamentals Workshop was held at the end of April in Charleston, South Carolina. It addressed the essential background information required for the development of high voltage transmission. This workshop provided participants with information gained by the Midwest ISO staff and stakeholders as a function of having worked on the development of the economic transmission evaluation process for two years in conjunction with the MTEP08. This was essentially a knowledge transfer workshop with examples of how the lessons could be applied to the JCSP requirements.

Four regional Transmission Overlay Development Workshops to develop the transmission overlay were conducted during June at the locations below:

- Hartford
- Wilmington
- St. Louis
- Knoxville

Multiple workshops provided opportunity for participation by a broader group of stakeholders than having a single workshop. Each of the regional workshops covered the same information but generated a regional perspective that was valuable.

The results of these workshops allowed for the development of high voltage overlays for both the Reference Future and the 20% Wind Energy Future. These initial overlays are conceptual plans and provide a starting point for further in-depth analysis.

Figure 4.4-8 is a schedule of the major events surrounding the economic assessment:

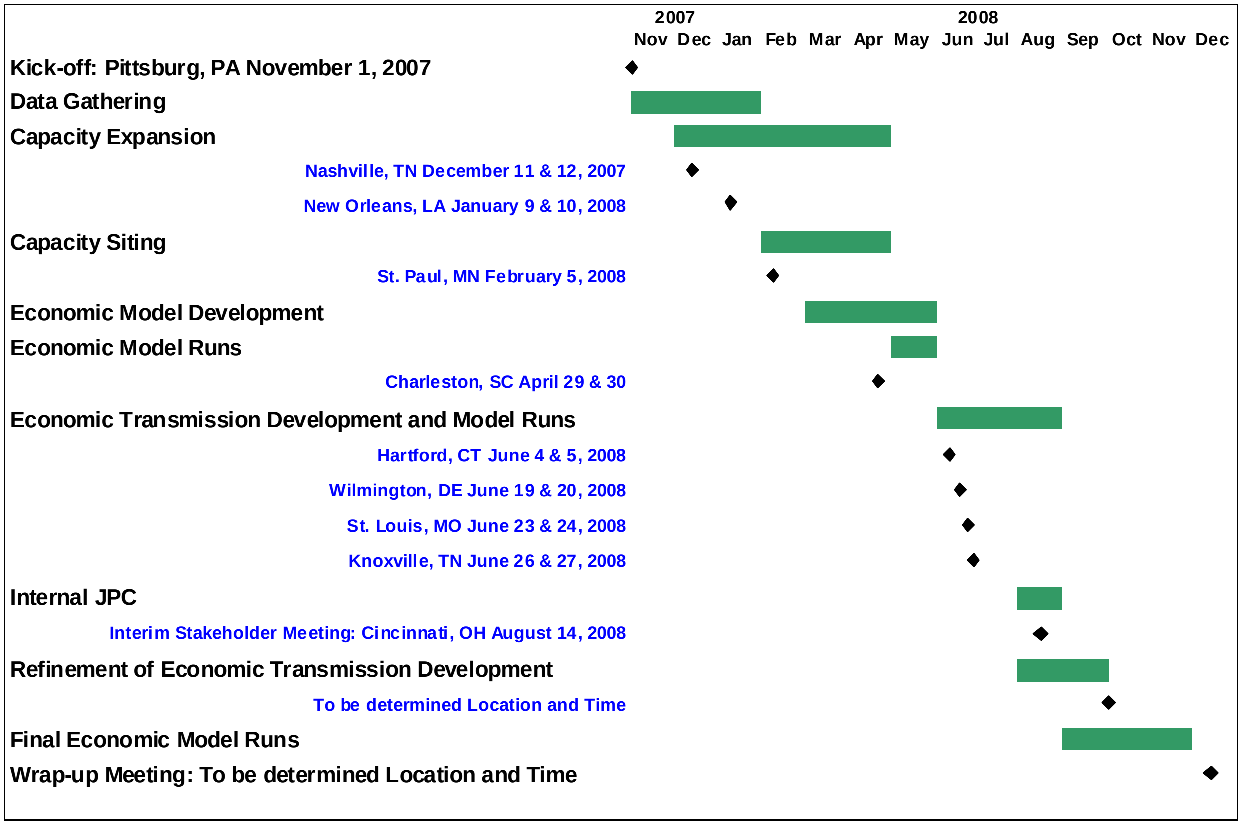


Figure 4.4-8: A Schedule of the Major Events Surrounding the Economic Assessment

Economic Assessment Results – High Voltage Overlays

As a result of nine months of intensive effort that included one general meeting and eight workshops, plus the dedication of numerous participants and JCSP study staff, the following initial high voltage overlays are available. Figure 4.4-9 is the Reference Future overlay and Figure 4.4-10 is the 20% Wind Energy Future overlay:

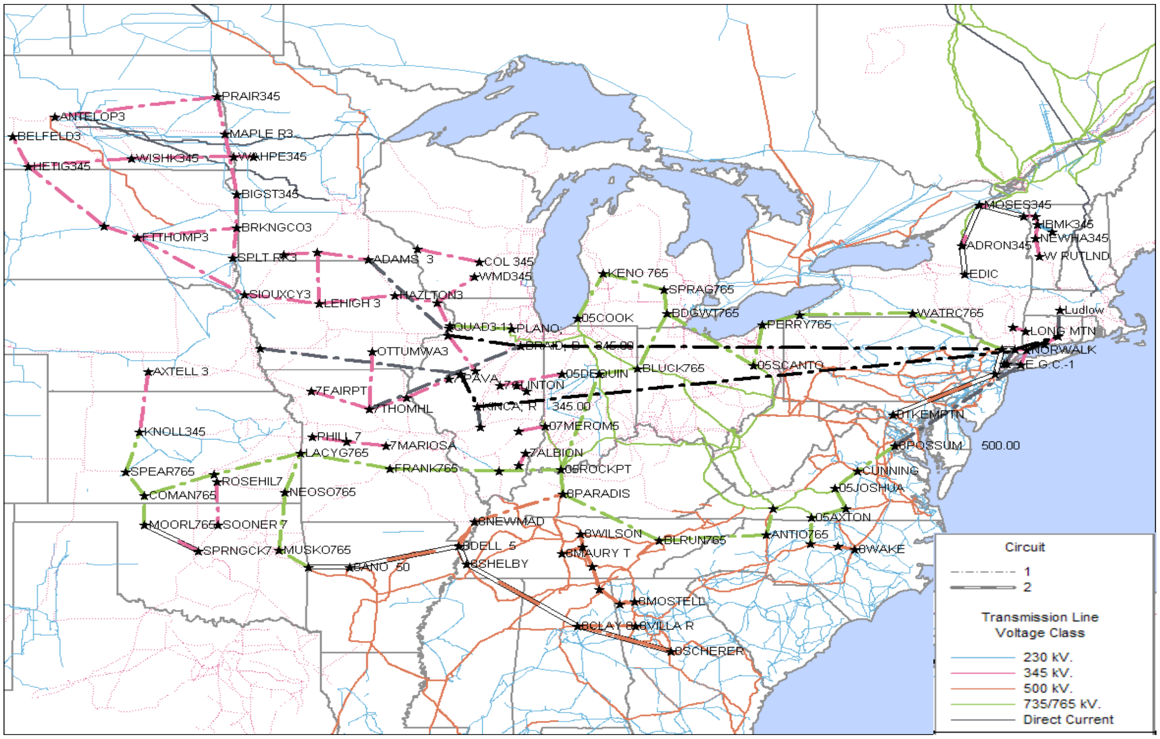


Figure 4.4-9: Reference Future Overlay

The process used to develop the high voltage overlays contains all of the same components used in the MTEP08 process. Section 4.2 in this report outlines the detailed process by which the MTEP08 overlays were developed. The intermediate steps and results for the JCSP are not presented in this report as there will be a formal JCSP report that describes that work effort in detail. The important concept is that the JCSP overlays have all of the same supporting processes and documentation as MTEP08.

Work continues on the refinement of the overlays to improve the benefit to cost ratios. Benefit/Cost ratios provide an efficient way to look for unproductive or missing line segments.

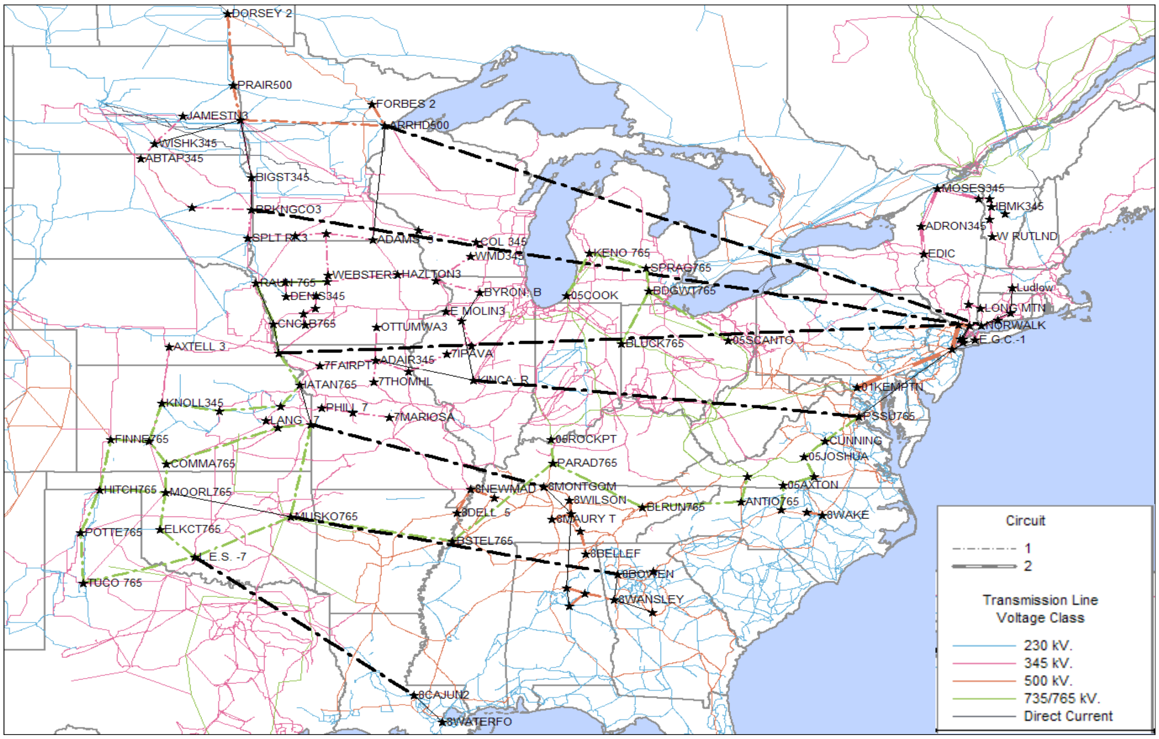


Figure 4.4-10: 20% Wind Energy Future Overlay

Tables 4.4-2 through 4.4.4 summarize the cost per mile assumptions by voltage class, estimated line miles by voltage class and the estimated cost in 2024 dollars for both overlays. The total costs in Table 4.4-4 also include a 25% adder on the line mile costs to cover the costs of sub stations.

Table 4.4-2

Cost per Mile Assumption

	345kV	(2) - 345kV	500kV	(2) - 500kV	765kV	DC - 400kV	DC - 800kV
2024$	2,250,000	3,750,000	2,875,000	4,792,000	5,125,000	3,800,000	6,000,000

Table 4.4-3

Estimated Line Mileage Summary (Miles)

	345kV	(2) - 345kV	500kV	(2) - 500kV	765kV	DC - 400kV	DC - 800kV	Total
Reference	3,329	292	508	946	3,118	282	2,400	10,875
20% Wind	2,042	193	864	279	3,977	0	7,582	14,937

Table 4.4-4

Estimated Cost Summary (Millions of 2024$)

	345kV	(2) - 345kV	500kV	(2) - 500kV	765kV	DC - 400kV	DC - 800kV	Total
Reference	9,363	1,371	1,825	5,668	19,975	1,698	14,400	54,298
20% Wind	5,742	905	3,106	1,671	25,478	0	45,492	82,394

For the Reference Future approximately 50% of the line miles are associated with 500kV or lower voltages. However, in the 20% Wind Energy Future there is a need to move increased amounts of energy from the western portion of the Eastern Interconnection to the east and this is effectuated through the inclusion of more 765kV and 800kV HVDC. In the 20% Wind Energy Future approximately 75% of the lines miles are associated with voltages higher than 500kV.

There is a significant amount of HVDC in the JCSP08 Futures relative to MTEP08. The operational and control benefits of HVDC are offsets to their high cost. In JCSP08 multi-terminal HVDC is used to reach more areas than when HVDC was considered in MTEP08. The integration of wind in the operation of the transmission system will be enhanced using HVDC by allowing the areas of greater load density at the end terminals to pick up the variability of wind. The topic of wind integration into the transmission system for the JCSP work is a separate study under the DOE's EWITS umbrella. The EWITS study is essentially comprised of three separate studies:

- The first is the development of the Mesoscale wind data – this data was discussed earlier and is being incorporated in part into the JCSP study. However, its more significant value will be seen in the Regional Generation Outlet Study (RGOS) that will be part of MTEP09 as well as its use in the Wind Integration Study.
- The second is the development of the transmission needed to deliver a 20% and 30% wind energy mandate for the majority of the Eastern Interconnect. This is essentially the role that the JCSP study has filled for DOE. However with the 30% Wind Energy Future put on hold this work will have to be part of the actual wind integration study.
- The third study is the wind integration study that investigates the operational impacts and needs of having 20% and 30% wind energy penetration.

The estimated cost of the Reference Case is $54 billion and the 20% Wind Energy Case is 50% higher at $82 billion. These cost estimates are ballpark only and should be used to gain an understanding of the level or magnitude of the overlays. As large as these numbers are they need to be placed in to context with the overall cost of providing service. Figure 4.4-11 provides a cost perspective as it compares the total cost breakdown through 2024 associated with new generation resource capital requirements, the transmission overlay capital requirements and the total production costs.

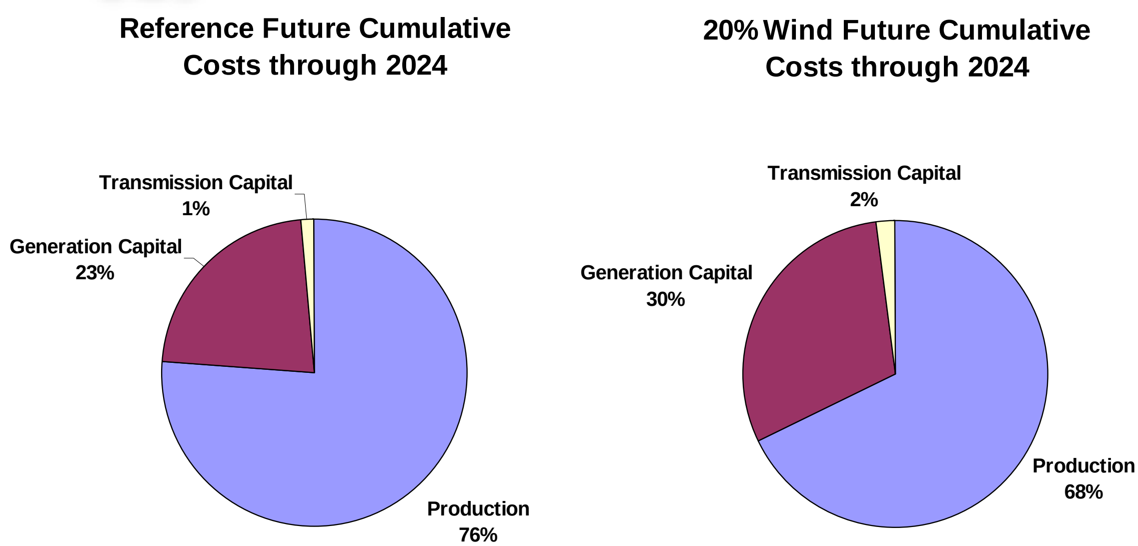


Figure 4.4-11: A Cost Perspective

The initial overlay results and associated cost information was presented at the Interim Stakeholder meeting that was held in Cincinnati, Ohio on August 14, 2008. The overlays will continue to be refined with Stakeholder input through an additional workshop to be held in early October. The results of the workshop will provide the basis for the overlay that will be presented at the Final JCSP08 Stakeholder meeting in late November or early December. These initial results will serve as the starting point for an ongoing JCSP study process that will need to be implemented. Many of the study participants would like to study a 10% Wind Energy Future. This Future would provide valuable information on how best to transition between the Reference Future, which is essentially a 5% wind energy case, and the 20% Future.

The JCSP study process has proven to be valuable and needs to be continued to address these large scale multi-Regional Transmission Organization (RTO)/regions issues that are facing the new industry paradigm.

Section 5: Reliability Analysis and New Appendix A Projects

MTEP07 performed a complete reliability analysis for the planning year 2013 and a screening analysis for 2018. The report was completed and approved by the Midwest ISO Board of Directors in December, 2007. For MTEP08, Midwest ISO staff's primary reliability analysis effort was the incremental reliability analysis performed to test the need for and effectiveness of the proposed projects moving to Appendix A in this planning cycle. Localized detailed contingency analysis was performed during the review process. There was more than a 50% increase in the number of projects moving to Appendix A in the MTEP08 planning cycle as compared to past MTEP planning cycles. This increase may be attributed in part to FERC Order 890 in that the Midwest ISO now reviews, for most Midwest ISO Transmission Owners, all projects whether they involve transmission that is transferred to the Midwest ISO functional control or not. In addition, some of the increase is due to normal variability (lumpiness) of the planning process.

FERC Order 890 requires an open and transparent planning process amongst other requirements. All but two of Midwest ISO Transmission Owners are using Attachment FF of the Midwest ISO Energy Markets Tariff to address Order 890 open planning process requirements. The project review process is managed by the Midwest ISO Transmission Expansion Plan (MTEP) study process. In MTEP08, 332 projects were reviewed by Midwest ISO staff and stakeholders in our open planning process and recommended for inclusion in Appendix A in this planning cycle. Approximately 75% of these projects are less than \$5 million with 35% under \$1 million and about 20% of the projects are on lower voltage transmission which is now handled through the MTEP process per Attachment FF (equivalent to Attachment K for other entities).

5.1 Model Assumptions for Project Analysis

The reliability planning process is described in detail in Section 6. Analysis was performed in MTEP08 to validate needs driving projects and effectiveness of projects moving to Appendix A. The final MTEP07 2013 summer peak model was used for project specific analysis in MTEP08. The power flow base case models used in this analysis had specific control area load, generation, loss and interchange values modeled. Note that the model control area generation specified in Tables 5.1, 5.2 and 5.3 is the amount of generation dispatched in the models to meet load plus losses taking into account the specified interchange. The generation amount listed is not the total generation available, therefore, it does not provide an indication of generation reserves levels available in the control area. The generation level does not provide an indication of off-line units or other reserves.

5.1.1 West Region Model Load and Generation Summary

The Midwest ISO West Planning Region is comprised of the following transmission owning/operating members:

- American Transmission Company (ATC LLC)
  comprised of ALTE, WEC, WPS, MGE, UPPCO systems
- ITC Midwest (ITCM)
- Xcel Energy North (XEL)
- Minnesota Power (MP)
- Great River Energy (GRE)
- Southern Minnesota Municipal Power Association (SMMPA)
- Otter Tail Power Company (OTP)

The following transmission owners are contained with other members' control areas in the models:

- Montana-Dakota Utilities (MDU)
- Northwestern Wisconsin Electric Company (NWEC)

The West Planning Region is contained within the following states: Wisconsin and Upper Michigan, Iowa, Minnesota, North Dakota, South Dakota, Nebraska. The Balancing Authority (BA) load, generation dispatched, and interchange in the MTEP07 2013 Summer Peak, 2018 Summer Peak models are shown in Table 5.1.

Table 5.1 West Balancing Area Summary for 2013/2018 Summer Peak Model

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Gener-ation	Load	Loss	Inter-change	Gener-ation	Load	Loss	Inter-change
331	ALTW	4,306	4,769	83	-546	4,884	4,792	107	-15
364	ALTE	4,554	3,648	129	776	3,976	4,165	178	-368
365	WEC	7,484	7,831	172	-521	9,151	8,356	178	616
366	WPS	2,612	3,116	79	-584	2,785	3,445	81	-742
367	MGE	265	849	15	-600	84	922	28	-870
368	UPPC	26	170	6	-150	108	200	6	-98
600	XEL	10,372	11,842	301	-1,772	11,274	12,964	380	-2,072
608	MP	2,020	1,859	89	72	2,079	2,044	78	-43
613	SMMPA	237	600	4	-367	242	600	2	-360
618	GRE	2,582	1,743	92	745	2,629	1,971	100	555
626	OTP	2,118	2,041	103	-26	1,631	2,129	78	-577
652	MDU (in WAPA)	292	500	194 (WAPA)	1246 (WAPA)	273	500	183 (WAPA)	1368 (WAPA)

5.1.2 Central Planning Region Model Load and Generation Summary

The Midwest ISO Central Planning Region is comprised of the following transmission owning members:

- Hoosier Energy (HE)
- Duke Energy Midwest (DEM)
- Indianapolis Power & Light Company (IP&L)
- Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana (Vectren)
- Ameren MO (AMMO)
- Ameren IL (AMIL)
- City of Columbia, MO (CWLD)
- City Water Light and Power (CWLP, Springfield, Illinois)
- Southern Illinois Power Cooperative (SIPC)

The following transmission owners do not have control areas in the model but are contained with member control areas:

- Indiana Municipal Power Agency (IMPA)
- Wabash Valley Power Association (WVPA).

The Central Planning Region includes portions of the states of Indiana, Illinois, and Missouri. The control area load, generation, and interchange in the MTEP07 2013 summer peak and 2018 summer peak cases are shown in Table 5-2.

Table 5-2 Central Balancing Area Summary for 2013 / 2018 Summer Peak Models

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Gener-ation	Load	Loss	Inter-change	Gener-ation	Load	Loss	Inter-change
207	HE	1,859	855	45	960	1,685	855	42	788
208	DEM	15,071	14,645	566	-151	13,958	15,745	557	-2,354
210	Vectren	1,844	2,081	31	-269	1,601	2,197	37	-633
216	IP&L	3,205	3,359	84	-241	3,241	3,593	81	-437
355	CWLD	146	315	2	-171	76	315	2	-241
356	AmerenMO	9,790	9,398	190	227	8,211	9,879	181	-1,824
357	AmerenIL	12,059	10,593	245	1,189	13,521	11,127	268	2,095
360	CWLP	492	489	3	0	572	513	4	55
361	SIPC	390	279	10	101	226	279	5	-58

5.1.3 East Region Model Load and Generation Summary

The Midwest ISO East Planning Region is comprised of the following transmission owning/operating members with controls areas modeled:

- FirstEnergy (FE d/b/a ATSI)
- Northern Indiana Public Service Company (NIPSCO)
- ITC*Transmission* (ITC)
- Michigan Electric Transmission Company (METC)
- Wolverine Power Cooperative (WPSC) within METC zone
- Michigan Public Power Agency (MPPA) within METC zone
- Michigan South Central Power Agency (MSCPA)
  non-Midwest ISO member is also contained in ITC/METC Michigan control areas.

The East Planning Region is contained within the following states: Michigan and Indiana and Ohio. The BA load, generation dispatched, and interchange in the MTEP07 2013 Summer Peak, 2018 Summer Peak models are shown in Table 5-3.

Table 5-3 East Control Area Summary for 2013/2018 Summer Peak Models

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Gener-ation	Load	Loss	Inter-change	Gener-ation	Load	Loss	Inter-change
202	First Energy	13,653	15,199	516	-2,063	15,170	16,203	434	-1,464
217	NIPSCO	3,170	3,717	61	-609	3,705	3,935	66	-296
218	METC	12,212	11,339	432	452	13,514	11,522	466	1,528
219	ITC	12,056	12,520	288	-752	12,585	12,737	295	-448

5.2 MTEP Appendices A, B, and C

MTEP Appendices A, B and C indicate where a project is in the MTEP planning process.

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). 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 for 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. That is, recommended projects need not wait for completion of the next MTEP for Board approval and inclusion in Appendix A. 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 eligible 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. 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 MTEP07 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 C projects are not eligible for regional cost sharing.

MTEP08 Appendices A, B, and C

The results of the MTEP07 and MTEP08 analyses and Midwest ISO service related studies have determined that the projects currently identified in the Appendix A (recommended by Midwest ISO staff for approval by Midwest ISO Board of Directors) and Appendix B (projects not recommended for approval at this time) of MTEP08 are sufficient to maintain system reliability and provide for requested service.

5.3 New Appendix A Projects in MTEP08

This section lists the projects which are moving to Appendix A as part of MTEP08.

Note that Appendix A is a rolling list which includes all previously approved projects plus those approved in MTEP08. The new projects listed in this section of the report can be noted in Appendix A by the B>A or C>B>A designations which indicate whether they were projects from past MTEP Studies which were in Appendix B or projects new to this planning cycle. The projects in Table 5-4 were recommended by the Midwest ISO staff for approval by the Board of Directors in MTEP08.

The table is sorted by:

- Planning Region
- Transmission Owners (TO)
- State
- Allocation FF Type
  - Baseline Reliability Project (BRP)
  - Generator Interconnection Project (GIP)
  - Transmission Service Delivery Project (TDSP)
  - Other
- Share Status
- Expected In Service Date
- Estimated Cost
- Facility under Midwest ISO functional control

Appendix D1 Central, Appendix D1 East, and Appendix D1 West files contain the complete project justifications for those interested in additional project information. The project's region is indicated in first column in Table 5-4.

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
Central	AmerenIL	IL	BaseRel	Not Shared	1529	Brokaw-State Farm Line 1596-Reconductor	Reconductor 3.3 miles of 138 kV line to 2000 A Summer Emergency capability	6/1/2010	$2,566,900	Y
Central	AmerenIL	IL	BaseRel	Not Shared	1532	Stallings-E. Collinsville-Upgrade Terminal Equipment, Increase Ground Clearance	Replace terminal equipment at Stallings, increase ground clearance between Stallings, Maryville REA	6/1/2011	$744,800	Y
Central	AmerenIL	IL	BaseRel	Not Shared	2060	East Peoria-Flint : Increase Clearances 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	6/1/2010	$2,113,000	Y
Central	AmerenIL	IL	BaseRel	Not Shared	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	11/1/2009	$553,000	Y
Central	AmerenIL	IL	BaseRel	Shared	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.	6/1/2012	$15,039,400	Y
Central	AmerenIL	IL	BaseRel	Shared	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	12/1/2012	$17,600,000	Y
Central	AmerenIL	IL	GIP	Shared	2113	G515	Network upgrades for tariff service request	12/1/2008	$2,244,000	Y
Central	AmerenIL	IL	GIP	Shared	2116	IP04	Network upgrades for tariff service request	9/1/2009	$2,027,957	Y
Central	AmerenIL	IL	Other	Not Shared	1232	Tap to Tilden-Fayetteville L1526	Tap to Tilden-Fayetteville L1526 for construction power for Prairie State	1/1/2008	$2,602,000	Y
Central	AmerenIL	IL	Other	Not Shared	1351	Pana North-Decatur Rt. 51 L1462	Pana North-Decatur Rt. 51 L1462	5/5/2008	$80,600	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	AmerenIL	IL	Other	Not Shared	1526	N. Staunton-Midway-Upgrade Terminal Equipment	Replace terminal equipment at N. Staunton	3/14/2008	$375,100	Y
Central	AmerenIL	IL	Other	Not Shared	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)	9/30/2009	$13,000,000	Y
Central	AmerenMO	MO	BaseRel	Not Shared	1238	GM-Point Prairie 161 kV to AECI Enon Sub.	Extend 1 mile of 161 kV to AECI Enon Substation	6/1/2011	$1,279,700	Y
Central	AmerenMO	MO	BaseRel	Shared	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.	12/1/2010	$19,000,000	Y
Central	AmerenMO	MO	Other	Not Shared	1235	Fredericktown-AECI Fredericktown	Increase ground clearance on 12 miles	6/1/2012	$970,500	Y
Central	AmerenMO	MO	Other	Not Shared	2072	Brick House Substation	This project would provide auxiliary power for Environmental load at Sioux power plant	10/1/2008	$8,700,000	Y
Central	AmerenMO	MO	Other (Reliability)	Excluded	717	Conway-Tyson-3 138 kV	Conway-Orchard Gardens section of Conway-Tyson-3 138 kV-Increase ground clearance	6/1/2010	$125,350	Y
Central	AmerenMO	MO	Other (Reliability)	Excluded	718	Conway-Tyson-4 138 kV	Conway-Orchard Gardens section of Conway-Tyson-4 138 kV-Increase ground clearance	6/1/2010	$125,350	Y
Central	CWLP	IL	BaseRel	Not Shared	1552	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation (two new tie lines) Convert Interstate sub from a 6 breaker ring bus to a 12 breaker breaker-and-a-half arrangement	10/1/2009	$2,800,000	Y
Central	DEM	OH	BaseRel	Not Shared	1512	Ashland to Rochelle 138	Install underground 138 kV circuit from Ashland to Rochelle.	6/1/2010	$2,878,513	Y
Central	DEM	IN	BaseRel	Not Shared	1895	Brownsburg to Avon East 138kV Reconductor	Brownsburg to Avon East 138kV Reconductor 4.2 miles of 138kV line with 954 ACSR-AFTER 138 kV CONVERSION	6/1/2011	$1,433,227	Y

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
Central	DEM	IN	BaseRel	Not Shared	1650	Fairview to HE Fairview 13854 Reconductor	Fairview to HE Fairview 13854 Reconductor with 954ACSR @ 100C	6/30/2012	$1,236,384	Y
Central	DEM	IN	BaseRel	Not Shared	841	Westwood Bk1 Limiting Equipment	Replace 1200A 138kV equipment with 2000A to allow full transformer rating.	6/1/2013	$554,000	Y
Central	DEM	IN	BaseRel	Not Shared	1560	Edwardsport 138kV cap	Install a 138kV 57.6MVAR capacitor at Edwardsport.	6/1/2010	$500,000	Y
Central	DEM	OH	BaseRel	Not Shared	1563	Todhunter to AK Steel 138 kV reconductor	Replace F5686 existing conductor with 954ACSR @ 100C from Todhunter to AK Steel and replace any limiting terminal equipment at both ends	10/15/2008	$302,000	Y
Central	DEM	IN	BaseRel	Not Shared	1651	Madison Michigan Rd to HE Fairview 13854 Uprate	Madison Michigan Rd to HE Fairview 13854 Uprate 397ACSR conductor to 100C operation	6/30/2012	$278,000	Y
Central	DEM	IN	BaseRel	Not Shared	1510	Wabash River to TH Water St 138 100C Uprate	Uprate 138kV from Wabash River to Terre Haute Water St to 100C.	6/1/2008	$120,282	Y
Central	DEM	IN	BaseRel	Not Shared	1507	Vectren Francisco 345/138	Loop 34516 line through new Vectren Francisco 345/138kV substation. Reroute Duke Energy 138kV around substation.	12/31/2007	$0	Y
Central	DEM	IN	BaseRel	Not Shared	1504	Honda	New substation for Honda in Greensburg taps the Duke Energy 138kV line between Greensburg and Shelbyville Northeast.	12/1/2007	$0	Y
Central	DEM	IN	GIP	Shared	1878	Speed Bk 1 replacement	Replace 138/69/12 kV BK 1 with a 138/69kV 150 MVA transformer w/LTC	6/1/2009	$2,000,000	Y
Central	DEM	IN	Other	Not Shared	1502	Tipton West 230/69 substation	Construct a new 230/69kV substation with 2-150MVA xfmrs	12/31/2008	$11,096,872	Y
Central	DEM	IN	Other	Not Shared	806	Gwynnville 345/69	Add 345/69kV transformer at Gwynnville. Construct four 69kV exits to connect to existing 69kV circuits.	6/1/2008	$7,823,698	NT
Central	DEM	IN	Other	Not Shared	810	Bloomington Bk5 230/69	Add 2nd 230/69kV transformer at Bloomington.	12/31/2007	$3,986,059	Y
Central	DEM	IN	Other	Not Shared	1245	Frankfort Jefferson to Potato Creek new 69kV Line	Construct new 69kV line from Frankfort Jefferson to new Potato Creek switching station.	6/1/2010	$2,094,115	NT

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	DEM	IN	Other	Not Shared	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	12/31/2009	$1,252,764	Y
Central	DEM	IN	Other	Not Shared	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	6/1/2010	$921,919	NT
Central	DEM	OH	Other	Not Shared	811	Evendale 69kV Caps 1&2	Add two 21.6 MVAR 69kV capacitors at Evendale	12/31/2007	$781,610	NT
Central	DEM	IN	Other	Not Shared	1501	Carmel 146th St 69kV Cap 2	Added second 36 MVAR 69kV capacitor at Carmel 146th St	6/1/2012	$624,145	NT
Central	DEM	IN	Other	Not Shared	1891	N. Manchester to N. Man. Sw. Sta. 69kV line rebuild	6923 ckt. reconductor from N. Manchester 69 sub to N. Manchester Sw Sta (0.53 mile) and a portion of the line section from N. Manchester 69 sub to Collamer along CR 1100N (1.03 miles), also replace transmission poles-new conductor will be 477ACSR@100C	6/1/2009	$618,143	NT
Central	DEM	IN	Other	Not Shared	1513	Metea 69kV Cap	Install 14.4MVAR 69kV capacitor at Metea.	6/1/2010	$568,653	NT
Central	DEM	IN	Other	Not Shared	1564	Roseburg Switching Station cap	Install 69kV 21.6MVAR std capacitor	6/1/2009	$500,000	NT
Central	DEM	IN	Other	Not Shared	834	Kingman 69kV Cap	Add 7.2 MVAR 69kV capacitor at Kingman.	6/1/2012	$500,000	NT
Central	DEM	IN	Other	Not Shared	1266	Hortonville 69kV Cap	Install 69kV 36MVAR cap bank at Hortonville	6/1/2009	$500,000	NT
Central	DEM	IN	Other	Not Shared	835	Pittsboro 69kV Cap	Add 14.4 MVAR 69kV capacitor at Pittsboro.	6/1/2010	$500,000	NT
Central	DEM	IN	Other	Not Shared	1265	Geist 69kV Cap 2	Add a second 69kV 36MVAR cap bank at Geist	6/1/2010	$500,000	NT
Central	DEM	IN	Other	Not Shared	830	Thorntown 69kV Cap	Add 28.8 MVAR 69kV capacitor at Thorntown.	11/2/2007	$456,723	NT
Central	DEM	IN	Other	Not Shared	1194	Prescott	Add 43.2 MVAR capacitor.	12/31/2010	$439,845	NT
Central	DEM	OH	Other	Not Shared	828	Northgreen 69kV Cap	Add 14.4 MVAR 69kV capacitor at Northgreen.	12/31/2007	$406,671	NT

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	DEM	IN	Other	Not Shared	1561	Kokomo Webster St 230 kV 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.	6/1/2011	$399,580	Y
Central	DEM	IN	Other	Not Shared	1648	Lafayette S to Lilly Uprate	Lafayette S to Lilly Uprate 397.5ACSR to 100C-4.13 miles-13808 ckt	10/15/2008	$389,256	Y
Central	DEM	IN	Other	Not Shared	1514	Wabash River to Staunton 230 100C Uprate	Uprate Wabash River to Staunton 23002 to 100C summer operating temperature and 80C winter (559MVA).	6/1/2009	$255,173	Y
Central	DEM	IN	Other	Not Shared	1505	HE Owensville North 138/69	Loop Gibson to Princeton 13863 line through new HE Owensville North 138/69 substation.	6/1/2008	$182,375	Y
Central	DEM	IN	Other	Not Shared	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 Zionsvile 69 sub for a min. capacity of 152MVA (502G6709)	6/1/2012	$163,390	NT
Central	DEM	IN	Other	Not Shared	1886	Columbus West 69kV line switches replace	Columbus West-replace 69kV switches 1&2 with 1200 amp switches-(in the 69146 ckt)	5/29/2009	$82,847	NT
Central	DEM	IN	Other	Not Shared	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	6/1/2010	$16,493	NT
Central	DEM	IN	Other	Not Shared	1506	Peru SE 69kV	Add 69kV ring breaker, line terminal and interconnection metering for new Peru Municiapal 69kV circuit.	12/31/2007		NT
Central	DEM	OH	Other	Excluded	625	Pierce/Beckjord 345/138 kV transformer addition	Add 3rd 345/138kV transformer, 400MVA, from Pierce 345kV bus to Beckjord 138kV North bus.	6/1/2008	$2,659,515	Y
Central	DEM	IN	Other (non-MISO GIP)	Not Shared	1515	Speed relays for LGEE Trimble	Replace Speed relays for the LGEE Trimble addition	6/1/2009	$145,922	Y
Central	DEM	IN	Other (Reliability)	Not Shared	1568	Qualitech 345/138 kV Transformer and breakers	Qualitech Sub-Install one 345/138 kV, 300Mva Xtr and 2-345 kV Bkrs and 1-138 kV Bkr to provide second 138 kV source to proposed Hendricks Co 138 kV system	6/1/2010	$4,561,674	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	DEM	IN	Other (Reliability)	Not Shared	1570	Plainfield South to Pittsboro 69 kV to 138 kV Conversion	Convert the existing 69 kV (69144) line from Plainfield S. to Pittsboro (and 4 distribution subs) over to 138 kV operation and connect to the new Qualitech to Pittsboro 138 kV line	6/1/2010	$4,139,000	Y
Central	DEM	IN	Other (Reliability)	Not Shared	1893	Mitchell Lehigh Portland to Bedford 25th St 6995 rebuild	Reconductor 10.3 miles of 69kV-6995 line with 477 ACSR@100C	6/1/2011	$3,620,481	NT
Central	DEM	IN	Other (Reliability)	Not Shared	1899	Macy to Rochester Metals Jct 69kV reconductor	Reconductor Macy to Rochester Metals Jct section of 6957 circuit with 477ACSR-approx 9.1 miles	12/31/2010	$3,102,711	NT
Central	DEM	IN	Other (Reliability)	Not Shared	1519	Noblesville NE to Geist 69	Build a new 69kV line from Noblesville NE sub to tap the Fishers North-Geist 69kV line	6/1/2011	$2,640,107	NT
Central	DEM	IN	Other (Reliability)	Not Shared	1892	Wabash to Hopewell Jct 69132 rebuild	69132 ckt. Reconductor 6.86 miles from Wabash to Hopewelll Jct. with 477ACSR	6/1/2009	$2,591,000	NT
Central	DEM	IN	Other (Reliability)	Not Shared	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	6/1/2011	$2,418,000	NT
Central	DEM	IN	Other (Reliability)	Not Shared	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	6/1/2009	$2,300,000	NT
Central	DEM	IN	Other (Reliability)	Not Shared	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 (7.13 miles)	6/1/2011	$1,510,946	NT
Central	DEM	IN	Other (Reliability)	Not Shared	1569	Qualitech to Pittsboro new 138 kV line	Construct new 138 kV line, Qualitech to Pittsboro, and connect to the Pittsboro-Brownsbg line to provide new 954ACSR outlet line from Qualitech 345/138kV Bank	6/1/2010	$1,507,856	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	DEM	IN	Other (Reliability)	Not Shared	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)	5/1/2010	$1,181,223	NT
Central	HE	IN	Other	Not Shared	2084	Worthington 161/138kV Transformer	Worthington 161/138kV Transformer replacement	9/1/2009	$4,500,000	Y
Central	HE	IN	Other	Not Shared	2095	Sandborn Primary	Sandborn Primary to Freelandville Switch 69 kV line and Sandborn Primary to Carlisle Switch 69 kV line	9/1/2008	$4,000,000	NT
Central	HE	IN	Other	Not Shared	1926	Gywnneville to Pioneer tie	69kV Tie from DE Gwynneville to HE Pioneer	9/1/2008	$1,000,000	NT
Central	HE	IN	Other	Not Shared	2083	Wayne County Industrial Park	69kV Substation and Tapline	9/1/2009	$750,000	NT
Central	HE	IN	Other (Reliability)	Not Shared	1635	Ramsey Primary Substation Ringbus	345kV Ringbus Addition/Modification to Ramsey Primary	12/1/2009	$7,000,000	Y
Central	HE	IN	Other (Reliability)	Not Shared	1323	Sandborn Primary Substation	161/69kV Primary Station at Sandborn	9/1/2008	$6,000,000	Y
Central	HE	IN	Other (Reliability)	Not Shared	1927	Hubbell Primary Ring Bus	138kV Ring Bus addition / Modification to Hubbell Primary	9/1/2010	$3,000,000	Y
Central	HE	IN	Other (Reliability)	Not Shared	1923	Spring Valley 69kV Switch Station	69kV Switching station w/ 69kV Ring Bus	9/1/2009	$2,600,000	NT
Central	HE	IN	Other (Reliability)	Not Shared	1928	Fairview Primary Ring Bus	138kV Ring Bus addition / Modification to Fairview Primary	9/1/2011	$1,500,000	Y
Central	HE	IN	Other (Reliability)	Not Shared	1929	Georgetown Primary Ring Bus	138kV Ring Bus addition / Modification to Georgetown Primary	9/1/2012	$1,250,000	Y
Central	HE	IN	Other (Reliability)	Not Shared	2082	Shelbyville Intel Park	138kV Substation and Tapline	9/1/2009	$1,000,000	Y
Central	IPL	IN	BaseRel	Not Shared	1634	Pete-Vincennes Line Capacity Upgrade	Increase Capacity By Changing CT Ratio At Petersburg To 1200A	1/1/2008	$2,500	Y
Central	IPL	IN	Other	Not Shared	1639	General IPL Capacitor Additions	Add capacitors to the IPL General Distribution System	6/1/2013	$50,000	Y
Central	SIPC	IL	Other	Not Shared	1778	Hamilton 138 kV Interconnect	Construct a 138 kV line connecting SIPC Hamilton Substation to Ameren Norris City Substation. This project includes the construction of 18 miles of 138 kV line.	7/1/2008	$5,000,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	Vectren (SIGE)	IN	BaseRel	Shared	1970	New 345/138kV Substation at AB Brown	New 448MVA 345/138kV transformer in addition to the Gibson-AB Brown-Reid 345kV line.	5/31/2011	$7,680,032	Y
Central	Vectren (SIGE)	IN	Other	Not Shared	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	5/31/2009	$8,950,000	Y
Central	Vectren (SIGE)	IN	Other	Not Shared	1784	Jasper#3 Sub Exp-Victory Line	Extend existing Victory line to new term at existing sub	6/1/2012	$1,250,000	NT
Central	Vectren (SIGE)	IN	Other	Not Shared	1783	Princeton Area Load Addition	Expansion of Substation	6/1/2009	$400,000	NT
Central	Vectren (SIGE)	IN	Other	Not Shared	1791	Y66-2 Angel Mounds to Eastside uprate	Uprate Y66-2 from Angel Mounds to East Side to increase transfer capacity	6/1/2012	$300,000	NT
Central	Vectren (SIGE)	IN	Other	Not Shared	1785	Z83 Upgrade	Upgrade terminal equipment at NE and NW.	6/1/2008	$100,000	Y
Central	Vectren (SIGE)	IN	Other	Not Shared	1786	Z98 Upgrade	Upgrade terminal equipment at AB Brown and Point	6/1/2008	$100,000	Y
Central	Vectren (SIGE)	IN	Other	Not Shared	995	Add 138/69 kV 60 MVA transformer to Mt. Vernon	Add 138/69 kV 60 MVA transformer to Mt. Vernon	12/31/2012	$80,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1023	Scott Township 138/69 kV Substation and Scott Township-Elliott 138 kV Line	New Scott Township 138/69 kV substation and new 138 kV line from Scott Township to Elliott	5/31/2009	$13,900,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1258	Pigeon Creek 138/69 kV Substation	New 'Pigeon Creek 138/69 kV Substation	5/31/2008	$10,700,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1002	New Northeast to Oak Grove to Culley Line 138 kV	New Northeast to Oak Grove to Culley Line 138 kV	5/31/2009	$8,500,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1782	NorthEast Sub Bus re-config	Rebuild existing straight bus with more reliable breaker and half scheme	6/1/2009	$3,300,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1787	Y75-Dale to Santa Clause	New 69kV line from Dale Sub to Santa Clause Sub	6/1/2012	$3,300,000	NT
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1781	Abengoa Ethanol Plant and line work	Add new Customer 138/12kV Substation with assoc. 138kV line work.	6/1/2009	$2,750,000	Y
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1779	Aventine Ethanol Plant and line work	Add new Customer 69/12kV Substation with assoc. 69kV line work.	6/1/2009	$2,715,000	NT

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1788	Y34-St. Wendel to Mohr Rd	New 69kV line from St. Wendel Sub to Mohr Rd Sub	6/1/2012	$2,600,000	NT
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1790	Y52 rebuild and Sunbeam loop	Rebuild/Reconductor existing Y52 and loop into Sunbeam	6/1/2012	$1,500,000	NT
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1789	Y56-City of Boonville Loop	New 69kV line from Boonville Sub to Boonville Pioneer Sub	6/1/2012	$1,400,000	NT
Central	Vectren (SIGE)	IN	Other (Reliability)	Not Shared	1780	Aventine Phase II	Expansion of Substation	6/1/2009	$1,325,000	NT
East	FE	OH	BaseRel	Shared	1610	SW Avon 92-AV-T New Transformer	Add new autotransformer to Avon Lake substation, along with station re-configuration to accomodate new transformer.	6/1/2009	$8,459,634	Y
East	FE	OH	BaseRel	Shared	1609	Tangy-Add 345/138kV Transformer, (2) 345kV BKR's, (1) 138kV BKR, additional substation work	Additional 345/138kV TR in 2009. Separate TR #3 and TR #4.	6/1/2009	$7,300,000	Y
East	FE	OH	BaseRel	Not Shared	1909	Davis Besse 345kV sub reconfiguration	Reconfigure the Davis Besse switch yard by extending J and K buses and adding 345kV breakers	6/1/2010	$3,345,000	Y
East	FE	OH	BaseRel	Not Shared	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.	6/1/2009	$1,267,900	Y
East	FE	OH	Other (Reliability)	Not Shared	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	11/1/2010	$12,000,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	FE	OH	Other (Reliability)	Not Shared	2096	New 138kV line to supply a new Stacy 138-36kV distribution sub	Construct a 138kV loop to a new Stacy substation for 138kV support in the area, with possible networking to other substations based on future growth.	1/1/2010	$12,000,000	Y
East	FE	OH	Other (Reliability)	Not Shared	1600	Beaver-Wellington New 138 kV Line	Build a new Beaver-Wellington 138 kV Line and establish a 138 kV ring bus at Wellington Substation.	6/1/2014	$5,000,000	Y
East	FE	OH	Other (Reliability)	Not Shared	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.	6/1/2010	$4,131,000	Y
East	FE	OH	Other (Reliability)	Not Shared	1601	Chamberlin-Shalersville New 138 kV Line	Build a new Chamberlin-Shalersville 138 kV Line to complete loop between Chamberlin, Shalersville and Hanna.	6/1/2010	$3,669,000	Y
East	FE	OH	Other (Reliability)	Not Shared	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.	6/1/2012	$3,275,000	Y
East	FE	OH	Other (Reliability)	Not Shared	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.	6/1/2010	$2,700,000	Y
East	FE	OH	Other (Reliability)	Not Shared	1912	Cardington-Tangy: R/C 69kV line	Reconductor The entire Cardington-Tangy 69kV line to 336.4 ACSR conductor.	12/31/2009	$2,400,000	Y
East	FE	OH	Other (Reliability)	Not Shared	1905	Salt Springs-New 138/69kV Transformer to R/P failed #2 Unit	Purchase and install new 138/69kV transformer to replace the failed Salt Springs #2 138/69kV transformer unit.	6/1/2008	$2,226,000	Y
East	FE	OH	Other (Reliability)	Not Shared	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	6/1/2009	$2,034,365	Y
East	FE	OH	Other (Reliability)	Not Shared	1908	Cook-Galion: R/C Galion-Snyder 69kV line section + Mansfield Waterworks-Alta line section	Reconductor 5.3 miles with 477 ACSR, andr 2.3 miles with 336.4 ACSR.	6/1/2008	$2,000,000	Y
East	FE	OH	Other (Reliability)	Not Shared	1907	Brookside: split Hale 69kV Line	Build new 69kV circuit from tap point on Hale 69kV circuit back to Brookside Substation.	6/1/2008	$769,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	FE	OH	Other (Reliability)	Not Shared	1596	Lakeview Sub-Install 34.5kV Cap Bank for 138kV system	Install 1-18.9 MVAR Capacitor bank	10/1/2009	$451,100	Y
East	ITC	MI	BaseRel	Not Shared	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.	6/1/2011	$1,400,000	Y
East	ITC	MI	GIP	Shared	1874	G526 Harvest Wind	Generation interconnection project to install 52 MW of wind turbines that will connect to the Cosmo Tap portion of the Arrowhead-Bad Axe 120 kV circuit	11/3/2007	$2,352,131	Y
East	ITC	MI	GIP	Shared	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	5/31/2009	$7,829,237	Y
East	ITC	MI	Other	Not Shared	1663	Cable Termination	replace cable terminations that have reached end of life or lack spare parts	4/1/2010	$4,000,000	Y
East	ITC	MI	Other	Not Shared	1866	Anti-galloping project	Throughout System	12/31/2008	$3,000,000	Y
East	ITC	MI	Other	Not Shared	1873	Tahoe	Distribution Interconnection to add a new 120/13.2kV transformer at Tahoe.	6/1/2010	$2,800,000	Y
East	ITC	MI	Other	Not Shared	1870	Clyde	Distribution Interconnection to add a new 120/41kV transformer at Clyde. Taps the Placid-Durant 120kV circuit	12/1/2009	$2,750,000	Y
East	ITC	MI	Other	Not Shared	1660	Horn	New Chrysler Plant Connection	1/21/2008	$2,700,000	Y
East	ITC	MI	Other	Not Shared	1661	Axle	Chrysler Axle Sub	10/1/2008	$2,400,000	Y
East	ITC	MI	Other	Not Shared	1662	Square Lake	Square Lake Substation	10/1/2008	$2,200,000	Y
East	ITC	MI	Other	Not Shared	1871	Hurst	Distribution Interconnection to add a new 120/41kV transformer at Hurst. Breaks up the Genoa-Durant 120kV circuit	12/1/2009	$2,100,000	Y
East	ITC	MI	Other	Not Shared	1664	Relay Betterment	replace relays that do not meet up to date standards	12/31/2008	$1,130,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	METC	MI	BaseRel	Shared	1814	Tippy-Chase 138kV	Rebuild 30 miles of 138kV 110 CU to 954 ACSR. Prebuild to 230kV construction.	12/31/2010	$30,000,000	Y
East	METC	MI	BaseRel	Shared	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.	5/31/2010	$21,000,000	Y
East	METC	MI	BaseRel	Shared	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.	6/1/2010	$21,000,000	Y
East	METC	MI	BaseRel	Shared	1796	Twining-Almeda 138kV	Rebuild 22 miles of 138kV of 110 Cu to 954 ACSR. Prebuild to 230kV construction.	6/1/2011	$19,500,000	Y
East	METC	MI	BaseRel	Shared	1818	Algoma-Croton	Rebuild 138 kV Line. Prebuild to 230 kV construction.	5/31/2011	$17,150,000	Y
East	METC	MI	BaseRel	Shared	480	Brickyard Jct.-Felch Road 138 kV	Rebuild 13 miles of 3/0 ACSR to 954 ACSR	6/1/2009	$10,000,000	Y
East	METC	MI	BaseRel	Shared	1819	Felch Road-Croton	Rebuild 138 kV Line. Prebuild to 230 kV construction.	12/31/2009	$7,750,000	Y
East	METC	MI	BaseRel	Not Shared	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.	12/31/2009	$2,200,000	Y
East	METC	MI	BaseRel	Not Shared	1829	Leoni-Beecher 138 kV	Increase capacity of Leoni-Beecher 138 kV ckt.	6/1/2010	$450,000	Y
East	METC	MI	BaseRel	Not Shared	1794	Argenta-Verona 138kV SAG Limit	Remove the SAG limit on Argenta-Verona 138kV.	6/1/2009	$160,000	Y
East	METC	MI	BaseRel	Not Shared	1799	Grand Rapids SAG limits	Remove the SAG limit on: Roosevelt-Tallmadge	6/1/2011	$1,000,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	METC	MI	Other	Not Shared	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	12/31/2009	$14,000,000	Y
East	METC	MI	Other	Not Shared	1820	METC Communication and Relaying Upgrade	Throughout system	12/31/2008	$10,000,000	Y
East	METC	MI	Other	Not Shared	1656	Relay NERC/8A Compliance	Upgrade relays throughout system	12/31/2008	$9,777,776	Y
East	METC	MI	Other	Not Shared	1655	Breaker Repair or Replace Program	throughout system	12/31/2008	$5,260,000	Y
East	METC	MI	Other	Not Shared	1832	Sag clearance 2008	Throughout system	12/31/2008	$3,250,000	Y
East	METC	MI	Other	Not Shared	1448	Simpson	Project to connect a distribution transformer at Simpson	6/1/2013	$2,200,000	Y
East	METC	MI	Other	Not Shared	1838	Meridian	New Distrbution Interconnection served from Delhi-Tihart 138kV circuit	9/1/2009	$2,200,000	Y
East	METC	MI	Other	Not Shared	1389	Midwest Grain Processor 138 kV load connection	Install a tap pole and two switches on Beecher-Samaria 138kV Line	11/3/2007	$360,000	Y
East	METC	MI	Other	Not Shared	1836	Riggsville	Modify Bus Protection at Riggsville 138kV bus due to 46kV transformer modifications	6/1/2008	$260,000	Y
East	METC	MI	Other	Not Shared	1837	Van Buren	New Distrbution Interconnection served from Campbell-Beals Road 138kV circuit	12/1/2008	$200,000	Y
East	METC	MI	Other	Not Shared	1834	Tirrell Road	New Distrbution Interconnection served from Battle Creek-Island Rd. 138kV circuit	12/1/2008	$200,000	Y
East	METC	MI	Other	Not Shared	1841	Eagles Landing	New Distrbution Interconnection served from Iosco-Karn 138kV circuit	6/1/2010	$175,000	Y
East	METC	MI	Other	Not Shared	1835	Geddes	New Distrbution Interconnection served from Lawndale-Claremont 138kV circuit	9/1/2008	$175,000	Y
East	METC	MI	Other	Not Shared	1443	Milham	Install a second distribuiton transformer served from Milham-Upjohn 138kV	6/1/2009	$100,000	Y
East	NIPS	IN	BaseRel	Shared	1551	Flint Lake to Tower Road-2nd circuit	Add a 2nd 138kV circuit between Flint Lake and Tower Road	11/1/2008	$5,050,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	NIPS	IN	BaseRel	Not Shared	2006	Kenwood Sub-Add 69 kV Capacitors-(2) 10.8 MVAR (Engineering Only in 2007)	Add two steps of 10.8 MVAR capacitors on the Kenwood Substation 69 kV bus.	12/1/2008	$983,000	Y
East	NIPS	IN	Other	Not Shared	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.	5/1/2008	$1,780,000	Y
East	NIPS	IN	Other	Not Shared	1982	34.5 and 69 kV Breaker Replacement Program	Angola sub circuit 6980 E Winamac sub circuit 6937 and 69 kV bus tie Goodland sub circuits 6963 and 6966 Plymouth sub circuit 6915 Marshall sub circuit 3420 recloser Winamac Sub circuit 6919 recloser	12/1/2008	$1,075,000	Y
East	NIPS	IN	Other	Not Shared	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.	12/1/2007	$190,000	Y
East	NIPS	IN	Other	Not Shared	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.	12/1/2008	$71,000	Y
East	NIPS	IN	Other (Reliability)	Not Shared	1977	Leesburg Sub-New 138/69 Substation	Install 138/69 kV Transformer and 2 69 kV Circuits at Leesburg Substation	12/1/2009	$5,407,000	Y
East	NIPS	IN	Other (Reliability)	Not Shared	919	Lagrange Sub-Increase #1 138-69 kV Transf. Capacity	Replace the existing No.1 138/69 kV 112 MVA transformer with a 138/69 kV 168 MVA transformer.. Substation.	5/1/2008	$1,593,300	Y
East	NIPS	IN	Other (Reliability)	Not Shared	2004	Northeast Sub-Add 69 kV Capacitors-(2) 10.8 MVAR	Add two steps of 10.8 MVAR capacitors on the Northeast Substation 69 kV bus.	1/1/2008	$870,000	Y
East	NIPS	IN	Other (Reliability)	Not Shared	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.	6/1/2008	$755,000	Y
East	NIPS	IN	Other (Reliability)	Not Shared	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.	4/1/2008	$126,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
East	WPSC	MI	GIP	Shared	2110	G566	Network upgrades for tariff service request	12/28/2007	$1,983,200	Y
East	WPSC	MI	Other	Not Shared	1577	Copemish-Bass Lake Line Rebuild	Rebuild line to 795ACSS	12/31/2012	$10,200,000	Y
East	WPSC	MI	Other	Not Shared	1968	Westwood Substation	Construct new substation at the Westwood location	12/31/2008	$2,000,000	Y
East	WPSC	MI	Other	Not Shared	1210	Lewiston II Breaker Station	Add a 69 kV breaker in the line from Atlanta to Gaylord	12/31/2008	$800,000	Y
East	WPSC	MI	Other	Not Shared	1218	Atlanta LTC replacement	Replace existing LTC in 138/69kV transformer	12/31/2008	$600,000	Y
East	WPSC	MI	Other	Not Shared	2121	Gaylord Lightning Protection	This project will upgrade the lightning protection.	12/31/2008	$350,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	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	12/31/2010	$17,550,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1967	Wayland to Portland	Rebuild Outdated line	12/31/2010	$14,245,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1313	Plains X to Hersey	Plains X to Hersey line rebuild	12/31/2010	$9,700,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1964	Chester Tie	Add 138/69kV Transformer to Copemish substation	12/31/2009	$8,000,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1581	Alba to Advance 69 rebuild	Alba to Advance 69 kV line rebuild	12/31/2011	$7,950,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1209	Hersey 69 kV 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	12/31/2010	$7,500,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1311	Copemish to Grawn	Copemish to Grawn line rebuild	12/31/2012	$7,100,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1965	Gray Tie	Add 138/69kV Transformer to WPSC's Garfield junction	12/31/2008	$6,600,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1276	Burnips to Wayland	Burnips to Wayland line rebuild	12/31/2011	$6,450,000	Y

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
East	WPSC	MI	Other (Reliability)	Not Shared	1219	Lake County-Plains Junction Line Rebuild	Rebuild line to 795ACSS	12/31/2009	$6,100,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1222	Lake County 69kV Ring Bus and Transformer	Convert 4 breaker bus at Lake County to Ring Bus and add 168MVA transformer	12/31/2011	$6,000,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1274	Blendon to Osipoff	Blendon to Osipoff line rebuild	12/31/2011	$5,850,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1587	Gaylord to Advance to Oden Build 138kV Circuit	Build New 138 kV line	12/31/2010	$5,000,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1214	Garfield X to Grawn	Rebuild Overloaded Line to 795 ACSS	7/1/2008	$3,350,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1315	Grand Traverse to East Bay	Potter to East Bay line rebuild	12/31/2009	$3,300,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1211	Grand Traverse-Grawn Line Rebuild	Rebuild line to 795ACSS	8/1/2009	$2,500,000	Y
East	WPSC	MI	Other (Reliability)	Not Shared	1213	Vestaburg Capacitor Bank	Add 6MVAR Additional Capacitors at Vestaburg Substation	12/31/2008	$300,000	Y
West	ATC LLC	WI	BaseRel	Shared	356	Rockdale-West Middleton 345 kV	Southern route: 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.	6/1/2013	$230,056,311	Y
West	ATC LLC	WI	BaseRel	Not Shared	1279	North Beaver Dam 49 MVAR cap bank	install two 24.5 MVAR cap bank at North Beaver Dam	6/1/2009	$2,500,000	Y
West	ATC LLC	MI	BaseRel	Not Shared	1670	Uprate Empire-Forsyth 138 kV line	Uprate Empire-Forsyth 138 kV line to 302 MVA	6/1/2008	$2,500,000	Y
West	ATC LLC	MI	BaseRel	Not Shared	1555	Perkins Capacitor Banks	Install two 16.33 MVAR 138kV capacitor banks at Perkins substation	6/1/2009	$1,395,185	Y
West	ATC LLC	WI	BaseRel	Not Shared	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	6/1/2009	$1,260,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	ATC LLC	WI	BaseRel	Not Shared	1931	Uprate North Appleton-Fox River 345 kV	Increase ground clearance for North Appleton-Fox River 345 kV to 200/230 degrees F	4/1/2008	$1,057,339	Y
West	ATC LLC	MI	BaseRel	Not Shared	1553	Hiawatha 138kV Capacitor Bank	Install one 16.33 MVAR 138kV capacitor bank at Hiawatha substation	6/1/2009	$615,283	Y
West	ATC LLC	WI	BaseRel	Not Shared	1735	Upgrade St. Martins 138 kV bus	Upgrade St. Martins 138 kV bus to 2000A	12/1/2007	$200,000	Y
West	ATC LLC	WI	BaseRel	Not Shared	1736	Upgrade St. Lawrence 138 kV bus	Upgrade St. Lawrence 138 kV bus	12/1/2007	$6,000	Y
West	ATC LLC	WI	GIP	Not Shared (Pre-RECB) Suspend?	881	Cypress generation facility projects	Forest Junction-Cypress-Arcadian 345 kV (loop line into new Cypress generation site)	6/1/2006	$7,136,787	Y
West	ATC LLC	WI	GIP	Not Shared (Pre-RECB) Suspend?	879	Forward Energy Center (generation facility)	Butternut-Forward Energy-South Fond du Lac 138 kV (loop into new Forward Energy site)	8/1/2006	$3,315,001	Y
West	ATC LLC	WI	Other	Not Shared	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	6/1/2012	$21,900,000	Y
West	ATC LLC	MI	Other	Not Shared	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	9/1/2009	$10,500,000	Y
West	ATC LLC	MI	Other	Not Shared	1665	Rebuild Atlantic-Osceola 69 kV line (Laurium #1)	Rebuild Atlantic-Osceola 69 kV line (Laurium #1)	7/1/2008	$7,953,102	Y
West	ATC LLC	WI	Other	Not Shared	1671	New Southwest Delevan-Bristol 138 kV line	New Southwest Delevan-Bristol 138 kV line operated at 69 kV	6/1/2008	$6,765,459	Y
West	ATC LLC	WI	Other	Not Shared	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	3/31/2010	$3,185,000	Y
West	ATC LLC	WI	Other	Not Shared	1684	Pleasant Valley 138 kV bus	Construct a 138 kV bus at Pleasant Valley substation to permit second distribution transformer interconnection	6/1/2009	$2,160,000	Y
West	ATC LLC	WI	Other	Not Shared	1673	Uprate X-17 Eden-Spring Green 138 kV line	Uprate X-17 Eden-Spring Green 138 kV line to 167 degrees F	1/1/2008	$1,200,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	ATC LLC	MI	Other	Not Shared	1666	Uprate Mass-Atlantic 69 kV line	Uprate Mass-Winona 69 kV line clearance to 185 deg F Uprate Winona-Atlantic 69 kV line clearance to 185 deg F	6/1/2008	$903,202	Y
West	ATC LLC	MI	Other	Not Shared	1677	Uprate Chandler-Cornell 69 kV line	Uprate Chandler-Cornell 69 kV line clearance from 120 to 167 deg F	6/1/2009	$900,000	Y
West	ATC LLC	MI	Other	Not Shared	1669	Roberts Capacitor Banks	Install one 4.08 MVAR 69 kV capacitor bank at Roberts substation	6/1/2008	$900,000	Y
West	ATC LLC	MI	Other	Not Shared	1676	L'Anse Capicitor Bank	Install one 4.08 MVAR 69 kV capacitor bank at L'Anse substation	6/1/2009	$600,000	Y
West	ATC LLC	MI	Other	Not Shared	1942	Uprate Atlantic138-69 kV Transformer	Replace limiting relay equipment on the Atlantic Transformer	6/1/2009	$418,036	Y
West	ATC LLC	MI	Other	Not Shared	1943	Uprate M38 138-69 kV Transformer	Replace limiting relay equipment on the M38 Transformer	6/1/2009	$418,036	Y
West	ATC LLC	WI	Other	Not Shared	1680	Uprate Walworth-North Lake Geneva 69 kV line	Uprate Walworth-North Lake Geneva 69 kV line to 69 MVA	6/1/2010	$370,000	Y
West	ATC LLC		Other	Not Shared	1945	Upgrade Sheekskin Capacitor 69 kV Bank	Upgrade Sheekskin Capacitor 69 kV Bank from 10.8 Mvar to 16.2 Mvar	9/7/2009	$272,268	Y
West	ATC LLC	WI	Other	Not Shared	1734	Berlin capacitor bank	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at Berlin 69 kV Substation	6/1/2008	$200,000	Y
West	ATC LLC	WI	Other	Not Shared	1933	Uprate Lakehead Delevan Tap to Lakehead Delevan radial-138 kV	Uprate Lakehead Delevan Tap to Lakehead Delevan radial-138 kV due to 2nd distribution transformer addition	6/1/2008	$166,050	Y
West	ATC LLC	WI	Other	Not Shared	1675	Sister Bay distribution Capacitor Banks	Install 2 1.2 MVAR distribution capacitor banks at Sister Bay 24.9 kV	6/1/2008	$62,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1682	Rebuild Crivitz-High Falls Dbl Ckt 69 kV line	Loop 69 kV line from Sandstone-Pioneer into Crivitz sub, Rebuild Crivitz-High Falls Dbl Ckt 69 kV line	6/1/2009	$20,733,935	Y
West	ATC LLC	MI	Other (Reliability)	Not Shared	1951	2nd Hiawatha Transformer	Install a 2nd Hiawatha 138-69 kV Transformer and a 69 kV breaker on the Hiawatha-Roberts line	1/10/2008	$3,000,000	Y
West	ATC LLC	MI	Other (Reliability)	Not Shared	1930	2nd Straits Transformer	Install a 2nd Straits 138-69 kV Transformer and a 138 kV bus tie breaker	12/20/2007	$3,000,000	Y

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Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	ATC LLC	WI	Other (Reliability)	Not Shared	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	6/1/2009	$1,770,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1683	Rebuild Sunset Point-Pearl Ave 69 kV line	Rebuild 2.37 miles of 69 kV from Sunset Point-Pearl Ave with 477 ACSR	6/1/2009	$1,759,714	Y
West	ATC LLC	MI	Other (Reliability)	Not Shared	1678	9 Mile Capicitor Banks	Install two 8.16 MVAR 69kV capacitor banks at 9 Mile substation	12/14/2007	$1,440,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1674	Uprate Portage 138/69 kV transformer	Uprate Portage 138/69 kV transformer to 143 MVA	6/1/2008	$1,400,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1672	Uprate Brick Church-Cobblestone 69 kV line	Uprate Brick Church-Cobblestone 69 kV line to 115 MVA	6/1/2008	$1,400,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1681	Uprate North Lake Geneva-Lake Geneva 69 kV line	Uprate North Lake Geneva-Lake Geneva 69 kV line to 115 MVA	6/1/2009	$1,300,000	Y
West	ATC LLC	MI	Other (Reliability)	Not Shared	1668	Munising Capacitor Banks	Install two 4.08 MVAR 69 kV capacitor banks at Munising substation	6/1/2008	$1,300,000	Y
West	ATC LLC	WI	Other (Reliability)	Not Shared	1280	South Lake Geneva two cap banks	install two 8.16 MVAR cap banks at South Lake Geneva 69 kV bus	6/1/2008	$1,251,336	Y
West	ATC LLC		TDSP	Direct Assigned	2104	A189/F037	Network upgrades for tariff service request	6/8/2008		Y
West	ATC LLC		TDSP	Direct Assigned	2102	A174/F035	Network upgrades for tariff service request	1/1/2008		Y
West	GRE	MN	GIP	Shared	2097	G389	Network upgrades for tariff service request	1/1/2009	$4,482,923	NT
West	GRE	MN	Other	Not Shared	2087	Libery (Becker) 115/69 kV transformer	Libery (Becker) 115/69 kV transformer	11/1/2007	$3,500,000	Y
West	GRE	MN	Other	Not Shared	2086	Wilson Lake 115/69 kV transformer	Wilson Lake 115/69 kV transformer	6/1/2008	$2,000,000	Y
West	GRE	MN	Other	Not Shared	2088	Enterprise Park 115/69 kV	Enterprise Park 115/69 kV	6/1/2009	$1,800,000	Y
West	GRE		TDSP	Direct Assigned	2101	A365	Network upgrades for tariff service request	6/1/2008		NT
West	GRE, XEL, OTP, MP, MRES	MN	BaseRel	Shared	286	Fargo, ND-St Cloud/Monticello, MN area 345 kV project	AlexandriaSS-Waite Park-Monticello 345 ckt 1, Sum rate 2085	7/1/2012	$490,000,000	Y

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Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	GRE/OTP	MN	Other (Reliability)	Not Shared	1033	Silver Lake 230/41.6 kV transformer	Silver Lake 230/41.6 kV transformer	6/1/2011	$1,840,000	Y
West	ITCM	MN	BaseRel	Shared	1618	Hrn Lk-Lkfld 161kV Ckt 1 Rbld	Rebuild Heron Lake-Lakefield 161kV line, sum rate 446 MVA	12/31/2009	$9,250,000	Y
West	ITCM	IA	BaseRel	Shared	1522	6th Street-Beverly	New line to serve new industrial customer load.	6/1/2009	$7,200,000	Y
West	ITCM	IA	BaseRel	Not Shared	1744	Maquoketa-Grand Mound 161kV Reconductor	Reconductor 161kV from Maquoketa to Grand Mound (old East Calamus-Maquoketa 161kV line)	12/31/2010	$4,400,000	Y
West	ITCM	IA	BaseRel	Not Shared	1641	OGS 50 MVAR Cap Bank	Install a 161kV 50 MVAR cap bank at the Ottumwa Generating Station.	12/31/2009	$800,000	Y
West	ITCM	IA	BaseRel	Not Shared	1644	Grand Junction 24 MVAR Cap Bank	Install a 161kV 24 MVAR cap bank at the Grand Junction substation.	12/31/2009	$650,000	Y
West	ITCM	IA	BaseRel	Not Shared	1643	Anita 24 MVAR Cap Bank	Install a 161kV 24 MVAR cap bank at the Anita substation.	12/31/2009	$650,000	Y
West	ITCM	IA	BaseRel	Not Shared	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	6/1/2009	$250,000	Y
West	ITCM	IA	BaseRel	Not Shared	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	6/1/2009	$100,000	Y
West	ITCM	IA	GIP	Shared	1749	G172 Mitchell County Substation	Build a new Mitchell Co 345kV 3 terminal sub. Network upgrades for tariff service request	10/31/2008	$6,874,024	Y
West	ITCM	MN	GIP	Shared	2108	G358	Network upgrades for tariff service request	12/31/2009	$2,119,692	Y
West	ITCM	IA	Other	Not Shared	1340	Hazleton-Lore-Salem 345 kV line with a Lore 345/161 kV 335 MVA transformer	Build a new Hazleton-Lore-Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2)	12/31/2011	$140,362,500	Y

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
West	ITCM	IA	Other	Not Shared	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.	12/31/2013	$25,630,000	Y
West	ITCM	IA	Other	Not Shared	1739	Arnold-Vinton-Dysart-Washburn 161kV Reconductor	Reconductor the 161kV from Arnold-Vinton-Dysart-Washburn, sum rate 446 MVA	12/31/2009	$19,614,000	Y
West	ITCM	IA	Other	Not Shared	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.	12/31/2008	$1,906,000	NT
West	ITCM	IA	Other	Not Shared	1751	Jefferson Co 161/69kV	Replace the failed Jefferson Co 161/69kV transformer with a new 100 MVA unit	12/31/2008	$1,600,000	Y
West	ITCM	IA	Other	Not Shared	1756	Dyersville-Peoasta 69kV Rebuild	Rebuild the 69kV line from Dyersville-Farley-Epworth-Peosta.	12/31/2008	$1,550,000	NT
West	ITCM	IA	Other	Not Shared	1750	Goose Pond 161kV Switching Station	Build a new Goose Pond 3 terminal 161kV switching station along the Palmyra-Twin Rivers 161kV line.	12/31/2008	$1,400,000	Y
West	ITCM	IA	Other	Not Shared	1760	New Wilder Jct-Windom 69kV	Build a new Wilder jct-Windom 69kV line. The new Heron Lake-Wilder-Windom 69kV line & Windom-Wilder-Lakefield 69kV will be tied N.O. at Wilder Jct.	12/31/2008	$1,400,000	NT
West	ITCM	IA	Other	Not Shared	1761	Readlyn-Tripoli 69kV Rebuild	Rebuild a 2.4 mile section of the 69kV line from Readlyn-Tripoli.	12/31/2008	$816,000	NT
West	ITCM	IA	Other	Not Shared	1754	Emery-Lime Creek 161kV Road move	Rebuild a portion of the Emery-Lime Creek 161kV line (about 1 mile)	12/31/2010	$365,000	Y
West	ITCM	IA	Other	Not Shared	1762	Dyersville Ethanol 69kV tap	Build a new 1.75 mile 69kV tap from the Liberty-Pfeiler REC 69kV to a new ethanol plant	12/31/2008	$327,000	NT
West	ITCM	IA	Other	Not Shared	1972	Decorah Mill St-Cresco dbl ckt Rebuild	Rebuild 0.65 miles of 69kV line on the Mill St-Cresco 69kV dble ckt line	12/31/2008	$203,000	NT
West	ITCM	IA	Other	Not Shared	1770	Postville-W Union 0.65 mi Rebuild	Rebuild 0.65 miles of the Postville-Wunion 69kV line	12/31/2008	$167,000	NT

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
West	ITCM	IA	Other	Not Shared	1769	Belle Plaine-Hwy 30 1.4 mi Rebuild	Rebuild 1.4 miles	12/31/2008	$110,000	Y
West	ITCM	IA	Other	Not Shared	1759	Pelican sub 69kV line taps	69kV line work require t accommodate the new CBPC 69kV Pelican switching station near Spirit Lake.	12/31/2008	$80,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1755	Washington-Hills 69kV Rebuild	Rebuild the 69kV line from Washington-Kalona T-N Crane T-Hills (MEC).	12/31/2008	$4,350,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1337	Rose Hollow Substation	New 161/69 kV substation will tap the Hills-Bertram 161kV Line	12/31/2009	$4,160,000	Y
West	ITCM	IA	Other (Reliability)	Not Shared	1747	Elk 161/69kV upgrades	Upgrade both Elk 161/69kV transformers and add a 161kV BKR between the new units.	6/1/2010	$4,000,000	Y
West	ITCM	IA	Other (Reliability)	Not Shared	1776	Thompson-Dexter 69kV	Build a new 6 mile 69kV line fromThompson-Menlo Rec & Rebuild the 7.5 miles from Menlo REC-Dexter 69kV line.	12/31/2009	$2,700,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	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.	12/31/2009	$2,407,708	Y
West	ITCM	IA	Other (Reliability)	Not Shared	1757	Cambridge REC-Maxwell 69kV Rebuild	Rebuild 6.35 miles of 69kV line from Cambridge REC to the Maxwell North Sub.	12/31/2008	$2,100,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1341	Replace two Hazleton 161/69 kV transformers	Replace two Hazleton 161/69 kV transformers with 74.7 MVA	6/1/2009	$1,800,000	Y
West	ITCM	IA	Other (Reliability)	Not Shared	1772	North Centerville 7 MVAR Cap bank	Install a new 69kV North Centerville 7 MVAR Cap bank & 69kV Bkr	12/31/2009	$1,400,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1773	Excel 13.2 MVAR Cap bank	Install a new 69kV Excel 13.2 MVAR Cap bank	12/31/2008	$1,400,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1752	Jefferson Co 69kV Cap banks	Install 2-15.6 MVAR Jefferson Co 69kV Cap banks	12/31/2008	$1,400,000	NT

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	ITCM	IA	Other (Reliability)	Not Shared	1753	Winnebago Jct south 161/69kV	Replace the Winnebago Jct 161/69kV 30 MVA transformer with a new 75 MVA unit	12/31/2008	$1,400,000	Y
West	ITCM	IA	Other (Reliability)	Not Shared	1636	Waterbury breaker station	Waterbury breaker station	12/31/2009	$1,000,000	NT
West	ITCM	IA	Other (Reliability)	Not Shared	1645	Leon 7.2 MVAR Cap Bank	Install a 69kV 7.2 MVAR cap bank at the Leon substation.	12/31/2009	$150,000	NT
West	ITCM	IA	TDSP	Direct Assigned	1748	Emery-Lime Crk 161kV, Ckt 1	Emery-Lime Creek 161 ckt 1, Sum rate 326 MVA	12/31/2010	$4,000,000	Y
West	MDU	ND	Other	Not Shared	1479	Cabin Creek: Switchyard & 115/69 kV transformer	Cabin Creek: Switchyard & 115/69 kV transformer	11/1/2007	$3,200,000	Y
West	MP	MN	Other	Not Shared	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	4/1/2009	$3,500,000	Y
West	MP	MN	Other	Not Shared	1481	Platte River 115/34.5-Transformer 115/34.5 kV 39 MVA	Platte River 115/34.5-Transformer 115/34.5 kV 39 MVA	12/1/2007	$1,900,000	Y
West	NWE	WI	Other	Not Shared	2018	Balsam Lake-Centuria 69 kV line	Build new 69 kV line to Centuria and build Distribution Sub	6/12/2008	$750,000	Y
West	NWE	WI	Other	Not Shared	2012	Falun-Penta 34.5 kV Rebuild	Rebuild the 34.5kV system between Falun and Penta sub at 69 kV with 477ASCR and horizontal post construction.	6/10/2008	$538,000	Y
West	NWE	WI	Other	Not Shared	2015	Balsam Lake Substation	Build new Balsam Lake transmission substation	6/11/2008	$500,000	Y
West	NWE	WI	Other	Not Shared	2014	Garfield-Balsam Lake 69 kV Rebuild	Rebuild the 69 kV line with 477 ASCR and horizontal post construction.	6/11/2008	$500,000	Y
West	NWE	WI	Other	Not Shared	2011	Frederic-Lewis 34.5 kV Rebuild	Rebuild the 34.5kV system between Frederic and Lewis sub at 69 kV with 477ASCR and horizontal post construction.	12/9/2008	$350,000	Y
West	NWE	WI	Other	Not Shared	2010	Eureka Tap-Balsam Lake 34.5 kV Rebuild	Rebuild the 34.5 kV system between Eureka Tap and Balsam Lake at 69 kV by replacing poles and using same conductor.	6/9/2008	$265,000	Y
West	NWE	WI	Other	Not Shared	2017	Milltown Tap-Balsam Lake 69 kV Reconductor	Reconductor 69 kV line with 477ACSR	6/12/2008	$250,000	Y
West	NWE	WI	Other	Not Shared	2013	Penta-Siren Tap 34.5 kV Rebuild	Rebuild the 34.5kV system between Penta sub and Siren Tap at 69 kV with 477ASCR and horizontal post construction.	6/10/2008	$175,000	Y

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Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	NWE	WI	Other	Not Shared	2008	Milltown-Luck NSP 34.5 kV Rebuild	Rebuild the 34.5kV system between Milltown and Luck NSP sub at 69 kV with 477ASCR and horizontal post construction.	6/8/2008	$165,000	Y
West	NWE	WI	Other	Not Shared	2009	Milltown Tap-Eureka Tap 34.5 kV Rebuild	Rebuild the 34.5 kV system between Milltown Tap and Eureka Tap at 69 kV by replacing poles and using same conductor.	6/9/2008	$125,000	Y
West	NWE	WI	Other	Not Shared	2016	Frederic-Coffee Cup 69 kV reconductor	Reconductor 69 kV line with 477ACSR	6/12/2008	$100,000	Y
West	OTP	ND	Other	Not Shared	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 end of 2009.	10/1/2009	$6,665,000	Y
West	OTP	MN	Other	Not Shared	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.	7/1/2009	$900,000	Y
West	OTP	MN	Other	Not Shared	2090	Cass Lake 115 kV capacitor	Cass Lake 115 kV capacitor 20 Mvar	11/1/2008	$630,000	Y
West	OTP/MPC	MN	BaseRel	Not Shared	971	Winger 230/115 kV Transformer Upgrade	Winger 230/115 kV Transformer upgrade	12/31/2010	$3,715,351	Y
West	OTP/MPC	MN	Other	Not Shared	2091	Cass Lake 115/69/41.6 kV sub	Cass Lake 115/69/41 kV substation	7/1/2009	$2,000,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	SMP	MN	Other	Not Shared	1633	Fairmont Area Upgrade	SMMPA is adding a 84MVA 161/69kV transformer and 31.5MVAR cap bank to the existing Rutland Substation and upgrading 4Miles of existing 69kV line to 10th St (Fairmont) to 4/0. GRE is building 6 Miles 69kV line from Rutland to Buffalo Lake sub. Expected inservice date mid-2008.	6/30/2008	$6,245,340	Y
West	SMP	MN	Other	Not Shared	1367	Lake City load serving upgrades	Lake City 69 kV capacitor, Lake City-Zumbro Falls 69 kV line (new), Zumbrota-Lena tap 69 kV line (new).	10/30/2008		NT
West	XEL	MN	BaseRel	Shared	1285	Build 18 miles 115 kV line from Glencoe-West Waconia	Build 18 miles 115 kV line from Glencoe-West Waconia	6/1/2011	$18,800,000	Y
West	XEL	MN	BaseRel	Shared	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.	12/1/2010	$5,264,000	Y
West	XEL	WI	BaseRel	Not Shared	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.	6/1/2009	$2,300,000	Y
West	XEL	SD	BaseRel	Not Shared	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.	12/1/2010	$1,189,200	Y
West	XEL	MN	BaseRel	Not Shared	1546	Dean Lake-Hyland Lake Upgrade	Upgrade 115 kV line from Dean Lake-Hyland Lake 115 kV line	10/1/2008	$1,057,000	Y
West	XEL	MN	GIP	Shared	2119	G417	Network upgrades for tariff service request	7/28/2008	$259,000	NT
West	XEL	WI	GIP	Shared	2109	G609	Network upgrades for tariff service request	7/31/2007	$34,200	Y

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Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	XEL	MN	Other	Not Shared	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.	6/1/2011	$14,000,000	Y
West	XEL	MN	Other	Not Shared	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.	12/1/2010	$3,765,200	Y
West	XEL	MN	Other	Not Shared	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.	12/1/2010	$720,000	NT
West	XEL	MN	Other	Not Shared	1961	Lake Emily Capacitor bank	This project is to add 10 MVAR cap bank at Lake Emiky	12/1/2010	$507,200	Y
West	XEL	WI	Other	Not Shared	1547	Ironwood bus upgrade	Replace the Ironwood 115 kV equipment with ratings below 450 Amps with 850 Amp equipment (or next standard size). This should inclue the following: 200 Amp CT, 300 Amp wave trap, 380 Amp Bus, 400 Amp Breaker CT	6/1/2008	$450,000	Y
West	XEL	WI	Other	Not Shared	1369	Osceola-Sand Lake 69 Reconductor	Osceola-Sand Lake 1 69 Reconductor	5/1/2009	$400,000	NT
West	XEL	WI	Other	Not Shared	552	Ironwood 92/34.5 kV transformer #2	Ironwood 92/34.5 kV transformer #2	6/1/2009	$300,000	NT
West	XEL	MN	Other	Not Shared	751	Nobles Co 34.5 kV-50 MVAR Reactor #1	Nobles Co 34.5 kV-50 MVAR Reactor #1	12/1/2007	$200,000	NT
West	XEL	WI	Other (Reliability)	Not Shared	1549	Eau Claire-Hydro Lane 161 kV Conversion	Cut Wheaton-Presto Tap 161 kV line and route line into Eau Claire substation. Reconductor Wheaton to Eau Claire 161 kV line to 795 ACSS conductor. Construct second circuit from Wheaton Tap to Wheaton Substation. Construct 50th Avenue Substation	6/1/2011	$20,602,000	Y

Table 5-4 New Appendix A Projects in MTEP08										
Region	**Reporting Source**	**ST**	**Allocation FF**	**Share Status**	**PrjID**	**Project Name**	**Project Description**	**Expected ISD**	**Estimated Cost**	**MISO Facility**
West	XEL	WI	Other (Reliability)	Not Shared	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	12/1/2012	$19,270,980	Y
West	XEL	WI	Other (Reliability)	Not Shared	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	5/1/2009	$10,000,000	Y
West	XEL	WI	Other (Reliability)	Not Shared	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	12/1/2010	$9,247,500	NT
West	XEL	WI	Other (Reliability)	Not Shared	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	12/1/2012	$7,080,000	Y
West	XEL	WI	Other (Reliability)	Not Shared	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	5/1/2009	$7,000,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	XEL	MN	Other (Reliability)	Not Shared	1486	Mary Lake-City of Buffalo 69 kV line 116 MVA	Mary Lake-City of Buffalo 69 kV line 116 MVA	6/1/2009	$2,190,000	NT
West	XEL	MN	TDSP	Direct Assigned	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	6/1/2010	$10,000,000	Y
West	XEL	MN	TDSP	Direct Assigned	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.	12/1/2009	$1,904,600	Y
West	XEL	MN	TDSP	Direct Assigned	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	6/1/2010	$1,500,000	Y
West	XEL	MN	TDSP	Direct Assigned	1371	Black Dog-Wilson 115 kV #2 Reconductor	Black Dog-Wilson 115 kV #2 Reconductor	6/1/2009	$900,000	Y
West	XEL	MN	TDSP	Direct Assigned	2105	A147/F043	Network upgrades for tariff service request	6/1/2009	$360,000	Y
West	XEL		TDSP	Direct Assigned	2100	A232 (depending on G405)	Network upgrades for tariff service request	6/1/2008		NT
West	XEL, DPC, RPU, SMP, WPPI	MN	BaseRel	Shared	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	12/15/2015	$360,000,000	Y
West	XEL, GRE	MN	Other (Reliability)	Not Shared	1380	Scott County-West Waconia 115	Scott County-West Waconia 1 115	5/1/2010	$13,600,000	Y

Table 5-4 New Appendix A Projects in MTEP08

Region	Reporting Source	ST	Allocation FF	Share Status	PrjID	Project Name	Project Description	Expected ISD	Estimated Cost	MISO Facility
West	XEL, GRE	MN	Other (Reliability)	Not Shared	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.	12/1/2009	$12,915,000	Y
West	XEL, GRE	MN	Other (Reliability)	Not Shared	1955	Bangor switching station	This project is to build a new three breaker switching station at the existing Bangor tap.	12/1/2009	$900,000	NT

Section 6: Reliability Planning Methodology

The Midwest ISO performs many types of reliability analyses in our MTEP studies. The reliability assessment tests the existing plan using appropriate NERC Table 1 events, determines if the system as planned meets Transmission Planning (TPL) standards, develops and tests additional transmission system upgrades to address the 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 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 representative of Category A and Category C requirements also, though TPL-001 and TPL-003 requirements are not be numbered identically. Additional elements of the study process are also described.

R1) The R1 requirement calls for the Planning Authority and Transmission Planner to 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 Transmission Service, over a range of forecast system demands, under the contingency conditions as defined in NERC TPL Table 1. This is the high level requirement which also requires that the sub requirements be met.

The Midwest ISO meets this requirement with analysis performed in MTEP studies. 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 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 is described in the following requirements.

R1.1) The requirement that assessment is made annually. The MTEP study assessments have been performed annually starting with MTEP07. Seasonal transmission assessments have been performed annually since 2003.

R1.2) The requirement that assessment is performed for near-term (years 1-5) and long-term (years 6-10) planning horizons. The MTEP reliability analyses provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System in near-term (years 1-5) and long-term (years 6-10) planning horizon. Recent analysis performed in MTEP07 studied 2013 summer peak, 2013 shoulder load and 2018 summer peak conditions.

R1.3) The requirement that the assessment of system reliability is supported by current analysis and/or past analysis of the NERC Table 1 events. During the past several MTEPs the following model years have been studied: 2009, 2011, 2013, and 2018. Category A, Category B, Category C and Category D events per Table 1 were analyzed. Section 6.4 below provides additional details on contingencies analyzed. Thermal and voltage issues were flagged using Transmission Owner's design criteria limits per Section 6.2. Seasonal transmission assessments have examined summer peak conditions for 2003, through 2008. Winter seasonal assessments have been performed since 2005.

R1.3.1) The sub-requirement that the more severe System contingencies in NERC Table 1 are analyzed. To meet this requirement the MTEP analyzed the Category A event and all Category B events. Category C events which are expected to produce the most severe results were analyzed. These events were developed in collaboration with Transmission Owners. A number of Category D events were analyzed. See Section 6.4 for more details on contingencies analyzed.

R1.3.2) The sub-requirement that critical system conditions are covered. MTEP analyzes the summer peak condition under contractual dispatch, which is one of the critical system conditions for reliability analysis. Another critical system condition for dynamic/transient stability issues is the shoulder load (70% of peak) condition. It is important due to system stress from higher levels of system transfers.

Recent analysis studied 2013 Summer peak condition and the 2013 shoulder (70%) load conditions were analyzed with dynamic simulations and 2018 summer peak conditions. Other stressed system conditions have been evaluated, including variations in dispatch based on probabilistic generation outages, as well as planned outage conditions have been evaluated in certain parts of the system based on indications from analysis or real-time operations that these conditions may result in marginal system performance against reliability standards.

R1.3.3) The sub-requirement that studies and simulation testing are performed annually, *unless* system conditions do not warrant such analyses. Contingency analysis is performed annually. A complete contingency analysis was performed in 2007 for MTEP07, incremental analysis was performed in 2008 for MTEP08, and a complete contingency analysis is expected to be performed in the second half of 2008 as part of the MTEP09 study cycle.

R1.3.4) The sub-requirement that analysis beyond the five year horizon is done only as needed to address margin conditions that may have longer lead-time solutions. The recent MTEP07 analysis focuses on system performance in near-term planning horizon (1-5 years) during summer peak operating conditions. For marginal issues identified in the 2013 near-term case, additional analysis was performed in 2018 long-term horizon. During project reviews for MTEP08, analysis at multiple demand levels was performed as required.

R1.3.5) The sub-requirement that the models used 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 6.3 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. The models used in MTEP analysis examined summer peak hour load and shoulder load (70% peak) conditions. See Section 6.3 for additional details. During project reviews for MTEP08 analysis at multiple demand levels was performed as required. A sensitivity to load forecast is performed for selected areas in seasonal transmission assessments.

R1.3.7) The sub-requirement that demonstrates system performance meets NERC TPL Table (Category A, B, C and D) contingencies. MTEP07 analyzed Category A, Category B, and Category C events and determined that there were some thermal and voltage issues to be addressed. Mitigation plans were developed and tested to address the identified issues. Section 5 of this report describes projects moving to Appendix A (moving from proposed to planned) in MTEP08. It shows that the new Appendix A projects are effective in addressing identified system performance issues in Table1 for projects required for Table 1 events. Many projects in Section 5 are driven by NERC TPL standards, though a majority of Section 5 projects are not on Bulk Electric System (BES) or do not address needs on BES. Proposed projects in Appendix B have also been demonstrated as effective in addressing identified system issues. The critical analyses were repeated to confirm the Planned and Proposed projects in the Baseline reliability transmission expansion plan provide adequate system reliability. MTEP07 Appendix D1 contains 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 for Category C events. MTEP08 Appendix D1 also demonstrates mitigation plan effectiveness.

R1.3.8) The sub-requirement that models include existing and planned facilities. The models used in MTEP analysis contain existing and planning transmission facilities. The topological starting point of MTEP analysis is projects with documented system needs in Appendix A and Appendix B. MTEP model future facilities (planned and proposed) are documented.

R1.3.9) The sub-requirement that powerflow models used in the analysis contain existing and planned reactive resources. 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) The sub-requirement that analyses includes effects of existing and planned protection systems. The MTEP models, contingency files and disturbance files used in this analysis include effects of existing and planning protection systems.

R1.3.11) The sub-requirement that analyses include effects of existing and planning 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) The sub-requirement that planned outages of Bulk Electrical System (BES) equipment at appropriate demand levels for the planned outages are included. Seasonal transmission assessments examine impacts of planned outages in upcoming season. The powerflow models used in MTEP analysis assume system intact condition as the base case. This assumption is reasonable because the primary condition analyzed is summer peak load in the 5 to 10 year planning horizon and planned outages are rare during these conditions and at this point in the planning horizon.

R1.4) The requirement that the assessment address planned upgrades needed to meet performance requirements of Table 1. The MTEP analyses include planned upgrades in powerflow cases or perform incremental analysis to demonstrate that the upgrades are effective in meeting the performance requirements. After completion of the MTEP planning cycle a powerflow model is prepared which includes all Appendix A and B projects. This model is then used for contingency analysis for next planning cycle.

R1.5) The requirement that the assessment considers Category A, Category B, Category C and Category D events per Table 1. The MTEP07 study analyzed these events. See Section 6.4 for additional details on contingencies analyzed. Thermal and voltages issues were flagged using Transmission Owner’s design criteria limits.

R2) The requirement that when system simulations identify the inability of the system to meet the performance requirements of Table 1 that a mitigation plan is developed per the sub-requirements. 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) The requirement that a written summary of plans is required to achieve system performance in the planning horizon. The MTEP summarizes the mitigation plans required to maintain adequate system performance in Appendix A and B of this study. Projects in Appendix C may address identified issues, but Midwest ISO staff has yet to document their effectiveness.

R2.1.1) The sub-requirement for an implementation schedule. MTEP Appendix A and B has for each project facility an expected in service date which forms a schedule for implementation.

R2.1.2) The sub-requirement of expected in service dates. MTEP Appendix A, B, and C have expected in-service dates for each project facility.

R2.1.3) The sub-requirement of considering lead times for implementation. 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.

R2.2) The requirement to review continuing need for projects identified. In the MTEP process, projects moving from Appendix B to Appendix A are reviewed by Midwest ISO staff. Therefore, it is possible that other system improvements or system changes have deferred or removed the need for the previously identified project since the prior planning cycle. 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 requirement to provide plans to the respective Regional Reliability Organizations. The final step of an annual planning cycle is to provide the MTEP report to the respective Regional Reliability Organizations per their requirements.

Added Planning Process Steps in 2008 to Address Order 890

FERC Order 890 described nine planning principals. The past Midwest ISO Transmission Planning Process meets those principals. A key element of the principals is involving transmission customers early in the planning process. At the beginning of the MTEP08 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 involve stakeholders early in planning process. Newly proposed transmission projects were discussed at the SPM held in January and February.

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; and
- the current transmission expansion plans from the planning process.

Planning criteria, models, contingencies, and mitigation plan development are discussed in the following sections.

6.2 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 our member's criteria (local flagging criteria) were applied to accurately reflect the different system design standards of our members in this assessment.

All system elements 100kV 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.

6.3 Baseline Models

The plan year for the MTEP07/08 baseline reliability analysis is 2013. The 2013 summer peak condition was analyzed. The Midwest ISO baseline reliability study models for 2013 summer peak and 2018 summer peak were developed by incremental updates to the models used in last MTEP. External region updates were applied along key seams. This section describes model assumptions used in MTEP analysis.

Model Assumptions

Transactions

The 2013 summer peak model (year 5) uses a contractual dispatch. The contractual dispatch will have all Firm drive-within, drive-in, drive-out, drive-through, and other external transactions modeled. (i.e. reflects original Firm transactions modeled in the NERC base case (starting case) and subsequent changes to the transactions list through the MTEP model review process). Virtual transactions and fake generators were removed and replaced with proxy generators from MTEP08 Reference future. The decision to replace virtual transaction with proxy generators results in a baseline reliability model which has reduced system transfers caused by the virtual transactions. Removal of virtual transaction reduces the occurrence of reliability issues being identified on neighboring system as a result of the virtual transaction. However, the proxy generators may cause or mask issues on the system which is deficient in generation during the plan year. Impacts of proxy generators are reviewed and documented.

2018 summer peak and 2013 summer off-peak (70% load) have security constrained economic dispatch within Midwest ISO, therefore, these cases will 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.

Losses

The powerflow models used determine control area losses and adequate generation is dispatched to cover transmission system losses and specified Firm transactions.

Load

Three different system load conditions were analyzed in MTEP07: 2013 summer peak demand with a 50/50 load forecast by control area; 2018 summer peak demand, and 2013 summer off-peak, 70% load (also called summer shoulder). Load forecasts in the models include existing demand side management and conservation programs. MTEP08 incremental reliability analysis for projects moving to Appendix A used these models as required.

Generation

A key assumption in transmission planning studies is the generation dispatch. MTEP07 study analyzed two dispatches: Contractual Blended Dispatch (contractual dispatch) for 2013 summer peak and Security Constrained Economic Dispatch (SCED) for 2018 summer peak and 2013 summer off-peak. The Contractual Dispatch is similar to traditional control area dispatch in that Load Serving Entities' designated resources are dispatched to meet their loads. The word *Blended* in Contractual Blended Dispatch implies that a couple of areas are short generation during this period, therefore, generators from MTEP08 Reference Generation Portfolio (Future) were included in those control areas to provide adequate level of generation resources. Analysis of Contractual Dispatch case drives reliability issues and supports development of the transmission system to support Financial Transmission Rights in the market. Future generators with signed Interconnection Agreements were modeled. Proxy generators were modeled in several control areas.

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 2013 or 2018 were not modeled in the respective models.

Two different 2013 summer peak models were used in preparation of MTEP08. These models are in addition to MTEP07 models used to perform contingency analysis in 2007 for MTEP07. The MTEP07 BRP 2013 Summer Peak Final model (8/23/07) was used as starting point to document need and effectiveness of projects moving to Appendix A in MTEP08. It contained the final plan from MTEP07, so it was logical starting point for this activity.

The MTEP08 2013 summer peak model (MTEP08_2013SP_AppAB_LODF_0818_v30.sav) was developed using Model On Demand application at the end of the MTEP08 cycle. Midwest ISO member transmission project data was exported from Model On Demand on June 4, 2008. After stakeholder review and updates, the model contained all projects moving to Appendix A and Appendix B required for performing cost allocation. Only projects which change network topology or impedances of branches were necessary for cost allocation. This model contains many new projects which are moving to Appendix A in MTEP08. See Appendix D4 for modeled future facility documentation of the models.

6.4 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 our members' transmission system at 100kV and above were analyzed in MTEP07, although some 69kV transmission was also analyzed.

- All NERC Category B (single line, single transformer, or single generator outage) contingency events were analyzed in AC contingency analysis.
- Approximately 4,800 explicitly defined NERC Category C (double circuit tower, breaker fault/failure, bus fault and double element outages including double generator outages) contingency events were analyzed.
- Approximately 58,000 automated double contingencies were analyzed in AC contingency analysis. In general, automated double branch contingencies for branches greater than 200kV were run by control area and included ties lines to neighboring control areas. Select automated doubles on the 100kV to 199kV system were also analyzed. The automated double contingencies are more severe than NERC Category C3 events and also capture many C1, C2, and C5 events.
- There were approximately 4,500 Category D events analyzed. There were 292 NERC Category A, B, C and D events studied with dynamic stability simulations. In total, approximately 79,000 contingency were analyzed with contingency 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 as we move forward based on our own 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.

Project specific contingencies were analyzed in MTEP08 as part of the project review and justification process for new Appendix A projects. This contingency analysis demonstrated the need and effectiveness of projects recommended to move to Appendix A in MTEP08 planning cycle. See Appendices D1 Central, East, and West for results of these analysis.

6.5 Load Deliverability Analysis

The traditional Midwest ISO Loss of Load Expectation (LOLE) Study that evaluates Load Deliverability was not performed for this year's MTEP study. For 2008, the Midwest ISO participated in the LOLE Study performed for the Midwest Planning Reserve Sharing Group (MPRSG). Also new this year is major revisions to Module E of the Midwest ISO Energy Markets Tariff (EMT) that more extensively defined Resource Adequacy Requirements (RAR). In the process the Midwest ISO laid the ground work for future LOLE Studies to be conducted in compliance with the tariff filing.

Midwest Planning Reserve Sharing Group – LOLE Study

As the administrator the Midwest ISO conducted the LOLE Study for the MPRSG The MPRSG LOLE study didn't explicitly evaluate load deliverability, but this analysis as an alternative utilized LOLE and the 1 day in 10 years reliability criteria to establish planning reserve margins for the period of June 2008 through May 2009, and evaluated reserves for the three MTEP planning areas: West, Central and East. The MPRSG study also evaluated the nine consecutive planning periods of June 2009 through May 2018. The study results indicate need for Planning Reserve Margins between 13% and 14%, and accounted for the relatively small amount of resources that are limited to serving local load, and are not deliverable in aggregate to all loads in the Midwest ISO market.

The MPRSG LOLE Study Report is posted at the following link:

http://www.midwestmarket.org/publish/Document/77a68f_119522dab5e_-7ec50a48324a

Module E – 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 RAR; these revisions were conditionally accepted by FERC on March 26, 2008. This filing laid the ground work for establishing a process by which LOLE study zones may be determined. Zones of interest will be based on identifying congestion in the transmission system and will be utilized in the calculation of planning reserve margins as well as in the evaluation of load deliverability.

The new process of defining zones will enhance the load deliverability study by identifying potential areas where load deliverability could be at higher risk due to constraints and also identify where generation may have limits to being deliverable outside of specific zones. The zones and the associated congestion are needed transmission system inputs to 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.

6.6 Mitigation Plan Development

The Midwest ISO staff works collaboratively with Transmission Owners and stakeholders to review and develop mitigation plans. New for MTEP08 is the use of Subregional Planning Meetings to review projects early in the planning process to meet many of NERC's nine planning principles. Proposed plans were then reviewed again at Subregional Planning Meetings (SPM) in June after Midwest ISO staff had reviewed the project proposals submitted earlier at the beginning of the planning cycle. Feedback from stakeholders is incorporated into the project review process.

The Midwest ISO transmission system is divided into three Planning regions to facilitate the MTEP study and Subregional Planning Meetings: West, Central, and East planning regions. 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 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 mitigation plan is presentation of the final plan to the Midwest ISO Board of Directors for their review and approval.

Section 7: MTEP08 Transmission Investment Summary

The present Midwest ISO Transmission System consists of approximately 53,000 miles of existing transmission lines over 100 kV and some 69 kV. This section provides a statistical overview of the expansion plans identified in the Midwest ISO Transmission Expansion Planning process. Appendix A lists the projects and associated facilities which are recommended to Midwest ISO Board of Directors as Planned. The projects in Appendix A have been analyzed and reviewed by Midwest ISO staff and the system needs driving the project have been documented. This level of independent validation process is required with regional cost sharing of Baseline Reliability Projects (BRP) via Attachment FF to the Energy Market Tariff (EMT). Projects in Appendix A are eligible for cost sharing, if they meet the requirements of the tariff. This section also discusses the projects in Appendix B. Appendix B contains projects which are proposed or have not gone through the validation process by Midwest ISO staff to become recommended. Appendix C contains projects just entering the planning process and also may contain conceptual plans.

Although Midwest ISO has knowledge of planned facilities that are adjacent to the Midwest ISO system, those facilities are not quantified in this section. Such facilities are considered in ongoing model building, coordinating planning studies, and operating responsibilities of the Midwest ISO Reliability Authority (RA).

The Midwest ISO system is divided into three planning regions, shown in Figure 7-1. Some of the information in this section will be summarized by Planning Region.

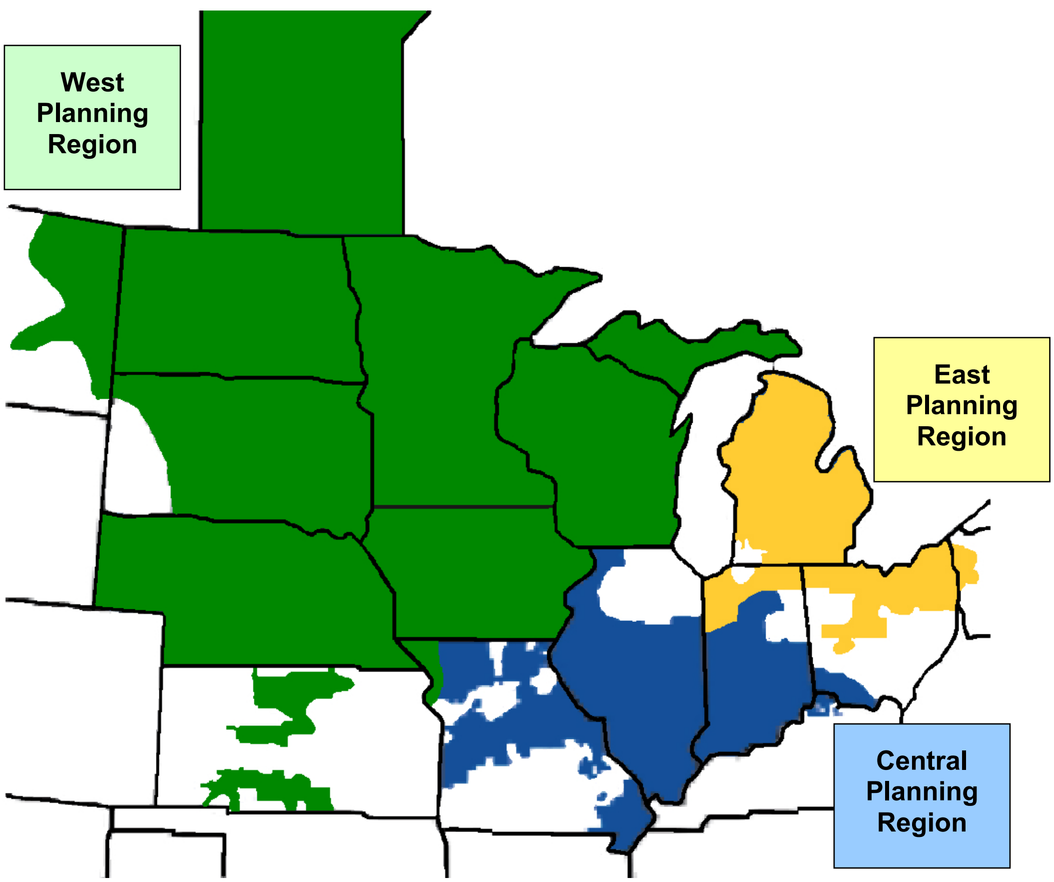

Figure 7-1: MTEP West, Central and East Planning Regions

7.1 Investment Summary

This section provides investment summaries of transmission system upgrades identified in MTEP 08 and past MTEP studies that are still in the planning process. The total estimated cost of the projects in both Appendix A and Appendix B for the period 2008 to 2014 is $5.15 billion. This is significantly larger than the $3.98 billion that was estimated for the period 2007-2013 in MTEP 07. Appendix A contains $4.17 Billion in investment through 2015, Appendix B contains $1.55 Billion of investment through 2018, and Appendix C contains $740 Million in investment through 2015 and $17 Billion in investment through end of 2018. The Reference Future Extra High Voltage (EHV) conceptual transmission overlay is $14 Billion in 2018 in Midwest ISO. See Section 4 for additional details on EHV overlay development.

The cumulative expected project spending over the 2008-2018 period is shown in Figure 7-2. 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.

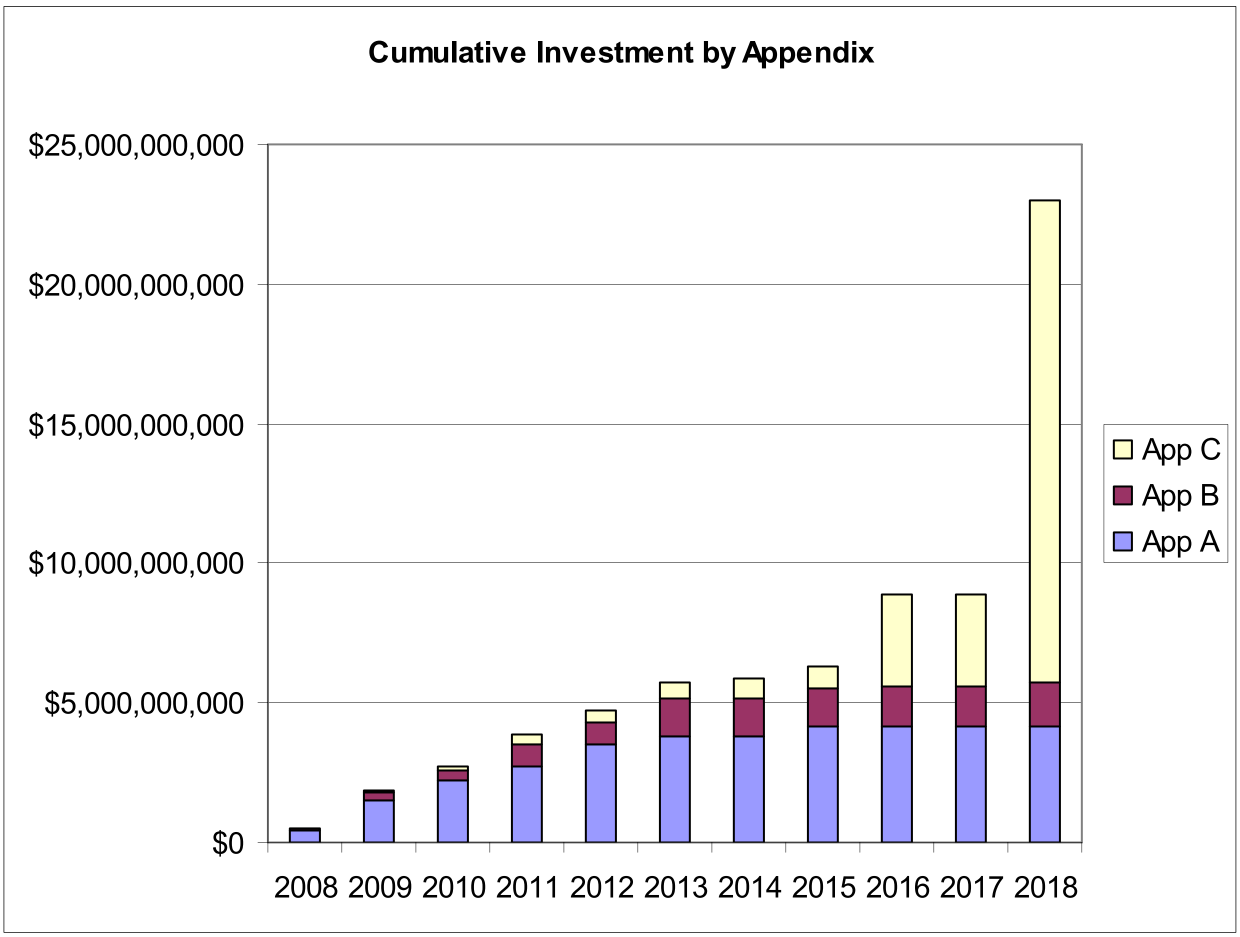

Figure 7-2: Cumulative Projected Investment by Year

See Section 11 for a summary of MTEP transmission investment for projects which have gone into service. The transmission investment by Planning Region through 2018 is shown in Table 7-1.

Table 7-1: Projected Transmission Investment by Planning Region through 2018			
Region	**Appendix A**	**Appendix B**	**Appendix C**
Central	$603,090,763	$253,882,977	$5,045,426,020
East	$826,590,999	$55,265,000	$5,127,455,600
West	$2,738,355,185	$1,246,944,293	$7,062,316,359
Total	$4,168,036,947	$1,556,092,270	$17,235,197,978

Table 7-2 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.[1] The numbers in Table 7-2 are a subset of Appendix A values shown in Table 7-1. These have a Target Appendix of 'A in MTEP08' and are new 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 of costs of the shared projects are eligible for sharing. Some BRP projects costs are not shared. Only 50% of GIP costs are shared to pricing zones.

Table 7-2: New Appendix A Investment by Preliminary Allocation Category by Planning Region					
Region	**Share Status**	**BaseRel**	**GIP**	**Other**	**TDSP**
Central	Excluded			$2,910,215	
	Not Shared	$17,362,306		$193,352,451	
	Shared	$59,319,432	$4,271,957		
Central Total		$76,681,738	$4,271,957	$196,262,666	
East	Not Shared	$10,805,900		$267,205,541	
	Shared	$147,209,634	$12,164,568		
East Total		$158,015,534	$12,164,568	$267,205,541	
West	Direct Assigned				$18,664,600
	Not Shared	$24,645,358		$482,072,565	
	Not Shared (Pre-RECB)		$10,451,788		
	Shared	$1,120,570,311	$13,769,839		
West Total		$1,145,215,669	$24,221,627	$482,072,565	$18,664,600
Grand Total		**$1,379,912,941**	**$40,658,152**	**$945,540,772**	**$18,664,600**

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

Further breakdown of the New Appendix A project data, as shown in Figure 7-3, reveals that new transmission build is largely concentrated in several states namely Minnesota, Wisconsin, Michigan, Iowa and Indiana. These geographic trends can be expected to change over time as existing capacity in other parts of the system are consumed and new build becomes similarly necessary in those areas.

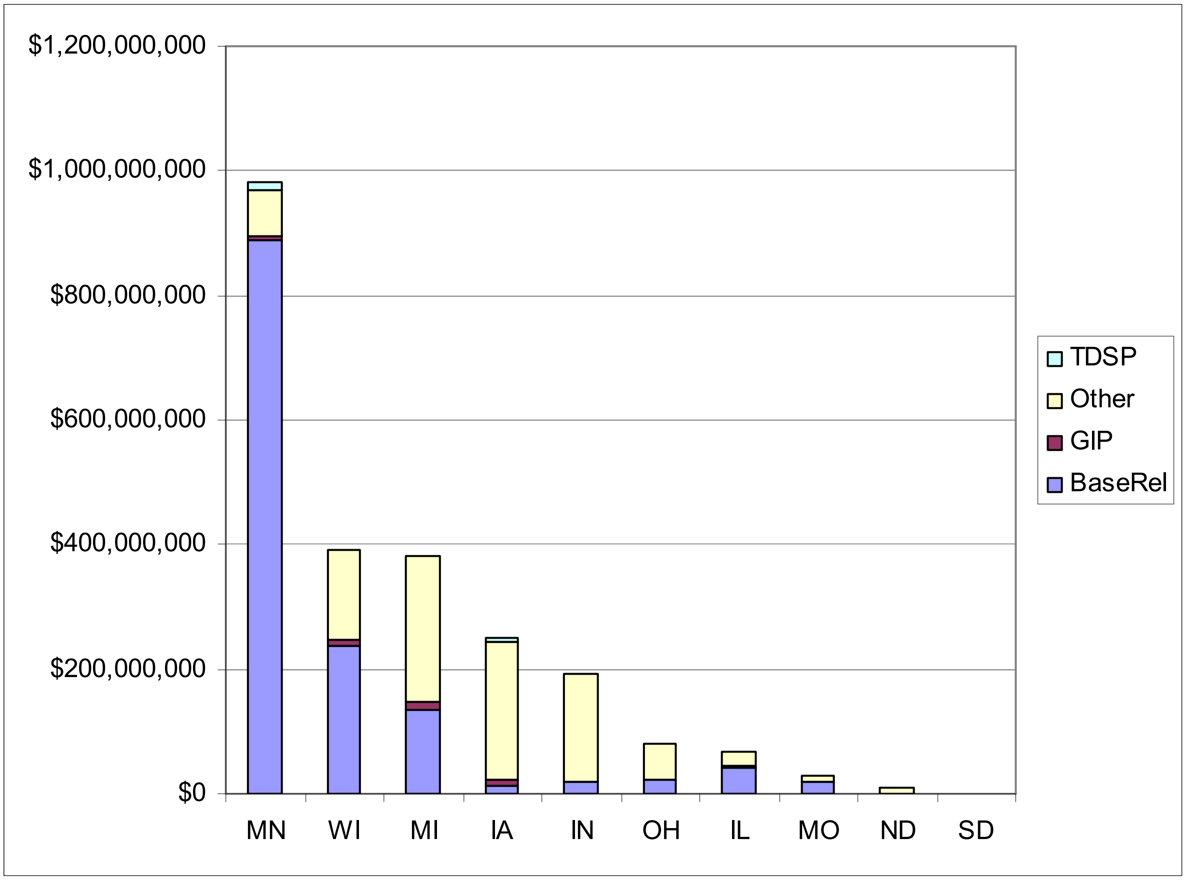

Figure 7-3: New Appendix A Investment by Allocation Category by State

7.2 Cost Sharing Summary

A total of $1.36 billion of costs associated with new MTEP 08 Appendix A projects are eligible for sharing. The total project cost number includes the $30 million from generator interconnection projects, where half is paid by generation developers and the $144 million of total project costs not shared within the Midwest ISO footprint. Additional details on new MTEP 08 cost allocations are in Appendix A-1 and A-2.

Since the RECB cost sharing methodology was implemented in MTEP 06 there have been 80 projects eligible for cost sharing representing $2.33 billion of transmission investment including 29 generator interconnection projects, at approximately $253 million of which 50% is paid by generation developers, and 51 baseline reliability projects at $2.08 billion.

Figure 7-4 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 Regional Expansion Criteria and Benefits (RECB) allocation. Costs are included for all RECB eligible projects from MTEP 2006 to MTEP 2008. 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 $1.77 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 $440 million for all pricing zones. Note that the chart excludes the portion assigned directly to generation developers. Additional details on MTEP 06 through 08 cost allocations are in Appendix A-3.

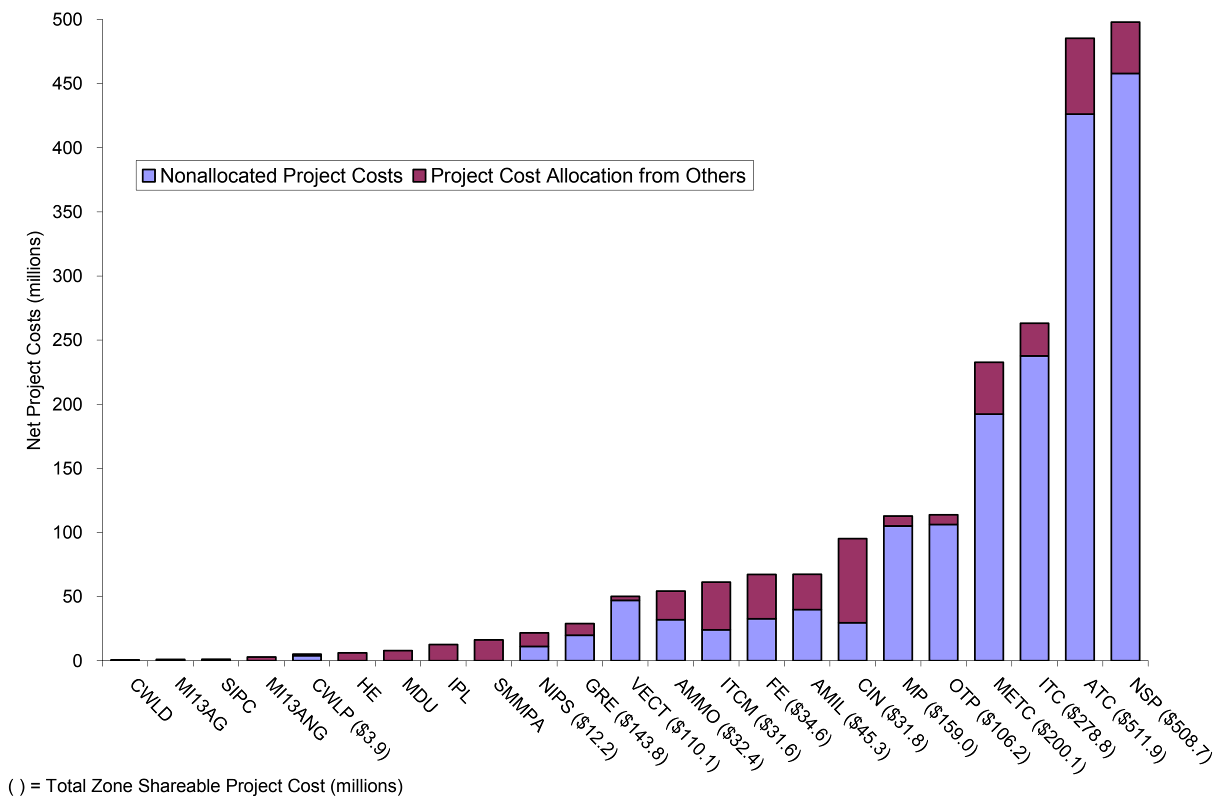

Figure 7-4: Net Project Costs by Pricing Zone from MTEP 06 through 08 Appendix A Projects

Figure 7-5 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.

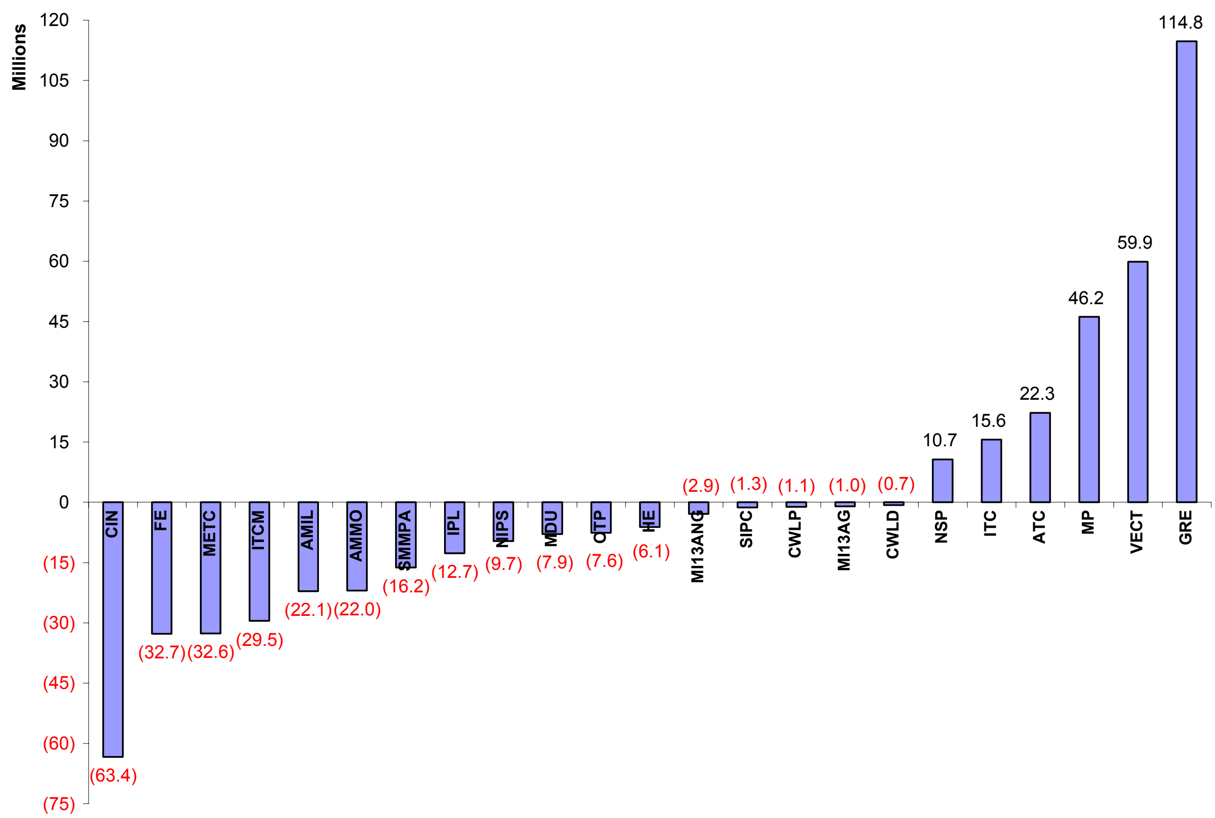

Figure 7-5: Net Impact on Pricing Zones of Cost Sharing for MTEP 06 through 08 Projects

Figure 7-6 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.

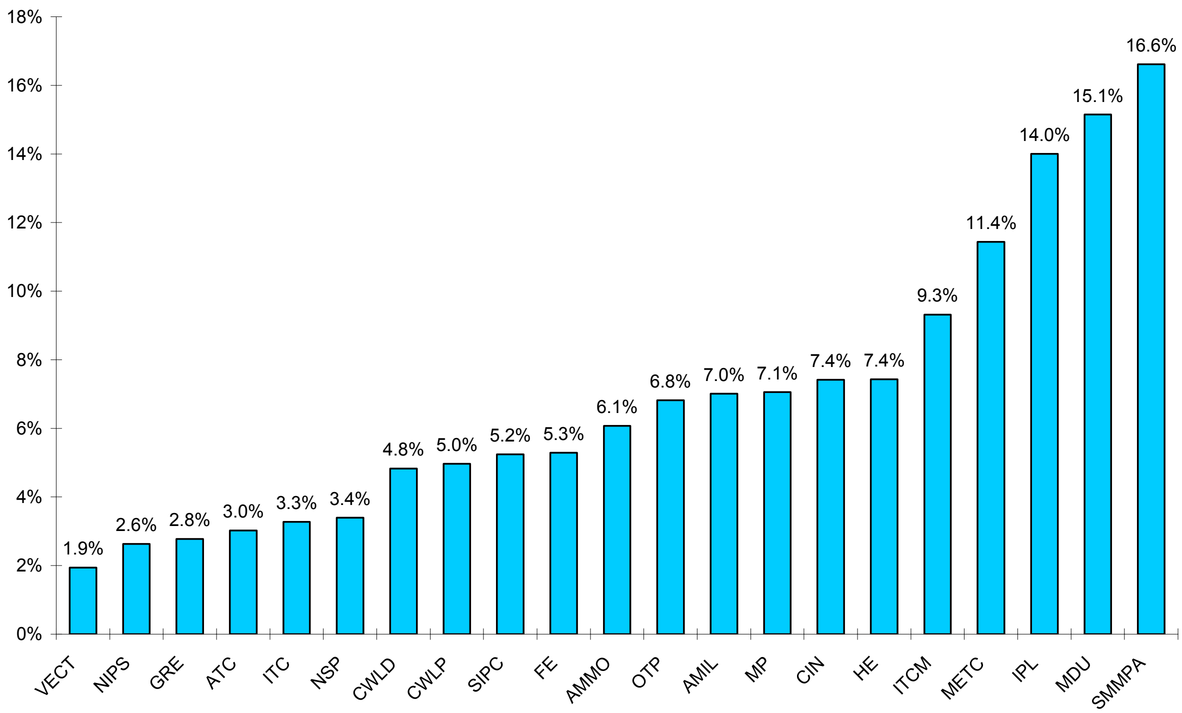

Figure 7-6: MTEP 06 through 08 Appendix A Project Costs Allocated from Other Pricing Zones as a Percent of Net Transmission Plant in Service (as of June 2008)

7.3 Equipment Summary

There are approximately 6,100 miles of new or upgraded transmission lines in the 2008 through 2015 timeframe in Appendices A, B, and C. There are an additional 1,200 miles of proposed transmission beyond the 2015 plan year in the 2016 to 2018 timeframe. The 1,200 miles does not include the EHV conceptual overlay portfolio of projects in Appendix C which is over 6,000 miles.

About 3,800 miles of transmission line *upgrades* are projected through 2018 which is about 7% of the approximately 53,000 miles of line existing higher voltage transmission throughout the Midwest ISO area. About 3,650 miles of transmission involving lines on *new* transmission corridors is also projected. Neither statistic includes the EHV conceptual overlay.

The miles of transmission line by voltage class are shown in Figure 7-7. EHV conceptual overlay line miles are not included.

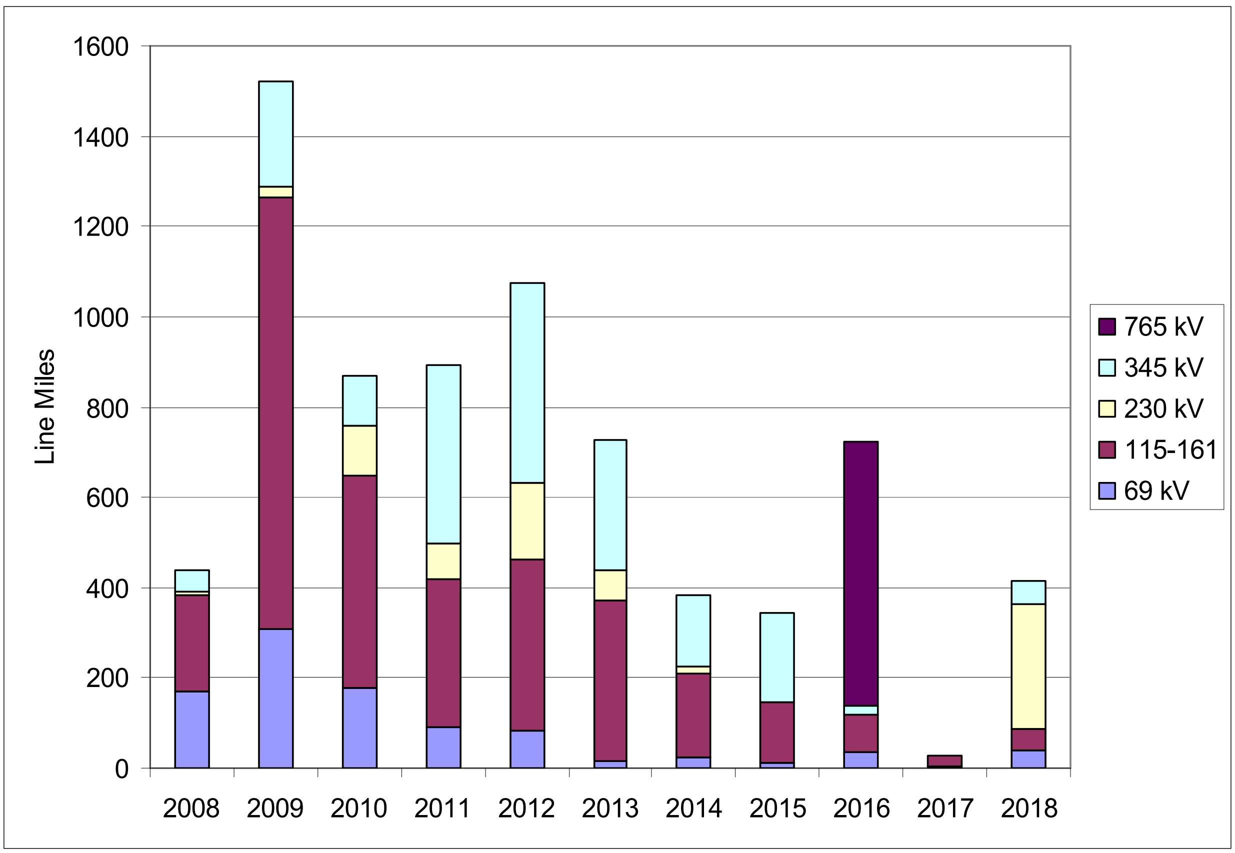

Figure 7-7: New or Upgraded Line Miles by Voltage Class in Kilovolts (kV) by Year

New transmission line mileage by state for 2008 through 2018 in all Appendices is shown in Figure 7-8. EHV conceptual overlay line miles are not included.

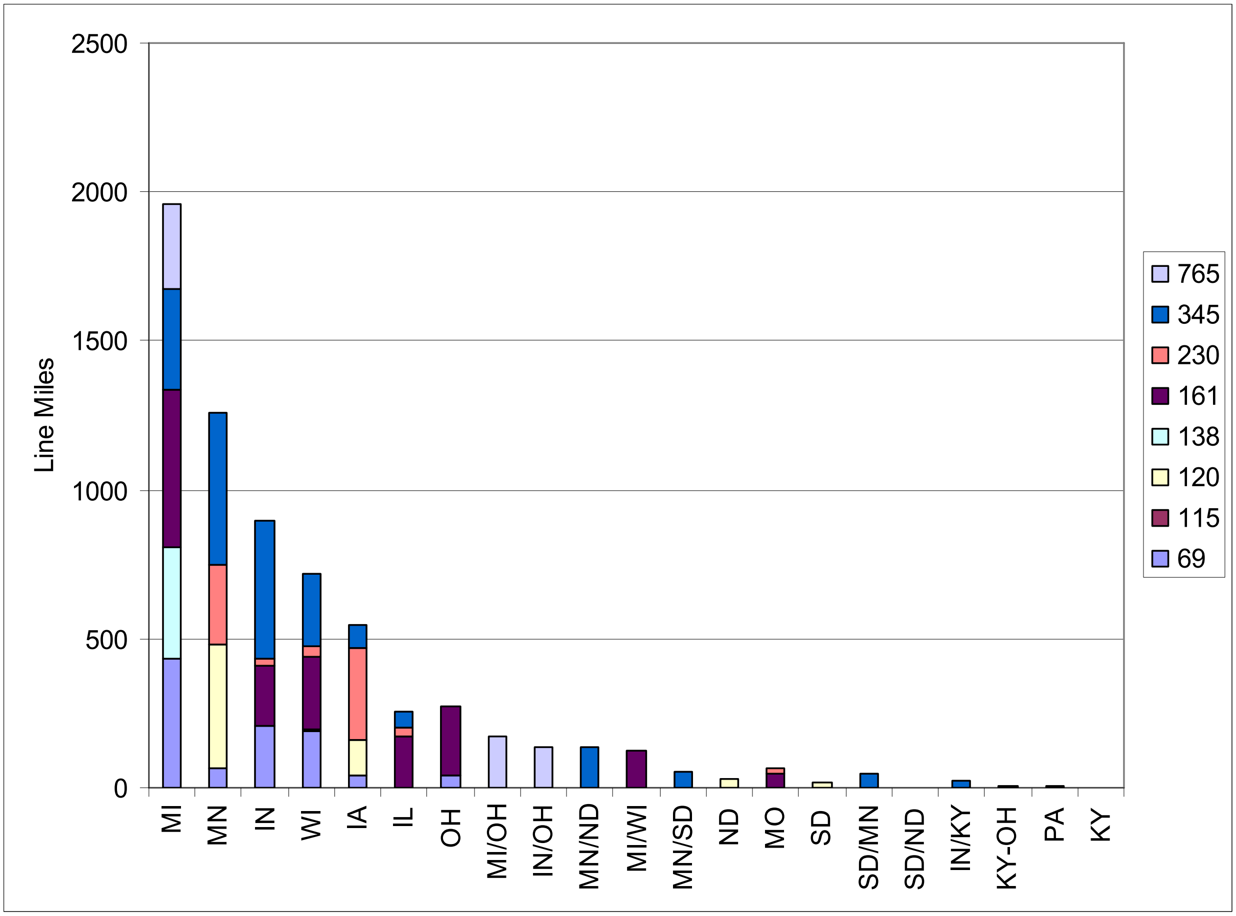

Figure 7-8: New or Upgraded Line Miles by Voltage Class and State

Section 8: Targeted Studies

8.1 Narrow Constrained Areas

A Narrow Constrained Area (NCA) is defined as "An electrical area that has been identified by the Independent Market Monitor (IMM) that is defined by one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours during a given year and within which one or more suppliers are pivotal." Historical Congestion has been tracked in all MTEP reports, as in Section 3.4 of this report. Concurrently the IMM has listed sets of Flowgates (FG) to define NCAs.

From the NCA discussion in Section 3.4 (pg.69) of MTEP07, there are currently three NCAs defined by the IMM in the Midwest ISO footprint:

- Wisconsin Upper Michigan System (WUMS)
- Northern WUMS
- SE_MN/N_IA/SW_WI which includes portions of southeast Minnesota, northern Iowa, and southwestern Wisconsin

Further identification of the NCAs in terms of transmission and generation facilities and their geographic location is illustrated in the following sub-sections. The purpose of the NCA analysis was to determine if NCAs are mitigated by existing plans. If not, develop and test plans to mitigate the NCAs.

8.1.1 Historical Constraint Review

The NCA's from the MTEP07 report have been combined with the congestion history. Table 8.1-1 lists the FGs associated with each of the three NCA along with a summary of the congestion hours on each for the periods of the 1st Market year, 2nd Market year, and the 3rd Market year. The FG's under each NCA are in descending order of contribution to total congestion hours for the NCA. The total post market congestion hours for each NCA is less than 500 hours until the point where the top one or two (depending on which NCA is viewed) are included in the total.

Table 8.1-1 also indicates if the annual sum for each post market year for the NCA exceeds 500 congestion hours. Also shown are the expansion projects that are expected to provide flow relief to the particular FG.

Figure 8.1-1 identifies the monitored facilities associated with each NCA group. Figure 8.1-2 shows the Commercial Pricing Nodes that the IMM found to experience positive Marginal Congestion Costs (MCC), relative to each of the three NCA's.

- The historical information for the Northern WUMS NCA shows that the annual hours have reduced below the 500 annual hours, and with pending projects in year 2009 are likely to remain below the 500 hours per year level.
- The historical information for the Wisconsin Upper Michigan System tracks above 1,000 hours per year, however the benefit of the Arrowhead-Gardner Park 345kV line was not realized during the 2007 summer period when most of the congestion occurs. It is expect that the 4th Market year will realize the benefit of the expansion and that the congestion will trend below the 500 hours per year level. Also, additional mitigation is expected from projects later on in the year 2010.
- The third NCA "SE_MN/N_IA/SW_WI" has binding hours below the 500 hours per year and had trended down in the 3rd Market year compared to the maximum of 389 hours in the 2nd Market year. The sum of binding hours alone is below the 500 hour level, however the IMM process also counts an event or FG hour for every hour that generators have been committed to run; recognizing that if they were not so committed to run, the respective FG's would require binding and the effective generation to manage the loading would not be on line. While this MTEP review has not quantified the hours that generators were committed to avoid binding, it is evident that the binding hours are trending downward. However, the simulations of the years 2008 and 2011 do provide the correct metric to capture all congestion hours, since unlike the Real Time operations the unit commitment is not adjusted to ward off pending congestion.

Table 8.1-1: Listing of Each NCA's Associated FG's With Congestion Hours and Projects that Mitigate Loading

		Post-MKT						
NERC ID or Real-Time name	FLOWGATE Name/Description	1st Year Congestion FG-Hr or FG-Hr/YR Apr 05 to Apr 06	2nd Year Congestion FG-Hr or FG-Hr/YR Apr 06 to Apr 07	3rd Year Congestion FG-Hr or FG-Hr/YR Apr 07 to Apr 08	Post MKT Congestion FG-Hr Apr 05 to Apr 08	Post MKT Sum of Hourly Shadow Prices $	Load Balancing Area	MTEP Map Grid
	WUMS NCA Annual Sums FG-Hr--->	1,949	667	1,271				
3006	Eau Claire-Arpin 345 kV	1529	245	794	2,568	212,767	WPS	J6
	P1 Arrowhead-Gardner Park 345kV line provides a parallel path; January 2008 actual in service							
3012	Paddock Xfmr 1 + Paddock-Rockdale	405	420	477	1,302	253,400	ALTE	K7
	P1256 Paddock-Rockdale 345kV circuit #2 provides the 2nd path for CE 6/1/2010 Appendix A							
3527	PleasPr-Racine 345 for Wempletown-Pad 345	15	0	0	15	3,170	WEC	
3707	LOR5-TRK RIV5 161kV/ Wempletown--Paddock 345kV	0	2	0	2	617	ALTW	J7
3025	Russel-Rockdale 138/Paddock-Rockdale 345	0	0	0	0	0	ALTE	
3522	Albers-Paris138 for Wempletown-Padock 345	0	0	0	0	0	WEC	
3534	Kenosha-Albers 138 for Wempletown-Paddock 345	0	0	0	0	0	WEC	
3736	Salem 345/161 flo Wempletown-Paddock 345	0	0	0	0	0	ALTW	J8
3001	Wempletown-Padock 345 kV	0	0	0	0	0	ALTE	
3015	Nelson Dewey Xfmr+Wempletown-Paddock	0	0	0	0	0	ALTE	
3017	Cassvl-NED 161 for Wempletown-Paddock 345	0	0	0	0	0	ALTE	
3034	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	0	0	0	0	0	ALTE	
3241	2221 Zion-PlsP for 17101 Wempletown-Pad	0	0	0	0	0	WEC	
3565	Paris-Burlington 138 (flo) Wempletown-Paddock 345	0	0	0	0	0	WEC	
3705	Arnold-Hazelton 345 for Wempletown-Paddock 345	0	0	0	0	0	ALTW	I7

Table 8.1-1: Listing of Each NCA's Associated FG's With Congestion Hours and Projects that Mitigate Loading

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	Northern WUMS NCA Annual Sums FG-Hr--->	801	199	306				
3567	Flow South	646	172	25	843	754,777	WEC	K5
	Stiles-Plains 138kV dbl circuit rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 Gardner Park-Highway 22 345kV line project and P345 Morgan-Werner West 345kV line connect Morgan-Plains 345kV line to the pre-existing 345kV system, hence increase voltage stability. P352 Cranberry-Conover 115kV and Conover-Plains conversion to 138kV will also help increase the FG limit. P177 12/1/2009 Appendix A P345 4/1/2009 Appendix A P352 6/1/2010 Appendix A							
3631	Highway V-Preble 138 (flo) Lost Dauphin-Red Maple 138			123	255	42,197	WPS	K6
3538	Stiles4-Pulliam 138+Stiles5-Pulliam 138	24	16	157	197	16,731	WPS	K6
3617	HighwayV-Preble+N APPLTN-WhiteClay	0	10	1	11	2,480	WPS	K6
3523	Stiles-Pioneer 138 for N.Appl-WhiteClay138	0	0	0	0	0	WEC	
3525	Stiles-Amberg 138 for Morgan-Plaines 345	0	0	0	0	0	WEC	
3528	N Appleton-Wh Clay 138 for Stiles-Pulliam 138	0	0	0	0	0	WEC	
3535	N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR	0	0	0	0	0	WEC	
3544	Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345	0	0	0	0	0	WEC	
3611	Kewaunee 345/138 Xfmr	0	0	0	0	0	WPS	L6
3613	Kewaunee Xfmr+Kewaunee-N Appleton	0	0	0	0	0	WPS	L6
3030	Green Lk-Roeder 138 for N Appleton-RoR 345	0	0	0	0	0	ALTE	

Table 8.1-1: Listing of Each NCA's Associated FG's With Congestion Hours and Projects that Mitigate Loading

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NERC ID or Real-Time name	FLOWGATE Name/Description	1st Year Congestion FG-Hr or FG-Hr/YR Apr 05 to Apr 06	2nd Year Congestion FG-Hr or FG-Hr/YR Apr 06 to Apr 07	3rd Year Congestion FG-Hr or FG-Hr/YR Apr 07 to Apr 08	Post MKT Congestion FG-Hr Apr 05 to Apr 08	Post MKT Sum of Hourly Shadow Prices $	Load Balancing Area	MTEP Map Grid
	SE_MN/N_IA/SW_WI NCA Annual Sums FG-Hr--->	161	389	209				
	NSPGEN07_Hazleton_HAZLTARNOL34_1_1	22	176	0	198	52,026	ALTW	I7
	2nd Wempletown-Padock 345kV line (in service in 2005) and P1256 Paddock-Rockdale 345kV circuit #2 provides the 2nd path of CE 6/1/2010 Appendix A P1288 Replace Hazleton 345/161kV transformer #1 with 335 MVA unit will increase ME limit 6/1/2010 Appendix A P1340 Build a new Hazleton-Lore-Salem 345kV line with a Lore 345/161kV 335/335 MVA transformer will close the loop of the 345kV system, hence relieve loading on ME Arnold-Hazleton 345kV line, and will relieve loading on parallel path of ME Hazleton-Dundee 161kV line 12/31/2011 Appendix A in MTEP08							
ALW3403_Hazleton_HAZLTDUNDE16_1_1		0	55	119	174	65,909	ALTW	
ALWGEN03_Arnold_ArnoldTIFFI34_1_1		30	28	0	58	12,403	#N/A	
BASE_Fox_LK_Fox_LRUTLA16_1_1		0	6	47	53	27,691	ALTW	
	P1746 Lakefield-Fox Lake-Rutland-Winnebago-Hayward-Adams 161kV line to double ckt 345 & 161kV. ISD 2015 Appendix C							
ALWMEC16_Hazleton_HAZLTDUNDE16_1_1		52	0	0	52	21,139	#N/A	
NSP34005_Lakefield_LAKEFHeron16_1_1		0	44	0	44	14,939	#N/A	
NSP34005_Fox_LK_Fox_LRUTLA16_1_1		0	5	29	34	19,385	ALTW	
NSP34005_Lakefield_LAKEFFox_L16_1_1		5	12	9	26	6,357	ALTW	
ALWMEC13_Hazleton_HAZLTBLKHA16_1_1		8	14	1	23	5,580	ALTW, MEC	
MEC34018_Hazleton_HAZLTDUNDE16_1_1		0	15	0	15	5,082	#N/A	
BASE_Hazleton_HAZLTDUNDE16_1_1		0	10	4	14	12,813	ALTW	
MEC34020_Hazleton_HAZLTDUNDE16_1_1		10	0	0	10	6,939	#N/A	
ALWMEC08_Hazleton_HAZLTDUNDE16_1_1		0	9	0	9	980	#N/A	
ALW3403G_Vinton_VINTODYSAR16_1_1		6	0	0	6	1,786	#N/A	
ALWMEC16_Hazleton_HAZLTBLKHA16_1_1		6	0	0	6	1,259	#N/A	
ALWARTIF_Hazleton_HAZLTDUNDE16_1_1		5	0	0	5	3,632	#N/A	
ALW34003_Dundee_TR94_TR94		4	0	0	4	5,206	#N/A	
ALWGEN03_E_CALMS_E_CALCALAM11_1_1		4	0	0	4	731	#N/A	

Table 8.1-1: Listing of Each NCA's Associated FG's With Congestion Hours and Projects that Mitigate Loading

		Post-MKT						
NERC ID or Real-Time name	FLOWGATE Name/Description	1st Year Congestion FG-Hr or FG-Hr/YR Apr 05 to Apr 06	2nd Year Congestion FG-Hr or FG-Hr/YR Apr 06 to Apr 07	3rd Year Congestion FG-Hr or FG-Hr/YR Apr 07 to Apr 08	Post MKT Congestion FG-Hr Apr 05 to Apr 08	Post MKT Sum of Hourly Shadow Prices $	Load Balancing Area	MTEP Map Grid
MEC34018_Salem3_TR21_TR21		0	4	0	4	1,957	#N/A	
NSP34002_Hazleton_TR21_TR21		0	4	0	4	4,149	#N/A	
ALW34003_Arnold_ARNOLVINTO16_1_1		3	0	0	3	452	#N/A	
MEC34025_Arnold_ARNOLTIFFI34_1_1		3	0	0	3	1,122	#N/A	
MEC34032_Rock_CK_TR21_TR21		0	3	0	3	557	#N/A	
MEC34033_Salem3_TR21_TR21		0	3	0	3	434	#N/A	
MP50X01_Lakefield_LAKEFFox_L16_1_1		2	0	0	2	321	#N/A	
ALWARTIF_E_CALMS_E_CALCALAM11_1_1		0	1	0	1	67	#N/A	
NSPGEN07_Arnold_TR21_TR21		1	0	0	1	58	#N/A	
ALENSP02_Hazleton_HAZLTDUNDE 16_1 _1		Column to left's name not found in Real Time Congestion data.						
ALENSP1G_Hazleton_HAZLTDUNDE 16_1_1		Column to left's name not found in Real Time Congestion data.						
ALW16001_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
ALW16019_Hiawatha_HIAWADRYC 11_1_1		Column to left's name not found in Real Time Congestion data.						
ALW 16042_Fox_LK_TR92_TR92		Column to left's name not found in Real Time Congestion data.						
ALW34003_Hazleton_HAZLTDUNDE 16_1_1		Column to left's name not found in Real Time Congestion data.						
ALW3403G_Arnold_ARNOLVINT016_1_1		Column to left's name not found in Real Time Congestion data.						
ALW3403G_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
ALWGEN03_E_Calamus_TR9 1_TR91		Column to left's name not found in Real Time Congestion data.						
ALWGEN07_MCBW_IP-MCBW-1_A		Column to left's name not found in Real Time Congestion data.						
Arnold_HazletonArnold_		Column to left's name not found in Real Time Congestion data.						
Arnold_Vinton_161_FOR_DArnold_Hazleton		Column to left's name not found in Real Time Congestion data.						
DPCGENO 1 _Lime_CK_Lime_Emery 16_1 _1		Column to left's name not found in Real Time Congestion data.						
DundeeHazleton161 kVFLODYSARTWashburn16		Column to left's name not found in Real Time Congestion data.						
Emery_Lime_Creek_161_FLO_Emery_Floyd_1		Column to left's name not found in Real Time Congestion data.						
Hazleton_Blackhawk_161kV_FLO_DYSART_WA		Column to left's name not found in Real Time Congestion data.						
Lakefield_Fox_LK_161_FOR_Lakefield_LGS		Column to left's name not found in Real Time Congestion data.						
Lime_Creek_Emery_161_FLO_Adams_Hazleton		Column to left's name not found in Real Time Congestion data.						

Table 8.1-1: Listing of Each NCA's Associated FG's With Congestion Hours and Projects that Mitigate Loading

		Post-MKT						
NERC ID or Real-Time name	FLOWGATE Name/Description	1st Year Congestion FG-Hr or FG-Hr/YR Apr 05 to Apr 06	2nd Year Congestion FG-Hr or FG-Hr/YR Apr 06 to Apr 07	3rd Year Congestion FG-Hr or FG-Hr/YR Apr 07 to Apr 08	Post MKT Congestion FG-Hr Apr 05 to Apr 08	Post MKT Sum of Hourly Shadow Prices $	Load Balancing Area	MTEP Map Grid
MEC34000_Arnold_ArnoldVINTO16_1 _1		Column to left's name not found in Real Time Congestion data.						
MEC34012_Salem3_TR21_TR21		Column to left's name not found in Real Time Congestion data.						
MEC34020_Arnold_ArnoldVINT016_1 _1		Column to left's name not found in Real Time Congestion data.						
MEC34X04_Salem3_TR2 1_TR21		Column to left's name not found in Real Time Congestion data.						
MECALW04_WSHEFFLD_WSHEFEmery 16_1_1		Column to left's name not found in Real Time Congestion data.						
MP50X01_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
NSP34002_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
NSP34005_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
NSP3405G_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
NSP3406_Lime_CK_Lime_Emery 16_1_1		Column to left's name not found in Real Time Congestion data.						
NSP34X1G_Lakefield_LAKEFFox_L16_1 _1		Column to left's name not found in Real Time Congestion data.						
NSP50004_Lakefield_LAKEFFox_L16_1 _1		Column to left's name not found in Real Time Congestion data.						
NSPALW02_Fox_LK_Fox_LRUTLA16_1 _1		Column to left's name not found in Real Time Congestion data.						
NSPGEN01_Lime_CK_Lime_Emery16_1 _1		Column to left's name not found in Real Time Congestion data.						
NSPGEN02_Lime_CK_Lime_Emery16_1 _1		Column to left's name not found in Real Time Congestion data.						
NSPGEN05 Lime_CK_Lime_Emery16_1_1		Column to left's name not found in Real Time Congestion data.						
NSPGEN07_Lime_CK_Lime_Emery 16_1 _1		Column to left's name not found in Real Time Congestion data.						
Salem_345_161_Xfmr_FLO_Tiffin_Arnold_3		Column to left's name not found in Real Time Congestion data.						
SUB_56_Davenport_ECalamus161 _FOR_QUAD_RO		Column to left's name not found in Real Time Congestion data.						
Tiffin_Arnold_345kV		Column to left's name not found in Real Time Congestion data.						
Tiffin_Arnold_345kV_FLO_Arnold_UNIT_1		Column to left's name not found in Real Time Congestion data.						
VJNTON_DYSART_16 1_FLO_Arnold_Hazleton_		Column to left's name not found in Real Time Congestion data.						

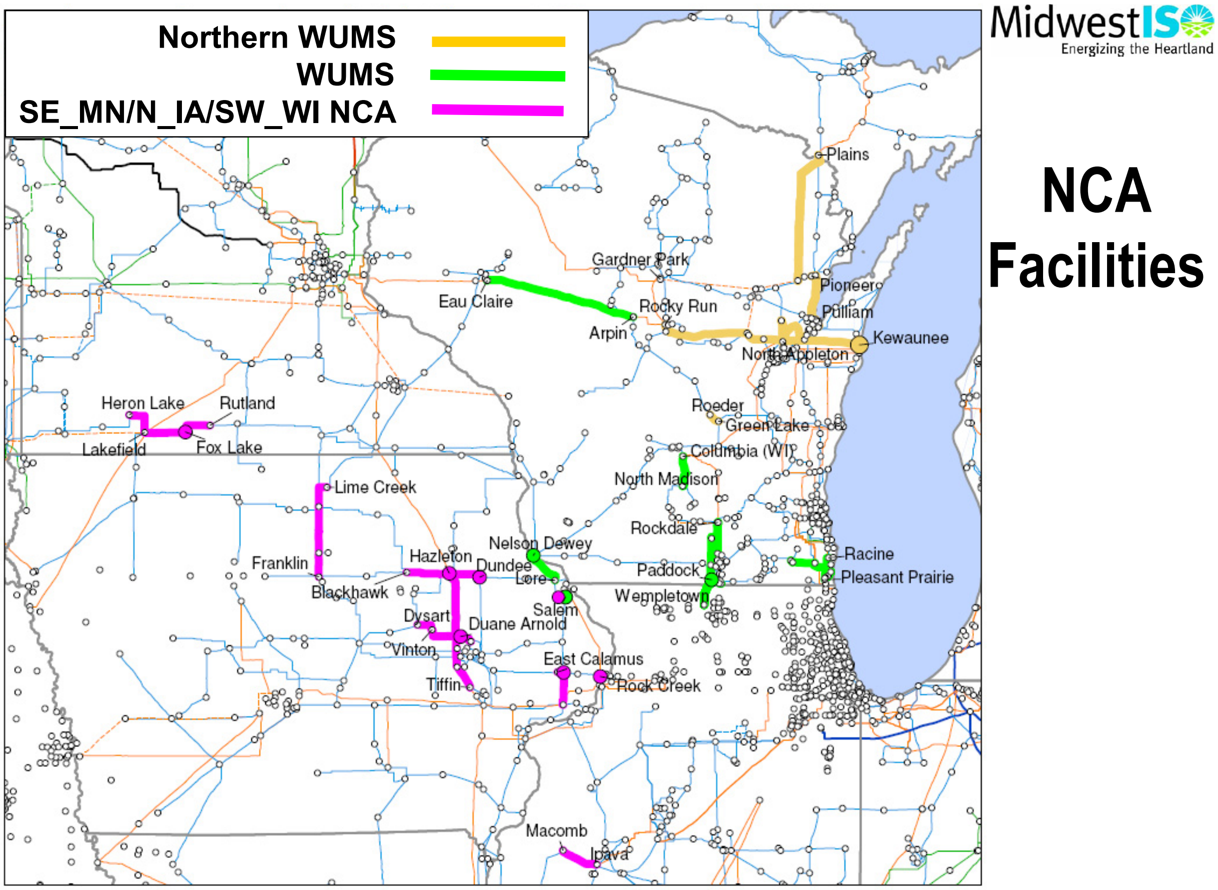

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Figure 8.1-1: Facilities Comprising Each of Three NCA's

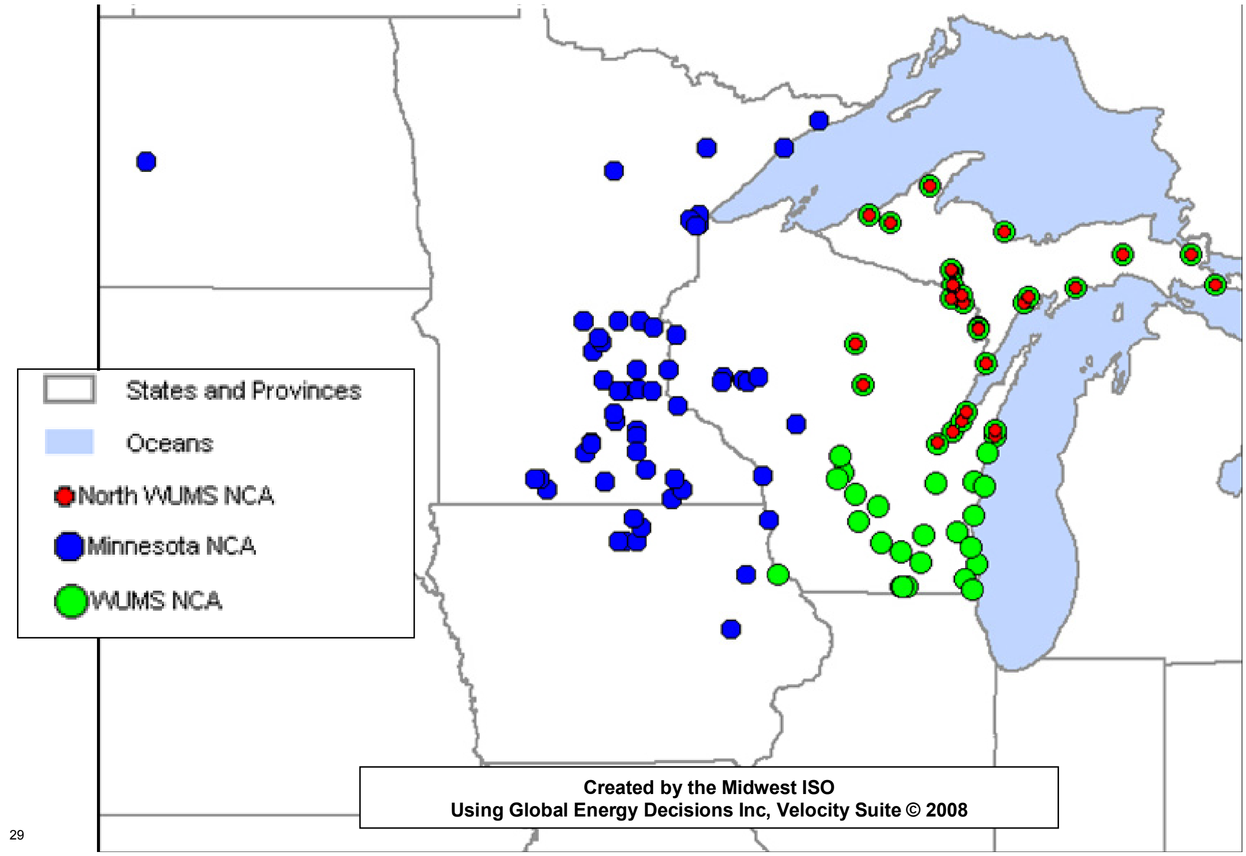

Figure 8.1-2: Commercial Pricing Nodes Associated with Positive Marginal Congestion Cost (MCC) Relative to Three NCA's

8.1.2 Constraint Valuation in Planning Horizon

A PROMOD® analysis can be performed to determine the congested hours of all three NCAs in the planning horizon. To accomplish the analysis, 2 years of PROMOD® models were prepared for the NCA study. A 2008 PROMOD® model was developed based on the MISO 2008 summer assessment power flow case, and 2011 PROMOD® model was developed from MTEP08 Reference Future analysis. PROMOD® uses an event file to define the flowgates to be monitored during the simulation. The event files for 2008, 2011 PROMOD® cases were reviewed and updated to make sure that all NCA related flowgates are monitored. Potential NCA mitigation projects from MTEP07 report are also reviewed and put into the respective PROMOD® cases according to their expected In Service Dates (ISD). Table 8.1-2 lists potential mitigation projects, their MTEP07 expected ISD, and model status:

Table 8.1-2: Potential mitigation plans and their status in 2008 and 2011 PROMOD® model

		MTEP07 Expected ISD	Status in			
			2008 model	2011 model	2011 P1340	2011 P1746
WUMS related projects						
P1	Arrowhead-Gardner Park 345kV line)	1/20/2008	Yes	Yes	Yes	Yes
P1256	Paddock-Rockdale 345kV circuit #2)	4/1/2010	No	Yes	Yes	Yes
P1617	New 161kV line Nelson Dewey-Liberty (now 2013 ISD)	6/1/2011	No	Yes	Yes	Yes
P1287	Replace Salem 345/161kV transformer with 448 MVA unit	6/1/2008	No	Yes	Yes	Yes
N_WUMS related projects						
P177	Gardner Park-Highway 22 345kV line	12/1/2009	No	Yes	Yes	Yes
P345	Morgan-Werner West 345kV line	12/1/2009	No	Yes	Yes	Yes
P567	(North Appleton-Lawn Road-White Clay 138kV uprate	2/1/2008	Yes	Yes	Yes	Yes
P880	Lost Dauphin-North Appleton-Mason Street 138kV uprates	6/1/2008	Yes	Yes	Yes	Yes
P352	Cranberry-Conover 115kV and Conover-Plains conversion to 138kV	12/31/2009	No	Yes	Yes	Yes
SE_MN / N_IA / SW_WI related projects						
P90	Emery-Lime Creek 161kV, Ckt 2	6/1/2007	Yes	Yes	Yes	Yes
P1288	Replace Hazleton 345/161kV transformer #1 with 335 MVA unit	6/1/2009	No	Yes	Yes	Yes
P1287	Replace Salem 345/161kV transformer with 448 MVA unit	6/1/2008	No	Yes	Yes	Yes
P1349	Replace Dundee 161/115kV transformer with new ratings as 112 MVA (non Midwest ISO project)	6/1/2011	No	Yes	Yes	Yes
P1342	Build Lewis Fields 161/115kV sub which taps the 115kV line Swamp Fox-Coggon. Build a new 161kV line from Hiawatha to Lewis Fields	6/1/2011	No	Yes	Yes	Yes
P1340	Build a new Hazleton-Lore-Salem 345kV line with a Lore 345/161kV 335 MVA transformer (This project now has 12/2011 ISD)	6/1/2013	No	No	Yes	Yes
P1618	Hrn Lk-Lakefield 161kV Ckt 1 rebuild	6/1/2013	No	No	No	No
P1346	Upgrade conductor inside the substation so the ratings of Rock Creek 345/161kV transformer are 448 MVA limited by transformer	6/1/2011	No	Yes	Yes	Yes
P1746	Upgrade Lakefield to Adams 161kV line (Appendix C)	12/1/2015	No	No	No	Yes

In Table 8.1-2, P1340 Salem-Hazleton 345kV project had a 2013 ISD in MTEP07 report and was not in the 2011 PROMOD® model initially. The new ISD for this project in MTEP08 is 2011. Therefore, an alternative 2011 PROMOD® run with P1340 included was also performed. Project P1746 has a 2015 ISD and was however simulated in 2011 to determine the effectiveness of the project.

Table 8.1-3 shows the binding hours for the three NCAs in 2008 and 2011 PROMOD® simulation:

Table 8.1-3 Binding Hours for three NCAs in 2008 and 2011

	Constrained Hours in 2008	Constrained hour in 2011	Constrained hour in 2011 with Project P1340	Constrained hour in 2011 with Projects P1340 and P1746
N_WUMS	1	0	0	0
WUMS	197	62	55	57
SE_MN/N_IA/SW_WI	595	1872	1517	28

Tables 8.1-4 to Table 8.1-7 show the binding hours of individual NCA flowgates in the 2008 and 2011 PROMOD® simulations. The results show that:

- The binding hours for WUMS and Northern WUMS NCA are well under 500 hours for both 2008 and 2011. In 2011 PROMOD® simulation, the addition of project 1340 (Salem to Hazleton 345kV) mitigates a number of constraints in WUMS and SE_MN/N_IA/SW_WI NCA.
- The Fox Lake-Rutland 161kV flowgate, continues to have over 1400 binding hours by itself. Fox Lake-Rutland is remote from project 1340.
- With P1340 as the only additional project, the SE_MN/N_IA/SW_WI NCA is still binding for more than 500 hours in 2008 and 2011. However, Table 8.1-7 shows the binding hours of individual NCA flowgates in 2011 by also adding the 161kV portion of P1746 (Lakefield-Fox Lake-Rutland-Winnebago-Hayward-Adams 161kV line to double ckt 345 & 161kV, ISD 2015).
- The 2011 PROMOD® simulation with P1340 and P1746 reduces the binding hours on the Fox Lake-Rutland 161 Flowgate to zero hours and the congestion on the SE_MN/N_IA/SW_WI to 28 hours.

Table 8.1-4 NCA flowgates binding hours in 2008 PROMOD® simulation			
NCA Name	**Description**	**Binding Hours**	**NCA Binding Hours**
North WUMS	Highway V-Preble 138 (Flo) Lost Dauphin-Red Maple 138	1	1
SE_MN/N_IA/SW_WI	Arnold_Vinton_161_FOR_DArnold_Hazleton	62	
SE_MN/N_IA/SW_WI	ALW3403_Hazleton_HAZLTDUNDE16_1_1	2	
SE_MN/N_IA/SW_WI	SUB_56_Davenport_ECalamus161 _FOR_QUAD_RO	15	
SE_MN/N_IA/SW_WI	NSP34005_Fox_LK_Fox_LRUTLA16_1_1	426	
SE_MN/N_IA/SW_WI	ALWGEN07_MCBW_IP-MCBW-1_A	90	595
WUMS NCA	Lore-Turkey River 161 FLO Wempletown-Paddock 345	34	
WUMS NCA	Paddock Xfmr 1 + Paddock-Rockdale	137	
WUMS NCA	Salem 345/161 FLO Wempletown-Paddock 345	26	197

Table 8.1-5 NCA flowgates binding hours in 2011 PROMOD® simulation (without P1340 or P1746)			
NCA Name	**Description**	**Binding Hours**	**NCA Binding Hours**
SE_MN/N_IA/SW_WI	ALW3403_Hazleton_HAZLTDUNDE16_1_1	253	
SE_MN/N_IA/SW_WI	Emery_Lime_Creek_161_FLO_Emery_Floyd_1	4	
SE_MN/N_IA/SW_WI	Lime Creek-Emery 161 flo Adams-Hazleton 345	17	
SE_MN/N_IA/SW_WI	NSP34005_Fox_LK_Fox_LRUTLA16_1_1	1484	
SE_MN/N_IA/SW_WI	ALW3403G_Arnold_ArnoldVINT016_1_1	81	
SE_MN/N_IA/SW_WI	ALWARTIF_Hazleton_HAZLTDUNDE16_1_1	33	1872
WUMS NCA	Kenosha-Albers 138 FLO Wempletown-Paddock 345	62	62

Table 8.1-6 NCA flowgates binding hours in 2011 PROMOD® simulation (with P1340)			
NCA Name	**Description**	**Binding Hours**	**NCA Binding Hours**
SE_MN/N_IA/SW_WI	Emery_Lime_Creek_161_FLO_Emery_Floyd_1	7	
SE_MN/N_IA/SW_WI	Lime_Creek_Emery_161_FLO_Adams_Hazleton	19	
SE_MN/N_IA/SW_WI	NSP34005_Fox_LK_Fox_LRUTLA16_1_1	1483	
SE_MN/N_IA/SW_WI	ALWMEC13_Hazleton_HAZLTBLKHA16_1_1	1	
SE_MN/N_IA/SW_WI	ALW3403G_Arnold_ARNOLVINT016_1_1	7	1517
WUMS NCA	Kenosha-Albers 138 FLO Wempletown-Paddock 345	55	55

Table 8.1-7 NCA flowgates binding hours in 2011 PROMOD® simulation (with P1340 and P1746)			
NCA Name	**Description**	**Binding Hours**	**NCA Binding Hours**
SE_MN/N_IA/SW_WI	Emery_Lime_Creek_161_FLO_Emery_Floyd_1	5	
SE_MN/N_IA/SW_WI	Lime_Creek_Emery_161_FLO_Adams_Hazleton	17	
SE_MN/N_IA/SW_WI	NSP34005_Fox_LK_Fox_LRUTLA16_1_1	0	
SE_MN/N_IA/SW_WI	ALWMEC13_Hazleton_HAZLTBLKHA16_1_1	1	
SE_MN/N_IA/SW_WI	ALW3403G_Arnold_ARNOLVINT016_1_1	5	28
WUMS NCA	Kenosha-Albers 138 FLO Wempletown-Paddock 345	57	57

8.1.3 Conclusion

The WUMS and Northern WUMS are mitigated by existing plans already approved in Appendix A, therefore, no new transmission plans are required to mitigate those NCAs. The NCA Technical Review Group (TRG) recommended that the projects to address the NCAs and their implementation schedule will be sent to the IMM to make him aware of when NCA is expected to be mitigated. After these upgrades are constructed, a request to remove the NCA will be formally made.

The SE_MN/N_IA/SW_WI NCA is also mitigated by existing plans, all but one of which are in Appendix A of MTEP08 report. While P1746 Lakefield-Adams 161kV line rebuild remains in Appendix C since it is not currently scheduled until 2015, the study clearly shows that the SE Minnesota NCA can be expected to no-longer qualify as a NCA when P1746 is in service. There is significant development of renewable resources in this area around P1746. Therefore, the NCA TRG recommends that the schedule for implementation of P1746 be reviewed as well as timing for addition of 345kV circuit to P1746. These reviews would be appropriately performed in the Regional Generation Outlet Study.

8.2 Regional Generation Outlet Study

On April 11, 2008, one hundred and thirty five Midwest ISO stakeholders helped kick off the Regional Generation Outlet Study (RGOS) for the western half of the Midwest ISO footprint. The primary purpose of the study is to develop a mid-term (5-15 years) set of transmission projects aimed at ensuring Midwest ISO load serving entities can meet their respective state Renewable Portfolio Standards (RPS).The states with RPS legislation[1] include Illinois, Iowa, Minnesota and Wisconsin.

The RGOS seeks to address the physics[2] component of Generator Interconnection Queue reform[3] by driving greater integration between longer term (MTEP) and shorter term (Generator Interconnection Queue) planning processes. The objective is the development of a regional collector system(s) to support existing Renewable Portfolio Standards. This will be accomplished with the identification of renewable energy zones within the region and developing necessary transmission to move the energy from those zones on to the transmission grid and load centers. The projects identified in this study will be included in the MTEP09 report and appendices.

The difficulty in performing this study is the multi-variable optimization nature of the task at hand (see discussion under Section 8.2.2). Multiple generation and transmission expansion options along with wind siting scenarios are being analyzed. The analysis includes economics (capacity, energy and transmission costs) and reliability, but coupled with multiple siting scenarios for wind, the optimization of such a transmission plan is difficult due to the intertwined nature of the variables. In concert with the technical issues, "policy" will play a key role as well. While the study is focused on the RPS requirements of four Midwest ISO states, wind siting and transmission may be developed in various other states and will include part of the Maryland Interconnect (PJM). The RGOS has similarities to efforts in Texas, California, and Colorado; however a significant difference is that those efforts benefited by being subject to only one state jurisdiction. Because of the numerous jurisdictions for RGOS, stakeholder involvement and coordination will play a key role in the success of this effort.

1 At the time of the study scope development

2 Three P's of queue reform: Process, Physics, Policy

3 See Queue Reform at:

http://www.midwestmarket.org/publish/Folder/67519_1178907f00c_-7fff0a48324a

Understanding the innate issues with the generation interconnection queue process, a balance is needed to provide an efficient and cost effective transmission build-out over the next 5-15 years. As identified in the study scope, there are several problem statements to be addressed by this study, including:

- The level of requests in the Midwest ISO generation interconnection queue, driven in large part, by renewable mandates has risen dramatically over the past two years. As of summer 2008, there were over 70 GW of wind generation requests out of approximately 80 GW total in the Midwest ISO queue. It is estimated that using the existing process under the tariff, the current FERC Order 2003 process, the Midwest ISO would not be able to clear the queue till 2050.
- The queue is a less than optimal method of performing transmission planning as it is based on individual projects rather than a collective system, leading to higher capital costs and less efficiency.
- A determination of generation size and location that should drive the 5-15 year transmission build-out is needed to establish a base-line for prudent transmission investment.
- Laws at the state and federal level reflect different energy and economic policies and thus regulatory processes; however a concerted collaborative effort can find improvements and solutions to enable the integration of this resource.
- Geographic areas that support wind typically to not support large communities of energy consumers and thus only a small fraction of the available wind resource can be used in the location it can be developed. Transmission to connect renewable resource areas to load centers needs to be constructed to meet state’s energy policy.

8.2.1 Stakeholder Involvement

Stakeholder involvement is being accomplished with the use of a Technical Review Group (TRG). The TRG concept is being utilized as a new piece in transmission planning process. The objective is to receive stakeholder involvement as early as possible in study efforts. On the front end of the process, early involvement includes helping to identify problems/issues that may lead to a study. The TRG is open to all interested stakeholders and for the RGOS is presently comprised of over 100 participants representing regulatory entities, transmission owners, load serving entities, wind developers, and others.

The role of the TRG is to provide input and feedback on study scope, methodology, assumptions, and results. With the help of the TRG, results are being coordinated with utilities, states, and other efforts that the Midwest ISO supports such that they have merit/credibility and regulatory support gained from stakeholder involvement.

A dedicated email exploder exists for RGOS members and is used for all communications related to the study. All that is needed to become a member of the TRG is to subscribe to the exploder. This can be done by establishing a Midwest ISO extranet account (http://extranet.midwestiso.org) and editing the account settings. As well, further information about the study can be obtained on the Midwest ISO website, under the Planning tab. This is located at: http://www.midwestmarket.org/page/Planning

8.2.2 Study Process

The RGOS study is following the Midwest ISO transmission planning process, see Section 2 of this report. This is a multi-step process that utilizes various generation scenarios, known as Futures[4], to represent plausible long-term generation expansions. As these Futures are analyzed, necessary transmission is developed to resolve any issues. Transmission developed in the analysis is then tested for robustness. Robustness looks for common transmission projects that provide benefit in all scenarios analyzed. The premise is that a particular transmission project that benefits all scenarios is a strong candidate for prudent future investment under a wide range of public policy direction.

The first step in this process for the RGOS is wind siting and the development of renewable energy zones. The RGOS is collecting data from the Department of Energy (DOE), National Renewable Energy Laboratory (NREL) for this purpose. NREL is conducting a study called the Eastern Wind Integration and Transmission Study (EWITS). EWITS will supply wind data for the upper Midwest that will allow the RGOS to identify, through a set of criteria, optimal wind resource locations to be utilized as generation sources, or renewable energy zones. During transmission analysis, collector points and transmission will be developed from these energy zones from which to move energy to load centers. The Midwest ISO Generator Interconnection Queue, while part of the input, will not be the driver for developing the energy resource zones. There is a weakness in using the queue for this since there are other factors that account for the geographic locations of queue requests. The queue also has a 60% drop out rate which makes it unstable for locating resource zones.

After the wind is sited, the next step is the creation of the Futures. In order to maintain consistency and coordination, the RGOS will use two Futures from MTEP09 as the basis for analysis. The two Futures to be used are the Reference Future and the Limited Investment Future (renamed Gas Only Future for RGOS). The Reference considers future generation expansion based on existing state/federal policies and requirements. This leads to a future biased with coal-type generation. The Gas Only Future considers more stringent requirements on coal generation expansion and also limited transmission corridor access. This leads to a future biased with natural gas generation expansion. These two Futures establish generation "bookends".

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[4] See Joint Coordinated System Plan at:

http://www.midwestmarket.org/publish/Folder/5d42c1_1165e2e15f2_-7efc0a48324a

Transmission expansion scenarios will be applied to the Futures using both a local and a regional expansion option. Local refers to transmission, and respective wind generation, sited wholly within a state to serve the respective states RPS needs. Regional refers to transmission expansion and wind generation sited optimally within the region regardless of state borders. This represents the transmission "bookends". See Figure 8.2-1.

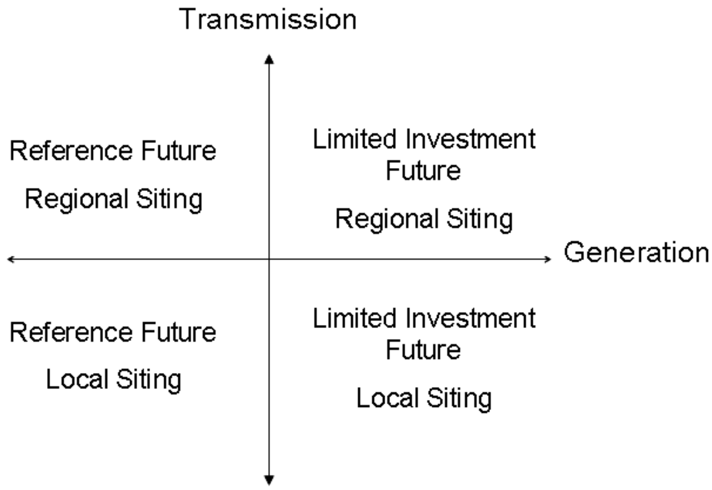

Figure 8.2-1: Transmission and Generation Bookends

Understanding the impacts of differing generation and transmission expansion options, impacts of renewable energy zone locations and the differences in the RPS and state requirements drives the RGOS to a multi-variable optimization type analysis. The RGOS will be looking to determine the most economical answer. Of utmost importance in this optimization is to provide transmission expansion options by which conscious decisions can be made for the future. In other words, the RGOS will help derive the necessary information by which decisions makers can use to determine the future direction of transmission. Traditionally projects are not developed in such a manner, but rather more from a local impact viewpoint. Generator Interconnection Queue studies are typically focused more on local impacts only.

8.2.3 Schedule

The RGOS is scheduled to be completed in the first quarter of 2009 with results included in the MTEP09 process and report. Upon completion of this study, a second study will commence for the eastern half of the Midwest ISO footprint, anticipated to include Ohio, Michigan and Indiana.

Task/Calendar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Stakeholder Review/Meeting												
Scope Development												
Siting Methodology												
Stakeholder Request (RPS requirements)												
Receive DOE Data												
EGEAS Model Creation (Step 1/2)												
Site Wind (Step 1/2)												
Create Futures (steps 1/2)												
Desing Preliminary Tx (PROMOD) (Step 3)												
* Iteration 1: Robustness and Tx Development (Step 4/5)												
* Iteration 2: Robustness and Tx Development (Step 4/5)												
* Iteration 3: Robustness and Tx Development (Step 4/5)												
Final Review												
Write Report												

* Robustness and Transmisison (Tx) Development consists of parallel PROMOD and power flow work to analyze and develop transmission projects. This process will be a 3-iteration process and will be performed in collaboration with the TRG members.

Figure 8.2-2: RGOS Project Schedule

8.3 Targeted Study: Southwestern Indiana Economic Projects

8.3.1 Introduction

From November 2006 to March 2007, MISO worked together with Transmission Owners (TO) in Indiana to evaluate the economic benefits of ten 345kV projects in Indiana proposed by DUKE. Based on the results, DUKE picked two projects (Wheatland-Whitestown 345kV line and Wheatland-Bloomington-Pritchard-Frank Twp-Hanna 345kV line) to include in MTEP 07 Appendix C. This study was done by using the 2011 PROMOD® case only.

In 2007, Indianapolis Power & Light (IPL) has been reviewing plans for new generation to meet future load growth. One of the many generation options being considered by IPL is a new plant in Southwest Indiana. They have included such a plant in their recently filed Integrated Resource Plan as a possible supply resource for the latter part of the next decade. During their review, IPL developed and studied some additional transmission plans that they believe should be evaluated as potential economic projects. These potential economic projects should be considered regardless of the selection of future resource plans by IPL because of possible regional benefits. Therefore, IPL asked MISO, together with influenced TOs in Indiana, to evaluate these potential economic projects individually and combined with other recently proposed projects in the Indiana region from the MISO Economic Study of Central and Southern Indiana and the MTEP08 process.

In December 2007, a study team is formed by the members from IPL, DUKE, Vectren, Hoosier Energy, NISPCO, ATC and MISO. IPL proposed three new 345kV projects. DUKE re-routed these two 345kV projects picked last year, and formed three new projects:

- Edwardsport-Whitestown 345kV line
- Edwardsport-Bloomington-Pritchard- Frank Twp-Hanna 345kV line
- Bloomington-Pritchard- Frank Twp-Hanna 345kV line

These six 345kV projects formed ten 345kV portfolios. The study team also proposed five 765kV projects which formed 6 765kV portfolios.

The scope document and assumptions for this study was finalized in March. In the same time, we sent out the 2011, 2016 and 2021 power flow cases, and the event files which would be used in this study to team members for reviewing. In this study, PROMOD® IV is used as a primary tool. Three years' (2011, 2016 and 2021) of PROMOD® cases were built and used in this study.

The results of the initial PROMOD® runs on these 16 portfolios were presented to the team on April 29th. The team reviewed the results, and proposed some updates to the base case, and some solutions to relieve the binding constraints shown in the system when the new portfolio added. The appropriate changes were made to the PROMOD® cases. The first round formal runs of these 16 portfolios was done in May and the results presented to the team on June 9th. After reviewing the results, the team decided to keep three 345kV projects which formed five portfolios for further evaluation. Because of the high cost of the 765kV portfolios, they did not show enough Benefit/Cost (B/C) ratios. The team believed that only considering the 765kV portfolio in Indiana would not bring enough benefit to offset the cost, so the team agreed on deferring the 765kV portfolio study to some future time after we have a better idea of the 765kV overlay in other areas/regions from Joint Coordinated System Planning (JCSP) and MTEP09 work.

We performed the second round of PROMOD® runs on these five 345kV portfolios. Besides the economic benefits, in this round run, we also calculated the energy loss and capacity loss benefits of these portfolios. The results were presented to the team on a conference call on July 23rd. A wrap-up meeting of this study was held on August 1st.

8.3.2 PROMOD® Cases and Assumptions

PROMOD® Cases

The MTEP08 Reference Future 2011, 2016 and 2021 PROMOD® cases are used as the starting cases for this study. We updated these cases based on the reviews and suggestions from the team members which make the cases better fit for the requirement of this study. These updates are summarized in the **Assumptions** section.

Assumptions

- **Power Flow Case:** MTEP08 2011, 2016 and 2021 power flow cases were reviewed and updated by the team members and ITC to incorporate proper planned and/or proposed transmission projects to have a better representation of the latest and most accurate transmission system for this study's specific need. Several updates were applied to MISO central and east regions. ITC also proposed to include some MTEP Appendix C projects that are under evaluation in reliability analysis in the base case models.
- **Future Generators:** The new generators identified in MTEP 08 Step 1 and 2 in Reference Future are included in the study, except the following modification:
    - Remove two 600 MW Strategist units (Year 2022) at Merom and Petersburg
    - Add 900 MW of new coal generation at Petersburg 345kV for 2016.
    - Add additional 300 MW of new coal generation at Petersburg 345kV for Year 2021, making total new generation to be 1200 MW, replacing the two Strategist units removed above.
    - Add 500 MW of wind at AEP's Dequine 345kV bus (Originally proposed location is Duke's Westwood 345kV bus), to be in service by 2011. Since that location seems to be the more likely place given the recent progress made by this request in the PJM queue.
    - Add 230MW (originally proposed is 130MW, but there are 230MW in that area already signed IAs) of wind at NIPSCO's Goodland 138kV bus, to be in service by 2011
    - Move the 600 MW new Coal (Year 2015) unit from Schafer in NIPSCO to First Energy's Sammis area
    - In Michigan, Fermi Nuclear unit (1563MW) and Karn Station Coal unit (863MW) are included in both 2016 and 2021 models. The same amount of Reference Future expansion units is removed to reflect the addition of these two units.

- **Event File:** Event file is the list of flowgates which will be treated as transmission constraints in security constrained unit commitment and economic dispatch. The quality of event file has a big impact on the quality of the study results. The 2011, 2016 and 2021 event files are also reviewed by the team members. Some new events (mainly the events used in last year's DUKE economic transmission projects study, and the events used in ITC's own PROMOD® cases) suggested by members are also added in.
- **Other Updates:** We did an initial round run of all base cases and portfolio cases, and identified the binding constraints in these cases. The study team went over these binding constraints, and found that some binding constraints can be relived by low cost fixes, or some projects already in MTEP Appendix B. So these fixes and projects are also added to the PROMOD® base cases:
  - Add new transformers in Dresser, Thompson, Pierce;
  - Replace the transformers in Petersburg, new rating is 300MVA;
  - Increase the ratings of the following 345kV lines from 956 to 1195MVA
    - 08HORTVL–08WHIST
    - 08NUCOR–08WHIST
    - 05BREED-16WHEAT
    - 16PETE-16THOMPS
  - Increase the rating of 345kV line 08WHEAT-08EDWDSP from 1195 to 1386MVA
  - Increase the rating of 138kV line 16SOUTH-16STOUTS from 276 to 427MVA
  - Increase the rating of 138kV line 08BEDFRD-08SHWSIC from 179 to 800MVA
  - Increase the rating of 230kV line 08WEBSTE-08WALTON from 319 to 797MVA
  - Increase the rating of Darwin-Eugene line to SN=971, SE =1419, WN=1234, WE = 1585
  - Update the contingency associated with Monitor Axton 765/138kV transformer (add the 2.5%, 138kV reactor in series with the Axton 765/138kV transformer)

8.3.3 Economic Project and Portfolios Evaluated

The economic projects are proposed by the team members based on their experience. Three 345kV projects come from last year's DUKE economic projects study (DUKE re-routed these projects, and broke one project into two projects). The others are newly proposed this year. The proposed projects include both the 345kV projects and 765kV projects. The study is performed on portfolios which are the combination of projects.

345kV New Projects:

- **Project 1:** Duke Gwynneville to the IPL Petersburg. New double circuit 345kV line.
- **Project 2:** Duke Gwynneville to the IPL Petersburg. New single circuit 345kV line.
- **Project 3:** Duke Greensboro to AEP Fall Creek. New single circuit 345kV line.
- **Project 4:** Edwardsport-Bloomington-Pritchard-Frank Twp-Hanna. New single circuit 345kV line.
- **Project 5:** Edwardsport-Whitestown. New single circuit 345kV line.
- **Project 6**: Bloomington-Pritchard-Frank Twp-Hanna. New single circuit 345kV line.

Figure 8.3-1 is the map showing these projects.

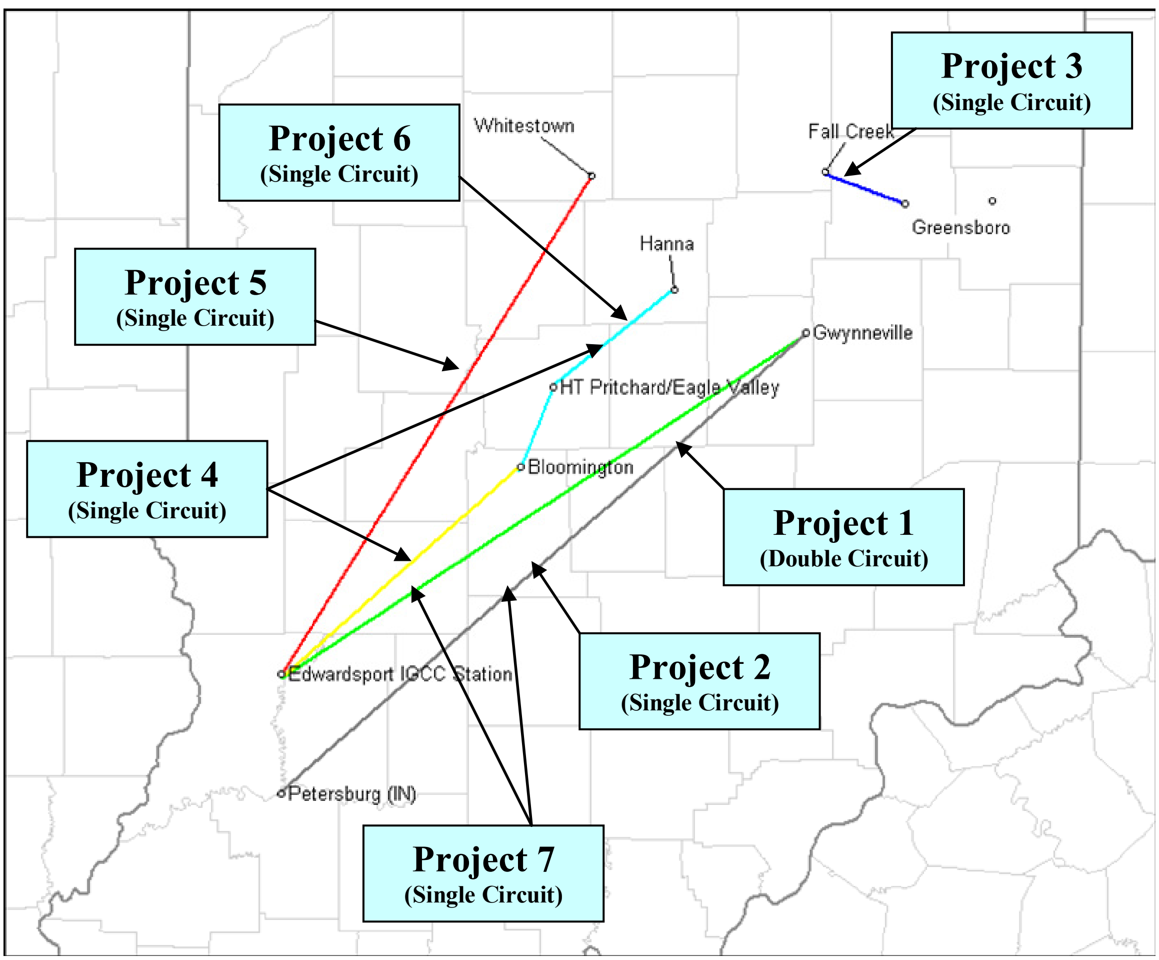

Figure 8.3-1: 345kV Projects

345kV Portfolios:

Portfolio is the combination of projects. Table 8.3-1 shows the 345kV portfolios and the projects form the portfolios. The cost of each portfolio is estimated by the team members.

Table 8.3-1: 345kV Portfolios Definitions and Costs

	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Cost (M$)
Length (Miles)	120	120	11	92	111	42	
345kV Portfolio 1				X			129
345kV Portfolio 2					X		170
345kV Portfolio 3	X		X				271
345kV Portfolio 4		X	X				225
345kV Portfolio 5				X	X		291
345kV Portfolio 6	X		X	X			400
345kV Portfolio 7		X	X	X			347
345kV Portfolio 8	X		X		X		433
345kV Portfolio 9		X	X		X		380
345kV Portfolio 10						X	58

765kV New Projects

- **Project 1**: Tie the AEP 765kV line from Jefferson to Greentown into the Duke 345kV Gwynneville substation. Add two 765/345kV autotransformers.
- **Project 2**: Tie the AEP 765kV line from Rockport to Sullivan into a new 765kV substation at Petersburg.
- **Project 3**: AEP Sullivan to Duke Greentown. New single circuit 765kV line.
- **Project 4:** AEP Sullivan to CE Wilton Junction New single circuit 765kV line.
- **Project 5:** IPL Petersburg-Duke Gwynneville New single circuit 765kV line.
- **Project 6:** Rockport- Edwardsport-Greentown. New single circuit 765kV line.

Figure 8.3-2 is the map showing these projects.

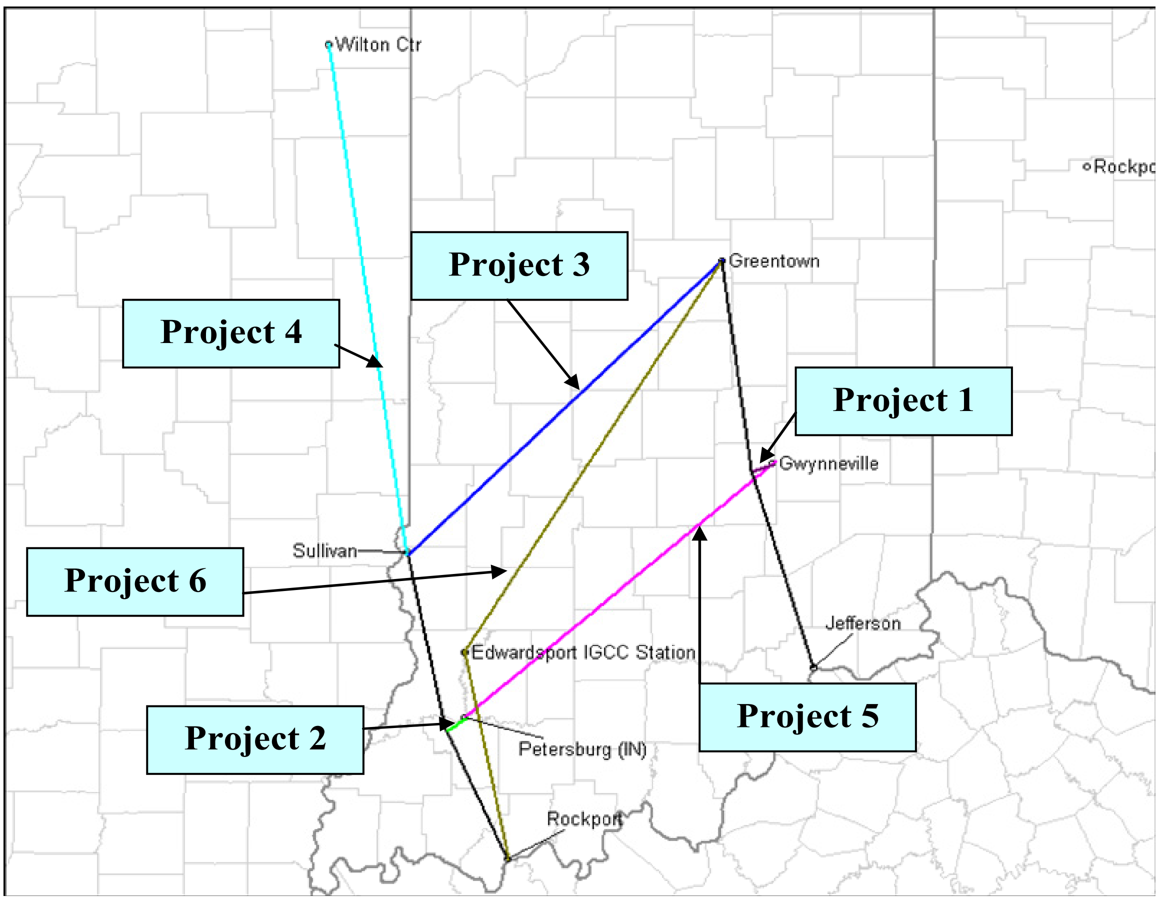

Figure 8.3-2: 765kV Projects

765kV Portfolios

Table 8.3-2 shows the 765kV portfolios and the projects form the portfolios. The costs of the portfolios are estimated by the team members.

Table 8.3-2: 765kV Portfolios Definitions and Costs								
	345 Project 3	**Project 1**	**Project 2**	**Project 3**	**Project 4**	**Project 5**	**Project 6**	**Cost (M$)**
Length (Miles)	11	N/A (directly tap)	6	150	175	120	196	
765kV Portfolio 1	X	X	X	X				695
765kV Portfolio 2	X	X	X		X			762
765kV Portfolio 3	X	X	X			X		604
765kV Portfolio 4	X	X	X	X		X		1,089
765kV Portfolio 5	X	X	X		X	X		1,156
765kV Portfolio 6	X						X	861

8.3.4 Economic Benefits Calculated

In each year (2011, 2016, 2021), we ran one base case, and 16 portfolios cases (for 2011, we did not run the 765kV portfolios, so there were ten portfolio cases run in 2011). Then we compared the economic indices difference between the portfolio case and the base case to get the corresponding economic benefits of the portfolio. The following economic benefits are calculated for each portfolio:

- **Adjusted Production Cost =** Production Cost +/- (Net Purchase)/(Net Sale) *(Load Weighted Locational Marginal Price (LMP))/(Generation Weighted LMP)
(depending on 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
- **Net Gen Revenue =** Unit Revenue (Generation*Generation LMP)-Production Cost-Fixed O&M

We also calculate the Regional Expansion Criteria & Benefits (RECBII) Benefit and B/C Ratio for all portfolios. The RECB II Benefit is defined as:

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

The RECB II B/C Ratio is calculated as:

- For 345kV portfolios, we run the 2011, 2016 and 2021 PROMOD® cases. The benefits of these years are directly from PROMOD® runs. The benefits of years between these years are the linear interpolation of these years. Then we calculate the NPV (net present value) of 11 years' (2011 to 2021) total benefits. We also calculated the NPV of same 11 years' total cost.
- For 765kV portfolios, we run the 2016 and 2021 PROMOD® cases. The benefits of these two years are directly from PROMOD® runs. The benefits of years between these two years and from Year 2021 to Year 2025 are the linear interpolation/extrapolation of these two years values. Then we calculate the Net Present Value (NPV) of ten years' (2016 to 2025) total benefits. We also calculated the NPV of the same ten years' total cost.

In these calculations, the 14% fixed charge rate, 10% discount rate, and 3% inflation rate are used. The 14% fixed charge rate is an assumption used in this study. To determine if projects meet RECB II criterion, actual Transmission Owner's fixed charge rate must be used in cost calculation.

Besides these economic benefits, for a selected set of portfolios, we also calculate the benefit of annual energy loss savings and capacity loss savings.

8.3.5 The First Round PROMOD® Run Results

In the first round PROMOD® run, we totally ran 45 PROMOD® cases:

- 2011 base case and ten 345 portfolios cases
- 2016 base case and all 16 345kV and 765kV portfolios cases
- 2021 base case and all 16 345kV and 765kV portfolios cases;

The detailed economic benefits (adjusted production cost savings, load cost savings and net generation revenue increases) of these portfolios on MISO planning regions (east, center, and west), and selected companies (these are companies in Indiana or close to these projects: AEP, DUKE, IPL, Vectren, Hoosier Energy, NIPSCO, AMEREN) are shown in Figure A-G-1 to Figure A-G-18 in Appendix G.

Figure 8.3-3 shows the RECB II B/C Ratio for these portfolios.

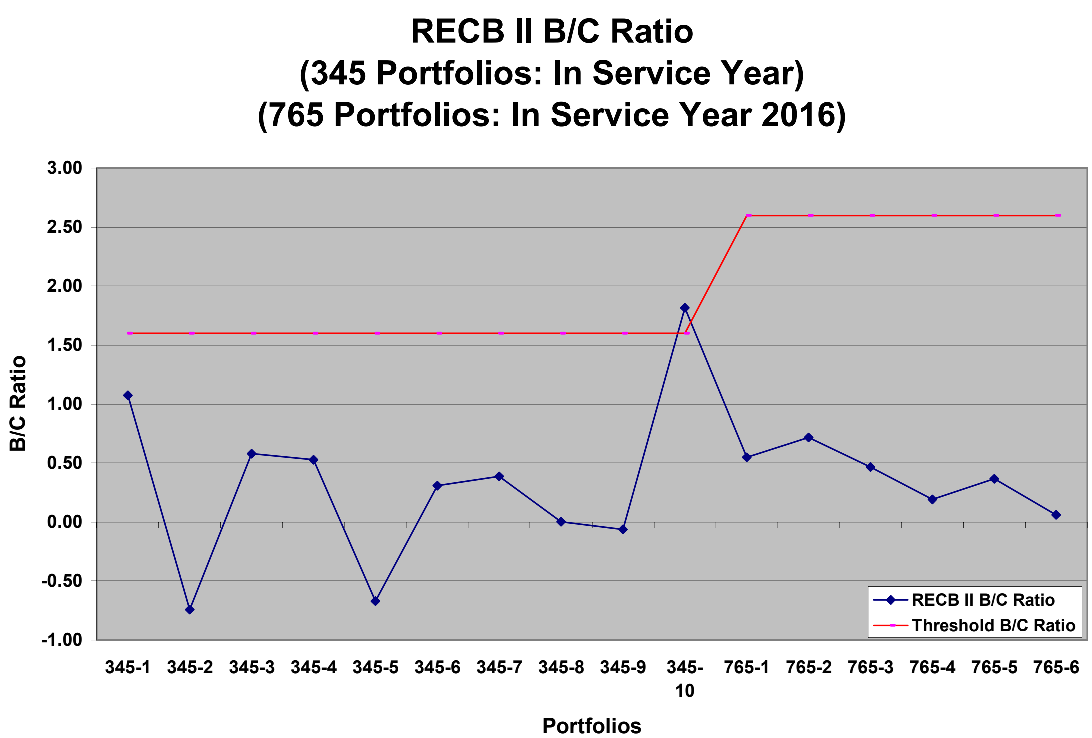

Figure 8.3-3: RECB II B/C Ratios

The red line in Figure 8.3-3 shows the B/C Ratio threshold defined in RECB II. Only if the B/C ratio of the portfolio passes the threshold B/C ratio, the portfolio is the Regional Benefit Project, and is eligible for the cost sharing. In RECB II, the threshold B/C ratio is not a constant. It increases linearly with the time until planned in-service year. In this study, we assume the in service year of 345kV portfolios is 2011, and of 765kV portfolios is 2016. So the RECB II threshold B/C ratio for 345kV portfolios is 1.6, and for 765kV portfolios, it is 2.6.

Among all these portfolios, only 345kV Portfolio 10 passes the threshold. But this calculation is based on the assumption of 14% fixed charge rate, 10% discount rate, and 3% inflation rate. Once these assumed numbers change, the B/C Ratio of the portfolio will also change. So the portfolio needs to be re-evaluated based on the Transmission Owner's actual fixed charge rate and discount rate, if the portfolio needs to be moved from MTEP Appendix B to Appendix A. For the 765kV portfolios, though they show benefits larger than the 345kV portfolios, because of their high project costs, the B/C ratio is still small.

After reviewing this round run's results, the study team made the following decisions:

- The study team believes that only adding 765kV lines in Indiana area will not bring enough benefits to cover its cost. The larger benefit of a 765kV line is not from relieving the binding constraints in local area, but from delivering power from a cheap source area to an expensive sink area. To achieve more benefit, these 765kV line portfolios should be studied together with 765kV lines in other areas/regions. The team agrees on deferring the 765kV portfolio study to some future time after we have a better idea of the 765kV overlay in other areas/regions from JCSP and MTEP09 work.
- 345kV Portfolio 2 (Project 2 (Edwardsport- Whitestown)) is not a good economic project, so we will not include it in the next round study.
- 345kV Portfolio 3 (Gwynneville-Petersburg 345kV double circuits) and Portfolio 4 (Gwynneville-Petersburg 345kV single circuits) do not show a big difference in the B/C ratio. So the team decided to keep Portfolio 3. In the mean time, one team member proposed an alternative to Portfolio 3, i.e., a 345kV single circuit Gwynneville-Petersburg + 345kV single circuit Gwynneville-Edwardsport. To decide which one to be kept, we did a test run of this new alternative, and compare its benefits and B/C ratio with those of Portfolio 3. They are similar. The team decided to use a new alternative to replace Portfolio 3.

The group also reviewed the binding constraints of 345kV Portfolios 1, 3 and 10. The constraints that worsened in these portfolios (comparing the total shadow price with base case) are:

- Breed to Wheatland 345kV line
- STOUTS transformer with the loss of both RockVille-Guion and RockVille-Thompson 345kV lines.

To relieve these constraints, the study team proposed two solutions:

- **Solution 1:** increase the rating of Breed to Wheatland 345kV line to 1386 MVA;
- **Solution 2:** add new switches in the RockVille substation to make sure that the 345kV lines RockVille-Guion and RockVille-Thompson will not be out of service at the same time, so we only need to consider one line outage (RockVille-Thompson) contingency.

8.3.6 The Second Round PROMOD® Run Results

This round PROMOD® run is performed on the reduced set of portfolios selected by the team based on the first round run results. In this round, we calculated the similar economic benefits as in the first round. In addition, we turned on the "Dynamic Loss" switch in PROMOD®, which can calculate the hourly loss for each company. Using these hourly loss values, we can capture the annual energy loss and capacity loss benefits of portfolios.

345kV Projects:

- **Project 3:** Duke Greensboro to AEP Fall Creek. New single circuit 345kV line.
- **Project 4:** Edwardsport-Bloomington-Pritchard-Frank Twp-Hanna. New single circuit 345kV line.
- **Project 6:** Bloomington-Pritchard-Frank Twp-Hanna. New single circuit 345kV line.
- **Project 7:** (alternative of Project 1). Duke Gwynneville to IPL Petersburg, and Duke Gwynneville to DUKE Edwardsport. New double circuit 345 kV line. IPL Comment: This line is 90% double circuit and then splits off to Petersburg and Edwardsport.

Solutions to Binding Constraints:

We also have two solutions for relieving binding constraints:

- **Solution 1:** increase the rating of Breed to Wheatland 345kV line to 1386 MVA;
- **Solution 2:** add new switches in RockVille substation to make sure that the 345kV lines RockVille-Guion and RockVille-Thompson will not be out of service at the same time, so we only need to consider one line outage (RockVille-Thompson) contingency.

345kV Portfolios:

Table 8.3-3 lists the 345kV portfolios for the second round PROMOD® runs and the associated projects. For Portfolio 1, 3 and 10, although the projects/solutions forming these portfolios are not exact same as the first round run, the changes are not big. So to help compare the results from the first round run and the second round run, we use the same portfolio numbers as in first round run for these three portfolios.

Table 8.3-3: 345kV Portfolios Definitions and Costs (the Second Round Run)

	Project 3	Project 4	Project 6	Project 7	Solution 1	Solution 2	Cost (M$)
Length (Miles)	11	92	42	120			
345kV Portfolio 1		X			X	X	138
345kV Portfolio 10			X			X	60
345kV Portfolio 3	X			X	X		279
345kV Portfolio 11	X	X		X	X	X	415
345kV Portfolio 12	X		X	X	X	X	339

Results:

The detailed economic benefits (adjusted production cost savings, load cost savings and net generation revenue increases) of these portfolios on MISO planning regions (east, center, and west), and selected companies (these are companies in Indiana or close to these projects: AEP, DUKE, IPL, Vectren, Hoosier Energy, NIPSCO, AMEREN) are shown in Figure A-G-19 to Figure A-G-36 in Appendix G.

Figure 8.3-4 shows the RECB II B/C Ratio for these portfolios.

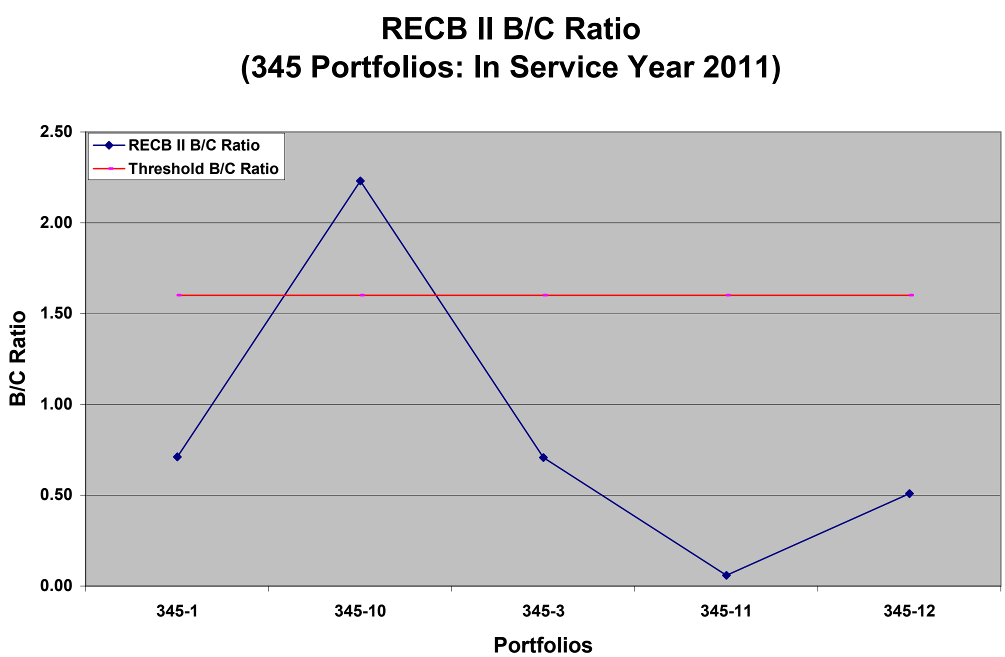

Figure 8.3-4: RECB II B/C Ratios

Among all these portfolios, only 345kV Portfolio 10 still passes the threshold. Because of the addition of Solution 2 to this portfolio, this round's B/C ratio is larger than that of the first round. But this calculation is based on the assumption of a 14% fixed charge rate, 10% discount rate, and 3% inflation rate. Once these assumed number change, the B/C Ratio of the portfolio will also change. So the portfolio need to be re-evaluated based on Transmission Owner's actual fixed charge rate and discount rate, if the portfolio needs to be moved from MTEP Appendix B to Appendix A.

Table 8.3-4 shows how the B/C ratio of the portfolio will change if the fixed charge rate changes. The B/C Ratio will increase with the decrease of the fixed charge rate.

Table 8.3-4: Portfolio B/C Ratio Change with the Change of Fixed Charge Rate					
Fixed Charge Rate	**345 Portfolio 1**	**345 Portfolio 10**	**345 Portfolio 3**	**345 Portfolio 11**	**345 Portfolio 12**
10%	1.00	3.12	0.99	0.08	0.71
12%	0.83	2.60	0.82	0.07	0.59
14%	0.71	2.23	0.71	0.06	0.51
16%	0.62	1.95	0.62	0.05	0.44
18%	0.55	1.74	0.55	0.05	0.40
20%	0.50	1.56	0.49	0.04	0.36
22%	0.45	1.42	0.45	0.04	0.32
24%	0.42	1.30	0.41	0.03	0.30

Loss Benefits:

In this round run, we also calculated the hourly loss of each company. The following loss related benefits are calculated for selected companies (DUKE, IPL, Vectren, Hoosier Energy, NIPSCO, and AMEREN) and MISO:

- **Energy Loss Benefit (MWH):** this is the annual total loss decrease (MWH) from base case to portfolio case;
- **Capacity Loss Benefit (MW):** the capacity loss benefit for each company is the loss decrease (MW) from base case to portfolio case in company's peak load hour.

To quantify the dollar value of the energy loss benefit, for each hour, besides the hourly company loss, we also calculate the hourly company loss cost which is the product of the company loss and the company load weighted LMP at the same hour. Then we can use the annual loss cost savings to quantify the dollar value of energy loss benefit.

To quantify the dollar value of the capacity loss benefit, we use $650/kW-$1200/kW as the price range for the construction of different type units. So the corresponding dollar value of capacity loss benefits will be the capacity value times these prices. And the dollar benefit values are in a range.

Besides these benefit information, we also calculated the following information:

- **Maximum hourly loss decrease (MW):** this is the maximum hourly loss decrease (MW) from base case to portfolio case in each company;
- **Maximum hourly loss increase (MW):** this is the maximum hourly loss increase (MW) from base case to portfolio case in each company. This information is actually not the benefit, but the worst situation in loss when adding the portfolio.
- **Loss decrease (MW) in MISO peak load hour:** this shows each company's loss decrease (MW) from base case to portfolio case in MISO peak load hour.

Tables 8.3-5 to 8.3-7 show the loss information in Year 2011, 2016 and 2021.

Table 8.3-5: Loss Information in Year 2011

Energy Loss Benefit -> Annual Total Loss Decrease (MWH)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	80,652	-27,366	33,816	2,153	4,198	-4,210		87,649
Portfolio 10	91,769	-43,380	16,504	1,492	868	-350		63,218
Portfolio 3	8,553	5,851	83,264	3,560	7,390	-7,727		109,451
Portfolio 11	91,783	-20,685	99,111	4,925	9,590	-8,081		186,088
Portfolio 12	95,530	-32,019	95,323	4,720	7,792	-9,112		168,787
Capacity Loss Benefit -> Loss Decrease (MW) in Company's Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	15.17	-2.76	4.77	0.21	1.01	18.34		11.48
Portfolio 10	18.06	-5.38	3.74	-0.33	1.38	19.91		7.05
Portfolio 3	5.43	-0.92	12.41	0.25	1.78	18.43		18.37
Portfolio 11	19.13	-4.19	13.68	0.40	2.13	17.16		24.60
Portfolio 12	19.86	-6.05	13.94	1.62	1.79	17.46		24.68
Max Hourly Loss Decrease (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	75	2	19	28	27	252		307
Portfolio 10	74	1	18	27	31	258		285
Portfolio 3	63	7	27	27	32	238		283
Portfolio 11	80	3	29	28	28	238		307
Portfolio 12	78	4	30	28	32	257		302
Max Hourly Loss Increase (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	67	10	12	30	18	227		263
Portfolio 10	64	14	15	26	19	269		268
Portfolio 3	81	5	6	26	18	229		261
Portfolio 11	68	10	4	27	17	241		250
Portfolio 12	67	12	4	27	17	275		260
Loss Decrease (MW) in MISO Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	2.91	-0.79	4.62	-0.33	-0.09	3.06		11.48
Portfolio 10	2.61	-2.34	1.55	-0.31	0.08	3.93		7.05
Portfolio 3	3.15	0.60	10.51	-0.14	0.49	2.33		18.37
Portfolio 11	8.12	-0.03	12.62	0.05	0.64	3.54		24.60
Portfolio 12	7.03	-1.21	11.69	0.08	0.51	3.92		24.68

Table 8.3-6: Loss Information in Year 2016

Energy Loss Benefit -> Annual Total Loss Decrease (MWH)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	71,402	-20,678	36,050	1,928	4,513	-3,180		93,052
Portfolio 10	82,222	-39,656	14,780	910	690	-382		56,911
Portfolio 3	15,055	9,261	93,395	2,668	7,990	-6,240		128,572
Portfolio 11	102,150	-10,939	114,655	4,860	10,638	-2,786		235,285
Portfolio 12	95,506	-24,834	105,451	4,074	8,490	-6,425		190,923
Capacity Loss Benefit -> Loss Decrease (MW) in Company's Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	-0.25	-0.98	3.72	0.09	0.80	17.69		17.70
Portfolio 10	4.31	-3.47	2.00	-0.11	0.19	18.05		4.52
Portfolio 3	5.55	1.75	13.45	0.07	1.58	-2.18		27.91
Portfolio 11	17.72	0.45	14.74	0.35	2.53	-3.97		38.84
Portfolio 12	7.20	-1.69	14.88	-0.21	1.62	16.82		30.14
Max Hourly Loss Decrease (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	113	3	35	31	25	236		344
Portfolio 10	117	3	32	31	24	234		347
Portfolio 3	99	7	45	30	25	239		357
Portfolio 11	116	6	49	35	30	252		369
Portfolio 12	100	3	41	32	30	235		351
Max Hourly Loss Increase (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	87	11	23	32	31	253		275
Portfolio 10	84	14	29	25	32	253		277
Portfolio 3	96	5	7	35	30	268		261
Portfolio 11	105	11	5	31	29	264		242
Portfolio 12	83	11	4	32	30	256		252
Loss Decrease (MW) in MISO Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	5.66	-0.43	6.35	-0.03	0.53	0.53		17.70
Portfolio 10	5.77	-2.68	2.00	0.21	-0.01	-0.31		4.52
Portfolio 3	5.80	1.30	14.96	0.47	0.70	0.28		27.91
Portfolio 11	14.56	0.91	18.28	0.42	1.12	-1.23		38.84
Portfolio 12	10.89	-0.78	16.25	0.05	0.68	-1.07		30.14

Table 8.3-7: Loss Information in Year 2021

Energy Loss Benefit -> Annual Total Loss Decrease (MWH)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	68,165	-18,833	33,085	902	4,612	-5,936		82,485
Portfolio 10	74,542	-40,118	10,268	426	525	-2,077		37,853
Portfolio 3	19,626	9,910	102,663	2,646	8,487	-8,355		142,294
Portfolio 11	98,489	-8,784	118,095	3,849	11,217	-8,085		229,042
Portfolio 12	96,135	-23,977	112,837	3,272	8,786	-8,631		197,998
Capacity Loss Benefit -> Loss Decrease (MW) in Company's Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	-16.84	-2.06	6.68	-2.13	-0.18	-1.31		11.21
Portfolio 10	-15.10	-5.82	2.04	-2.85	-1.20	-0.36		3.59
Portfolio 3	-20.49	0.84	19.08	-2.86	0.72	2.06		106.25
Portfolio 11	-9.82	-0.50	21.92	-2.60	1.35	-10.86		20.15
Portfolio 12	-10.98	-3.14	20.59	-2.41	0.76	-2.19		33.70
Max Hourly Loss Decrease (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	101	4	31	31	32	247		328
Portfolio 10	106	6	33	30	31	283		316
Portfolio 3	123	7	56	27	32	282		341
Portfolio 11	104	5	43	29	32	261		356
Portfolio 12	103	4	44	30	32	248		374
Max Hourly Loss Increase (MW)								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	96	10	22	27	27	285		330
Portfolio 10	92	15	29	28	36	452		338
Portfolio 3	107	12	7	26	35	355		322
Portfolio 11	84	10	4	33	32	260		305
Portfolio 12	86	12	6	33	32	290		312
Loss Decrease (MW) in MISO Peak Load Hour								
	DUKE	**HEC**	**IPL**	**NIPS**	**SIGE**	**AMEREN**		**MISO**
Portfolio 1	11.11	-3.33	5.78	2.22	0.61	-0.35		11.21
Portfolio 10	12.48	-7.12	0.88	2.13	0.05	0.41		3.59
Portfolio 3	21.60	5.13	26.62	0.65	0.41	-9.23		106.25
Portfolio 11	19.98	-0.19	23.43	0.94	0.46	-16.92		20.15
Portfolio 12	17.16	-4.19	21.70	2.82	1.17	-1.22		33.70

Tables 8.3-8 to 8.3-10 show the loss cost saving (dollar value of energy loss benefit) in three study years. Red means positive benefits. Black means negative benefits.

Table 8.3-8: Loss Cost Savings in Year 2011

Annual Total Loss Cost Saving ($)								
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	3,476,587	-1,196,958	1,760,260	103,188	144,537	-130,105		4,242,664
Portfolio 10	3,911,451	-1,921,049	875,696	75,203	18,146	-49,914		2,879,434
Portfolio 3	428,729	249,051	4,124,297	179,607	269,733	-260,128		5,767,323
Portfolio 11	4,011,445	-914,232	4,922,909	247,803	338,590	-297,680		9,240,003
Portfolio 12	4,147,768	-1,423,742	4,716,997	248,138	268,784	-313,296		8,538,333

Table 8.3-9: Loss Cost Savings in Year 2016

Annual Total Loss Cost Saving ($)								
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	3,976,205	-1,207,761	2,667,063	93,949	125,490	-153,223		6,116,286
Portfolio 10	4,340,054	-2,342,896	1,288,400	28,702	-84,898	-190,796		3,686,963
Portfolio 3	1,369,706	518,023	6,110,909	161,488	314,789	-295,590		9,162,261
Portfolio 11	3,893,098	-677,838	6,820,041	250,754	646,061	167,441		12,096,664
Portfolio 12	5,506,238	-1,447,543	6,848,888	228,011	310,588	-554,810		11,775,554

Table 8.3-10: Loss Cost Savings in Year 2021

Annual Total Loss Cost Saving ($)								
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	5,002,407	-1,660,688	4,461,133	95,528	-110,784	-863,240		5,215,211
Portfolio 10	5,515,535	-3,259,086	2,641,375	114,269	-386,314	-516,349		3,709,614
Portfolio 3	2,296,700	515,466	9,870,206	412,112	148,890	-619,387		15,052,718
Portfolio 11	6,767,711	-1,017,798	10,984,948	495,457	240,722	-698,655		17,075,529
Portfolio 12	6,943,820	-2,134,178	10,693,646	364,541	112,568	-575,593		17,874,918

Tables 8.3-11 to 8.3-13 show the dollar value of capacity loss benefit in three study years. Red means positive benefits. Black means negative benefits.

Table 8.3-11: Dollar Value of Capacity Loss Benefit in Year 2011

	$ Value of Capacity Loss Benefit (k$)							
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	9,860 ~ 18,204	-1,794 ~ -3,313	3,100 ~ 5,724	136 ~ 252	656 ~ 1,212	11,921 ~ 22,008		7,461 ~ 13,775
Portfolio 10	11,739 ~ 21,672	-3,497 ~ -6,456	2,431 ~ 4,487	-215 ~ -396	897 ~ 1,656	12,941 ~ 23,892		4,582 ~ 8,459
Portfolio 3	3,529 ~ 6,516	-599 ~ -1,104	8,066 ~ 14,892	162 ~ 300	1,157 ~ 2,136	11,979 ~ 22,116		11,940 ~ 22,043
Portfolio 11	12,434 ~ 22,956	-2,724 ~ -5,029	8,892 ~ 16,416	259 ~ 479	1,384 ~ 2,556	11,154 ~ 20,592		15,990 ~ 29,520
Portfolio 12	12,909 ~ 23,832	-3,933 ~ -7,261	9,061 ~ 16,728	1,053 ~ 1,944	1,163 ~ 2,148	11,349 ~ 20,952		16,042 ~ 29,615

Table 8.3-12: Dollar Value of Capacity Loss Benefit in Year 2016

	$ Value of Capacity Loss Benefit (k$)							
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	-163 ~ -300	-638 ~ -1,176	2,418 ~ 4,464	58 ~ 108	520 ~ 960	11,498 ~ 21,228		11,504 ~ 21,239
Portfolio 10	2,801 ~ 5,172	-2,256 ~ -4,164	1,300 ~ 2,400	-72 ~ -132	123 ~ 228	11,732 ~ 21,660		2,937 ~ 5,423
Portfolio 3	3,607 ~ 6,660	1,137 ~ 2,100	8,742 ~ 16,140	45 ~ 84	1,027 ~ 1,896	-1,417 ~ -2,616		18,141 ~ 33,492
Portfolio 11	11,518 ~ 21,264	292 ~ 540	9,581 ~ 17,688	227 ~ 420	1,644 ~ 3,036	-2,581 ~ -4,765		25,246 ~ 46,608
Portfolio 12	4,680 ~ 8,640	-1,099 ~ -2,028	9,672 ~ 17,856	-137 ~ -252	1,053 ~ 1,944	10,933 ~ 20,184		19,590 ~ 36,167

Table 8.3-13: Dollar Value of Capacity Loss Benefit in Year 2021

	$ Value of Capacity Loss Benefit (k$)							
	DUKE	HEC	IPL	NIPS	SIGE	AMEREN		MISO
Portfolio 1	-10,946 ~ -20,208	-1,339 ~ -2,472	4,342 ~ 8,016	-1,385 ~ -2,556	-117 ~ -216	-852 ~ -1,572		7,286 ~ 13,452
Portfolio 10	-9,815 ~ -18,120	-3,784 ~ -6,985	1,326 ~ 2,448	-1,853 ~ -3,420	-780 ~ -1,440	-234 ~ -432		2,333 ~ 4,307
Portfolio 3	-13,319 ~ -24,588	545 ~ 1,007	12,402 ~ 22,896	-1,859 ~ -3,432	467 ~ 863	1,338 ~ 2,471		69,062 ~ 127,500
Portfolio 11	-6,384 ~ -11,784	-325 ~ -600	14,248 ~ 26,304	-1,690 ~ -3,120	877 ~ 1,620	-7,060 ~ -13,032		13,097 ~ 24,179
Portfolio 12	-7,138 ~ -13,176	-2,041 ~ -3,768	13,383 ~ 24,708	-1,567 ~ -2,892	494 ~ 912	-1,424 ~ -2,628		21,905 ~ 40,439

From these tables we can see that although Portfolio 10 has the largest B/C ratio, it shows the least loss benefit.

8.3.7 Conclusions

In this study, we performed two rounds of PROMOD® runs, and evaluated a total of 18 portfolios (12 345kV Portfolios and six 765kV Portfolios).

For the 765kV portfolios, though they show benefits larger than the 345kV portfolios, because of their high project costs, the B/C ratio is still small. The study shows that only adding 765kV lines in the Indiana area will not bring enough benefits to cover its cost. The larger benefit of 765kV line is not from relieving the binding constraints in a local area, but from delivering power from a cheap source area to an expensive sink area. That is the reason why we defer the 765kV portfolio study to some future time after we have a better idea of the 765kV overlay in other areas/regions from JCSP and MTEP09 work.

As to the 345kV Portfolios, they will bring different economic benefits (load cost savings, adjusted production cost savings, net generation revenue increases) to different companies. When we use the RECB II criterion, only 345kV Portfolio 10 (Bloomington-Pritchard-Frank Twp-Hanna single circuit 345kV line) passes the B/C ratio threshold. But this calculation is based on the assumption of 14% fixed charge rate, 10% discount rate, and 3% inflation rate. Once these assumed number change, the B/C Ratio of the portfolio will also change. So the portfolio need to be re-evaluated based on the Transmission Owner’s actual fixed charge rate and discount rate, if the portfolio needs to be moved from MTEP Appendix B to Appendix A.

8.4 Targeted Studies: ITC Study

8.4.1 Executive Summary

On November 6, 2006, ITC Holdings, Inc. (ITC) and American Electric Power (AEP) announced plans to perform a joint technical study to evaluate the feasibility and benefits of building a 765kV transmission network in Michigan's Lower Peninsula and connecting to AEP's existing 765kV transmission network in Michigan and Ohio. This proposed transmission infrastructure will span approximately 700 miles and would expect to significantly improve Michigan import capability and enhance overall system reliability. ITC and AEP are committed to working with Midwest ISO and Maryland Interconnect (PJM) to have this proposed 765kV transmission infrastructure expansion evaluated under the Midwest ISO MTEP and the PJM RTEP planning processes. This technical report provides the preliminary draft results of the initial study work that Midwest ISO has conducted and a study team has been formed to ensure coordinated planning. The study team includes Detroit Edison, Consumers Energy, ITC, AEP, DUKE, First Energy, IPL, PJM, Midwest ISO, ABATE, NIPSCO, Michigan PSC and Michigan Public Power Agency.

The conceptual 765kV transmission expansions in Michigan and Ohio were initiated for MTEP03 as Exploratory Studies for informational purposes only. Since the boundaries and membership of Midwest ISO and PJM were not firm at the time the studies were performed, limited analysis was done on the conceptual expansion. MTEP06 continued the development of long-term expansion plans using regional exploratory studies. The Michigan Exploratory study investigated a 500kV HVDC and a 765kV option across Michigan to increase import capability into ITC as needed to meet one day in ten year loss of load expectation for ITC. Targeted studies replaced regional exploratory studies in MTEP08. AEP-ITC 765kV targeted study scope was first addressed to solicit the study team at the East Sub-regional Planning Meeting on Jan 22nd, 2008. The first kick off conference meeting was held on Jan, 31st, 2008 to discuss the scope of the study. The second conference meeting was held on Feb 21st, 2008 to go over the review results of the input assumptions. With the locked down input assumptions on Friday Feb 29th, 2008, the economic benefit and load deliverability analysis have been performed and completed at the end of April, and the third stakeholder meeting was held on May 8th, 2008 at Michigan to go over the results and discuss the findings and next step.

The purpose of this study is to evaluate the economic benefits of the proposed 765kV transmission project under various future generation scenarios and transmission portfolio options. This study is also to explore and determine the need justifications for the project, longer term reliability, capacity or regionally economic beneficial. Currently this proposed project is a conceptual solution in MTEP Appendix C without needs proven. To fully capture the value of the proposed long-term project, a broader set of value metrics should be under consideration for justification.

PROMOD IV® is a commercial production cost model to perform hourly chronological security constrained unit commitment and economic dispatch recognizing both generation and transmission impacts. It can be used to evaluate the economic benefits of transmission expansion projects. Midwest ISO used PROMOD IV® as the primary tool and MTEP08 model input assumptions as basis to evaluate the economic benefit of AEP-ITC 765kV transmission project.

8.4.2 Study Methodology and Assumptions

Model Development

MTEP08 developed power flow and PROMOD® economic models and input assumptions were used as the starting point for this economic benefit study effort. MTEP08 2016 and 2021 power flow models were reviewed and updated to incorporate proper planned and/or proposed transmission projects to have a better representation of the latest and most accurate transmission system for this study specific need. Several updates were applied to Midwest ISO central and east regions. And ITC proposed MTEP Appendix C projects that are under evaluation in reliability analysis were included in the base case models as well.

MTEP08 2016 and 2021 PROMOD® event files (transmission constraint list) were reviewed and updated with the identified changes for existing events and additional new events.

Future Generation Portfolio Assumptions

MTEP08 Step 1 and 2 developed four different Future Generation Portfolios to represent four potential future scenarios with different input assumptions and uncertainty variables. Please refer to section 4.1 Generation Futures Development for more details.

Reference Future, Renewable Future and Environmental Future were selected for this study to represent different future generation expansion scenarios. Reference Future is considered the status quo future and is the base case scenario for this study. These three Future Generation Portfolios were reviewed by the study team and PROMOD® models were updated to reflect the identified generation expansion changes. The detailed updates for each Future are described below.

Reference Future

Fermi Nuclear unit with 1563MW and Karn Station Coal unit with 863MW were included in both 2016 and 2021 models. The same MW amount of future expansion units was replaced to reflect the addition of these two units.

1500MW wind units in Midwest ISO Queue were included and assumed to be in service before year 2011. The locations were spread out in West, Central and Thumb of Michigan to achieve the geographical diversity. Since 15% of the wind nameplate capacity is counted towards to the reserve margin, 225MW of future expansion thermal units were replaced to reflect the added 1500MW Midwest ISO Queue wind units.

Renewable Future

In the original MTEP08 Renewable Mandate Future, there were 4500MW future resource forecasting wind units sited in Michigan. The study team agreed 4500MW is a reasonable wind amount for a renewable scenario. The wind units in Midwest ISO queue were used first to replace the same amount of future expansion wind units and the remaining MW used future expansion units to meet the total 4500MW wind mandate.

Fermi Nuclear unit with 1563MW and Karn Station Coal unit with 863MW were included in Renewable Future as well. The same amount of future expansion units were replaced as in the Reference Future.

Environmental Future

The same generation updates were applied in Environmental Future as in the Reference Future.

The following generation changes identified in the parallel Southern Indiana Targeted Study reference scenario were incorporated in the Reference Future generation scenario:

- Remove two 600 MW Strategist units (2022) at Merom and Petersburg.
- Add 900 MW of new coal generation at Petersburg 345kV for 2016. Add additional 300 MW of new coal generation at Petersburg 345kV for 2021, making total new generation to be 1200 MW, replacing the two Strategist units removed above.
- Remove existing Edwordsport units 6, 7 and 8 since they will be retired when the new 600 MW unit comes online.

Table 8.4-1 shows the updated future generation expansion unit information for Reference Future, Renewable Future and Environmental Future. Only the units located in Michigan are listed in the table.

Table 8.4-1: Michigan Future Generation Portfolios

MTEP 08 Resource Forecasting Units	TYPE	Buss Name	Reference	Pmax	Renewable	Pmax	Enviromental	PMAX
Q36704: Kalaska CC	cc	18KEYS	2013	375			2012	975
Q36665: Fremont Energy Center CC	cc	02LEMOYN	2013	600				
Q39001: Tittabawassee Coal	coal	18TITB	2014	600	2019	300	2014	1200
Q39357-03 Michigan Karn Coal	coal	18HAMPTO	2015	863	2014	1200	2015	863
QNew: Rogers City Coal: Livingston Sub	coal	18LVNS					2019	1200
Brownfield: Campbell Coal	coal	18CAMP W	2019	600			2015	300
Q39350-02 Fermi Nuclear 3 -- FERMI-3	Nuclear	19ENFPP	2016	1563	2016	1563	2016	1563
Q38425: MI Thumb Wind	WIND	19GRNEC			2017	300		
Q38478: MI Thumb Wind West	WIND	18THETFR			2018	900		
MISO 02/14/08 Current Queue Wind units	**Control Areas**	**Bus Name**	**Reference**	**Pmax**	**Renewable**	**AEP-ITC 765kV Pmax**	**Enviromental**	**PMAX**
Qwind Michigan Thumb:1	MECS	greenwood 345kV	2006	200	2006	200	2006	200
Qwind Michigan West:1	MECS-CONS	Ludington 345kV	2006	100	2006 100MW, 2016 additional	600	2006	100
Qwind Michigan Thumb:2	MECS-DECO	Arrowhead 120kV	2006	52	2006	52	2006	52
Qwind Michigan West:2	MECS-CONS	Wexford 138kV	2009	20	2009	20	2009	20
Qwind Michigan West:3	MECS-CONS	Keyston 345kV			2010	200		
Qwind Upper WI:1	WEC	Presque Isle 138kV			2009	200		
Qwind Michigan West:2	MECS-CONS	Wexford 138kV			2009	50		
Qwind Michigan Central:1	MECS-CONS	Moore road 138 kV			2010	300		
Qwind Michigan West:4	MECS-CONS	Pere Marquette 345kV			2010	70		
Qwind Upper WI:2	UPPC	Winona 138 kV sub			2009	120		
Qwind Michigan West:4	MECS-CONS	Pere Marquette 345kV	2011	150	2011	150	2011	150
Qwind Michigan Thumb:2	MECS-DECO	Arrowhead 120kV	2008	60	2008	60	2008	60
Qwind Michigan Central:2	MECS-CONS	Tittabawasse 345kV	2010	320	2010	320	2010	320
Qwind Michigan West:5	MECS-METC	Livingston 345kV			2010	120		
Qwind Michigan Central:3	MECS-CONS	Nelson Road 345KV	2010	300	2010	300	2010	300
Qwind Upper WI:3	WEC	Perkins 138kV			2010	200		
Qwind Michigan West:6	MECS-METC	Kenowa 345kV	2011	300	2011	300	2011	300
Qwind Michigan West:7	MECS_CONS	Tallmadge 345kV			2010	120		

8.4.3 PROMOD® Economic Benefit Analysis

This section summarizes the economic benefits based on the preliminary results. A further comprehensive cost benefit analysis of potential alternatives will be required before making any recommendations for need justification.

Transmission Project Options

To evaluate the potential economic benefits of the AEP-ITC proposed 765kV project, four transmission project options were included in the analysis.

- **Option1:** ITC Proposed 765kV Transmission Project
- **Option2:** Option1 + MTEP08 765kV Transmission Overlay Non-Midwest ISO East Region
- **Option3:** Option2 + MTEP08 765kV Transmission Overlay Midwest ISO Central Region
- **Option4:** Option1 + MTEP08 765kV Transmission Overlay Midwest ISO Central Region

Table 8.4-2 gives the detailed description for each option. The conceptual MTEP08 high voltage transmission overlay was developed through the MTEP08 process based on economic justification.

Table 8.4-2: Transmission Project Options

Transmission Projects	Option 1	Option 2	Option 3	Option 4
ITC Proposed 765kV Transmission Project Alone Cook - Evans - Spague Creek - Bridgewater Bridgewater - Blue Creek Bridgewater - South Canton	X	X	X	X
MTEP08 MISO Central Region 765kV Transmisison Overlay Sullivan - Dequine Dequine - Chicago (Tap Wilton - Dumont 765kV line) Dequine - Greentown - Blue Creek			X	X
MTEP08 NonMISO East Region 765kV Transmisison Overlay South Canton - Perry - Watercure - Ramapo - Branchburg Bedington - Doubs - Peach Bottom - Deans		X	X	

Figures 8.4-1 to 8.4-4 show the detailed graphical representation for the four transmission project options respectively.

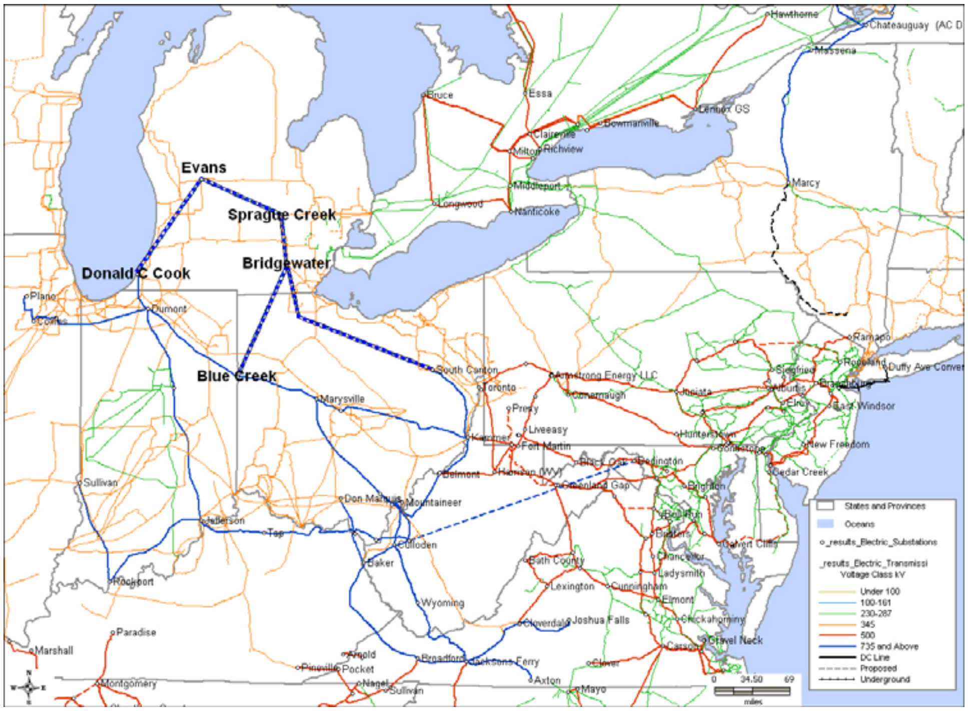

Figure 8.4-1: Transmission Option 1

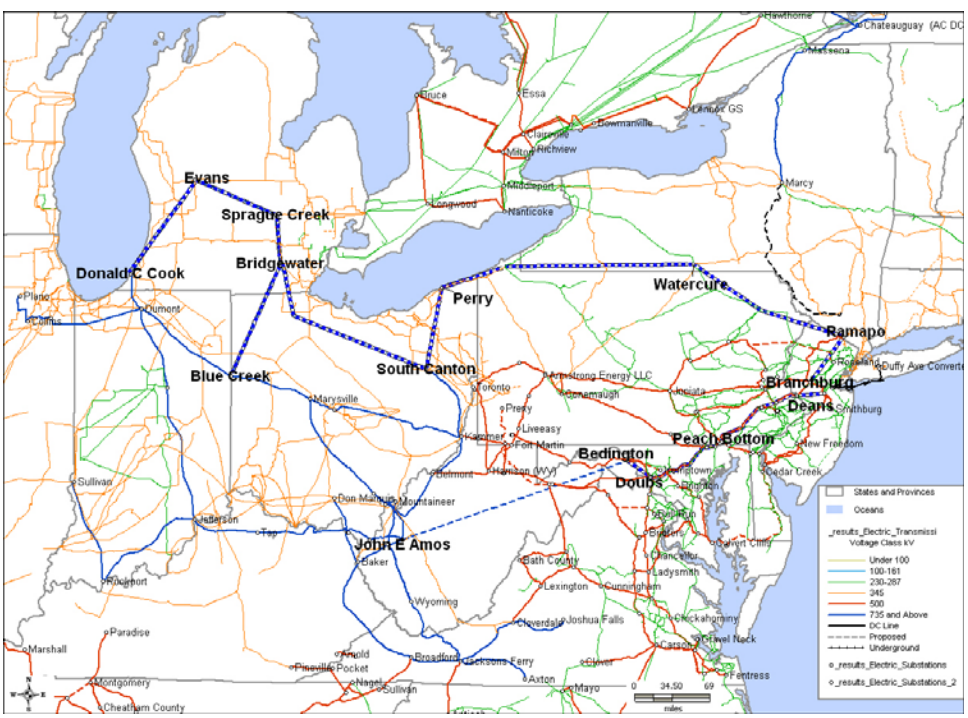

Figure 8.4-2: Transmission Option 2

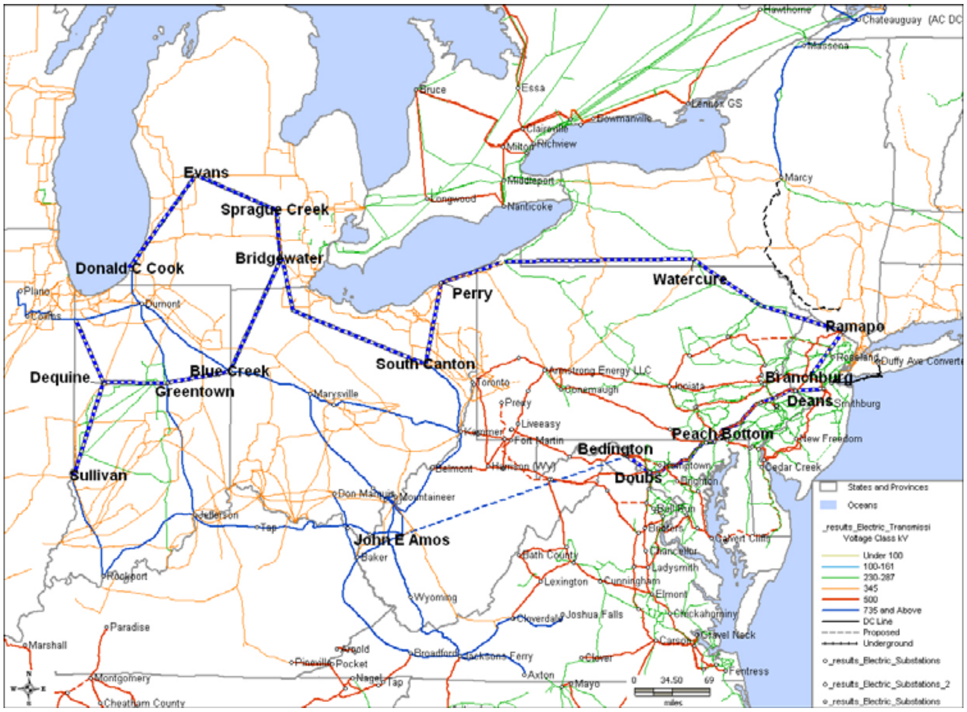

Figure 8.4-3: Transmission Option 3

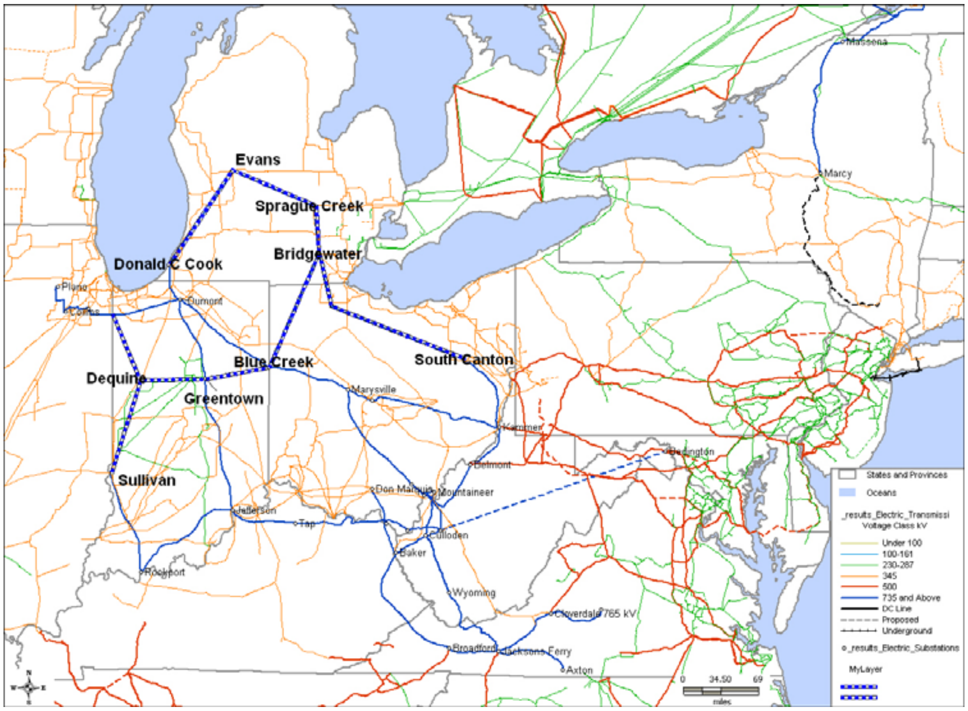

Figure 8.4-4: Transmission Option 4

Future Generation Portfolio Analysis

The initial study efforts considered three Future Generation Portfolios, Reference Future, Renewable Future and Environmental Future. 2016 and 2021 PROMOD® economic models were developed to reflect the power flow updates and future generation expansion changes based on the inputs of the study team.

Economic Benefit Savings

To determine the economic benefit savings, 2016 and 2021 PROMOD® analyses with and without the proposed transmission project options have been performed for each Future Generation Portfolio. Load cost savings, adjusted production cost savings and Regional Expansion Criteria and Benefits (RECBII) type benefit savings were calculated for Midwest ISO, PJM, Michigan and whole East Interconnection footprint respectively.

Table 8.4-3 represents the RECBII Benefit savings, adjusted production cost saving and load cost savings for three different future scenarios with ITC 765kV proposed project (optiona1). Approximately $111 million to $135 million RECBII benefit savings were achieved in Michigan.

Table 8.4-3: 2021 ITC 765kV Proposed Project (option1) Benefit Savings Results

70%APC+30%LMP RECBII Type Benefit Savings ($)	Reference Future	Renewable Future	Environmental Future
MISO	98,330,082	209,065,197	128,871,565
MICH	135,286,298	126,748,211	111,188,898
PJM	(45,996,974)	24,469,905	27,775,921

Adjusted Production Cost Savings ($)	Reference Future	Renewable Future	Environmental Future
MISO	50,048,220	59,822,708	130,565,722
MICH	45,527,931	60,176,261	117,542,839
PJM	8,685,254	(10,459,147)	(15,505,039)

Load Cost Savings Savings ($)	Reference Future	Renewable Future	Environmental Future
MISO	210,987,761	557,297,674	124,918,533
MICH	344,722,489	282,082,761	96,363,035
PJM	(173,588,841)	105,971,026	128,764,827

Table 8.4-4 shows economic benefit savings for the Reference Future with four transmission project options. Under economic market operation, energy tends to flow from a low cost area to a high cost area. With MTEP08 765kV transmission overlay connected to the East coast, lower price energy from Midwest ISO region is accessible to the East coast high energy price regions, therefore a significant amount of savings are achieved for the whole East Interconnect and the majority benefit savings are located in PJM.

Table 8.4-4: 2021 Reference Future Transmission Options – Benefit Savings Results

70%APC+30%LMP RECBII Type Benefit Savings ($)	ITC 765kV (Option 1)	ITC 765kV + NonMISO East (Option 2)	ITC765kV + NonMISO East + MISO Central (Option 3)	ITC765kV + MISO Central (Option 4)
MISO	98,330,082	(458,597,426)	(415,743,491)	166,987,290
MICH	135,286,298	4,992,117	24,367,516	155,321,590
PJM	(45,996,974)	1,279,509,635	1,354,201,724	65,884,716

Adjusted Production Cost Savings	ITC 765kV (Option 1)	ITC 765kV + NonMISO East (Option 2)	ITC765kV + NonMISO East + MISO Central (Option 3)	ITC765kV + MISO Central (Option 4)
MISO	50,048,220	121,028,047	155,641,116	77,640,277
MICH	45,527,931	82,977,176	86,429,423	42,086,572
PJM	8,685,254	898,282,977	957,756,752	63,798,232

Load Cost Savings	ITC 765kV (Option 1)	ITC 765kV + NonMISO East (Option 2)	ITC765kV + NonMISO East + MISO Central (Option 3)	ITC765kV + MISO Central (Option 4)
MISO	210,987,761	(1,811,056,862)	(1,748,974,242)	375,463,654
MICH	344,722,489	(176,973,019)	(120,443,600)	419,536,632
PJM	(173,588,841)	2,169,038,505	2,279,239,992	70,753,180

B/C ratio calculation

Ten year Net Present Value (NPV) project costs in 2016 dollars were calculated using 14% levelized fixed charge rate of total line and station costs in 2007 dollars with an inflation rate of 3% and a discount rate at 8%. And ten year NPV benefit savings from 2016 to 2025 were escalated using PROMOD® simulated 2016 and 2021 benefit saving values with discount rate at 8%. The annual RECBII type benefit savings were calculated using 70% adjusted production cost savings plus 30% load cost savings. The total costs for the four transmission project options 1, 2, 3, 4 in 2007 dollars are $2,626 million, $5,272 million, $6,345 million, $3,700 million respectively. The cost allocation between Midwest ISO and PJM for all transmission project options was based on year 2024 annual load energy ratio between Midwest ISO and PJM, 0.43/0.57. This is a study assumption and there is not an existing tariff agreement to distribute the costs in this manner. The transmission project options were assumed to be in service at year 2016. The same B/C ratio calculation assumptions described in this section carry though all the case studies.

Table 8.4-5 lists B/C ratio results of the AEP-ITC 765kV proposed transmission project in three different Future Scenarios. The B/C ratios are below 1.0 and do not meet the RECBII criteria.

Table 8.4-5: AEP-ITC Proposed 765kV Project (Option 1) B/C Ratio Results

70%APC+30%LMP RECBII Type B/C Ratio	Reference Future	Renewable Future	Environmental Future
MISO	0.47	0.86	0.53
MICH	0.60	0.56	0.47
PJM	0.00	0.05	0.10
Combined MISO+PJM	0.15	0.40	0.28

Table 8.4-6 shows B/C ratio results of the Reference Future with four transmission project options. With MTEP08 765kV transmission overlay connected to the East coast, more energy from the Midwest ISO region is delivered to the East coast high energy price regions and PJM is the major beneficiary with a B/C ratio that ranges between 2.34 to 2.69.

Table 8.4-6: Reference Future Transmission Options - B/C Ratio Results

70%APC+30%LMP RECBII Type B/C Ratio	ITC 765kV (Option 1)	ITC 765kV + NonMISO East (Option 2)	ITC765kV + NonMISO East + MISO Central (Option 3)	ITC765kV + MISO Central (Option 4)
MISO	0.47	0.00	0.00	0.54
MICH	0.60	0.00	0.03	0.48
PJM	0.00	2.69	2.34	0.18
Combined MISO+PJM	0.15	1.06	0.98	0.34

Top Binding Constraints in 2021

PROMOD® analysis provides the information of the binding constraints, the number of binding hours, and sum of the shadow prices of relieving binding constraints in the system. Table 8.4-7 and Table 8.4-8 list the identified 2021 Top 10 binding constraints outside Midwest ISO and within Midwest ISO respectively for all four transmission project options. With the MTEP08 conceptual 765kV transmission overlay central and non Midwest ISO east portions in the system, the total shadow prices and total binding hours of the top binding constraints outside Midwest ISO are mitigated, while the total shadow prices and total binding hours of the top binding constraints within Midwest ISO are aggravated due to additional energy delivery to the East coast. Most Midwest ISO top binding constraints are located in the west region.

Table 8.4-7: 2021 Top 10 Binding Constraints outside Midwest ISO Region

2021 Reference		ITC765kV		ITC 765_NonMISO East		ITC765_NonMISOE_MISOCentral		ITC765_MISOCentral	
Top 10 Binding Constraints Outside MISO	Region	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)
CARLISLE 205 PJMW GARDNERS 1209 PJMW 345	PJM	6,526	2,390	6004	2100.9	6022	2092.25	6533	2381.57
6CRAWFIS 19177 TVA 6KENSNGN 19303 TVA 1	SERC	4002	1981.44	4069	2037.6	4006	2010.04	3933	1963.62
05AXTON 22752 AEP 05DANVL2 24507 AEP 218	PJM	1,702	1,247	1450	1049.53	1464	1064.27	1728	1274.98
WHITPAIN 15 PJME WHITPAN1 4600 PJME 1	PJM	431	797	639	1062.78	644	1063.84	433	794.4
BRIGHTON 3 PJMS BRIGH230 7026 PJMS 1	PJM	427	756	519	787.34	524	787.74	431	756.31
06PIERC2 24962 AEP 06PIERCE 24964 AEP 161	PJM	665	679	607	575.96	551	510.07	623	604.3
MILLWOOD 3104 PJMW MILLW-H2 3978 PJMW 346	PJM	534	642	335	409.2	338	412.7	533	637.67
CRAIGJT4 54015 SPPW ASHWEST4 53226 SPPW 19	SPP	3,500	620	3478	619.28	3419	605.07	3484	622.39
6UNIONCY 16019 STHRN 6WLCMALL 16021 STHRN 364	SERC	243	516	243	525.07	245	521.86	242	519.04
BRUNNER 3054 PJMW WHEMP-H1 3976 PJMW 1	PJM	748	430	852	511.64	848	513.2	740	430.94
NIAGAR2W 79592 NYPP PA27 REG 81516 ONTHY 1	NYPP-IESO	2116	417.08	1993	415.35	1953	401.78	2084	404.54
Total		20,894	10,475	20,189	10,095	20,014	9,983	20,764	10,390

Table 8.4-8: 2021 Top 10 Binding Constraints in Midwest ISO Region

2021 Reference		ITC 765kV		ITC 765_NonMISO East		ITC765_NonMISOE_MISOCentral		ITC765_MISOCentral	
Top 10 Binding Constraints in MISO	Region	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)	Total Binding Hours	Total Shadow Price (k$/MW)
ADAMS 3 60102 NSP ADAMS 5 34014 ALWST 32	West	3247	7625.19	3249	7670.9	3249	7711.43	3255	7616.68
ADAMS_N5 34570 ALWST ROCHSTR5 69547 DPC 184	West	2929	4240.76	2902	4252.72	2906	4255.76	2915	4197.76
OAKES 4 63362 OTP ELLENDL4 67326 MDU 1	West	1950	2391.55	1951	2425.32	1948	2382.73	1940	2376.65
16PETE 27824 IP&L YBUS142 99718 394	Central	1219	1667.04	1180	1648.27	1224	1847.98	1246	1822.59
PR ISLD3 60105 NSP BYRON 3 61950 NSP 1	West	1947	1003.81	1941	1002.06	1961	1010.58	1934	1009.68
NEWTON 31331 CIPS EFFINGHM 30524 CIPS 91	Central	4056	977.47	4304	1062.11	4542	1084.34	4399	1017.51
KELSEY 4 67505 MHSP BIRCHTR4 67591 MHSP 1	MHSP	7112	877.05	7121	894.14	7104	890.99	7130	875.36
ADAMS 3 60102 NSP ADAMS 5 34014 ALWST 1	West	1099	684.07	1079	683.43	1074	671.62	1092	691.1
18THETR 28528 CEC 18DELA 28649 CEC 436	East	275	646.24	298	713.77	304	696.36	274	634.78
PR ISLD3 60105 NSP REDROCK3 60236 NSP 199	West	7379	637.82	7340	646.27	7331	643.51	7362	635.99
16PETE 27824 IP&L 16THOMPS 27828 IP&L 414	Central	2404	636.52	2785	790.01	1786	482.75	1449	367.56
PANA 31445 CIPS PANA 31446 CIPS 69	Central	3898	436.15	4156	516.73	5124	697.32	4900	603.33
Total		37515	21823.67	38306	22305.73	38553	22375.37	37896	21848.99

ITC Proposed 765kV Project Segment Evaluation

There are three individual segments for the AEP-ITC proposed 765kV project, which include segment 1 Blue Creek to Bridge Water 765kV, segment 2 the Cook to Evans to Sprague Creek to Bridgewater 765kV, and segment 3 the South Canton to Bridgewater 765kV. The economic benefits of the following segment groups were evaluated in Reference Future scenario as a part of the study effort.

- Segment1
- Segment 1 + Segment 2
- Segment 1 + Segment 3
- Segment 1 + Segment 3 + Sprague Creek - Bridgewater

The Benefit/Cost (B/C) ratio calculation results of the segment groups described above are provided in Table 8.4-9. The same B/C ratio calculation assumptions described in the previous **B/C ratio calculation section** carry though all the case studies. Given the assumption that the project in-service date is 2016, the B/C ratios are below RECBII metrics criteria and ranges from 0.48 to 1.03.

Table 8.4-9: Reference Future ITC 765kV Project Segment Evaluation - B/C Ratio

70%APC+30%LMP RECBII Type B/C Ratio	Segment 1	Segment 1 + Segment 2	Segment 1 + Segment 3	Segment 1 + Segment 3 + Sprague Creek - Bridgewater
MISO	1.03	0.48	0.77	0.63
MICH	1.40	0.67	0.84	0.81
PJM	0.16	0.00	0.10	0.00
Combined MISO+PJM	0.54	0.15	0.39	0.25

Sensitivity Analysis

In addition to the initial primary Future Generation Portfolio analysis, two sensitivity scenarios were analyzed to evaluate the economic benefit of the AEP-ITC proposed 765kV project.

Scenario 1: Midwest ISO Top Binding Constraint Mitigation 345kV Solution

As shown in the Future Generation Portfolio analysis above, the majority of the Midwest ISO top binding constraints are located in the west region. Without relieving these constraints in the west, limited benefits can be achieved by Midwest ISO. The following 345kV projects were used to mitigate the Midwest ISO top 10 binding constraints:

- CAPX Group 1 projects
  - P286: Maple River to Monticello
  - P279: Bemidji to Boswell
  - P1203: Brookings to Hampton Corners
  - P1024: Hampton Corners to Rochester to LaCrosse
  - P1340: Hazelton to Salem 345kV
- Palmyra – Meradosia – Ipava 345kV
- Pana – Mt. Zion – Kansas 345kV
- Merom to Newton 345kV
- P1557: Wheatland – Bloomington – Pritchard – Frank Twp – Hanna 345kV

The economic benefit savings brought by Midwest ISO top binding constraint mitigation 345kV solution projects are provided in Table 8.4-10. By relieving the most significant points of congestion within Midwest ISO, transmission system performance improves substantially and huge benefit savings are achieved in Midwest ISO west and central regions.

Table 8.4-10: Benefit Savings of Midwest ISO Top Binding Constraint Mitigation Solution

Base Case with Binding Relief Projects - Base Case	70%APC+30%LMP RECBII Type Benefit Savings ($) 2021	Adjusted Production Cost Savings 2021	Load Cost Savings 2021
MISO	1,234,227,919	833,190,912	2,169,980,934
MICH	136,335,826	(9,378,875)	476,336,794
PJM	316,732,668	(12,987,769)	1,086,080,355

Two cases were developed to calculate benefit savings of the ITC proposed 765kV project under this scenario, base case with binding mitigation solution projects and 765kV project case with binding mitigation solution project. Table 8.4-11 shows the comparison of the economic benefit savings between the original proposed 765kV project case and the 765kV project with the addition of the top binding constraint mitigation solution. Although the binding constraint mitigation solution can bring significant benefit savings within Midwest ISO, the sensitivity scenario analysis provides the same level of performance as the original ITC 765kV project case. By just relieving binding constraints, the desired energy can not be delivered to the desired locations efficiently, limited energy can be transferred from west to east and the majority of the Michigan import is from southeast.

Table 8.4-11: Benefit Savings Comparison of ITC proposed 765kV Project

70%APC+30%LMP RECBII Type Benefit Savings ($)	Original AEP- ITC Proposed 765kV Project	ITC 765kV Project Sensitivity Scenario 1
MISO	98,330,082	94,693,261
MICH	135,286,298	128,764,186
PJM	(45,996,974)	(3,873,415)

Adjusted Production Cost Savings	Original AEP- ITC Proposed 765kV Project	ITC 765kV Project Sensitivity Scenario 1
MISO	50,048,220	51,092,143
MICH	45,527,931	42,451,194
PJM	8,685,254	33,424,590

Load Cost Savings	Original AEP- ITC Proposed 765kV Project	ITC 765kV Project Sensitivity Scenario 1
MISO	210,987,761	196,429,201
MICH	344,722,489	330,161,169
PJM	(173,588,841)	(90,902,093)

Scenario 2: Hybrid Lower Voltage Alternative

Hybrid Lower voltage alternative was developed to provide an alternative to the ITC proposed 765kV project and the detailed description of the project is as follows:

- Tap Dumont to Marysville 765kV and install a 765kV station
- Tap two 345kV lines from Sorenson to Desoto and install a 345kV station
- Install two 765/345kV transformers between these new two stations
- 2nd parallel 345kV line on existing Rights of Way (ROW) from Robison Park to Allen to Sorenson
- Two 345kV lines on existing ROW from Robison Park to Midway
- 2nd parallel 345kV line on existing ROW from Midway to Lemoyne to Majestic
- New 765kV station at Lemoyne
- Two 765/345kV transformers at Lemoyne
- 765kV line from South Canton to Lemoyne

Table 8.4-12 shows the economic benefit savings of the hybrid low voltage alternative option, approximately half of the benefit savings are achieved compared to the original proposed 765kV project. Due to the lower project cost, the hybrid low voltage alternative does have a higher B/C ratio as shown in Table 8.4-13.

Table 8.4-12: Benefit Savings of Hybrid Low Voltage Alternative

70%APC+30%LMP RECBII Type Benefit Savings ($)	Original AEP-ITC Proposed 765kV Project	Hybrid Low Voltage Alternative Sensitivity Scenario 2
MISO	98,330,082	57,931,576
MICH	135,286,298	66,270,074
PJM	(45,996,974)	28,447,494

Adjusted Production Cost Savings	Original AEP-ITC Proposed 765kV Project	Hybrid Low Voltage Alternative Sensitivity Scenario 2
MISO	50,048,220	34,558,526
MICH	45,527,931	20,226,566
PJM	8,685,254	29,515,134

Load Cost Savings	Original AEP-ITC Proposed 765kV Project	Hybrid Low Voltage Alternative Sensitivity Scenario 2
MISO	210,987,761	112,468,694
MICH	344,722,489	173,704,927
PJM	(173,588,841)	25,956,334

Table 8.4-13: Benefit/Cost Ratio of Hybrid Low Voltage Alternative

70%APC+30%LMP RECBII Type B/C Ratio	ITC Original 765kV Project	Hybrid Low Voltage Alternative Sensitivity Scenario 2
MISO	0.47	0.90
MICH	0.60	1.07
PJM	0	0.27
Combined MISO+PJM	0.15	0.54

8.4.4 LOLE Analysis

As part of the study, system reliability enhancements were evaluated using Loss of Load Expectation (LOLE) for planning years of 2016 and 2021. With the purposed 765kV transmission project there are reliability improvements in the form of reduced LOLE for the study years of 2016 and 2021. There is also the potential for deferred installed capacity required to maintain a less than one day in ten years loss of load expectation.

Zones and Study System

The LOLE model is an equalized transportation style model as oppose to using a fully detailed transmission model. Therefore a collection of zones and interfaces are used to capture the capabilities and limitations of the transmission system.

For this specific study, the zones consisted of the electrical area systems surrounding the purposed transmission project. Figure 8.4-5 shows system configuration.

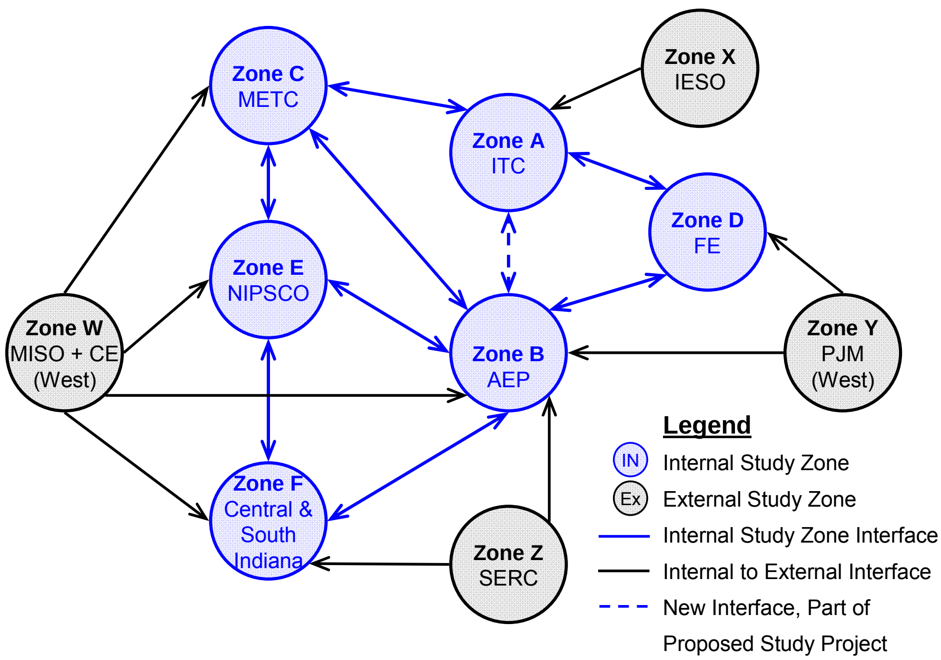

Figure 8.4-5: Study System Configuration Diagram

Stand Alone LOLE Analysis

Each defined zone was initially evaluated on a stand-alone island basis, where each zone was isolated from the other study zones it would otherwise normally be interconnected to. The stand-alone zone evaluation included calculating the isolated LOLE values for each study zone and then determining what internal zonal capacity adjustments would bring the isolated zone to the one day in ten years target LOLE criteria. Zones with higher than the targeted criteria LOLE would require positive capacity adjustments to reach the target and likewise zones with lower LOLE could lose capacity before hitting the criteria. The results of the isolated LOLE evaluation as well as data summaries for each zone are provided in Table 8.4-14.

Table 8.4-14: Stand Alone LOLE Results

Study Year: 2016		Zone Data Summary				Isolated (Stand-Alone)	
Zone	Name	Peak Load Month	Peak Load (MW)	Interruptible Load (MW)	Capacity at Time of Peak (MW)	LOLE (days/yr)	0.1 days/year Adjusted Capacity
Zone-A	ITC	July	13,124	489	13,239	5.411	2,567
Zone-B	AEP	July	33,304	729	39,729	0.073	-244
Zone-C	METC	July	11,622	265	15,927	0.003	-1,585
Zone-D	FE	August	14,573	71	14,821	8.878	2,688
Zone-E	NIPSCO	July	3,932	292	3,697	27.700	1,275
Zone-F	CENT&SOUTH-IN	July	21,587	731	22,102	8.241	3,042

Study Year: 2021		Zone Data Summary				Isolated (Stand-Alone)	
Zone	Name	Peak Load Month	Peak Load (MW)	Interruptible Load (MW)	Capacity at Time of Peak (MW)	LOLE (days/yr)	0.1 days/year Adjusted Capacity
Zone-A	ITC	July	13,608	529	13,239	8.746	3,075
Zone-B	AEP	July	35,996	729	41,089	0.505	1,480
Zone-C	METC	July	12,324	305	16,504	0.005	-1,428
Zone-D	FE	August	14,955	111	15,974	3.468	1,924
Zone-E	NIPSCO	July	4,161	312	3,697	46.061	1,492
Zone-F	CENT&SOUTH-IN	July	23,006	867	23,828	5.194	2,860

Interface Limits & Interconnected LOLE Analysis

To evaluate the proposed project an interconnected LOLE analysis was performed. The LOLE reliability improvements of the project are realized through changes in interface limits between models with and without the proposed project.

2016 and 2021 PROMOD® Security Constrained Economic Dispatch (SCED) models were used to determine the transfer limits for the defined zones. Monthly interface limits between zones were calculated by averaging the daily interface flows that occurred at the zone's peak load hour.

Tables 8.4-15 and 8.4-16 show the study results of the interconnected LOLE analysis with and without the proposed project for both 2016 and 2021 study years. LOLE values without utilizing interruptible load are also included.

Table 8.4-15: Interconnected LOLE results for 2016

Study Year: 2016		Base Case (no project)		Change Case (with project)	
Zone	Name	LOLE (days/yr)	LOLE(1) (days/yr)	LOLE (days/yr)	LOLE(1) (days/yr)
Zone-A	ITC	0.024	0.067	0.010	0.029
Zone-B	AEP	0.000	0.001	0.000	0.001
Zone-C	METC	0.000	0.000	0.000	0.000
Zone-D	FE	0.000	0.002	0.000	0.002
Zone-E	NIPSCO	0.003	0.019	0.003	0.020
Zone-F	CENT&SOUTH-IN	0.000	0.003	0.000	0.002
(1)Without utilizing Interruptible Load					

Table 8.4-16: Interconnected LOLE results for 2021

Study Year: 2021		Base Case (no project)		Change Case (with project)	
Zone	Name	LOLE (days/yr)	LOLE(1) (days/yr)	LOLE (days/yr)	LOLE(1) (days/yr)
Zone-A	ITC	0.062	0.179	0.020	0.068
Zone-B	AEP	0.001	0.006	0.001	0.006
Zone-C	METC	0.000	0.001	0.000	0.001
Zone-D	FE	0.002	0.011	0.002	0.011
Zone-E	NIPSCO	0.003	0.032	0.003	0.033
Zone-F	CENT&SOUTH-IN	0.002	0.011	0.002	0.011
(1)Without utilizing Interruptible Load					

ITC & METC Deferred Installed Capacity

With the proposed transmission project the Michigan ITC and METC zone may realize potential deferred installed capacity requirements to maintain a less than one day and ten years loss of load criteria. To evaluate this potential, the ITC and METC zones were driven to the 0.1 days/year LOLE, and the deferred capacity was calculated by taking the capacity adjustment difference between the cases with and without the proposed project as shown in Table 8.4-17.

Table 8.4-17: Deferred Capacity

Measured Potential for Deferred Installed Capacity			
Zone	**Name**	**2016**	**2021**
Zone-A	ITC	287	397
Zone-C	METC	80	190
Total	**Michigan**	**367 MW**	**587 MW**

8.4.5 Conclusion and Next Steps

The focus of this study is evaluating market efficiency benefits of the AEP-ITC proposed 765kV project. Based on the economic benefit analysis preliminary results, the proposed project does not meet the 3:1 B/C ratio for long term transmission expansions. As the large scale projects is to meet multiple planning objectives beyond basic congestion relief which RECBII metrics is more appropriated for, RECBII metrics are very limited to fully capture all the benefits the long term project creates, a further thorough analysis would be needed to explore additional value metrics to support the long term projects such as import capability, deferred generation capacity, loss reduction, constraint relief, etc. Table 8.4-18 provides the RECBII B/C ratios for all Reference Future case analyses in this study, none of the cases passes the RECBII criteria. Currently several value measures are under development with the ongoing Midwest ISO Value Measures workshops which includes quantitative measures, qualitative measures as well as risk measures. In order to determine the need justification for the proposed project, additional potential alternatives need to be under consideration and are compared against a set of value measures. Please see Section 10 for additional discussion on that topic.

Table 8.4-18: RECBII Benefit/Cost Ratio

Reference Future Project Cases	Combined MISO + PJM B/C Ratio	Threshhold	RECB Status	Discount Rate	LFCR
ITC Proposed 765kV Project Option1	0.15	3.00	Fail	8	14
ITC 765kV Project + NonMISO East Option 2	1.06	3.00	Fail	8	14
ITC 765kV Project + NonMISO East + MISO Central Option3	0.98	3.00	Fail	8	14
ITC 765kV Project + MISO Central Option 4	0.34	3.00	Fail	8	14
ITC 765kV Project Segment 1	0.54	3.00	Fail	8	14
ITC 765kV Project Segment 1 + Segment 2	0.15	3.00	Fail	8	14
ITC 765kV Project Segment 1 + Segment 3	0.39	3.00	Fail	8	14
ITC 765kV Project Segment 1 + Segment 3 + Sprague - Bridgewater	0.25	3.00	Fail	8	14
ITC 765kV Project Sensitivity Scenario 1	0.17	3.00	Fail	8	14
ITC 765kV Project Alternative Sensitivity Scenario 2	0.54	3.00	Fail	8	14

One important observation from sensitivity scenario 1 Midwest ISO top binding constraint mitigation 345kV solution is that relieving the most significant points of congestion can achieve substantial benefit savings and by selecting the proper transmission portfolio group, the benefits achieved are well beyond what can be achieved solely by one component. Additional transmission portfolio assessment analysis will be executed as part of the MTEP09 process.

8.5 Transmission Portfolio Development

One of Midwest ISO's governing planning principals is to make the benefits of a competitive energy market available to customers by providing access to the lowest possible energy costs. This section also discusses the Top 4 conceptual transmission plan which passes the Regional Expansion Criteria and Benefits II (RECB II) criteria for the assumptions used in MTEP08. The Top 4 produces a RECB II Benefit/Cost (B/C) Ratio of 4.3 for a requirement of 2.6 with a 15% levelized annual fixed charge rate. The Top 4 will pass the RECB II criteria to a levelized fixed charge rate of up to 22% with the assumptions of the study.

All lines in the Top 4 have been proposed for study purposes in MTEP08 by transmission owners.

The ITC Targeted Study identified a set of lines which would mitigate the Top 10 constraints (Section 8.4, Page 12) in the Midwest ISO energy market in 2021identifed a conceptual plan. The Top 10 passed the RECB II criteria. The Top 4 is a refinement of the Top 10 and excludes lines that are in Appendix A and includes one Appendix B line from the Southwestern Indiana Economic Targeted Study (Section 8.3). Transmission lines in Appendix A are covered under the reliability criterion and RECB I. Appendix B lines have been identified as one prospective solution, of several possible, to an identified future problem. Appendix B transmission lines have not yet been analyzed with the process to qualify for Appendix A.

The Top 4 transmission portfolio of projects makes the market work better by addressing a group of market constraints. One of Midwest ISO's challenges is finding transmission upgrades that improve market operations and lower energy costs. This portfolio of upgrades does that.

8.5.1 Transmission Portfolio for Top 4

The Top 4 is a combination of 345kV line additions that as a portfolio relieve constraints in a 2021 analysis that would produce economic benefits sufficient to pass RECB II. The portfolio of transmission lines was identified as part of a conceptual transmission plan to resolve the Top 10 Constraints in a 2021 case. The lines in the Top 10 were chosen from lines proposed by the transmission owners for MTEP08 studies. The Top 4 and other Appendix A transmission expansions provide increased power transfer between the Minnesota, Iowa, Illinois and Indiana areas. The portfolio of transmission lines provides value to market and demonstrates the benefit of combining individual projects into a portfolio to address enough market constraints to provide value.

There were two targeted studies that produced projects that may meet the RECB II criteria, the Southwestern Indiana Economic Targeted Study and the ITC Study. The result of the Southwestern Indiana Study (could essentially be combined with the Top 10 Constraints) which came out of the ITC Study to make one transmission portfolio that provides value to the energy market and would help energy costs. All the other transmission portfolios analyzed in Targeted Studies are noted in Figure 8.5-1 as small diamonds below the green line. Note how individual projects have lower B/C ratios than the transmission portfolios. The Top 4 study is represented by the large blue square.

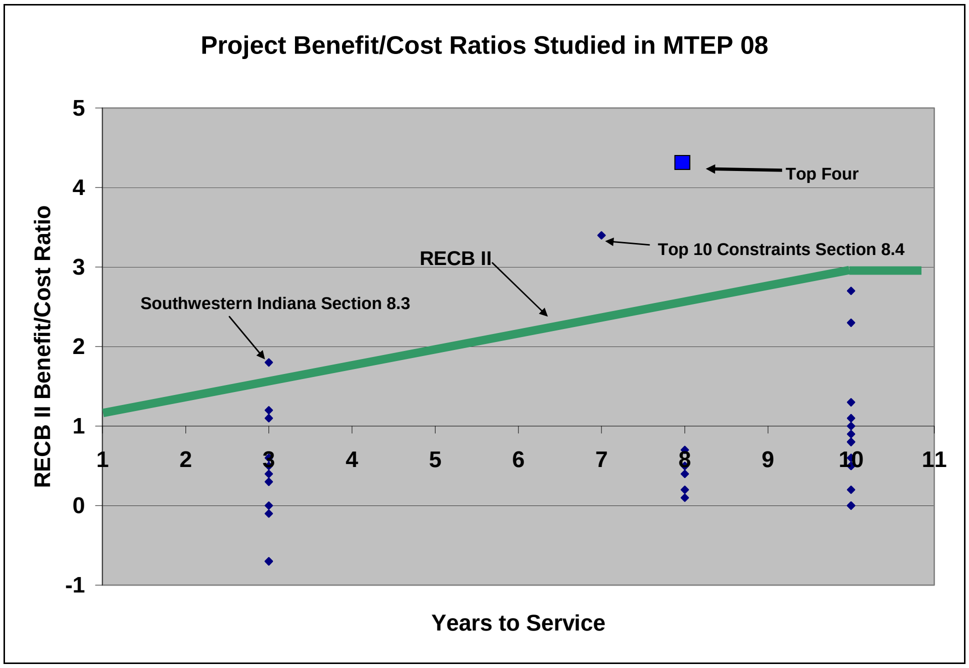

Figure 8.5-1: Benefit to Cost Ratio of Studies for MTEP08

The transmission portfolio for the Top 4 is shown in Figure 8.5-2 The combination of the projects enhances the power transfer capability between the Western and the Central Midwest ISO regions.

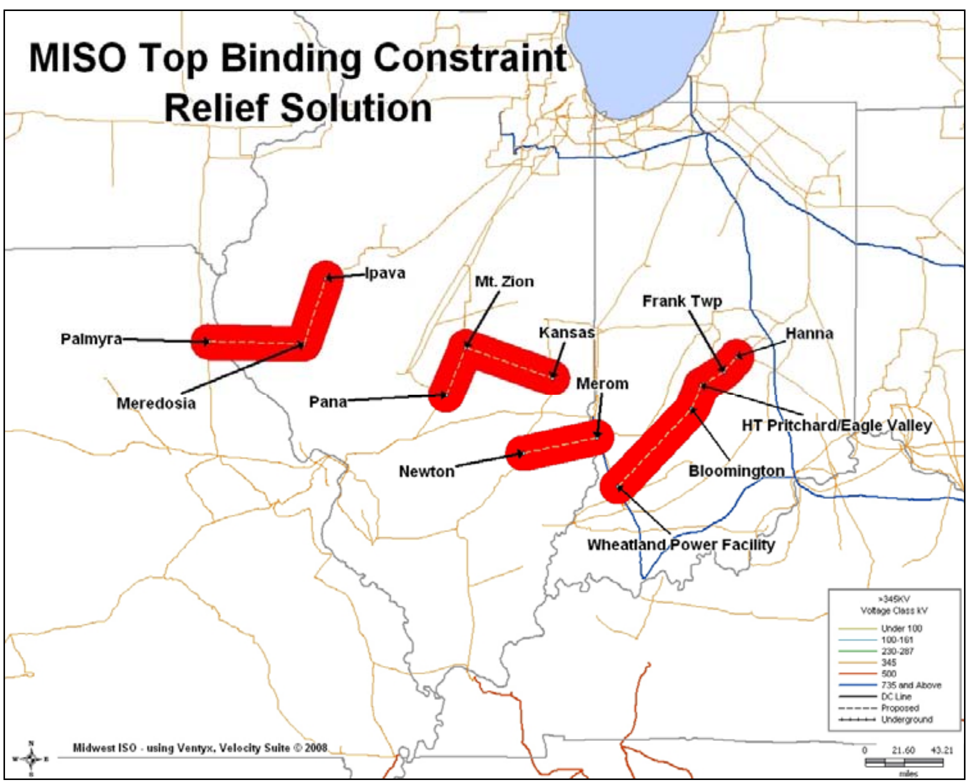

Figure 8.5-2 Top 4 Projects to Address Constraints in 2021

Table 8.5-1 Top 4 **Transmission Portfolio to Constraints in 2021**				
Project ID	Project Description	In Service Date	Estimated Cost	Appendix Status
P1557	Wheatland – Bloomington – Pritchard – Frank Twp – Hanna 345kV line	TBD	$150,000,000	Appendix B
Step 3 Short-Term 1	Palmyra – Meradosia – Ipava 345kV line	N/A	$130,000,000	N/A
Step 3 Short-Term 2	Pana – Mt. Zion – Kansas 345kV line	N/A	$115,000,000	N/A
Step 3 Short-Term 3	Merom - Newton 345kV line	N/A	$60,000,000	N/A
			$455,000,000	

P1557 cost is updated with the estimated number from Southern IN study; original cost is M$95.

Figure 8.5-3 shows that the B/C ratio changes with a range of Levelized Fixed Charge Rates (LFCR) from 12% to 22%. The in-service dates for these four projects are assumed at 2016. The B/C ratio of the new portfolio does meet the RECBII criteria based on MTEP08 study assumptions for ITC study. Additional analysis should be done in the next MTEP09 planning cycle before making any recommendations for need justification.

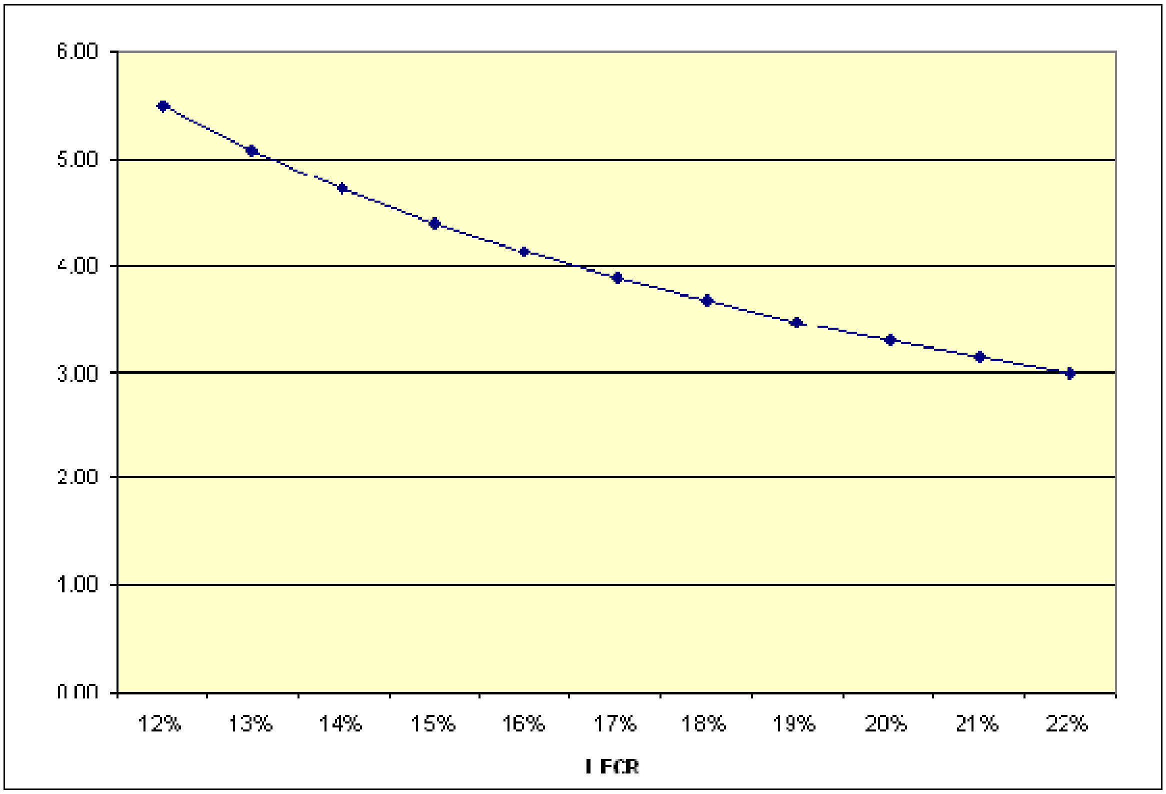

Figure 8.5.3: B/C Ratio Compared to a Change in LFCR

The cost of the Top 4 is $455 million in 2007 dollars. A 3% escalation rate is applied to the cost to escalate the cost to later years. The levelized fixed charge rate that was used in the study was 15%. The levelized fixed charge rate is used as an approximation of the annual revenue requirements that would be required for a transmission investment. The cost of blended capital (equity and borrowed), taxes, insurance, Overhead & Maintenance, and depreciation are the components of the LFCR The LFCR is different for each transmission owner in the Midwest ISO. The 15% number was set by a stakeholder consensus during the establishment of the assumptions to use in MTEP08. Individual transmission owners may have as high as 22% LFCR.

Using the same assumptions for the Top 4 and the ITC targeted study (Section 8.4), and using results from simulated years 2016 and 2021, the Top 4 component B/C performances were analyzed and ares presented below. Each component of the Top 4 is named in Table 8.5.1.

Figure 8.5.4 displays the B/C ratio comparison with a range of LFCRs from 12% to 22%. All the benefits are based from 2016 and 2021 two year run results. Ten year NPV values are calculated for the benefit savings and costs from 2016 to 2025. The B/C ratio is calculated by 10year NPV benefits divided by 10 year NPV costs.

The RECB II benefit savings for, Step 3 Short Term 2 is $137M.

The RECB II benefit savings for, Step 3 Short Term 3 is $171M.

The Step 3 Short-Term 2 and 3 do have a better B/C ratio compared to the combined portfolio

The RECB II benefit savings for the combined portfolio is $455M.

This gives us a very good indication that a proper combined portfolio of transmission projects can achieve more economic benefit savings by addressing more congested areas than just a single component.

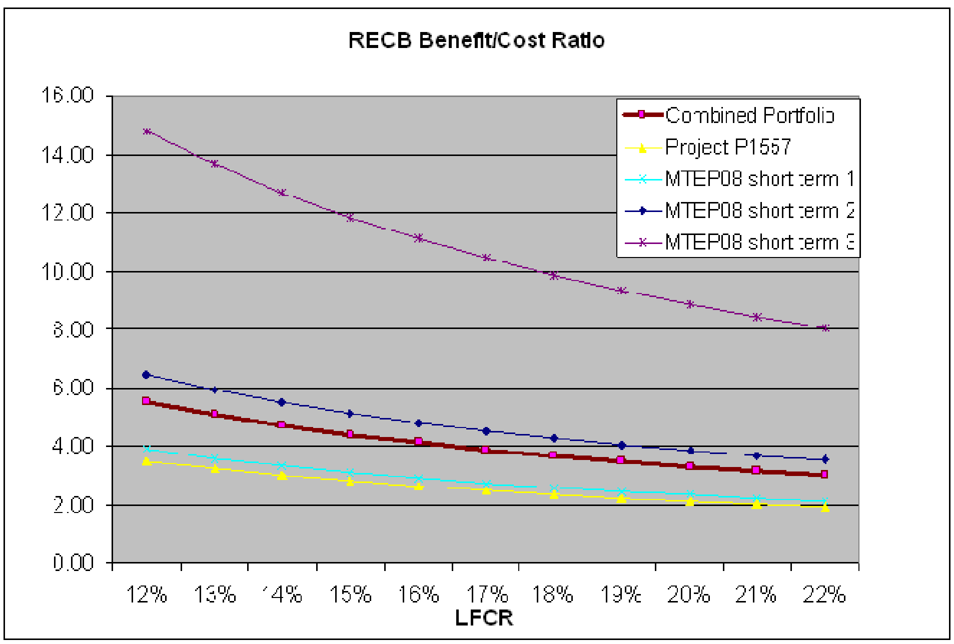

Figure 8.5.4 B/C Ratio Compared to a Change in LFCR

8.5.2 Conclusion

Expanding the transmission system with a portfolio of transmission lines may be economically beneficial, providing benefits to the energy market. The benefits of individual lines may be less than a transmission portfolio which addresses the primary congested area. The Top 4 transmission portfolio or its components would enable more efficient operation of Midwest ISO energy markets.

Section 9: Economic Assessment of Recommended and Proposed Expansion Plan

Midwest ISO MTEP Appendix A/B contains the planned/proposed projects that have been evaluated based on the reliability criterion. These projects have been proven to be able to relieve the reliability problems in Midwest ISO. In addition to the reliability benefit, these projects may provide economic benefits. In this section, we use PROMOD® as a primary tool to evaluate the economic benefits of these projects. The economic benefits considered include:

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

9.1 Study Methodology and Assumptions

To get the economic benefits of these projects, we need to run two PROMOD® cases: one case without these projects, and one case with these projects. Then we compare the results from these two cases to get the economic benefit.

PROMOD® Cases

The MTEP 09 Reference Future database (contains all generator, load, fuel, and environment information) is used to develop the PROMOD® case. As we already have the MTEP08 2013 power flow case which has these Appendix A/B projects modeled, we decided to develop the 2013 PROMOD® case for this study.

Two PROMOD® cases are developed:

- 2013 PROMOD® case with Appendix A/B
- 2013 PROMOD® case without Appendix A/B

Power Flow Case

To develop these two PROMOD® cases, we need two power flow cases:

- 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 out of Midwest ISO are the same; they are from the Eastern Interconnection Regional Reliability Organization (ERAG) 2013 summer peak power flow case. The Midwest ISO portions are generated from the Midwest ISO Model on Demand (MOD) tool. The base case in MOD is ERAG 2008 summer peak case. Appendix A/B projects have been entered into the MOD and can be combined with base case to generate other power flow cases. So the Midwest ISO portion of the power flow case without Appendix A/B is the same as the base case in MOD. The Midwest ISO portion of the power flow case with Appendix A/B is the base case plus all Appendix A/B projects.

Table 9-1 shows the difference of these two power flow cases.

Table 9-1: Power Flow Cases Difference

	Power Flow Case with Appendix A/B	Power Flow Case without Appendix A/B
MIDWEST ISO Transmission	ERAG 2008 Summer Peak + Appendix A/B	ERAG 2008 Summer Peak
Non-MIDWEST ISO Transmission	ERAG 2013 Summer	ERAG 2013 Summer
Generation/Load/Interchange	Not Used in PROMOD(R)	Not Used in PROMOD(R)

New Generators

The new generators identified in MTEP09 Step 1 and 2 in Reference Future are included in the study.

Event File

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 event file has a big impact on the quality of the study results. As PROMOD® has a limit on the total number of events, we can not put all N-1 or N-2 contingencies in the event file. The event file for this 2013 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. They are identified during the reliability study of the Appendix A/B projects.

Some Appendix A/B projects are rating upgrades. These projects are also included in the event file with different ratings in with an Appendix A/B PROMOD® case and without an Appendix A/B PROMOD® case.

We also used the PROMOD® Analysis Tool (PAT) to identify the event with potential reliability problem, and included them in the event file.

9.2 Study Results

The following benefits are calculated from PROMOD® simulation:

- Economic Indices (for detail definition, please see Section 8.3)
  - Adjusted Production Cost Savings
  - Load Cost Savings
  - Regional Expansion Criteria and Benefits (RECB) II benefit:
    *70% * Adjusted Production Cost Savings + 30% * Load Cost Savings*
- Loss Benefit (for detail definition, please see Section 8.3)
  - Energy Loss Benefit (MWH)
  - Capacity Loss Benefit (MW)
  - Dollar Value of Energy Loss Benefit
  - Dollar Value of Capacity Loss Benefit:
    Use 650$/kW – 1200$/kW as the price range for the construction of different type units. The dollar values are in a range.
  - Maximum hourly loss decrease (MW)
- Generation, Capacity Factor, and CO_2 Emission Change:
  compare 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.

9.2.1 Economic Indices

Table 9-2 shows the adjusted production cost savings, Load Cost Savings and RECBII benefit for the MTEP Appendix A/B projects.

Table 9-2: Economic Indices

	Load Cost Savings	Adjusted Production Cost Savings	RECB II Benefits
Midwest ISO East	$714 million	$293 million	$419 million
Midwest ISO Central	$78 million	$386 million	$293 million
Midwest ISO West	$268 million	$272 million	$ 271 million
Midwest ISO	$1,060 million	$951 million	$983 million

The MTEP Appendix A/B projects can save Midwest ISO $951 million in adjusted production cost, and $1 billion in Load Cost.

The total cost of the MTEP Appendix A/B projects in MTEP08 2013 power flow case is $4.8 billion. Table 9-3 shows the B/C Ratio of the Appendix A/B projects under different fixed charge rates. The benefit used in the table is the Midwest ISO RECB II benefits.

Table 9-3: B/C Ratio of Appendix A/B project (Use MIDWEST ISO RECB II Benefits)

	Total Project Cost - $4,800 million		
Fixed Charge Rate	Annual Project Cost (million $)	RECB II Benefit (million $)	B/C Ratio
14%	672	983	1.46
16%	768	983	1.28
18%	864	983	1.14
20%	960	983	1.02
22%	1,056	983	0.93
24%	1,152	983	0.85
26%	1,248	983	0.79
28%	1,344	983	0.73

9.2.2 Loss Benefits

Table 9-4 shows the loss benefits of Midwest ISO. The annual (2013) energy loss decrease is 383,913 MWH. If we use 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 about $78 million.

The capacity loss benefit is the loss decrease of Midwest ISO in Midwest ISO peak hour. It is about 93 MW in this case. If we use $650/kW – $1200/kW (the range of construction cost of different type units) to price it, it represents $60 – $111 million saving in new unit construction.

Table 9-4: MIDWEST ISO Loss Benefits with Appendix A/B Project

	Energy Loss Benefit	Value of Energy Loss Benefit	Capacity of Loss Benefit	Value of Capacity Loss Benefit	Maximum Hourly Loss Decrease
Midwest ISO	383,913	$78 million	93 MW	$60~111 million	568 MW

9.2.3 Generation, Capacity Factor, and CO_2 Emission Change

Table 9-5 shows the annual generation and capacity factor changes for different types of units. These are Midwest ISO units only. We can see that after adding the Appendix A/B projects, the constraints of the system are relieved, and the generations are shifted from the higher cost combined cycle, combustion turbine units to the lower cost steam turbine coal units. This causes the annual CO_2 emission increase as shown in Table 9-6. But this increase only represents 0.23% of the total CO_2 emissions.

Table 9-5: Generation and Capacity Factor Change for Different Type Units

		Generation (MWH)	Capacity Factor
Combined Cycle	No Appendix Projects	18,647,558	15.60%
	With Appendix Projects	17,654,515	14.77%
	Change	-993,042	-0.83%
CT Gas	No Appendix Projects	3,797,218	1.50%
	With Appendix Projects	3,707,115	1.47%
	Change	-90,103	-0.04%
CT Oil	No Appendix Projects	94,052	0.18%
	With Appendix Projects	72,551	0.14%
	Change	-21,501	-0.04%
Hydro (existing)	No Appendix Projects	14,133	19.44%
	With Appendix Projects	14,133	19.44%
	Change	0	0.00%
Hydro Run-of-River	No Appendix Projects	3,875,264	39.57%
	With Appendix Projects	3,875,264	39.57%
	Change	0	0.00%
Hydro Storage	No Appendix Projects	1,036,273	41.99%
	With Appendix Projects	1,036,273	41.99%
	Change	0	0.00%
IGCC	No Appendix Projects	166,607	6.74%
	With Appendix Projects	148,300	6.00%
	Change	-18,307	-0.74%
Nuclear	No Appendix Projects	78,767,170	86.96%
	With Appendix Projects	78,767,170	86.96%
	Change	0	0.00%
ST Coal	No Appendix Projects	467,176,371	72.37%
	With Appendix Projects	468,404,468	72.56%
	Change	1,228,097	0.19%
ST Gas	No Appendix Projects	138,415	0.86%
	With Appendix Projects	428,995	2.65%
	Change	290,580	1.80%
ST Oil	No Appendix Projects	8,638	0.05%
	With Appendix Projects	9,398	0.05%
	Change	761	0.00%

Table 9-6: Annual CO_2 Emission Change for Different Type Units

	CO2 Emission (Ton)
No Appendix Projects	**460,450,872**
With Appendix Projects	**461,519,525**
Emission Increase	**1,068,652**

9.3 Conclusion

The PROMOD® simulations show that the Appendix A/B projects will bring not only the reliability benefit to Midwest ISO, but also the economic benefit. In the study year (2013), Midwest ISO will save about $1 billion in load cost, and $950 million in adjusted production cost. The total project cost is about $4.8 billion. If we use the 20% fixed charge rate, the Benefit/Cost ratio of these project is about 1.0.

The simulation also shows that the Appendix A/B project brings the loss benefits. The annual energy loss decrease is about 384 GWH, which equals to about $78 million saving. The capacity loss benefit is about 98 MW, which means we can defer the installation of a 98 MW unit. This is equivalent to about $60 to $111 million savings in new unit construction.

The Appendix A/B projects relieve the constraints in the Midwest ISO system. Therefore, the cheaper coal units generate more. This leads to the increase of CO_2 emission. But the increased CO_2 emission only represents 0.23% of the annual total CO_2 emission in Midwest ISO.

Section 10: Transmission Valuation Metric Development

10.1 Background

As the Midwest ISO regional transmission expansion planning process has evolved, so too has the need for consideration of additional value measures in the evaluation of transmission projects. As discussed in Section 2, the Midwest ISO is shifting from a reliability based assessment to value-based planning which incorporates reliability assessment. The Midwest ISO believes that a planning paradigm based primarily on assessing reliability, which minimizes transmission build, leaves value for consumers on the table.

Overall, Midwest ISO's planning function seeks to optimize value for Midwest ISO stakeholders. This value will be perceived differently based on the stakeholder's role in the marketplace, but maximizing the value for the region is at the foundation of the planning process. A major challenge in developing a value-driven expansion planning approach is to identify and quantify the total value of transmission projects.

The advent of Regional Expansion Criteria and Benefits (RECB II) in 2006 began the process of advancing assessment of transmission projects through the identification of valuation measures specifically focused on market efficiency. Usage of production cost and locational marginal price allows the capture of the benefits of reducing the delivered cost of energy. However, as this process has evolved, it has become clear that there are additional value drivers for expansion projects that are not recognized in the current methodology. For example, with the advent of Renewable Portfolio Standards (RPS) there are public policy drivers which must be considered in the evaluation of a project. To uncover the total value of a transmission expansion project, transmission planning must expand the analysis even further. The Midwest ISO seeks to meet the challenge by continuing to work with stakeholders to develop the appropriate value measures for expansion projects that will allow a more complete value to be identified and quantified. These measures will contribute to an improved business case for proposed projects that will move the Midwest ISO planning process closer to its goal of developing a comprehensive expansion plan that meets both reliability and economic expansion needs.

10.2 Value Measure Considerations

Before discussing the value measures, it is important to consider the potential usage of them within the transmission planning process. In the current RECB paradigm, the valuation measures for project assessment and inclusion are not well differentiated from those used for cost allocation. This does not, however, need to be the case. Today, although individual Transmission Owners (TO) may sponsor projects based on independent analysis of a broader range of benefits, the analysis presented in the MTEP report relies solely on the metrics defined under the current RECB I and RECB II criteria. Should a project not pass the RECB criteria, but be justified by an individual transmission owner and identified as having no harm to the system it is identified in the category "Other". Formally expanding the business case analysis and comparison of alternatives is the first expected usage of the newly derived valuation measures. The valuation measures described in Section 10.3 reflect the attempts to determine a set of measures with somewhat universal applicability to achieve this goal. Adding additional metrics to the analysis will allow the Midwest ISO to more fully evaluate alternatives and provide stakeholders with a more consistent and wholistic assessment of project value. This is critical as the Midwest ISO begins to assess an increasing number of projects that do not fit cleanly within the existing reliability or economic paradigm, but require full discussion of benefits nonetheless.

A second possible usage of valuation measures is for cost allocation. Today, the criteria used for inclusion are the same as those for cost allocation. However, the valuation measures used to justify a project may be different than those used to determine cost allocation, or even cost allocation eligibility. In some ways this is similar to using underlying criteria, such as project size, on top of the base allocation criteria, to determine whether a project is eligible for cost allocation. Having said that, initial assessments of and stakeholder feedback around RECB effectiveness (as discussed in the Midwest ISO RECB filing available at http://www.midwestmarket.org/publish/Document/25f0a7_11c1022c619_-7bd50a48324a? indicate that there may in fact be additional reasonable criteria for cost allocation, some of which may already be identified in the value measure analysis work that has been done to support improving the business case analysis for transmission.

A final potential use for value measures is to support the justification of an individual business case at the state or local level. As mentioned previously, the list of metrics stakeholders have discussed to date represent an attempt to determine a list of metrics for project inclusion that is universal, and as such would be applied to all projects. A project may, however, have additional benefits that should be described or included as part of the business case. A number of measures that were eliminated by stakeholders from current consideration fall into that category. A good example of this is local economic impact. For some, if not all projects, the transmission or generation it supports may represent an economic development opportunity for a given region. That fact should certainly be reflected in the justification of a given project, even if it is not a good differentiator for comparison of alternatives in different regions due to differing viewpoints on the economic development impacts of a specific project. As work on value measures continue, the Midwest ISO will seek ways to incorporate additional measures into the project description and justification, even if they are not appropriately included in the inclusion or cost allocation criteria for Appendix A of the MTEP report.

10.3 Status of the Value Measure Approach

In 2007, the Midwest ISO began working with stakeholders to determine what additional value measures should be considered for inclusion in future evaluations of proposed projects. The effort began with a total of 34 value measures that were categorized as either quantitative, qualitative, or risk measures. After collaborating with stakeholders to refine the list, a poll was taken to determine the prioritization that the measures should be given. This work resulted in 13 value measures being identified for inclusion in the future development of this approach. Those measures, along with short descriptions, are listed below.

Quantitative

- **RECB II Benefit/Cost Ratio:** intent of measure is to capture the reduction in adjusted production cost through more efficient dispatch of generation resources and reduction in load cost (reduced Locational Marginal Pricing (LMP)), which is achieved by reducing congestion costs and also through more efficient dispatch of generation resources.
- **Reserve Margin:** capture value associated with reducing the amount of new generation reserves needed in the Midwest ISO footprint and local pockets.
- **Losses:** capture savings achieved by reducing the level of capacity losses.

Qualitative

- **Eliminate Market Power:** capture value of relieving a narrowly constrained area as defined in the Midwest ISO tariff.
- **System Reliability:** value of improving reliability of transmission system by providing additional insurance in addition to meeting all currently applicable North American Electric Reliability Corporation (NERC) standards.
- **Payback Period:** intent of measure is to capture additional value of projects where net present value of benefits exceeds net present value of costs in a shorter period of time.
- **Environmental:** ability of project to contribute to reduction of key emissions, such as CO_2, NO_X, SO_2, and mercury emmisions.
- **Right-of-Way Usage:** value associated with a project that more efficiently utilizes new and existing corridors by measuring power transmitted per square foot of right-of-way.

Risk

- **States involved in regulatory approval process:** intent is to capture expected complexity of attaining the necessary regulatory approval as the number of states involved increases.
- **Utilization of new vs. existing right-of-way:** capture expected difficulty of attaining new Right-of-Way for a project as opposed to utilizing existing corridors.
- **Number of landowners involved in attaining necessary right-of-way:** capture increased complexity for project to be placed in service as the number of landowners that must be dealt with increases.
- **Project supports State policies where it resides:** reduced difficulty in attaining regulatory approval for those projects that support certain policies in the state(s) it will be constructed.
- **Right-of-way Environmental Impacts:** capture increased complexity of attaining regulatory approval for right-of-way when project could impact certain environmentally sensitive areas.

Incorporating these measures into a cost/benefit calculation will result in a more accurate portrayal of the value provided by a particular transmission expansion project. Any benefits related to these value measures will be used to evaluate projects in addition to the current measures of adjusted production costs and load LMP savings.

10.4 Incorporating the Value Measures in Future Assessments

The Midwest ISO will continue to work with stakeholders throughout the remainder of 2008 on further development of the value measures approach. This new methodology will bring a more thorough evaluation to projects and allow for more real benefits to be incorporated in the analysis.

Today, projects that are regionally beneficial are analyzed under RECB II, which employs a sliding scale to reflect the increased uncertainty of projects with expected completion dates further out in the future. For a project to be included in MTEP as a Regionally Beneficial Project, it must meet a benefit-to-cost threshold that is based on its in-service date. The initial determination of benefits is based on an evaluation process that uses a combination of 70% of the adjusted production cost savings and 30% of the load LMP savings. The benefits are determined for multiple years with sensitivities to produce a single present value Benefit/Cost (B/C) ratio that is tied to the in-service date of the project. For example, a project with an in-service date that is two years in the future would need a B/C ratio of 1.4 while a project with an in-service date ten years in the future would need a B/C ratio of 3.0 or higher.

Using the value measures to evaluate projects will allow for a more expanded analysis. Projects and/or portfolios of projects will be assessed to determine their value based on some combination of B/C ratios, strong performance against all futures, qualitative value and minimal risk as shown in Table 10-1. The 13 value measures discussed in Section 10.2 will make up this analysis. Much work remains to determine the appropriate method to incorporate the measures into a single evaluation of project both on a standalone basis against an absolute threshold as well as on a comparative basis to other projects.

Table 10-1: Sample Application of Value Measures

Project/Portfolio	B/C	Qualitative	Robustness	Risk
A	3.0	50	1.00	70
B	2.7	50	0.40	50
C	1.5	40	0.75	60
D	2.4	75	0.10	40

- **B/C:** average Benefit / Cost ratio based on quantitative measures across all Futures.
- **Qualitative:** additional qualitative value of project/portfolio
- **Robustness:** standard deviation of the benefit / cost value across all Futures.
- **Risk:** assessed risk value of project/portfolio, where a lower value represents reduced risk associated with that project/portfolio

One alternative for calculating a broader benefit is to include the value of the quantitative measures into the B/C ration approach used today. For the others, preliminary discussions have focused on developing a numerical rating system enable qualitative and risk measures to be incorporated into the analysis. This numerical analysis could be used to incrementally adjust the benefit cost ratio to capture the impact of the "soft metrics". The challenge will be balancing the assessment so that qualitative and quantitative measures are incorporated in proportion to the weight by which those paying for the transmission would view those benefits.

A final goal of the new methodology is to produce fewer future regrets should conditions deviate from those forecasted by selecting the project with the highest benefit and value, the least variablitiy in value across various potential future states, and the lowest risk. Value must be placed on projects that acheive relatively high scores under multiple future states, as it is unknown at the present which, if any, future state will become reality in the coming years. Using the value measures to determine quantitative, qualitative, variability, and risk scores will allow for the identification of those projects that provide the greatest optionality under all future states.

Section 11: MTEP Plan Status

11.1 MTEP07 Status Report

This section gives an update on implementation of projects approved by the Board of Directors in the Midwest ISO Transmission Expansion Plan 2007 (MTEP07) and prior MTEP studies. A given MTEP Appendix A contains newly approved and previously approved projects.

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 MTEP07 in December of 2007. This section provides a review of the status of the approved project facilities contained in the MTEP07 listed in MTEP07 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 the 2008 status report to the Board of Directors with status on MTEP07 projects through July 31, 2008.

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 that include the considerations above.

These approved MTEP07 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 either market flow constraints. A transmission system upgrade project may be comprised of multiple facilities. Over half of the projects in MTEP07 Appendix A are comprised of multiple facilities.

Status on MTEP07 Planned Facilities

MTEP07 Appendix A has 239 projects comprised of 459 facilities. The MTEP07 Appendix A includes expansion facilities through 2016 plan year.

As a whole, 456 of the 459 (99.3%) approved facilities included in MTEP07 are in service or moving forward towards completion at the original estimated in-service date as shown in Figure 11-1. If we use estimated investment cost as basis for the statistic, there would be $2.036 billion out of $2.258 billion in MTEP07 Appendix A (90.2%) of investment expected at the original in-service dates. Of the facilities that have been delayed over half are due to customer requests and reasons that are out of the TO's control or do not impact system reliability. Additional discussion on projects with delays in implementation is below.

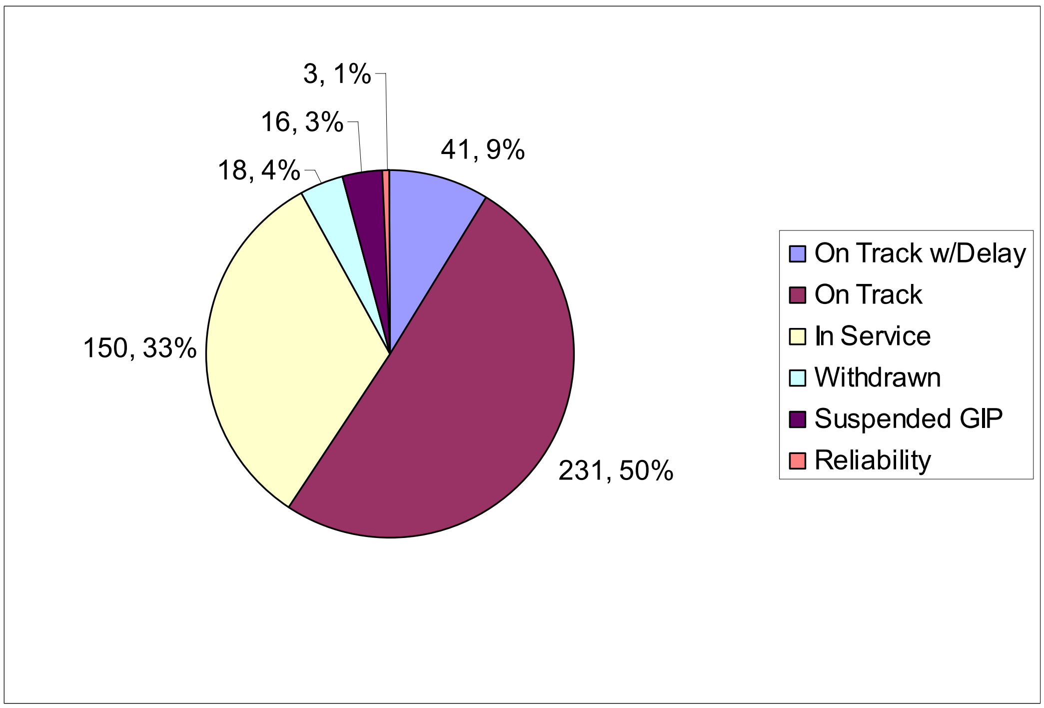

Figure 11-1: MTEP07 Approved Project Facility Status

One hundred forty nine of the approved facilities went in service prior to the summer peak load period of 2008. Figure 11.2 shows the cumulative in service progression of Appendix A facilities at the quarterly Board of Directors reports. Construction does taper off during the summer peak period.

Of the 459 projects, 330 (72%) were In Service or On Track at the time of system peak. The remaining 129 facilities are accounted for in Figure 11-1.

The most serious category in Figure 11-1 is the Reliability category for which there are three facilities in two projects. These are projects that have the potential of impacting reliability because of delay in expected in service date. The cause of delay for the two of the projects is siting issues. The total cost of two projects is $222 million.

An examination of the withdrawn projects is prudent to ensure the planning process of Midwest ISO and it's members not only addresses the needed system additions, but to be sure that when a project is withdrawn that there is good cause or that a different project covers the need of the project that was withdrawn.

There are 18 projects that were withdrawn for various reasons:

- Nine were withdrawn because the customers plans changed
- Three because the plan was replaced with another plan
- Three because a change in planning philosophy after change in ownership
- Two because the plan needed to be redefined to better meet the needs
- One was withdrawn because there was no longer a need.

Although there were 51 in service date adjustments to projects most of the projects were not very large in terms of dollars. The adjustments to the larger projects were associated with Generator Interconnection Projects (GIP) at the customer's request. Little or no impact on reliability is expected because of the schedule adjustments.

11.2 MTEP In Service Transmission Investment

Figure 11-2 shows the cumulative transmission investment dollars for projects which have gone into service for all past MTEP's from 2004 through the current MTEP cycle and accounts for the first six months of 2008. Contributing factors to the steady increase in planned facilities are certainly a testament to the coordinated planning efforts of Midwest ISO and its Transmission Owning members. Another contributing factor to this statistic is the number of new Midwest ISO members adding their planning investments to the total and inclusion of lower voltage transmission investment.

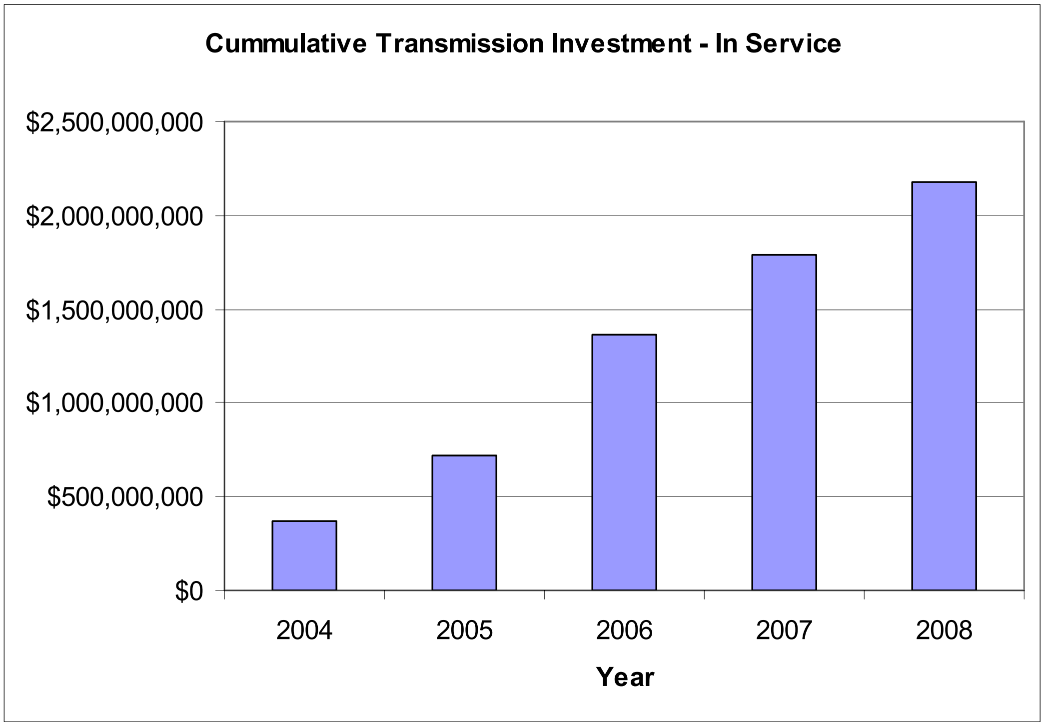

Figure 11-2: Cumulative Facilities In Service at Quarterly Reports

List of Acronyms Commonly Used Throughout MTEP08

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
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
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
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
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: Project Table

Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
A	Central	AmerenIL	150	Prairie State Power Plant transmission outle	Establish a new Prairie State 345 kV switchyard includin	IL		Other	Not Shared (Pre-RECB 1)	$77,987,700	6/1/2010	Planned	345		A	Y
A	Central	AmerenIL	725	LaSalle Area Development	N. LaSalle-Wedron Fox River 138 kV - 20 miles new line	IL		Other	Excluded	$21,357,530	6/1/2009	Planned	138		A	Y
A	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	6/1/2009	Planned	138		A	Y
A	Central	AmerenIL	736	W. Tilton 138 kV Substation	W. Tilton 138 kV Substation - Install 138 kV breaker	IL		BaseRel	Not Shared	$2,658,600	9/8/2008	Under Construction	138		A	Y
A	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	Central	AmerenIL	865	Havana-Monmouth 138 kV River Crossing	Havana-Monmouth 138 kV Line 1362 - Rebuild river crossing	IL		Other	Not Shared	$2,674,600	6/1/2009	Planned	138		A	Y
A	Central	AmerenIL	873	Baldwin Plant 345 kV Switchyard	Replace 6-345 kV breakers with breakers having 3000 A continuous capability	IL		Other	Not Shared (Pre-RECB 1)	$12,232,800	1/31/2009	Planned	345		A	Y
A	Central	AmerenIL	1241	Mattoon, West Wind Farm Connection	Install 138 kV Breaker at Mattoon, West Substation to connect Wind Farm	IL		Other	Not Shared	$659,400	12/1/2009	Planned	138		A	Y
A	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	Central	AmerenMO	153	Central-Watson-1 138 kV	CEE Tap - Watson section of Central-Watson-1 138 kV - Reconductor line	MO		Other	Not Shared	$277,200	9/15/2008	Under Construction	138		A	Y
A	Central	AmerenMO	155	Joachim 345/138 kV	Joachim 345/138 kV - New Substation	MO		Other	Excluded	$13,345,100	10/1/2008	Under Construction	345	138	A	Y
A	Central	AmerenMO	719	Labadie Plant	Labadie Plant - Replace 4-345 kV Breakers	MO		Other	Not Shared	$2,511,700	6/1/2009	Planned	345		A	Y
A	Central	AmerenMO	857	Rush Island-Joachim 345 kV Line	Rush Island-Joachim 345 kV - Replace terminal equipment at Rush Island	MO		Other	Not Shared	$285,400	10/1/2008	Planned	345		A	Y
A	Central	CWLP	1620	G412 - Dallman 4 Unit	Network Upgrades associated with 200 MW Dallman #4 in Springfield, Illinois	IL		GIP	Shared	$7,829,300	1/1/2010	Planned	138		A	Y
A	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	$9,035,572	6/1/2010	Planned	138		A	Y
A	Central	DEM	91	Hillcrest 345/138	Construct new 345/138 kV Hillcrest substation. Tap Suart to Foster 345kV line. Construct new 138kV line from Eastwood to Hillcrest. Replace 345kV relays at Stuart and Foster. Replace 138kV relays at Brown and Ford Batavia.	OH		BaseRel	Shared	$15,604,406	6/1/2008	Under Construction	345	138	A	Y
A	Central	DEM	200	W Laf Purdue to Purdue NW 138kV Upgrate and Switch replacement	Upgrade 138kV switches at West Lafayette Purdue and uprate conductor to 100C.	IN		Other	Excluded	$9,878	6/1/2008	Under Construction	138		A	Y
A	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	12/31/2009	Planned	138		A	Y
A	Central	DEM	627	Kenton to West End New 138 Circuit	Construct new 138kV line from Kenton to West End.	KY	OH	Other	Excluded	$1,980,041	6/1/2013	Planned	138		A	Y
A	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	6/1/2009	Planned	138		A	Y
A	Central	DEM	807	Dresser Bk 1&2 Limiting Equipment	Replace 138kV breakers and switches to achieve full transformer rating.	IN		BaseRel	Not Shared	$395,678	6/1/2009	Planned	345	138	A	Y
A	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	6/1/2011	Planned	138		A	Y
A	Central	DEM	852	Crawfordsville to Tipmont Concord to Lafayette SE 138 Reconductor	Reconductor 13819 circuit with 954ACSR 100C.	IN		BaseRel	Shared	$9,308,037	6/1/2010	Planned	138		A	Y

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A	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
A	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	Planned	138		A	Y
A	Central	DEM	1198	Bedford Switch Automation	Add motors and automation to the 34506 and 34521 line switches.	IN		Other	Not Shared	$199,211	6/1/2008	Under Construction	345		A	Y
A	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	Central	DEM	1200	Speed Bk3 Limiting Equipment	Upgrade 2000A 138kV breaker & switch and any other Bk3 limiting equipment. Replace any equipment that would limit the 345/138 xfr to less than the hot spot rating of 520 MVA.	IN		BaseRel	Not Shared	$173,193	6/1/2010	Planned	345	138	A	Y
A	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	6/1/2011	Planned	230		A	Y
A	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	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	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	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	Central	DEM	1254	Charletown to CMC new 138kV line	Construct 8.5 mi. of 138kV line from Charlestown to CMC.	IN		Other	Not Shared	$5,497,000	12/31/2009	Planned	138		A	Y
A	Central	DEM	1262	HE Durgee Rd	HE 138/12 kV substation.	IN		Other	Not Shared	$227,341	6/1/2009	Planned	138		A	Y
A	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	$9,560,000	5/30/2011	Planned	345		A	Y
A	Central	HE	204	Tapline 138 to Buena Vista, Batesville, & North Charleston	Buena Vista-Tapline 138, Batesville-Tapline 138, North Charleston-Tapline 138	IN		Other	Not Shared	$1,850,000	6/1/2009	Proposed	138	13	A	Y
A	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	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	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	6/2/2009	Planned	138		A	Y
A	Central	IPL	893	North 138 kV 150 MVAR Capacitor	Capacitor Bank SizeUpgrade: North 138 kV 100 MVAR To 150 MVAR	IN		BaseRel	Not Shared	$300,000	6/1/2010	Planned	138		A	Y
A	Central	IPL	895	Georgetown To Northeast 138kV Loop-In	Loop Georgetown to Northeast 138kV Line Into North Substation	IN		BaseRel	Not Shared	$2,700,000	6/1/2008	Under Construction	138		A	Y
A	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

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A	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	East	FE	1327	Babb - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$865,400	6/1/2009	Planned	138		A	Y
A	East	FE	1328	Barberton - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$677,600	6/1/2014	Planned	138		A	Y
A	East	FE	1329	West Akron - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$257,000	6/1/2014	Planned	138		A	Y
A	East	FE	1331	East Akron - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$305,000	6/1/2014	Planned	138		A	Y
A	East	FE	1333	Brookside -Add 138kV Cap Banks	Add 2 - 50 MVAR Cap Bank with 2 - 138 kV Breakers	OH		BaseRel	Not Shared	$1,000,200	6/1/2014	Planned	138		A	Y
A	East	FE	1334	Longview -Add 138kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Switcher	OH		BaseRel	Not Shared	$523,800	6/1/2014	Planned	138		A	Y
A	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	12/31/2011	Planned	345	120	A	Y
A	East	ITC	905	Marysville Decommissioning	Decommission Marysville Station, expand Bunce Creek Station creating new Bunce Creek - Cypress, Bunce Creek - Menlo, Bunce Creek - Wabash 2 120 kV lines.	MI		Other	Not Shared	$2,333,334	12/31/2008	Under Construction	120		A	Y
A	East	ITC	907	Goodison Station	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	12/31/2010	Planned	345	120	A	Y
A	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	6/1/2009	Under Construction	120		A	Y
A	East	ITC	1301	Yost Line Breaker	Adds a line breaker on the Yost end of the Yost-Polaris 120 kV Circuit to reduce the trasnmission system exposure to faults on distribution circuits	MI		Other	Not Shared	$791,000	10/1/2008	Under Construction	120		A	Y
A	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	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	$1,750,000	12/31/2008	Planned	345		A	Y
A	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	$1,850,000	12/31/2008	Planned	345		A	Y
A	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	6/1/2009	Under Construction	120		A	Y
A	East	METC	481	Tallmadge 345/138 kV TB3 transformer #3	Tallmadge 345/138 kV TB3 transformer #3 addition	MI		BaseRel	Shared	$9,913,090	12/1/2008	Planned	345	138	A	Y
A	East	METC	497	Tallmadge - Wealthy Street 138 kV line #2	Tallmadge - Wealthy Street 138 kV line #2	MI		Other	Excluded	$250,000	12/31/2008	Planned	138		A	Y
A	East	METC	660	Keystone - Clearwater - Stover 138 kV line Phase 1	Keystone to Clearwater 138 kV line - rebuild 23.2 miles to 795 ACSS	MI		BaseRel	Shared	$10,200,000	11/1/2008	Under Construction	138		A	Y
A	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	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	12/31/2009	Planned	138		A	Y
A	East	METC	1016	Bard Road	Bard Road - New Capacitor	MI		BaseRel	Not Shared	$1,661,100	12/31/2008	Planned	138		A	Y
A	East	METC	1017	Croton	Croton - New Capacitor	MI		BaseRel	Not Shared	$1,661,100	12/31/2008	Planned	138		A	Y
A	East	METC	1390	Goss Station 345kV Bus	Rebuild Goss 345kV bus from GIS to air insulated and replace 345kV breakers	MI		Other	Not Shared	$8,800,000	7/31/2008	Under Construction	345		A	Y
A	East	METC	1406	Breaker Repair or Replace Program	Replace 138kV Alpena 188 breaker	MI		Other	Not Shared	$160,000	12/31/2008	Planned	138		A	Y
A	East	METC	1407	Ludington 345kV Reactor	Repair or replace faulty (gasing) 100MVAR reactor and replace the existing circuit switcher with a breaker	MI		Other	Not Shared	$3,000,000	6/1/2008	Under Construction	345		A	Y
A	East	METC	1408	RTU / SCADA upgrade	Install and/or upgrade RTU's and SCADA points throughout system	MI		Other	Not Shared	$801,000	12/31/2008	Under Construction	345	138	A	Y

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A	East	METC	1410	Mobile 138kV Bulk Capacitor	Purchase a mobile 14.4 - 36MVAR capacitor for flexible use where needed throughout the system	MI		Other	Not Shared	$700,000	12/1/2008	Planned	138		A	Y
A	East	METC	1414	Thetford 345kV Line Relaying	Upgrade line relaying on 345kV lines	MI		Other	Not Shared	$300,000	12/31/2008	Planned	345		A	Y
A	East	METC	1416	Tittabawassee-Hemlock Semiconductor 138 kV line	Install a second 138kV Tittabawasee-HSC line (14.7 miles) along with required 138kV breakers at each end (5 total breakers) and install a 2 mile 138kV double circuit to swap the existing Tittabawasee and Lawndale line connections into HSC.	MI		BaseRel	Shared	$4,527,000	10/1/2007	Under Construction	138		A	Y
A	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	12/31/2008	Planned	138		A	Y
A	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	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
A	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	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	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	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	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	East	METC	1446	Gaines	Install bulk substation at Gaines	MI		Other	Not Shared	$50,000	6/1/2010	Planned	138		A	Y
A	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	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	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	Proposed	138	69	A	Y
A	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	$45,400,502	6/1/2009	Planned	345		A	Y
A	East	NIPS	612	Hiple - Add 2nd 345-138 kV Transformer	Install a 2nd 345/138 kV 560 MVA transformer, associated breakers and bus at F.G. Hiple Substation.	IN		BaseRel	Shared	$5,799,614	5/1/2008	Planned	345	138	A	Y
A	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	5/1/2008	Planned	138		A	Y
A	East	WPSC	1227	Gaylord Gen - Gaylord OCB	Gaylord Generation to Gaylord OCB line rebuild	MI		Other (Reliability)	Not Shared	$2,600,000	12/31/2009	Planned	69		A	Y
A	East	WPSC	1228	ANR Elpaso New Load	Add 14MW load off of Wolverine's Westwood Junction	MI		Other (Reliability)	Not Shared	$1,800,000	8/1/2008	Planned	69		A	Y

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A	East	WPSC	1229	Plains Junction Breaker Station	Replace Relaying and Breakers at Plains Junction Substation	MI		Other (Reliability)	Not Shared	$800,000	11/30/2008	Planned	69		A	Y
A	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 (Reliability)	Not Shared	$3,000,000	12/31/2012	Planned	138	69	A	Y
A	West	ATC LLC	1	Arrowhead-Gardner Park 345 kV	Arrowhead - Gardner Park 345 kV line	WI	MN	Other	Excluded	$26,000,000	6/30/2008	Planned	345	230	A	Y
A	West	ATC LLC	177	Gardner Park-Highway 22 345 kV line projects	Construct Gardner Park-Highway 22 345 kV line and Construct new Highway 22 345 kV substation	WI		Other	Not Shared (Pre-RECB 1)	$128,900,000	12/1/2009	Planned	345		A	Y
A	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	$20,450,000	5/31/2009	Planned	138		A	Y
A	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	$137,757,371	4/30/2009	Planned	345		A	Y
A	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		BaseRel	Shared	$84,100,000	6/1/2010	Planned	138	69	A	Y
A	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	West	ATC LLC	570	Rock River-Bristol-Elkhorn conversion to 138 kV	Rock River - Bristol - Elkhorn conversion to 138 kV	WI		Other	Excluded	$15,063,960	8/28/2008	Under Construction	138		A	Y
A	West	ATC LLC	571	North Madison-Waunakee 138 kV line	New North Madison - Huiskamp 138 kV line and a new 138/69 kV substation near Huiskamp including a 100 MVA 138/69-kV transformer	WI		Other	Excluded	$14,072,115	3/15/2009	Planned	138	69	A	Y
A	West	ATC LLC	572	Menominee 138/69 kV transformer	Loop West Marinette - Bay de Noc 138 kV line into Menominee. Total project cost $2,000,000.	MI	WI	Other	Excluded	$3,915,000	11/1/2008	Under Construction	138	69	A	Y
A	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)	$44,706,194	6/1/2010	Planned	345	138	A	Y
A	West	ATC LLC	886	North Lake (Cedar) sub relocation	North Lake (Cedar) substation relocation	MI		Other	Not Shared	$7,300,000	5/1/2009	Under Construction	138		A	Y

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A	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	6/1/2010	Proposed	345		A	Y
A	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	$22,100,000	6/1/2010	Proposed	138	69	A	Y
A	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	9/1/2009	Planned	138	34.5	A	Y
A	West	ATC LLC	1463	G384	Net: new two breaker 138 kV substation, loop line Y-51 into the substation, perform a relay replacement for Kewaunee sub 138 kV line Y-51 to Shoto sub.	WI		Other	Not Shared (Pre-RECB 1)	$3,268,000	10/1/2009	Planned	138		A	Y
A	West	ATC LLC	1470	G483	50 MW wind farm at Whistling Wind 69 kV substation	WI		GIP	Shared	$7,538,732	9/1/2009	Planned	69		A	Y
A	West	ATC LLC	1617	G527	280 MW coal unit at Nelson Dewey 161 kV sub	WI		GIP	Shared	$11,074,000	2/1/2013	Planned	161		A	Y
A	West	GRE	599	Crooked Lake - Enterprise Park 115 kV line	Crooked Lake - Enterprise Park 115 kV line	MN		Other	Excluded	$3,600,000	12/1/2010	Planned	115		A	Y
A	West	GRE	601	Mud Lake - Wilson Lake 115 kV line	Mud Lake - Wilson Lake 115 kV line	MN		Other	Excluded	$8,500,000	10/1/2008	Under Construction	115		A	Y
A	West	GRE	1026	Linwood 230-69 kV transformer	Required for TSR A125 and A130	MN		TDSP	Direct Assigned	$5,000,000	6/15/2008	Under Construction	230	69	A	Y
A	West	GRE	1361	Badoura - Birch Lake 115 lines	Badoura - Birch Lake 115 lines	MN		Other	Not Shared	$11,275,000	5/1/2010	Planned	115		A	Y
A	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	16	A	Y
A	West	ITCM	1287	Replace Salem 345/161 kV transformer with 448 MVA unit	Replace Salem 345/161 kV transformer with 448 MVA unit	IA		BaseRel	Shared	$5,650,000	6/1/2009	Planned	345	161	A	Y
A	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	$5,000,000	12/31/2010	Planned	345	161	A	Y
A	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	12/31/2010	Planned	115		A	Y
A	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	$4,550,000	6/1/2010	Planned	161	115	A	Y
A	West	ITCM	1344	Build a new 345 kV Beverly substation which taps the Arnold -Tiffin 345 kV line	Build a new 345 kV 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	$4,300,000	6/1/2012	Proposed	345	161	A	Y
A	West	ITCM	1473	Mason City Armor - Emery North 69 kV line	Mason City Armor - Emery North 69 kV line	IA		TDSP	Direct Assigned	$975,000	6/1/2009	Planned	69		A	NT
A	West	MDU	548	Bismarck Downtown-East Bismarck 115 kV upgrade to at least 160 MVA	Bismarck Downtown-East Bismarck 115 kV upgrade to at least 160 MVA	ND		BaseRel	Not Shared	$363,000	11/1/2007	Planned	115		A	Y
A	West	MDU	1008	Bismarck/Mandan 115 kV Circuits transferred from old to new Memorial Bridge	Bismarck/Mandan 115 kV Circuits transferred from old to new Memorial Bridge	ND		Other	Not Shared	$6,560,000	11/1/2009	Planned	115		A	Y
A	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	$19,995,000	5/1/2010	Planned	115		A	Y
A	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

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A	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	$1,750,000	6/1/2008	Planned	115		A	Y
A	West	MP	1359	International Falls - Capacitor 115 add new	International Falls - Capacitor 115 add new	MN		BaseRel	Not Shared	$245,000	6/30/2007	Planned	115		A	Y
A	West	MP/GRE	600	Baxter - Southdale 115 kV line	Baxter - Southdale 115 kV line	MN		Other	Excluded	$7,650,000	12/1/2009	Planned	115		A	Y
A	West	MP/GRE	1021	Embarass to Tower 115 kV Line	115 kV line from 34L tap to Tower 46 kV	MN		Other	Not Shared	$11,114,000	11/1/2009	Under Construction	115		A	Y
A	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	5/1/2009	Under Construction	115		A	Y
A	West	MPC, XEL, OTP, MP	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	$72,360,000	7/1/2012	Proposed	230	115	A	Y
A	West	OTP	274	Appleton - Dawson 115 kV Line	Appleton - Dawson 115 kV line, conversion of 41.6 kV line to 115 kV	MN		Other	Not Shared	$2,080,600	8/1/2008	Planned	115	12.5	A	Y
A	West	OTP	275	Canby - Dawson 115 kV Line	Dawson - Canby 115 ckt 1, Sum rate 96	MN		Other	Not Shared	$519,400	8/1/2008	Under Construction	115		A	Y
A	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	10/1/2009	Planned	230		A	Y
A	West	OTP, MRES, GRE	755	Alexandria Capacitor Addition	Alexandria Switching Station 115 kV 25 MVAR Capacitors	MN		BaseRel	Not Shared	$530,000	6/1/2008	Under Construction	115		A	Y
A	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	$36,111,000	12/31/2010	Planned	161	69	A	Y
A	West	XEL	385	Xcel Energy Wind 425-825 MW project	Buffalo Ridge (SW MN) 825 MW of Generation Outlet. Split Rock-Nobles-Lakefield 345 kV line plus many other upgrades	MN		TDSP	Not Shared	$5,792,805	12/31/2009	Planned	345	115	A	Y
A	West	XEL	1454	G176, 37319-01	Net: Yankee Substation 115/34.5 kV transformer Int: two 34.5 feeder bays at Yankee Sub terminating at the dead-end switch structures outside Yankee Sub.	MN		Other	Not Shared (Pre-RECB 1)	$581,280	10/1/2007	Planned	34.5		A	Y
A	West	XEL	1455	G238, 37642-02, Increase of generating capacity at Riverside Generating Plant	Net: 3 new 115 kV, 63 kA interrupting rating circuit breakers, disconnect switches, and relocate the existing Apache 115 kV line to a new termination in the same substation	MN		Other	Not Shared (Pre-RECB 1)	$2,770,000	5/1/2009	planned	115		A	Y
A	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	$38,735,000	12/31/2010	Planned	345		A	Y
A	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
A	West	XEL	1489	Woodbury - Tanners Lake upgrade	Reconductor the line from Woodbury - Tanners Lake to 310 MVA	MN		BaseRel	Not Shared	$525,000	6/1/2009	Planned	115		A	Y

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A	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	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 MTEP08	Central	AmerenIL	1232	Tap to Tilden-Fayetteville L1526	Tap to Tilden-Fayetteville L1526 for construction power for Prairie State	IL		Other	Not Shared	$2,602,000	1/1/2008	In Service			B>A	Y
A in MTEP08	Central	AmerenIL	1351	Pana North - Decatur Rt. 51 L1462	Pana North - Decatur Rt. 51 L1462	IL		Other	Not Shared	$80,600	5/5/2008	In Service	138		B>A	Y
A in MTEP08	Central	AmerenIL	1526	N. Staunton-Midway - Upgrade Terminal Equipment	Replace terminal equipment at N. Staunton	IL		Other	Not Shared	$375,100	3/14/2008	In Service	138		B>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		C>B>A	Y
A in MTEP08	Central	AmerenIL	1531	S. Bloomington-Clinton Rt. 54 - Upgrade Terminal Equipment	Replace terminal equipment at S. Bloomington	IL		Other	Not Shared	$25,000	1/1/2008	In Service	138		B>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		B>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		C>B>A	Y
A in MTEP08	Central	AmerenIL	2060	East Peoria - Flint : Increase Clearances 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		C>B>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		C>B>A	Y

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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	C>B>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		C>B>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		C>B>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 (Reliability)	Excluded	$125,350	6/1/2010	Proposed	138		B>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 (Reliability)	Excluded	$125,350	6/1/2010	Proposed	138		B>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		B>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		C>B>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	C>B>A	Y
A in MTEP08	Central	AmerenMO	2072	Brick House Substation	This project would provide auxiliary power for Environmental load at Sioux power plant	MO		Other	Not Shared	$8,700,000	10/1/2008	Planned	138	13.8	C>B>A	Y
A in MTEP08	Central	AMRN	2113	G515	Network upgrades for tariff service request	IL		GIP	Shared	$2,244,000	12/1/2008	Planned	138		C>B>A	Y
A in MTEP08	Central	CWLP	1552	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation (two new tie lines) Convert Interstate sub from a 6 breaker ring bus to a 12 breaker breaker-and-a-half arrangement. P2071 is companion Ameren project.	IL		BaseRel	Not Shared	$2,800,000	10/1/2009	Planned	138		B>A	Y
A in MTEP08	Central	DEM	625	Pierce/Beckjord 345/138 kV transformer addition	Add 3rd 345/138kV transformer, 400MVA, from Pierce 345kV bus to Beckjord 138kV North bus.	OH		Other	Excluded	$2,659,515	6/1/2008	Under Construction	345	138	C>B>A	Y
A in MTEP08	Central	DEM	806	Gwynnville 345/69	Add 345/69kV transformer at Gwynnville. Construct four 69kV exits to connect to existing 69kV circuits.	IN		Other	Not Shared	$7,823,698	6/1/2008	In Service	345	69	C>B>A	NT
A in MTEP08	Central	DEM	810	Bloomington Bk5 230/69	Add 2nd 230/69kV transformer at Bloomington.	IN		Other	Not Shared	$3,986,059	12/31/2007	In Service	230	69	C>B>A	Y
A in MTEP08	Central	DEM	811	Evendale 69kV Caps 1&2	Add two 21.6 MVAR 69kV capacitors at Evendale	OH		Other	Not Shared	$781,610	12/31/2007	In Service	69		C>B>A	NT
A in MTEP08	Central	DEM	828	Northgreen 69kV Cap	Add 14.4 MVAR 69kV capacitor at Northgreen.	OH		Other	Not Shared	$406,671	12/31/2007	In Service	69		C>B>A	NT
A in MTEP08	Central	DEM	830	Thorntown 69kV Cap	Add 28.8 MVAR 69kV capacitor at Thorntown.	IN		Other	Not Shared	$456,723	11/2/2007	In Service	69		C>B>A	NT
A in MTEP08	Central	DEM	834	Kingman 69kV Cap	Add 7.2 MVAR 69kV capacitor at Kingman.	IN		Other	Not Shared	$500,000	6/1/2012	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	835	Pittsboro 69kV Cap	Add 14.4 MVAR 69kV capacitor at Pittsboro.	IN		Other	Not Shared	$500,000	6/1/2010	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	841	Westwood Bk1 Limiting Equipment	Replace 1200A 138kV equipment with 2000A to allow full transformer rating.	IN		BaseRel	Not Shared	$554,000	6/1/2013	Planned	345	138	C>B>A	Y
A in MTEP08	Central	DEM	1194	Prescott	Add 43.2 MVAR capacitor.	IN		Other	Not Shared	$439,845	12/31/2010	Planned	69		C>B>A	NT

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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	6/1/2010	Planned	69		C>B>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	6/1/2010	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	1266	Hortonville 69kV Cap	Install 69kV 36MVAR cap bank at Hortonville	IN		Other	Not Shared	$500,000	6/1/2009	Planned	69		C>B>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	6/1/2012	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	1502	Tipton West 230/69 substation	Construct a new 230/69kV substation with 2-150MVA xfmrs	IN		Other	Not Shared	$11,096,872	12/31/2008	Planned	230	12.5	C>B>A	Y
A in MTEP08	Central	DEM	1504	Honda	New substation for Honda in Greensburg taps the Duke Energy 138kV line between Greensburg and Shelbyville Northeast.	IN		BaseRel	Not Shared	$0	12/1/2007	In Service	138		B>A	Y
A in MTEP08	Central	DEM	1505	HE Owensville North 138/69	Loop Gibson to Princeton 13863 line through new HE Owensville North 138/69 substation.	IN		Other	Not Shared	$182,375	6/1/2008	In Service	138		B>A	Y
A in MTEP08	Central	DEM	1506	Peru SE 69kV	Add 69kV ring breaker, line terminal and interconnection metering for new Peru Municiapal 69kV circuit.	IN		Other	Not Shared		12/31/2007	In Service	69		C>B>A	NT
A in MTEP08	Central	DEM	1507	Vectren Francisco 345/138	Loop 34516 line through new Vectren Francisco 345/138kV substation. Reroute Duke Energy 138kV around substation.	IN		BaseRel	Not Shared	$0	12/31/2007	In Service	138		B>A	Y
A in MTEP08	Central	DEM	1510	Wabash River to TH Water St 138 100C Uprate	Uprate 138kV from Wabash River to Terre Haute Water St to 100C.	IN		BaseRel	Not Shared	$120,282	6/1/2008	Planned	138		B>A	Y
A in MTEP08	Central	DEM	1512	Ashland to Rochelle 138	Install underground 138 kV circuit from Ashland to Rochelle.	OH		BaseRel	Not Shared	$2,878,513	6/1/2010	Planned	138		C>B>A	Y
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		C>B>A	NT
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	$255,173	6/1/2009	Planned	230		B>A	Y
A in MTEP08	Central	DEM	1515	Speed relays for LGEE Trimble	Replace Speed relays for the LGEE Trimble addition	IN		Other (non-MISO)	Not Shared	$145,922	6/1/2009	Planned	345		B>A	Y
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 (Reliability)	Not Shared	$2,640,107	6/1/2011	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	1560	Edwardsport 138kV cap	Install a 138kV 57.6MVAR capacitor at Edwardsport.	IN		BaseRel	Not Shared	$500,000	6/1/2010	Planned	138		C>B>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		C>B>A	Y
A in MTEP08	Central	DEM	1563	Todhunter to AK Steel 138kv reconductor	Replace F5686 existing conductor with 954ACSR @ 100C from Todhunter to AK Steel and replace any limiting terminal equipment at both ends	OH		BaseRel	Not Shared	$302,000	10/15/2008	Planned	138		B>A	Y
A in MTEP08	Central	DEM	1564	Roseburg Switching Station cap	Install 69kV 21.6MVAR std capacitor	IN		Other	Not Shared	$500,000	6/1/2009	Planned	69		C>B>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 (Reliability)	Not Shared	$4,561,674	6/1/2010	Planned	345	138	B>A	Y
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 (Reliability)	Not Shared	$1,507,856	6/1/2010	Planned	138		B>A	Y

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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 (Reliability)	Not Shared	$4,139,000	6/1/2010	Planned	138		B>A	Y
A in MTEP08	Central	DEM	1648	Lafayette S to Lilly Uprate	Lafayette S to Lilly Uprate 397.5ACSR to 100C - 4.13 miles - 13808 ckt	IN		Other	Not Shared	$389,256	10/15/2008	Planned	138		C>B>A	Y
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	6/30/2012	Proposed	138		C>B>A	Y
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	Proposed	138		C>B>A	Y
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	6/1/2009	Planned	138	69	B>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	12/31/2009	Planned	138		C>B>A	Y
A in MTEP08	Central	DEM	1886	Columbus West 69kV line switches replace	Columbus West - replace 69kV switches 1&2 with 1200 amp switches - (in the 69146 ckt)	IN		Other	Not Shared	$82,847	5/29/2009	Planned	69		C>B>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 (Reliability)	Not Shared	$2,418,000	6/1/2011	Planned	69		C>B>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 (Reliability)	Not Shared	$2,300,000	6/1/2009	Planned	69		C>B>A	NT
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 (Reliability)	Not Shared	$1,181,223	5/1/2010	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	1891	N. Manchester to N. Man. Sw. Sta. 69kV line rebuild	6923 ckt. reconductor from N. Manchester 69 sub to N. Manchester Sw Sta (0.53 mile) and a portion of the line section from N. Manchester 69 sub to Collamer along CR 1100N (1.03 miles), also replace transmission poles - new conductor will be 477ACSR@100C	IN		Other	Not Shared	$618,143	6/1/2009	Planned	69		C>B>A	NT
A in MTEP08	Central	DEM	1892	Wabash to Hopewell Jct 69132 rebuild	69132 ckt. Reconductor 6.86 miles from Wabash to Hopewelll Jct. with 477ACSR	IN		Other (Reliability)	Not Shared	$2,591,000	6/1/2009	Planned	69		C>B>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 (Reliability)	Not Shared	$3,620,481	6/1/2011	Planned	69		C>B>A	NT
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	6/1/2011	Planned	138		C>B>A	Y
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	6/1/2010	Planned	69		C>B>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	6/1/2010	Planned	69		C>B>A	NT
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 (Reliability)	Not Shared	$3,102,711	12/31/2010	Planned	69		C>B>A	NT

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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 (7.13 miles)	IN		Other (Reliability)	Not Shared	$1,510,946	6/1/2011	Planned	69		C>B>A	NT
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	$163,390	6/1/2012	Planned	69		C>B>A	NT
A in MTEP08	Central	HE	1323	Sandborn Primary Substation	161/69kV Primary Station at Sandborn	IN		Other (Reliability)	Not Shared	$6,000,000	9/1/2008	Planned	161	69	C>B>A	Y
A in MTEP08	Central	HE	1635	Ramsey Primary Substation Ringbus	345kV Ringbus Addition/Modification to Ramsey Primary	IN		Other (Reliability)	Not Shared	$7,000,000	12/1/2009	Planned	345		B>A	Y
A in MTEP08	Central	HE	1923	Spring Valley 69kV Switch Station	69kV Switching station w/ 69kV Ring Bus	IN		Other (Reliability)	Not Shared	$2,600,000	9/1/2009	Planned	69		C>B>A	NT
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		C>B>A	NT
A in MTEP08	Central	HE	1927	Hubbell Primary Ring Bus	138kV Ring Bus addition / Modification to Hubbell Primary	IN		Other (Reliability)	Not Shared	$3,000,000	9/1/2010	Planned	138		C>B>A	Y
A in MTEP08	Central	HE	1928	Fairview Primary Ring Bus	138kV Ring Bus addition / Modification to Fairview Primary	IN		Other (Reliability)	Not Shared	$1,500,000	9/1/2011	Planned	138		C>B>A	Y
A in MTEP08	Central	HE	1929	Georgetown Primary Ring Bus	138kV Ring Bus addition / Modification to Georgetown Primary	IN		Other (Reliability)	Not Shared	$1,250,000	9/1/2012	Planned	138		C>B>A	Y
A in MTEP08	Central	HE	2082	Shelbyville Intel Park	138kV Substation and Tapline	IN		Other (Reliability)	Not Shared	$1,000,000	9/1/2009	Planned	138	12.5	C>B>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	C>B>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	C>B>A	Y
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		C>B>A	NT
A in MTEP08	Central	IPL	1634	Pete-Vincennes Line Capacity Upgrade	Increase Capacity By Changing CT Ratio At Petersburg To 1200A	IN		BaseRel	Not Shared	$2,500	1/1/2008	In Service	138		B>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			C>B>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		C>B>A	Y
A in MTEP08	Central	Vectren (SIGE)	995	Add 138/69 kV 60 MVA transformer to Mt. Vernon	Add 138/69 kV 60 MVA transformer to Mt. Vernon	IN		Other	Not Shared	$80,000	12/31/2012	Proposed	138	69	C>B>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	5/31/2009	Planned	138	69	C>B>A	Y
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 (Reliability)	Not Shared	$8,500,000	5/31/2009	Planned	138		B>A	Y
A in MTEP08	Central	Vectren (SIGE)	1023	Scott Township 138/69 kV Substation and Scott Township - Elliott 138 kV Line	New Scott Township 138/69 kV substation and new 138 kV line from Scott Township to Elliott	IN		Other (Reliability)	Not Shared	$13,900,000	5/31/2009	Planned	138	69	B>A	Y
A in MTEP08	Central	Vectren (SIGE)	1258	Pigeon Creek 138/69 kV Substation	New 'Pigeon Creek 138/69 kV Substation	IN		Other (Reliability)	Not Shared	$10,700,000	5/31/2008	Planned	138	69	C>B>A	Y
A in MTEP08	Central	Vectren (SIGE)	1779	Aventine Ethanol Plant and line work	Add new Customer 69/12kV Substation with assoc. 69kV line work.	IN		Other (Reliability)	Not Shared	$2,715,000	6/1/2009	Planned	69	12.47	C>B>A	NT
A in MTEP08	Central	Vectren (SIGE)	1780	Aventine Phase II	Expansion of Substation	IN		Other (Reliability)	Not Shared	$1,325,000	6/1/2009	Planned	69	12.47	C>B>A	NT

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A in MTEP08	Central	Vectren (SIGE)	1781	Abengoa Ethanol Plant and line work	Add new Customer 138/12kV Substation with assoc. 138kV line work.	IN		Other (Reliability)	Not Shared	$2,750,000	6/1/2009	Planned	138	12.47	C>B>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 (Reliability)	Not Shared	$3,300,000	6/1/2009	Planned	138		C>B>A	Y
A in MTEP08	Central	Vectren (SIGE)	1783	Princeton Area Load Addition	Expansion of Substation	IN		Other	Not Shared	$400,000	6/1/2009	Planned	69	12.47	C>B>A	NT
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		C>B>A	NT
A in MTEP08	Central	Vectren (SIGE)	1785	Z83 Upgrade	Upgrade terminal equipment at NE and NW.	IN		Other	Not Shared	$100,000	6/1/2008	Planned	138		C>B>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	6/1/2008	Planned	138		C>B>A	Y
A in MTEP08	Central	Vectren (SIGE)	1787	Y75 - Dale to Santa Clause	New 69kV line from Dale Sub to Santa Clause Sub	IN		Other (Reliability)	Not Shared	$3,300,000	6/1/2012	Planned	69		C>B>A	NT
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 (Reliability)	Not Shared	$2,600,000	6/1/2012	Planned	69		C>B>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 (Reliability)	Not Shared	$1,400,000	6/1/2012	Planned	69		C>B>A	NT
A in MTEP08	Central	Vectren (SIGE)	1790	Y52 rebuild and Sunbeam loop	Rebuild/Reconductor existing Y52 and loop into Sunbeam	IN		Other (Reliability)	Not Shared	$1,500,000	6/1/2012	Planned	69		C>B>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		C>B>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	C>B>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 (Reliability)	Not Shared	$4,131,000	6/1/2010	Planned	138	69	C>B>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 (Reliability)	Not Shared	$2,034,365	6/1/2009	Planned	138	69	C>B>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 (Reliability)	Not Shared	$451,100	10/1/2009	Planned	34.5		C>B>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	6/1/2009	Planned	138		B>A	Y
A in MTEP08	East	FE	1600	Beaver - Wellington New 138 kV Line	Build a new Beaver - Wellington 138 kV Line and establish a 138 kV ring bus at Wellington Substation.	OH		Other (Reliability)	Not Shared	$5,000,000	6/1/2014	Proposed	138		C>B>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 (Reliability)	Not Shared	$3,669,000	6/1/2010	Planned	138		C>B>A	Y
A in MTEP08	East	FE	1609	Tangy -Add 345/138kV Transformer, (2) 345kV BKR's, (1) 138kV BKR, additional substation work	Additional 345/138kV TR in 2009. Separate TR #3 and TR #4.	OH		BaseRel	Shared	$7,300,000	6/1/2009	Planned	345	138	C>B>A	Y
A in MTEP08	East	FE	1610	SW Avon 92-AV-T New Transformer	Add new autotransformer to Avon Lake substation, along with station re-configuration to accomodate new transformer.	OH		BaseRel	Shared	$8,459,634	6/1/2009	Planned	345	138	B>A	Y
A in MTEP08	East	FE	1905	Salt Springs - New 138/69kV Transformer to R/P failed #2 Unit	Purchase and install new 138/69kV transformer to replace the failed Salt Springs #2 138/69kV transformer unit.	OH		Other (Reliability)	Not Shared	$2,226,000	6/1/2008	In Service	138	69	C>B>A	Y
A in MTEP08	East	FE	1907	Brookside: split Hale 69kV Line	Build new 69kV circuit from tap point on Hale 69kV circuit back to Brookside Substation.	OH		Other (Reliability)	Not Shared	$769,000	6/1/2008	In Service	69		C>B>A	Y

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A in MTEP08	East	FE	1908	Cook-Galion: R/C Galion-Snyder 69kV line section + Mansfield Waterworks-Alta line section	Reconductor 5.3 miles with 477 ACSR, andr 2.3 miles with 336.4 ACSR.	OH		Other (Reliability)	Not Shared	$2,000,000	6/1/2008	In Service	69		C>B>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	$3,345,000	6/1/2010	Planned	345		C>B>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 (Reliability)	Not Shared	$12,000,000	11/1/2010	Proposed	138	69	C>B>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 (Reliability)	Not Shared	$2,400,000	12/31/2009	Planned	69		C>B>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 (Reliability)	Not Shared	$2,700,000	6/1/2010	Planned	69		C>B>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 (Reliability)	Not Shared	$3,275,000	6/1/2012	Planned	69		C>B>A	Y
A in MTEP08	East	FE	2096	New 138kV line to supply a new Stacy 138-36kV distribution sub	Construct a 138kV loop to a new Stacy substation for 138kV support in the area, with possible networking to other substations based on future growth.	OH		Other (Reliability)	Not Shared	$12,000,000	1/1/2010	Planned	138	36	C>B>A	Y
A in MTEP08	East	ITC	1660	Horn	New Chrysler Plant Connection	MI		Other	Not Shared	$2,700,000	1/21/2008	In Service	120		C>B>A	Y
A in MTEP08	East	ITC	1661	Axle	Chrysler Axle Sub	MI		Other	Not Shared	$2,400,000	10/1/2008	In Service	120		C>B>A	Y
A in MTEP08	East	ITC	1662	Square Lake	Square Lake Substation	MI		Other	Not Shared	$2,200,000	10/1/2008	Under Construction	120		C>B>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			C>B>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			C>B>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		BaseRel	Not Shared	$1,400,000	6/1/2011	Proposed	120		C>B>A	Y
A in MTEP08	East	ITC	1866	Anti-galloping project	Throughout System	MI		Other	Not Shared	$3,000,000	12/31/2008	Under Construction			C>B>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	12/1/2009	Planned	120		C>B>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	12/1/2009	Planned	120		C>B>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	6/1/2010	Planned	120		C>B>A	Y
A in MTEP08	East	ITC	1874	G526 Harvest Wind	Generation interconnection project to install 52 MW of wind turbines that will connect to the Cosmo Tap portion of the Arrowhead - Bad Axe 120 kV circuit	MI		GIP	Shared	$2,352,131	11/3/2007	In Service	120		C>B>A	Y

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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	$7,829,237	5/31/2009	Planned	120		C>B>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	6/1/2009	Planned	138		C>B>A	Y
A in MTEP08	East	METC	1389	Midwest Grain Processor 138 kV load connection	Install a tap pole and two switches on Beecher - Samaria 138kV Line	MI		Other	Not Shared	$360,000	11/3/2007	In Service	138		C>B>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	Proposed	138	12.5	C>B>A	Y
A in MTEP08	East	METC	1448	Simpson	Project to connect a distribution transformer at Simpson	MI		Other	Not Shared	$2,200,000	6/1/2013	Proposed	138	12.5	C>B>A	Y
A in MTEP08	East	METC	1655	Breaker Repair or Replace Program	throughout system	MI		Other	Not Shared	$5,260,000	12/31/2008	In Service	345		C>B>A	Y
A in MTEP08	East	METC	1656	Relay NERC/8A Compliance	Upgrade relays throughout system	MI		Other	Not Shared	$9,777,776	12/31/2008	Planned	345		C>B>A	Y
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		C>B>A	Y
A in MTEP08	East	METC	1794	Argenta-Verona 138kV SAG Limit	Remove the SAG limit on Argenta-Verona 138kV.	MI		BaseRel	Not Shared	$160,000	6/1/2009	Under Construction	138		C>B>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		C>B>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		C>B>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	$21,000,000	6/1/2010	Planned	138		C>B>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	Proposed	345		C>B>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	12/31/2009	Planned	138		C>B>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	12/31/2010	Planned	138		C>B>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		C>B>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		C>B>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			C>B>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	6/1/2010	Planned	138		C>B>A	Y
A in MTEP08	East	METC	1832	Sag clearance 2008	Throughout system	MI		Other	Not Shared	$3,250,000	12/31/2008	Planned	138		C>B>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	12/1/2008	Planned	138		C>B>A	Y

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A in MTEP08	East	METC	1835	Geddes	New Distrbution Interconnection served from Lawndale-Claremont 138kV circuit	MI		Other	Not Shared	$175,000	9/1/2008	Under Construction	138		C>B>A	Y
A in MTEP08	East	METC	1836	Riggsville	Modify Bus Protection at Riggsville 138kV bus due to 46kV transformer modifications	MI		Other	Not Shared	$260,000	6/1/2008	In Service	138		C>B>A	Y
A in MTEP08	East	METC	1837	Van Buren	New Distrbution Interconnection served from Campbell-Beals Road 138kV circuit	MI		Other	Not Shared	$200,000	12/1/2008	Under Construction	138		C>B>A	Y
A in MTEP08	East	METC	1838	Meridian	New Distrbution Interconnection served from Delhi-Tihart 138kV circuit	MI		Other	Not Shared	$2,200,000	9/1/2009	Planned	138		C>B>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		C>B>A	Y
A in MTEP08	East	NIPS	919	Lagrange Sub - Increase #1 138-69 KV Transf. Capacity	Replace the existing No.1 138/69 KV 112 MVA transformer with a 138/69 kV 168 MVA transformer.. Substation.	IN		Other (Reliability)	Not Shared	$1,593,300	5/1/2008	Planned	138	69	B>A	Y
A in MTEP08	East	NIPS	1551	Flint Lake to Tower Road - 2nd circuit	Add a 2nd 138kV circuit between Flint Lake and Tower Road	IN		BaseRel	Shared	$5,050,000	11/1/2008	Planned	138		C>B>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 (Reliability)	Not Shared	$5,407,000	12/1/2009	Proposed	138	69	C>B>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	12/1/2007	Planned	69		C>B>A	Y
A in MTEP08	East	NIPS	1982	34.5 and 69 kV Breaker Replacement Program	Angola sub circuit 6980 E Winamac sub circuit 6937 and 69 kV bus tie Goodland sub circuits 6963 and 6966 Plymouth sub circuit 6915 Marshall sub circuit 3420 recloser Winamac Sub circuit 6919 recloser	IN		Other	Not Shared	$1,075,000	12/1/2008	Planned	69	34.5	C>B>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 (Reliability)	Not Shared	$755,000	6/1/2008	Planned	138	69	C>B>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 (Reliability)	Not Shared	$126,000	4/1/2008	Planned	138	69	C>B>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	5/1/2008	Planned	69		C>B>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	$71,000	12/1/2008	Planned	69		C>B>A	Y
A in MTEP08	East	NIPS	2004	Northeast Sub - Add 69 KV Capacitors - (2) 10.8 MVAR	Add two steps of 10.8 MVAR capacitors on the Northeast Substation 69 kV bus.	IN		Other (Reliability)	Not Shared	$870,000	1/1/2008	In Service	69		C>B>A	Y
A in MTEP08	East	NIPS	2006	Kenwood Sub - Add 69 KV Capacitors - (2) 10.8 MVAR (Engineering Only in 2007)	Add two steps of 10.8 MVAR capacitors on the Kenwood Substation 69 kV bus.	IN		BaseRel	Not Shared	$983,000	12/1/2008	Planned	69		C>B>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 (Reliability)	Not Shared	$7,500,000	12/31/2010	Planned	138		B>A	Y
A in MTEP08	East	WPSC	1210	Lewiston II Breaker Station	Add a 69KV breaker in the line from Atlanta to Gaylord	MI		Other	Not Shared	$800,000	12/31/2008	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1211	Grand Traverse - Grawn Line Rebuild	Rebuild line to 795ACSS	MI		Other (Reliability)	Not Shared	$2,500,000	8/1/2009	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1213	Vestaburg Capacitor Bank	Add 6MVAR Additional Capacitors at Vestaburg Substation	MI		Other (Reliability)	Not Shared	$300,000	12/31/2008	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1214	Garfield X to Grawn	Rebuild Overloaded Line to 795 ACSS	MI		Other (Reliability)	Not Shared	$3,350,000	7/1/2008	Proposed	69		C>B>A	Y

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A in MTEP08	East	WPSC	1218	Atlanta LTC replacement	Replace existing LTC in 138/69kV transformer	MI		Other	Not Shared	$600,000	12/31/2008	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1219	Lake County - Plains Junction Line Rebuild	Rebuild line to 795ACSS	MI		Other (Reliability)	Not Shared	$6,100,000	12/31/2009	Planned	69		B>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 (Reliability)	Not Shared	$6,000,000	12/31/2011	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1274	Blendon to Osipoff	Blendon to Osipoff line rebuild	MI		Other (Reliability)	Not Shared	$5,850,000	12/31/2011	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1276	Burnips to Wayland	Burnips to Wayland line rebuild	MI		Other (Reliability)	Not Shared	$6,450,000	12/31/2011	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1311	Copemish to Grawn	Copemish to Grawn line rebuild	MI		Other (Reliability)	Not Shared	$7,100,000	12/31/2012	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1313	Plains X to Hersey	Plains X to Hersey line rebuild	MI		Other (Reliability)	Not Shared	$9,700,000	12/31/2010	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1315	Grand Traverse to East Bay	Potter to East Bay line rebuild	MI		Other (Reliability)	Not Shared	$3,300,000	12/31/2009	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1577	Copemish - Bass Lake Line Rebuild	Rebuild line to 795ACSS	MI		Other	Not Shared	$10,200,000	12/31/2012	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1581	Alba to Advance 69 rebuild	Alba to Advance 69 kV line rebuild	MI		Other (Reliability)	Not Shared	$7,950,000	12/31/2011	Planned	69		B>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 (Reliability)	Not Shared	$17,550,000	12/31/2010	Planned	69		B>A	Y
A in MTEP08	East	WPSC	1587	Gaylord to Advance to Oden Build 138kV Circuit	Build New 138 kV line	MI		Other (Reliability)	Not Shared	$5,000,000	12/31/2010	Proposed	138		C>B>A	Y
A in MTEP08	East	WPSC	1964	Chester Tie	Add 138/69kV Transformer to Copemish substation	MI		Other (Reliability)	Not Shared	$8,000,000	12/31/2009	Planned	138		C>B>A	Y
A in MTEP08	East	WPSC	1965	Gray Tie	Add 138/69kV Transformer to WPSC's Garfield junction	MI		Other (Reliability)	Not Shared	$6,600,000	12/31/2008	Planned	138		C>B>A	Y
A in MTEP08	East	WPSC	1967	Wayland to Portland	Rebuild Outdated line	MI		Other (Reliability)	Not Shared	$14,245,000	12/31/2010	Planned	69		C>B>A	Y
A in MTEP08	East	WPSC	1968	Westwood Substation	Construct new substation at the Westwood location	MI		Other	Not Shared	$2,000,000	12/31/2008	Planned	69		C>B>A	Y
A in MTEP08	East	WPSC	2110	G566	Network upgrades for tariff service request	MI		GIP	Shared	$1,983,200	12/28/2007	Planned	138	34.5	C>B>A	Y
A in MTEP08	East	WPSC	2121	Gaylord Lightning Protection	This project will upgrade the lightning protection.	MI		Other	Not Shared	$350,000	12/31/2008	Planned	69		C>B>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	Proposed	345	138	B>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	6/1/2012	Proposed	161	138	B>A	Y
A in MTEP08	West	ATC LLC	879	Forward Energy Center (generation facility)	Butternut-Forward Energy-South Fond du Lac 138 kV (loop into new Forward Energy site)	WI		GIP	Not Shared (Pre-RECB 1)	$3,315,001	8/1/2006	Planned	138		C>B>A	Y
A in MTEP08	West	ATC LLC	881	Cypress generation facility projects	Forest Junction-Cypress-Arcadian 345 kV (loop line into new Cypress generation site)	WI		GIP	Not Shared (Pre-RECB 1)	$7,136,787	6/1/2006	Planned	345		C>B>A	Y

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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	$1,260,000	6/1/2009	Proposed			B>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	6/1/2009	Proposed	138		B>A	Y
A in MTEP08	West	ATC LLC	1280	South Lake Geneva two cap banks	install two 8.16 MVAR cap banks at South Lake Geneva 69 kV bus	WI		Other (Reliability)	Not Shared	$1,251,336	6/1/2008	Planned	69		B>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	6/1/2009	Planned	138		B>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	6/1/2009	Planned	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1665	Rebuild Atlantic-Osceola 69 kV line (Laurium #1)	Rebuild Atlantic-Osceola 69 kV line (Laurium #1)	MI		Other	Not Shared	$7,953,102	7/1/2008	Planned	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1666	Uprate Mass-Atlantic 69 kV line	Uprate Mass-Winona 69 kV line clearance to 185 deg F Uprate Winona-Atlantic 69 kV line clearance to 185 deg F	MI		Other	Not Shared	$903,202	6/1/2008	Planned	69		C>B>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	9/1/2009	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1668	Munising Capacitor Banks	Install two 4.08 MVAR 69 kV capacitor banks at Munising substation	MI		Other (Reliability)	Not Shared	$1,300,000	6/1/2008	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1669	Roberts Capacitor Banks	Install one 4.08 MVAR 69 kV capacitor bank at Roberts substation	MI		Other	Not Shared	$900,000	6/1/2008	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1670	Uprate Empire-Forsyth 138 kV line	Uprate Empire-Forsyth 138 kV line to 302 MVA	MI		BaseRel	Not Shared	$2,500,000	6/1/2008	Planned	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1671	New Southwest Delevan-Bristol 138 kV line	New Southwest Delevan-Bristol 138 kV line operated at 69 kV	WI		Other	Not Shared	$6,765,459	6/1/2008	Under Construction	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1672	Uprate Brick Church-Cobblestone 69 kV line	Uprate Brick Church-Cobblestone 69 kV line to 115 MVA	WI		Other (Reliability)	Not Shared	$1,400,000	6/1/2008	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1673	Uprate X-17 Eden-Spring Green 138 kV line	Uprate X-17 Eden-Spring Green 138 kV line to 167 degrees F	WI		Other	Not Shared	$1,200,000	1/1/2008	In Service	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1674	Uprate Portage 138/69 kV transformer	Uprate Portage 138/69 kV transformer to 143 MVA	WI		Other (Reliability)	Not Shared	$1,400,000	6/1/2008	Planned	138	69	C>B>A	Y
A in MTEP08	West	ATC LLC	1675	Sister Bay distribution Capacitor Banks	Install 2 1.2 MVAR distribution capacitor banks at Sister Bay 24.9 kV	WI		Other	Not Shared	$62,000	6/1/2008	Proposed	24.9		C>B>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	6/1/2009	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1677	Uprate Chandler-Cornell 69 kV line	Uprate Chandler-Cornell 69 kV line clearance from 120 to 167 deg F	MI		Other	Not Shared	$900,000	6/1/2009	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1678	9 Mile Capicitor Banks	Install two 8.16 MVAR 69kV capacitor banks at 9 Mile substation	MI		Other (Reliability)	Not Shared	$1,440,000	12/14/2007	In Service	69		C>B>A	Y
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 (Reliability)	Not Shared	$1,770,000	6/1/2009	Proposed	69		C>B>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	6/1/2010	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1681	Uprate North Lake Geneva-Lake Geneva 69 kV line	Uprate North Lake Geneva-Lake Geneva 69 kV line to 115 MVA	WI		Other (Reliability)	Not Shared	$1,300,000	6/1/2009	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1682	Rebuild Crivitz-High Falls Dbl Ckt 69 kV line	Loop 69 kV line from Sandstone-Pioneer into Crivitz sub, Rebuild Crivitz-High Falls Dbl Ckt 69 kV line	WI		Other (Reliability)	Not Shared	$20,733,935	6/1/2009	Planned	69		C>B>A	Y

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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 (Reliability)	Not Shared	$1,759,714	6/1/2009	Proposed	69		C>B>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	6/1/2009	Proposed	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1734	Berlin capacitor bank	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at Berlin 69-kV Substation	WI		Other	Not Shared	$200,000	6/1/2008	Under Construction	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1735	Upgrade St. Martins 138 kV bus	Upgrade St. Martins 138 kV bus to 2000A	WI		BaseRel	Not Shared	$200,000	12/1/2007	In Service	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1736	Upgrade St. Lawrence 138 kV bus	Upgrade St. Lawrence 138 kV bus	WI		BaseRel	Not Shared	$6,000	12/1/2007	In Service	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1930	2nd Straits Transformer	Install a 2nd Straits 138-69 kV Transformer and a 138-kV bus tie breaker	MI		Other (Reliability)	Not Shared	$3,000,000	12/20/2007	In Service	138	69	C>B>A	Y
A in MTEP08	West	ATC LLC	1931	Uprate North Appleton-Fox River 345-kV	Increase ground clearance for North Appleton-Fox River 345-kV to 200/230 deg F	WI		BaseRel	Not Shared	$1,057,339	4/1/2008	Planned	345		C>B>A	Y
A in MTEP08	West	ATC LLC	1933	Uprate Lakehead Delevan Tap to Lakehead Delevan radial-138 kV	Uprate Lakehead Delevan Tap to Lakehead Delevan radial-138 kV due to 2nd distribution transformer addition	WI		Other	Not Shared	$166,050	6/1/2008	Proposed	138		C>B>A	Y
A in MTEP08	West	ATC LLC	1942	Uprate Atlantic138-69 kV Transformer	Replace limiting relay equipment on the Atlantic Transformer	MI		Other	Not Shared	$418,036	6/1/2009	Proposed	138	69	C>B>A	Y
A in MTEP08	West	ATC LLC	1943	Uprate M38 138-69 kV Transformer	Replace limiting relay equipment on the M38 Transformer	MI		Other	Not Shared	$418,036	6/1/2009	Proposed	138	69	C>B>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			Other	Not Shared	$272,268	9/7/2009	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	1951	2nd Hiawatha Transformer	Install a 2nd Hiawatha 138-69 kV Transformer and a 69-kV breaker on the Hiawatha-Roberts line	MI		Other (Reliability)	Not Shared	$3,000,000	1/10/2008	In Service	138	69	C>B>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	Proposed	69		C>B>A	Y
A in MTEP08	West	ATC LLC	2102	A174/F035	Network upgrades for tariff service request			TDSP	Direct Assigned		1/1/2008	Planned	138		C>B>A	Y
A in MTEP08	West	ATC LLC	2104	A189/F037	Network upgrades for tariff service request			TDSP	Direct Assigned		6/8/2008	Planned	138	69	C>B>A	Y
A in MTEP08	West	GRE	2086	Wilson Lake 115/69 kV transformer	Wilson Lake 115/69 kV transformer	MN		Other	Not Shared	$2,000,000	6/1/2008	Planned	115	69	C>B>A	Y
A in MTEP08	West	GRE	2087	Libery (Becker) 115/69 kV transformer	Libery (Becker) 115/69 kV transformer	MN		Other	Not Shared	$3,500,000	11/1/2007	Planned	115	69	C>B>A	Y
A in MTEP08	West	GRE	2088	Enterprise Park 115/69 kV	Enterprise Park 115/69 kV	MN		Other	Not Shared	$1,800,000	6/1/2009	Planned	115	69	C>B>A	Y
A in MTEP08	West	GRE	2097	G389	Network upgrades for tariff service request for G389	MN		GIP	Shared	$4,482,923	1/1/2009	Planned	230		C>B>A	NT
A in MTEP08	West	GRE	2101	A365	Network upgrades for tariff service request			TDSP	Direct Assigned		6/1/2008	Planned	69		C>B>A	NT
A in MTEP08	West	GRE, XEL, OTP, MP, MRES	286	Fargo, ND - St Cloud/Monticello, MN area 345 kV project	AlexandriaSS - Waite Park - Monticello 345 ckt 1, Sum rate 2085	MN		BaseRel	Shared	$490,000,000	7/1/2012	Planned	345	115	B>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 (Reliability)	Not Shared	$1,840,000	6/1/2011	Planned	230	41.6	C>B>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 (Reliability)	Not Shared	$4,160,000	12/31/2009	Planned	161	69	C>B>A	Y
A in MTEP08	West	ITCM	1340	Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335 MVA transformer	Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2)	IA		Other	Not Shared	$140,362,500	12/31/2011	Planned	345	161	B>A	Y

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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 (Reliability)	Not Shared	$1,800,000	6/1/2009	Planned	161	69	C>B>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	$250,000	6/1/2009	Proposed	345		B>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	$100,000	6/1/2009	Planned	345	161	B>A	Y
A in MTEP08	West	ITCM	1522	6th Street - Beverly	New line to serve new industrial customer load.	IA		BaseRel	Shared	$7,200,000	6/1/2009	Planned	161		B>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	$9,250,000	12/31/2009	Planned	161		B>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 (Reliability)	Not Shared	$2,407,708	12/31/2009	Planned	161	69	B>A	Y
A in MTEP08	West	ITCM	1636	Waterbury breaker station	Waterbury breaker station	IA		Other (Reliability)	Not Shared	$1,000,000	12/31/2009	Planned	69		C>B>A	NT
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	$25,630,000	12/31/2013	Planned	161	34	C>B>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	$800,000	12/31/2009	Planned	161		C>B>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	12/31/2009	Proposed	161		C>B>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	12/31/2009	Proposed	161		C>B>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 (Reliability)	Not Shared	$150,000	12/31/2009	Proposed	69		C>B>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	$19,614,000	12/31/2009	Planned	161		C>B>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	$4,400,000	12/31/2010	Planned	161		C>B>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 (Reliability)	Not Shared	$4,000,000	6/1/2010	Planned	161	69	C>B>A	Y
A in MTEP08	West	ITCM	1748	Emery-Lime Crk 161kV, Ckt 1	Emery - Lime Creek 161 ckt 1, Sum rate 326 MVA	IA		TDSP	Direct Assigned	$4,000,000	12/31/2010	Proposed	161		C>B>A	Y
A in MTEP08	West	ITCM	1749	G172 Mitchell County Substation	Build a new Mitchell Co 345kV 3 terminal sub. Network upgrades for tariff service request	IA		GIP	Shared	$6,874,024	10/31/2008	Planned	345	34.5	C>B>A	Y
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	$1,400,000	12/31/2008	Proposed	161		C>B>A	Y
A in MTEP08	West	ITCM	1751	Jefferson Co 161/69kV	Replace the failed Jefferson Co 161/69kV transformer with a new 100 MVA unit	IA		Other	Not Shared	$1,600,000	12/31/2008	Planned	161	69	C>B>A	Y

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A in MTEP08	West	ITCM	1752	Jefferson Co 69kV Cap banks	Install 2-15.6 MVAR Jefferson Co 69kV Cap banks	IA		Other (Reliability)	Not Shared	$1,400,000	12/31/2008	Planned	69		C>B>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 (Reliability)	Not Shared	$1,400,000	12/31/2008	Planned	161	69	C>B>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	12/31/2010	Proposed	161		C>B>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 (Reliability)	Not Shared	$4,350,000	12/31/2008	Planned	69		C>B>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	$1,550,000	12/31/2008	Proposed	69		C>B>A	NT
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 (Reliability)	Not Shared	$2,100,000	12/31/2008	Planned	69		C>B>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	Planned	69		C>B>A	NT
A in MTEP08	West	ITCM	1759	Pelican sub 69kV line taps	69kV line work require t accommodate the new CBPC 69kV Pelican switching station near Spirit Lake.	IA		Other	Not Shared	$80,000	12/31/2008	Proposed	69		C>B>A	NT
A in MTEP08	West	ITCM	1760	New Wilder Jct-Windom 69kV	Build a new Wilder jct-Windom 69kV line. The new Heron Lake-Wilder-Windom 69kV line & Windom-Wilder-Lakefield 69kV will be tied N.O. at Wilder Jct.	IA		Other	Not Shared	$1,400,000	12/31/2008	Proposed	69		C>B>A	NT
A in MTEP08	West	ITCM	1761	Readlyn-Tripoli 69kV Rebuild	Rebuild a 2.4 mile section of the 69kV line from Readlyn Tripoli.	IA		Other	Not Shared	$816,000	12/31/2008	Planned	69		C>B>A	NT
A in MTEP08	West	ITCM	1762	Dyersville Ethanol 69kV tap	Build a new 1.75 mile 69kV tap from the Liberty-Pfeiler REC 69kV to a new ethanol plant	IA		Other	Not Shared	$327,000	12/31/2008	Proposed	69		C>B>A	NT
A in MTEP08	West	ITCM	1769	Belle Plaine - Hwy 30 1.4 mi Rebuild	Rebuild 1.4 miles	IA		Other	Not Shared	$110,000	12/31/2008	Proposed			C>B>A	Y
A in MTEP08	West	ITCM	1770	Postville-W Union 0.65 mi Rebuild	Rebuild 0.65 miles of the Postville-Wunion 69kV line	IA		Other	Not Shared	$167,000	12/31/2008	Proposed	69		C>B>A	NT
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 (Reliability)	Not Shared	$1,400,000	12/31/2009	Planned	69		C>B>A	NT
A in MTEP08	West	ITCM	1773	Excel 13.2 MVAR Cap bank	Install a new 69kV Excel 13.2 MVAR Cap bank	IA		Other (Reliability)	Not Shared	$1,400,000	12/31/2008	Planned	69		C>B>A	NT
A in MTEP08	West	ITCM	1776	Thompson-Dexter 69kV	Build a new 6 mile 69kV line fromThompson-Menlo Rec & Rebuild the 7.5 miles from Menlo REC-Dexter 69kV line.	IA		Other (Reliability)	Not Shared	$2,700,000	12/31/2009	Planned	69		C>B>A	NT
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	12/31/2008	Proposed	69		C>B>A	NT
A in MTEP08	West	ITCM	2108	G358	Network upgrades for tariff service request	MN		GIP	Shared	$2,119,692	12/31/2009	Planned	161	34.5	C>B>A	Y
A in MTEP08	West	MDU	1479	Cabin Creek: Switchyard & 115/69 kV transformer	Cabin Creek: Switchyard & 115/69 kV transformer	ND		Other	Not Shared	$3,200,000	11/1/2007	In Service	115	60	B>A	Y
A in MTEP08	West	MP	1481	Platte River 115/34.5 - Transformer 115/34.5 kV 39 MVA	Platte River 115/34.5 - Transformer 115/34.5 kV 39 MVA	MN		Other	Not Shared	$1,900,000	12/1/2007	In Service	115	34.5	C>B>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	$3,500,000	4/1/2009	Proposed	115	34.5	C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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		C>B>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	C>B>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 end of 2009.	ND		Other	Not Shared	$6,665,000	10/1/2009	Planned	115		C>B>A	Y
A in MTEP08	West	OTP	2090	Cass Lake 115 kV capacitor	Cass Lake 115 kV capacitor 20 Mvar	MN		Other	Not Shared	$630,000	11/1/2008	Planned	115		C>B>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	$900,000	7/1/2009	Proposed	115		C>B>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	12/31/2010	Proposed	230	115	B>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	$2,000,000	7/1/2009	Planned	115	41.6	C>B>A	Y
A in MTEP08	West	SMP	1367	Lake City load serving upgrades	Lake City 69 kV capacitor, Lake City - Zumbro Falls 69 kV line (new), Zumbrota - Lena tap 69 kV line (new).	MN		Other	Not Shared		10/30/2008	In Service	69		C>B>A	NT
A in MTEP08	West	SMP	1633	Fairmont Area Upgrade	SMMPA is adding a 84MVA 161/69kV transformer and 31.5MVAR cap bank to the existing Rutland Substation and upgrading 4Miles of existing 69kV line to 10th St (Fairmont) to 4/0. GRE is building 6 Miles 69kV line from Rutland to Buffalo Lake sub. Expected inservice date mid - 2008.	MN		Other	Not Shared	$6,245,340	6/30/2008	In Service	161	69	C>B>A	Y
A in MTEP08	West	XEL	552	Ironwood 92/34.5 kV transformer #2	Ironwood 92/34.5 kV transformer #2	WI		Other	Not Shared	$300,000	6/1/2009	Proposed	92	34.5	C>A	NT

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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	Proposed	115		B>A	Y
A in MTEP08	West	XEL	751	Nobles Co 34.5 kV -50 MVAR Reactor #1	Nobles Co 34.5 kV -50 MVAR Reactor #1	MN		Other	Not Shared	$200,000	12/1/2007	In Service	34.5		B>A	NT
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	Proposed	115		B>A	Y
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 (Reliability)	Not Shared	$7,000,000	5/1/2009	Proposed	115	69	C>B>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	5/1/2009	Proposed	69		C>B>A	NT
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 (Reliability)	Not Shared	$10,000,000	5/1/2009	Proposed	161	23.9	B>A	Y
A in MTEP08	West	XEL	1371	Black Dog - Wilson 115 kV #2 Reconductor	Black Dog - Wilson 115 kV #2 Reconductor	MN		TDSP	Direct Assigned	$900,000	6/1/2009	Planned	115		B>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		B>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		B>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 (Reliability)	Not Shared	$2,190,000	6/1/2009	Planned	69		C>B>A	NT
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 (Reliability)	Not Shared	$9,247,500	12/1/2010	Proposed	69		C>B>A	NT
A in MTEP08	West	XEL	1546	Dean Lake - Hyland Lake Upgrade	Upgrade 115 kV line from Dean Lake - Hyland Lake 115 kV line	MN		BaseRel	Not Shared	$1,057,000	10/1/2008	Planned	115		B>A	Y
A in MTEP08	West	XEL	1547	Ironwood bus upgrade	Replace the Ironwood 115 kV equipment with ratings below 450 Amps with 850 Amp equipment (or next standard size). This should inclue the following: 200 Amp CT, 300 Amp wave trap, 380 Amp Bus, 400 Amp Breaker CT	WI		Other	Not Shared	$450,000	6/1/2008	Planned	115		C>B>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	6/1/2009	Planned	161		C>B>A	Y

Appendix A: Project Table *Project Information from Facility table*

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
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 (Reliability)	Not Shared	$20,602,000	6/1/2011	Planned	161	69	C>B>A	Y
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	Proposed	115		C>B>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	12/1/2010	Proposed	115		C>B>A	Y
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	12/1/2009	Proposed	345		C>B>A	Y
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 (Reliability)	Not Shared	$7,080,000	12/1/2012	Proposed	161	69	C>B>A	Y
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 (Reliability)	Not Shared	$19,270,980	12/1/2012	Proposed	161		C>B>A	Y

Appendix A: Project Table

Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
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	12/1/2010	Proposed	115		C>B>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	12/1/2010	Proposed	69		C>B>A	NT
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	Proposed			C>B>A	Y
A in MTEP08	West	XEL	2100	A232 (depending on G405)	Network upgrades for tariff service request			TDSP	Direct Assigned		6/1/2008	In Service	69		C>B>A	NT
A in MTEP08	West	XEL	2105	A147/F043	Network upgrades for tariff service request	MN		TDSP	Direct Assigned	$360,000	6/1/2009	Planned	69		C>B>A	Y
A in MTEP08	West	XEL	2109	G609	Network upgrades for tariff service request	WI		GIP	Shared	$34,200	7/31/2007	Planned	34.5		C>B>A	Y
A in MTEP08	West	XEL	2119	G417	Network upgrades for tariff service request	MN		GIP	Shared	$259,000	7/28/2008	Planned	69		C>B>A	NT
A in MTEP08	West	XEL, DPC, RPU, SMP, WPPI	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	12/15/2015	Planned	345	161	B>A	Y
A in MTEP08	West	XEL/GRE	1380	Scott County - West Waconia 115	Scott County - West Waconia 1 115	MN		Other (Reliability)	Not Shared	$13,600,000	5/1/2010	Proposed	115		C>B>A	Y
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 (Reliability)	Not Shared	$12,915,000	12/1/2009	Planned	161	115	B>A	Y
A in MTEP08	West	XEL/GRE	1955	Bangor switching station	This project is to build a new three breaker switching station at the existing Bangor tap.	MN		Other (Reliability)	Not Shared	$900,000	12/1/2009	Proposed	69		C>B>A	NT

Appendix A: Project Facility Table

Target Appendix	Region	Rep Source	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	Central	Ameren	152	399	12/1/2010	Big River	Rockwood	1	138		339	new line	MO		10	Planned	$13,381,100.00	Y		Y	A
A	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	$659,400.00			Y	A
A	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	$12,178,600.00			Y	A
A	Central	AmerenIP	150	1422	6/1/2010	Baldwin	Rush Island	1	345		1793	26 miles of new 345 kV line	IL		26	Planned	$46,149,200.00			Y	A
A	Central	AmerenIP	150	1667	6/1/2010	Prairie State	substation	1	345		1793	new switchyard (6 position, 4 lines, 2 units)	IL			Planned	$15,872,700.00			Y	A
A	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	$2,172,100.00			Y	A
A	Central	AmerenIP	725	1418	6/1/2009	N. LaSalle	Wedron Fox River	1	138		266	2 CB at N LaSalle, 1 CB at Wedron Fox River Substation	IL		25	Planned	$21,357,530.00			Y	A
A	Central	AmerenIP	726	1419	6/1/2009	Ottawa	Wedron Fox River	1	138		266	1 CB at Ottawa, new 138 kV line to Wedron Fox River Substation	IL		8	Planned	$8,962,967.00			Y	A
A	Central	AmerenIP	736	1429	9/8/2008	W. Tilton	Tilton Energy Center		138			new 138 kV breaker addition at W. Tilton	IL			Under Construction	$2,658,600.00			Y	A
A	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	$6,410,900.00			Y	A
A	Central	AmerenIP	865	841	6/1/2009	Havana	Monmouth	1	138		259	Build new river crossing	IL		0.44	Planned	$2,674,600.00			Y	A
A	Central	AmerenIP	873	851	1/31/2009	Baldwin	Turkey Hill	1	345		956	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600.00			Y	A
A	Central	AmerenIP	873	850	1/31/2009	Baldwin	Stallings	1	345		1195	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600.00			Y	A
A	Central	AmerenIP	873	849	1/31/2009	Baldwin	W. Mt. Vernon	1	345		1195	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600.00			Y	A
A	Central	AmerenMO	150	398	6/1/2010	Rush Island	Baldwin	1	345		1793	terminal at Rush Island & river crossing only	IL		2	Planned	$1,615,100.00			Y	A
A	Central	AmerenMO	153	400	9/15/2008	CEE Tap	Watson	1	138		367	reconductor	MO	0.8		Under Construction	$277,200.00			Y	A
A	Central	AmerenMO	155	401	10/1/2008	Joachim 345/138 kV	transformer	1	345	138	560	new 345/138 kV transformer	MO			Under Construction	$13,345,100.00			Y	A
A	Central	AmerenMO	719	1410	6/1/2009	Labadie Plant	Replace 4-345 kV Breakers		345			replace existing 345 kV breakers	MO			Planned	$2,511,700.00			Y	A
A	Central	AmerenMO	857	832	10/1/2008	Rush Island	Joachim	1	345		1206	Replace terminal equipment at Rush Island	MO			Planned	$285,400.00			Y	A
A	Central	CWLP	1620	2726	1/1/2010	Dallman			138			138 kV Breakers, 138 kV Switches, 69 kV Breaker, 138/69 kV Transformer	IL			Planned	$3,642,200.00	Y		Y	A
A	Central	CWLP	1620	2731	1/1/2010	Dallman	Culver		69			Line relocation needed to provide clearance for the Dallman 4 unit 5) Line 15 Dallman - Culver 69 kV Relocation - $411,300	IL			Planned	$411,300.00	Y		NT	A
A	Central	CWLP	1620	2730	1/1/2010	Dallman	Stevenson		69			Line relocation needed to provide clearance for the Dallman 4 unit 4) Line 10 Lakeside - Stevenson 69 kV Relocation - $411,300	IL			Planned	$411,300.00	Y		NT	A
A	Central	CWLP	1620	2729	1/1/2010	Dallman	Franklin Park		69			Line relocation needed to provide clearance for the Dallman 4 unit 3) Line 11 Dallman - Franklin Park 69 kV Relocation - $968,500	IL			Planned	$968,500.00	Y		NT	A
A	Central	CWLP	1620	2728	1/1/2010	Dallman	Eastdale		138			Line relocation needed to provide clearance for the Dallman 4 unit. 2) Line 32 Dallman - Eastdale 138 kV Relocation - $1,390,500	IL			Planned	$1,390,500.00	Y		Y	A
A	Central	CWLP	1620	2727	1/1/2010	Dallman	Spaulding		138			Line relocation needed to provide clearance for the Dallman 4 unit. 1) Line 31 Dallman -Spaulding 138 kV Relocation - $1,005,500	IL			Planned	$1,005,500.00	Y		Y	A

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A	Central	DEM	42	2926	6/1/2009	Seymour	Bus & Disc. sw's		138		478	Seymour 13829 Bus & Disconnect Switches - Reconductor 2 sections of ring bus and upgrade 13829-51 and 13880-29 breaker disconnects	IN			Planned	$175,073.00			Y	A
A	Central	DEM	42	184	6/1/2009	Shawswick	Pleasant Grove	1	138		306	Reconductor	IN	18.3		Planned	$4,719,516.00			Y	A
A	Central	DEM	42	181	6/1/2010	Airport Road Jct	Seymour	1	138		306	Reconductor	IN	2.2		Planned	$752,906.00			Y	A
A	Central	DEM	42	183	6/1/2010	Pleasant Grove	Airport Road Jct	1	138		306	Reconductor	IN	9.3		Planned	$3,388,077.00			Y	A
A	Central	DEM	91	358	6/1/2008	Hillcrest 345/138	transformer	1	345	138	450	Add new 345/138 transformer	OH			Under Construction	$4,120,000.00	Y		Y	A
A	Central	DEM	91	362	6/1/2008	Hillcrest	Eastwood	1	138		304	Add new line - F8887	OH		8	Under Construction	$4,704,406.00	Y		Y	A
A	Central	DEM	91	2556	6/1/2008	Hillcrest 345 kV	substation upgrades		345			345 kV upgrades for 345/138 transformer	OH			Under Construction	$6,473,212.00	Y	Y	Y	A
A	Central	DEM	91	2540	6/1/2008	Foster	Relays		345			Replace relays at Foster on the 345kV line to the new Hillcrest substation.	OH			Under Construction	$213,385.00	Y	Y	Y	A
A	Central	DEM	91	2539	6/1/2008	Stuart	Relays		345			Replace relays at Stuart on the 345kV line to the new Hillcrest substation.	OH			Under Construction	$93,403.00	Y	Y	Y	A
A	Central	DEM	200	2567	6/1/2008	West LafayettePurdue	Purdue NW Tap		138		179	Uprate to 100C	IN			Under Construction	$9,878.00			Y	A
A	Central	DEM	624	1300	12/31/2009	Cloverdale	Plainfield South	1	138		No change	Upgrade static and grounding	IN	24.3		Planned	$1,816,905.39			Y	A
A	Central	DEM	627	1304	6/1/2013	Kenton	West End	1	138		241	Add new line	KY-OH	4.5	4.3	Planned	$1,980,041.00			Y	A
A	Central	DEM	627	1853	6/1/2013	Buffington Reactor	Florence		138			Remove reactor when Kenton to West End project is completed.	KY			Planned	$0.00			Y	A
A	Central	DEM	627	1953	6/1/2013	Crescent	West End		138		241	3 wires of existing 6 wire circuit will be used for the new Kenton to West End circuit, lowering the rating of Crescent to West End.	KY			Planned	$0.00			Y	A
A	Central	DEM	632	1309	6/1/2009	Gallagher	HE Georgetown	1	138		201	reconductor 250CU, 477ACSR already 100C (no cost)	IN	2.8		Planned	$1,065,110.00			Y	A
A	Central	DEM	807	812	6/1/2009	Dresser 345/138 Bk1	transformer	1	345	138	523	Upgrade limiting equipment to achieve full transformer rating	IN			Planned	$197,839.00			Y	A
A	Central	DEM	807	813	6/1/2009	Dresser 345/138 Bk2	transformer	2	345	138	543	Upgrade limiting equipment to achieve full transformer rating	IN			Planned	$197,839.00			Y	A
A	Central	DEM	851	826	6/1/2011	Lafayette Cumberland Ave	Laf AE Staley	1	138		306	13806 reconductor with 954ACSR 100C 604F6347	IN	1.3		Planned	$349,357.40			Y	A
A	Central	DEM	852	827	12/31/2009	Lafayette Southeast	Tipmont Concord Jct	1	138		306	13819 reconductor with 954ACSR 100C 604F6351	IN	8		Planned	$1,125,284.00	Y		Y	A
A	Central	DEM	852	2995	6/1/2010	LNDNT	Tipmont Concord Jct		138		306	13819 reconductor with 954ACSR 100C	IN	6.96		Planned	$3,273,101.27	Y		Y	A
A	Central	DEM	852	1979	6/1/2010	Crawfordsville	LNDNT		138		306	13819 reconductor with 954ACSR 100C	IN	10.44		Planned	$4,909,651.91	Y		Y	A
A	Central	DEM	853	828	6/1/2015	West Lafayette	Cumberland Ave	1	138		306	13806 reconductor with 954ACSR 100C 604F6352	IN	2		Planned	$706,921.48			Y	A
A	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			Planned	$150,376.81			Y	A
A	Central	DEM	1198	1849	6/1/2008	Bedford			345			Add motors and automation to the 34506 line switch, replace with 3000A and automate the 34521 line switch, and automate all 6 of the 345kV ring breakers' disconnect switches.	IN			Under Construction	$199,211.00			Y	A
A	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	$10,000.00			Y	A
A	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	$10,000.00			Y	A

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A	Central	DEM	1200	1852	6/1/2010	Speed		3	345	138	520	Upgrade 2000A 138kV breaker & switch and any other Bk3 limiting equipment. Replace any equipment that would limit the 345/138 xfr to less than the hot spot rating of 520 MVA.	IN			Planned	$173,193.11			Y	A
A	Central	DEM	1244	1945	6/1/2011	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	$68,733.00			Y	A
A	Central	DEM	1244	1946	6/1/2011	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	$98,827.00			Y	A
A	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	$24,038.00			Y	A
A	Central	DEM	1247	1948	6/1/2011	Greentown	Peru SE		230		478	Uprate 23021 circuit to 100C operating temp	IN			Planned	$28,403.00			Y	A
A	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	$24,038.00			Y	A
A	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	$24,038.00			Y	A
A	Central	DEM	1254	1955	12/31/2009	Charlestown	CMC		138		306	Construct 8.5 mi. of 138kV line from Charlestown to CMC. CO2: this will now be owned by IMPA	IN		8.5	Planned	$5,497,000.00			Y	A
A	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	$0.00			Y	A
A	Central	DEM	1262	1978	6/1/2009	HE Durgee Rd			138			HE 138/12 kV substation.	IN			Planned	$227,341.00			Y	A
A	Central	DEM	1263	2571	5/15/2009	Amo 345 kV sub			345			Amo Station – On the 345 kV circuit to the New 345 kV ring bus switching station (formerly the Wheatland-Amo 345 kV circuit), upgrade the primary and back-up relaying and carrier facilities.	IN			Planned	$175,000.00	Y	Y	Y	A
A	Central	DEM	1263	2572	5/30/2011	Wheatland 345 kV sub			345			Wheatland Station – On the 345 kV circuit to the New 345 kV ring bus switching station (formerly the Wheatland-Amo 345 kV circuit), upgrade the primary and back-up relaying and carrier facilities.	IN			Planned	$185,000.00	Y	Y	Y	A
A	Central	DEM	1263	1980	5/30/2011	Edwardsport 345 kV Sub			345			New 345 kV ring bus switching station, This LGIA to include five (5) 345 kV, 3000A, 50 kA circuit breakers, 2 sets of 345 kV interconnection metering, foundations, steel structures, grounding, relaying, control cables, and associated equipment.	IN			Planned	$8,000,000.00	Y	Y	Y	A
A	Central	DEM	1263	2570	5/30/2011	Edwardsport 345 kV sub			345			345 kV Extension – Loop the Wheatland-Amo 345 kV circuit into the New 345 kV ring bus switching station. Utilize Bundled 954 kcm ACSR 45X& phase conductors and 3/8ST7 static wires.	IN			Planned	$1,200,000.00	Y	Y	Y	A
A	Central	HE	204	179	6/1/2009	North Charleston	Tapline w/ substation	1	138	13		New Construction, taps Duke 13857	IN		0.1	Proposed	$900,000.00			Y	A
A	Central	HE	204	171	6/1/2009	Batesville	Tapline w/ substation	1	138	13		New Construction, taps Duke 13833	IN		0.5	Proposed	$950,000.00			Y	A
A	Central	HE	1321	2179	3/1/2008	Napoleon	Capacitor & CB Addition, and bus upgrades	1	161		30MVAR	New Construction	IN			Planned	$800,000.00			Y	A
A	Central	HE	1321	2180	12/1/2008	Napoleon Primary	DCSS	1	161		338MVA	New Construction	IN		25	Planned	$7,200,000.00			Y	A
A	Central	HE	1322	2182	6/1/2008	Owensville Primary Tapline	Cinergy 138 (Gibson to Princeton)	1	138		215MVA	New Construction	IN		0.5	Planned	$2,500,000.00			Y	A

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A	Central	HE	1322	2181	6/1/2008	Owensville Primary		1	138	69	150MVA	New Construction	IN			Planned	$5,500,000.00			Y	A
A	Central	IPL	40	177	6/2/2009	Indian Creek	Julietta	1	138		286 MVA	New 138kV Line	IN		5	Planned	$2,500,000.00			Y	A
A	Central	IPL	40	178	6/2/2009	Cumberland	Julietta	1	138		286 MVA	New 138kV Line	IN		4.55	Planned	$2,500,000.00			Y	A
A	Central	IPL	893	902	6/1/2010	North	Capacitor		138		150 MVAR	Increase Capacitor Size To 150 MVAR	IN			Planned	$300,000.00			Y	A
A	Central	IPL	895	904	6/1/2008	North	Breaker		138		245 MVA	New 2000 Amp Breaker	IN			Under Construction	$1,350,000.00			Y	A
A	Central	IPL	895	905	6/1/2008	North	Breaker		138		245 MVA	New 2000 Amp Breaker	IN			Under Construction	$1,350,000.00			Y	A
A	Central	SIPC	81	60	7/1/2009	Marion	CarrierMills	1	161		286		IL		27	Planned	$7,083,000.00			Y	A
A	Central	Vectren	1257	1972	5/31/2011	AB Brown	Gibson (Duke)	15	345		1430/1430	new line	IN		40	Planned	$39,400,000.00	Y	Y	Y	A
A	Central	Vectren	1257	1973	5/31/2011	AB Brown	Reid (BREC)	17	345		1430/1430	new line	IN/KY		24	Planned	$26,600,000.00	Y	Y	Y	A
A	East	FE	1327	2193	6/1/2009	Babb	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$865,400.00			Y	A
A	East	FE	1328	2194	6/1/2014	Barberton	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$677,600.00			Y	A
A	East	FE	1329	2195	6/1/2014	West Akron	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$257,000.00			Y	A
A	East	FE	1331	2197	6/1/2014	East Akron	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$305,000.00			Y	A
A	East	FE	1333	2199	6/1/2014	Brookside	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$1,000,200.00			Y	A
A	East	FE	1334	2200	6/1/2014	Longview	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$523,800.00			Y	A
A	East	ITC	692	1383	12/31/2011	Bismarck 345 kV	Troy 345 kV	1	345		700		MI		15.4	Planned	$145,000,000.00	Y	Y	Y	A
A	East	ITC	692	1384	12/31/2011	Troy 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000.00	Y		Y	A
A	East	ITC	905	929	12/31/2008	Bunce Creek 120 kV	Wabash 120 kV 2	2	120		299		MI	0.1		Under Construction	$1,166,666.00			Y	A
A	East	ITC	905	931	12/31/2008	Bunce Creek 120 kV	Cypress 120 kV	1	120		313		MI	0.1		Under Construction	$1,166,668.00			Y	A
A	East	ITC	907	916	12/31/2010	Spokane 120 kV	Tienken 120 kV	1	120		343		MI	0.1		Planned	$2,000,000.00	Y		Y	A
A	East	ITC	907	915	12/31/2010	Goodison 120 kV	Tienken 120 kV	1	120		343		MI	2.78	2.34	Planned	$9,000,000.00	Y		Y	A
A	East	ITC	907	914	12/31/2010	Goodison 120 kV	Sunbird 120 kV	1	120		229		MI	3.55	2.87	Planned	$11,000,000.00	Y		Y	A
A	East	ITC	907	913	12/31/2010	Goodison 120 kV	Pontiac 120 kV	1	120		343		MI		6.3	Planned	$11,000,000.00	Y		Y	A
A	East	ITC	907	912	12/31/2010	Goodison 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000.00	Y		Y	A
A	East	ITC	907	911	12/31/2010	Goodison 345 kV	Pontiac 345	1	345		2002	Goodison 345 kV substation	MI	6.3		Planned	$6,000,000.00	Y	Y	Y	A
A	East	ITC	907	910	12/31/2010	Goodison 345 kV	Belle River 345	1	345		2151	Goodison 345 kV substation	MI	35.2		Planned	$6,000,000.00	Y	Y	Y	A
A	East	ITC	1011	1583	6/1/2009	Genoa 120 kV	Durant 120 kV	1	120		343		MI		8.5	Under Construction	$15,000,000.00			Y	A
A	East	ITC	1301	2132	10/1/2008	Yost 120 kV	Polaris 120 kV	1	120		349	line breaker and line relaying upgrade	MI	0.9		Under Construction	$791,000.00			Y	A
A	East	ITC	1308	2141	12/31/2009	Bunce Creek PAR		1	220				MI			Planned	$25,000,000.00			Y	A
A	East	ITC	1309	2145	12/31/2008	Monroe 345 kV pos. MF	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2152	12/31/2008	Monroe 345 kV pos. BM	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2147	12/31/2008	Monroe 345 kV pos. MM	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2153	12/31/2008	Monroe 345 kV pos. BT	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2143	12/31/2008	Monroe 345 kV pos. CM	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2142	12/31/2008	Monroe 345 kV pos. CF	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1309	2151	12/31/2008	Monroe 345 kV pos. BF	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1310	2159	12/31/2008	St. Clair 120 kV pos. HS	circuit breaker		120			CB replacement	MI			Planned	$150,000.00			Y	A
A	East	ITC	1310	2158	12/31/2008	St. Clair 120 kV pos. KB	circuit breaker		120			CB replacement	MI			Planned	$150,000.00			Y	A
A	East	ITC	1310	2156	12/31/2008	Warren 230 kV pos. CF	circuit breaker		230			CB replacement	MI			Planned	$200,000.00			Y	A
A	East	ITC	1310	2154	12/31/2008	Waterman 230 kV pos. BF	circuit breaker		230			CB replacement	MI			Planned	$200,000.00			Y	A
A	East	ITC	1310	3419	12/31/2008	Monroe 345kV pos. MF	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1310	3420	12/31/2008	Monroe 345kV pos. MM	circuit breaker		345			CB replacement	MI			Planned	$250,000.00			Y	A
A	East	ITC	1310	3423	12/31/2008	Spokane 120kV pos. HG	circuit breaker		120			CB replacement	MI			Planned	$150,000.00			Y	A
A	East	ITC	1310	3424	12/31/2008	Navarre 120kV pos. HX	circuit breaker		120			CB replacement	MI			Planned	$150,000.00			Y	A
A	East	ITC	1310	2155	12/31/2008	Waterman 230 kV pos. CF	circuit breaker		230			CB replacement	MI			Planned	$200,000.00			Y	A
A	East	ITC	1310	3422	12/31/2008	Phoenix 120kV pos. HK	circuit breaker		120			CB replacement	MI			Planned	$150,000.00			Y	A

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A	East	ITC	1488	1584	6/1/2009	Placid 120 kV	Durant 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	16.7		Under Construction	$5,650,000.00			Y	A
A	East	ITC	1488	1585	6/1/2009	Placid 120 kV	Proud 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	14.3		Under Construction				Y	A
A	East	METC	481	1332	12/1/2008	Tallmadge 3rd 345/138 kV	transformer	3	345	138			MI			Planned	$3,649,203.00	Y		Y	A
A	East	METC	481	1534	12/1/2008	Tallmadge Remove Reactors	Tallmadge Remove Reactors	1&2	345			remove 138 kV reactors	MI			Planned	$0.00	Y		Y	A
A	East	METC	481	2557	12/1/2008	Tallmadge 345 kV	substation upgrades		345			sub upgrades for 3rd transformer	MI			Planned	$6,263,887.00	Y	Y	Y	A
A	East	METC	497	1322	12/31/2008	Tallmadge	Wealthy	2	138			CT overload	MI			Planned	$250,000.00			Y	A
A	East	METC	660	1347	11/1/2008	Keystone	Clearwater	1	138				MI	23.2		Under Construction	$10,200,000.00	Y		Y	A
A	East	METC	981	1544	6/1/2013	Wabasis J. - N. Belding - Vergennes	Wabasis	1	138			Install aTap Pole and Switches	MI			Planned	$160,000.00			Y	A
A	East	METC	988	1551	12/31/2009	Simpson	Batavia	1	138				MI		30	Planned	$13,000,000.00	Y		Y	A
A	East	METC	1016	1588	12/31/2008	Bard Road	Bard Road - New Capacitor	1	138		36 Mvar	Bard Road - New 45 Mvar Capacitor	MI			Planned	$1,661,100.00			Y	A
A	East	METC	1017	1589	12/31/2008	Croton	Croton - New Capacitor	1	138		36 Mvar	Croton - New 45 Mvar Capacitor	MI			Planned	$1,661,100.00			Y	A
A	East	METC	1390	2393	7/31/2008	Goss 345kV	345kV GIS bus and breakers		345			Replace old, leaking 345kV GIS bus & breakers with open-air type. Patchwork repairs haven't been successful.	MI			Under Construction	$8,800,000.00			Y	A
A	East	METC	1406	2409	12/31/2008	Alpena 138kV	Breaker 188		138			Replace overdutied breaker with higher capacity breaker.	MI			Planned	$160,000.00			Y	A
A	East	METC	1407	2410	6/1/2008	Ludington 345kV	Reactor		345			replace existing 100MVAR reactor and replace circuit switcher with a breaker	MI			Under Construction	$3,000,000.00			Y	A
A	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	$801,000.00			Y	A
A	East	METC	1410	2413	12/1/2008	Mobile 138kV Capacitor			138		14.4 - 36MVAF	Purchase a mobile 138kV capacitor for use where needed during outages, heavy transfers, etc.	MI			Planned	$700,000.00			Y	A
A	East	METC	1414	2418	12/31/2008	Thetford 345kV	Line Relaying		345			Upgrade 345kV line relaying.	MI			Planned	$300,000.00			Y	A
A	East	METC	1416	2421	10/1/2007	HSC 138kV	Tittabawasee 138kV	2	138			Install new,second 138kV Tittabawasee-HSC line and 5 total 138kV breakers for connecting the line at each end. (HSC Project)	MI			Under Construction	$4,527,000.00	Y		Y	A
A	East	METC	1425	2430	12/31/2008	Keystone 138kV	Elmwood 138kV	1	138			Install a new substation. Relay upgrades. (Gray Rd)	MI			Planned	$4,136,000.00			Y	A
A	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	$2,200,000.00			Y	A
A	East	METC	1434	2438	6/1/2010	Spaulding 138kV			138			Install bulk substation served from the Spaulding 138kV ring bus (Five Mile)	MI			Planned	$750,000.00			Y	A
A	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	$160,000.00			Y	A
A	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	$80,000.00			Y	A
A	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	$80,000.00			Y	A
A	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	$160,000.00			Y	A
A	East	METC	1445	2449	6/1/2010	Emmet 138kV	distribution		138			Install a second distribution transformer at Emmet (Emmet)	MI			Planned	$2,750,000.00			Y	A
A	East	METC	1446	2450	6/1/2010	Gaines 138kV			138			Install bulk substation at Gaines (Gaines)	MI			Planned	$50,000.00			Y	A
A	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	$2,200,000.00			Y	A

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A	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	$160,000.00			Y	A
A	East	METC	1817	3661	12/31/2008	Orr Road	capacitor	1	138			New 138 kV Capacitor	MI			Planned				Y	A
A	East	METC	1817	3660	12/31/2008	Orr Road	HSC	1	138			Reconductor	MI			Planned	$139,273.00	Y		Y	A
A	East	METC	1817	3659	12/31/2008	Orr Road	substation	1	138			New switching station	MI			Under Construction	$10,697,555.00	Y		Y	A
A	East	METC	1817	3662	12/31/2008	Orr Road	Solar #1	1	138			Change Termination of Distribution Connectiion	MI			Planned				Y	A
A	East	METC	1817	3663	12/31/2008	Orr Road	Solar #2	1	138			Change Termination of Distribution Connectiion	MI			Planned				Y	A
A	East	METC	1817	3664	12/31/2008	Orr Road	Semi-Conductor #1	1	138			New Distribution Connection	MI			Planned				Y	A
A	East	METC	1817	3665	12/31/2008	Orr Road	Semi-Conductor #2	1	138			New Distribution Connection	MI			Planned				Y	A
A	East	METC	1817	3666	6/1/2009	Tittabawassee	Substation Equipment		138			Remove reactors	MI			Planned				Y	A
A	East	METC	1817	3651	6/1/2009	Richland 345 kV	Richland 138 kV	1	138			New 345/138 kV transformer	MI			Planned	$4,268,777.00	Y		Y	A
A	East	METC	1817	3656	6/1/2009	Richland	Lawndale	1	138			Lawndale-HSC 138 kV line cut into Richland	MI			Planned	$512,599.00			Y	A
A	East	METC	1817	3667	6/1/2009	Tittabawassee	Substation Equipment		138			Replace nine 138 kV breakers	MI			Planned	$2,234,922.00			Y	A
A	East	METC	1817	3655	6/1/2009	Richland	Orr Road #2	1	138			New 3-5 mile 138 kV Line	MI		3	Planned	$2,875,997.00	Y		Y	A
A	East	METC	1817	2972	6/1/2009	Richland	138 kV substation		138			new 138 kV substation	MI			Planned	$10,694,426.00			Y	A
A	East	METC	1817	3654	6/1/2009	Richland	Orr Road #1	1	138			Tittabawassee-HSC#2 cut into Richland	MI			Planned	$512,599.00			Y	A
A	East	METC	1817	3653	6/1/2009	Richland	Tittabawassee	1	345			New switching station with Nelson Road-Tittabawassee cut in	MI			Planned	$6,219,578.00	Y		Y	A
A	East	METC	1817	3652	6/1/2009	Richland	Nelson Road	1	345			New switching station with Nelson Road-Tittabawassee cut in	MI			Planned	$6,219,578.00	Y		Y	A
A	East	METC	1817	3657	6/1/2009	Richland	Tittabawassee	1	138			Tittabawassee-HSC#2 cut into Richland	MI			Planned	$512,599.00			Y	A
A	East	METC	1817	3658	6/1/2009	Richland	HSC	1	138			Lawndale-HSC 138 kV line cut into Richland	MI			Planned	$512,599.00			Y	A
A	East	NIPS	612	1279	5/1/2008	Hiple	transformer	2	345	138	560	Add 2nd 345/138 kV transformer	IN			Planned	$4,344,699.63	Y		Y	A
A	East	NIPS	612	2999	5/1/2008	Hiple	transformer	2	345			345 kV upgrades	IN			Planned	$1,454,914.37	Y	Y	Y	A
A	East	NIPS	1298	2128	5/1/2008	Inland #5	Marktown	1	138		316/380	Upgrade Connections and Circuit	IN	2.2		Planned	$750,000.00			Y	A
A	East	WPSC	1227	3137	12/31/2009	Bagley X	Gaylord OCB	1	69		198/257.4	Rebuild Overloaded line	MI	3.32		Planned	$1,200,000.00			Y	A
A	East	WPSC	1227	1927	12/31/2009	Gaylord Generation	Bagley X	1	69		198/257.4	Rebuild 69 kV Line	MI	4		Planned	$1,400,000.00			Y	A
A	East	WPSC	1228	1928	8/1/2008	Westwood	New Load		69			Add 14MW Load to Westwood	MI			Planned	$1,800,000.00			Y	A
A	East	WPSC	1229	1929	11/30/2008	Plains X	Substation Upgrade		69			Upgrade exsisting 69KV bus	MI			Planned	$800,000.00			Y	A
A	East	WPSC	1272	1994	12/31/2012	Redwood 138	Redwood 69		138	69	75MVA	Add 75MV transformer	MI			Planned	$3,000,000.00			Y	A
A	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			Proposed	$164,997.00			Y	A
A	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	Proposed	$1,080,000.00			Y	A
A	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			Proposed	$845,291.00	Y		Y	A
A	East	WPSC	1465	2562	10/1/2008	Redwood 138/69	transformer		138	69		upgrade?	MI			Proposed	$2,022,328.00	Y		Y	A

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A	East	WPSC	1465	2563	10/1/2008	G418, 69 kV line upgrades			69			69 kV line upgrades	MI			Proposed	$1,080,000.00	Y		Y	A
A	West	ATC LLC	177	2455	6/1/2009	Whitcomb	Caroline	1	115		239/239 MVA		WI			Planned	$0.00			Y	A
A	West	ATC LLC	177	607	12/1/2009	Gardner Park (new Weston)	HWY 22 (formerly Central Wisconsin)	1	345		1776 MVA SE		WI		47	Planned	$116,700,000.00			Y	A
A	West	ATC LLC	177	862	12/1/2009	HWY 22 (formerly Central Wisconsin)	new substation		345			new substation	WI			Planned	$12,200,000.00			Y	A
A	West	ATC LLC	339	433	5/31/2009	Rockdale	Lakehead Cambridge		138		287	uprate	WI			Planned	$200,000.00			Y	A
A	West	ATC LLC	339	449	5/31/2009	Jefferson	Lake Mills (provisional)		138		290	construct new	WI		6	Planned	$9,850,000.00			Y	A
A	West	ATC LLC	339	429	5/31/2009	Lakehead Cambridge	Jefferson		138		348	uprate	WI			Planned	$150,000.00			Y	A
A	West	ATC LLC	339	892	5/31/2009	Boxelder	Stonybrook		138		287	uprate	WI			Planned	$200,000.00			Y	A
A	West	ATC LLC	339	450	5/31/2009	Lake Mills (provisional)	Stonybrook		138		290	construct new	WI		6	Planned	$9,850,000.00			Y	A
A	West	ATC LLC	339	434	5/31/2009	Rockdale	Boxelder	1	138		383	uprate	WI			Planned	$200,000.00			Y	A
A	West	ATC LLC	345	608	11/24/2008	Clintonville	Werner West		138		381/529 MVA		WI	14	2	Under Construction	$6,091,242.00	Y	Y	Y	A
A	West	ATC LLC	345	480	4/30/2009	Morgan	Central WI		345		1882 MVA SE	new line	WI		23.5	Planned	$64,066,400.00	Y	Y	Y	A
A	West	ATC LLC	345	2994	4/30/2009	Central WI	Werner West		345		1882 MVA SE	new line	WI		23.5	Planned	$64,066,400.00	Y	Y	Y	A
A	West	ATC LLC	345	2458	4/30/2009	Badger	Clintonville	1	138		321/339 MVA		WI			Planned	$3,533,329.00	Y	Y	Y	A
A	West	ATC LLC	352	3532	6/1/2008	Lakota Rd (formerly Conover) 138-69 kV	transformer	1	138	69	60	138/69 transformer	WI			Planned				Y	A
A	West	ATC LLC	352	445	2/1/2009	Lakota Road-Iron Grove-	Aspen-Plains	1	138		290 or 400 MV	convert 69 to 138 kV, new Iron Gr-Plains 138 kV line, Iron Grove sub relocate	MI/WI	73		Under Construction	$84,100,000.00	Y		Y	A
A	West	ATC LLC	352	3464	6/1/2010	Iron Grove		1	138	69	60	Install 60 MVA 138/69 kV transformer at Iron Grove substation	MI			Planned				Y	A
A	West	ATC LLC	352	3465	6/1/2010	Aspen		1	138	69	60	Install 60 MVA 138/69 kV transformer at Aspen substation	MI			Planned				Y	A
A	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	$1,250,000.00			Y	A
A	West	ATC LLC	570	1257	8/28/2008	West Darien	Southwest Delavan	1	138		381		WI			Under Construction	$1,610,612.00			Y	A
A	West	ATC LLC	570	1256	8/28/2008	Bradford RCEC	West Darien	1	138		381		WI			Under Construction	$3,410,708.00			Y	A
A	West	ATC LLC	570	1260	8/28/2008	Bristol	Elkhorn	1	138		292		WI			Under Construction	$3,410,708.00			Y	A
A	West	ATC LLC	570	1258	8/28/2008	Southwest Delavan	North Shore	1	138		381		WI			Under Construction	$3,410,708.00			Y	A
A	West	ATC LLC	570	1255	8/28/2008	La Prairie RCEC	Bradford RCEC	1	138		381		WI			Under Construction	$1,610,612.00			Y	A
A	West	ATC LLC	570	1259	8/28/2008	North Shore	Bristol	1	138		381		WI			Under Construction	$1,610,612.00			Y	A
A	West	ATC LLC	571	3523	1/31/2009	Huiskamp			138			Construct a new 138/69 kV substation new Huiskamp	WI			Planned				Y	A
A	West	ATC LLC	571	3524	1/31/2009	Huiskamp			138	69	187 MVA	Install a 138/69 kV transformer at new Huiskamp substation	WI			Planned				Y	A
A	West	ATC LLC	571	1992	3/15/2009	North Madison	Huiskamp	1	138		481 MVA SE		WI			Under Construction	$14,072,115.00			Y	A
A	West	ATC LLC	572	1263	11/1/2008	West Marinette	Menominee	1	138		345		MI/WI		0.45	Under Construction	$1,000,000.00			Y	A
A	West	ATC LLC	572	1264	11/1/2008	Menominee 138/69	transformer	1	138	69			MI			Under Construction	$1,915,000.00			Y	A
A	West	ATC LLC	572	1262	11/1/2008	Ingalls/Bay de Doc	Menominee	1	138		345		WI		0.45	Under Construction	$1,000,000.00			Y	A
A	West	ATC LLC	877	3459	6/1/2009	Racine			345			Replace CT's at Racine 345 kV substation	WI			Planned				Y	A
A	West	ATC LLC	877	868	6/1/2009	Ramsey	Norwich		138		288	loop Ramsey5-Harbor into Norwich and Kansas to form Ramsey-Norwich and Harbor-Kansas	WI	3		Proposed	$200,000.00			Y	A
A	West	ATC LLC	877	863	6/1/2009	Oak Creek	Ramsey		138		293	reconductor (need 382 MVA for A035)	WI	8.5		Proposed	$200,000.00			Y	A

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A	West	ATC LLC	877	482	6/1/2009	Oak Creek 345/138 #2	transformer	2	345	138	500		WI			Planned	$6,600,000.00			Y	A
A	West	ATC LLC	877	866	6/1/2009	Pleasant Prairie	replace two circuit breakers		345			replace circuit breakers	WI			Proposed	$2,357,175.00			Y	A
A	West	ATC LLC	877	864	6/1/2009	Oak Creek	Allerton		138		242	reconductor	WI	5.4		Proposed	$2,000,000.00			Y	A
A	West	ATC LLC	877	869	6/1/2009	Harbor	Kansas		138		157	loop Ramsey5-Harbor into Norwich and Kansas to form Ramsey-Norwich and Harbor-Kansas	WI	2.72		Proposed	$200,000.00			Y	A
A	West	ATC LLC	877	865	6/12/2009	Oak Creek	Relaying replacements		230			replace relaying	WI			Proposed	$2,500,000.00			Y	A
A	West	ATC LLC	877	867	6/12/2009	Oak Creek	Expand 345 kV switchyard to interconnect new generator		345			expand switchyard to interconnect new generator	WI			Proposed	$19,277,005.00			Y	A
A	West	ATC LLC	877	871	6/1/2010	Kansas	Ramsey6		138		290	uprate	WI	5.7		Proposed	$500,000.00			Y	A
A	West	ATC LLC	877	872	6/1/2010	Oak Creek	Root River		138		293	uprate	WI			Proposed	$136,007.00			Y	A
A	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			Proposed	$10,600,000.00			Y	A
A	West	ATC LLC	877	873	6/1/2010	Oak Creek	Nicholson		138		332	uprate	WI	6.8		Proposed	$136,007.00			Y	A
A	West	ATC LLC	886	886	5/1/2009	North Lake	Substation relocation		138			Cedar substation rename/relocation	MI			Under Construction	$7,300,000.00			Y	A
A	West	ATC LLC	1256	2461	6/1/2010	Rockdale			345			convert to a modifed breaker and a half configuration, replace 5 overdutied 138 kV breakers and replace existing transformer with 500MVA	WI			Proposed	$12,300,000.00			Y	A
A	West	ATC LLC	1256	2463	6/1/2010	Paddock			345			upgrade protection system	WI			Proposed	$300,000.00			Y	A
A	West	ATC LLC	1256	2462	6/1/2010	Christiana			138			replace five overdutied 138 kV breakers	WI			Proposed	$1,100,000.00			Y	A
A	West	ATC LLC	1256	1964	6/1/2010	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	Proposed	$112,800,000.00			Y	A
A	west	ATC LLC	1267	3235	6/1/2009	Oak Ridge			138			new 138 kV substation	WI			Proposed	$1,300,000.00			Y	A
A	West	ATC LLC	1267	1985	6/1/2010	Verona	Oak Ridge	1	138			line to new T-D substation	WI			Proposed	$17,900,000.00			Y	A
A	west	ATC LLC	1267	3234	6/1/2010	Verona			138	69		Expand from existing 69 kV sub; cost estimate exclude the transformer cost	WI			Proposed	$1,200,000.00			Y	A
A	west	ATC LLC	1267	1984	6/1/2010	Verona 138/69	transformer	1	138	69	100		WI			Proposed	$1,700,000.00			Y	A
A	West	ATC LLC	1461	2509	9/1/2009	Green Lake Sub						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	$170,146.00			Y	A
A	West	ATC LLC	1461	2511	9/1/2009	Green Lake Sub	transformer		138	34.5	178 MVA	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	$2,049,696.00			Y	A
A	West	ATC LLC	1461	2512	9/1/2009	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	$94,856.00			Y	A
A	West	ATC LLC	1463	2519	10/1/2009	Mishicot			138			Line Y-51 Loop into New Substation. This interconnection will include the installation of two new 45' steel poles (labeled as 163A and 163B) to facilitate entry of Line Y-51 into the substation at right angles, the removal of old line conductors between	WI			Planned	$231,000.00			Y	A

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A	West	ATC LLC	1463	2518	10/1/2009	Mishicot			138			This interconnection will include extension of the 138 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	$179,000.00			Y	A
A	West	ATC LLC	1463	2520	10/1/2009	Kewaunee	Relaying replacements		138			Kewaunee Substation 138 kV Line Y-51, to Shoto, Relay Replacement, This relay upgrade will include replacing the existing line protection relays and panels with a new panel containing relays for a directional comparison unblocking (DCUB) system. The DCUB	WI			Planned	$123,000.00			Y	A
A	West	ATC LLC	1463	2521	10/1/2009	Shoto	Relaying replacements		138			Shoto Substation 138 kV Line Y-51, to Kewaunee, Relay Replacement. This relay upgrade will include replacing the existing line protection relays and panels with a new panel containing relays for a directional comparison unblocking (DCUB) system. The DCUB	WI			Planned	$123,000.00			Y	A
A	West	ATC LLC	1463	2517	10/1/2009	Mishicot	new substation		138			New Substation between Kewaunee Sub and Shoto Sub, New two-breaker 138 kV substation in a configuration allowing future expansion to a seven position ring bus. Two line positions will allow for looping line Y-51 into the substation. The sub will also prov	WI			Planned	$2,612,000.00			Y	A
A	West	ATC LLC	1470	2479	9/1/2009	Generating Facility Sub			69			New two-breaker 69 kV substation in a configuration allowing future expansion to a six-position ring bus	WI			Planned	$1,765,957.00	Y		Y	A
A	West	ATC LLC	1470	2483	9/1/2009	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	$125,620.00	Y		Y	A
A	West	ATC LLC	1470	2481	9/1/2009	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	$193,240.00	Y		Y	A
A	West	ATC LLC	1470	2480	9/1/2009	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	$5,268,974.00	Y		Y	A
A	West	ATC LLC	1470	2482	9/1/2009	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	$184,941.00	Y		Y	A
A	West	ATC LLC	1617	2715	2/1/2013	Nelson Dewey	Liberty	1	161		292 MVA	New 161 kV line Nelson Dewey - Liberty (cost estimate for WI section of the line, apprx. 2 miles)	WI, IA			Planned	$4,621,000.00	Y		Y	A
A	West	ATC LLC	1617	2718	2/1/2013	Nelson dewey			161			Replace three existing CBs at Nelson Dewey 16 kV sub for stability requirement	WI			Planned	$1,771,000.00	Y		Y	A
A	West	ATC LLC	1617	2716	2/1/2013	New G527 Generator Position at Nelson Dewey			161			Modify the existing 161 kV ring bus, install one new CB and other equipment	WI			Planned	$970,000.00	Y		Y	A

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A	West	ATC LLC	1617	2714	2/1/2013	New G527 auxiliary transformer position			161			Modify the existing 161 kV ring bus, install one new CB and other equipment	WI			Planned	$1,029,000.00	Y		Y	A
A	West	ATC LLC	1617	2717	2/1/2013	Nelson dewey			161			Terminal work related to the new 161 kV line, install a new CB and other equipment	WI, IA			Planned	$1,435,000.00	Y		Y	A
A	West	ATC LLC	1617	2719	2/1/2013	Nelson dewey			161			Other terminal work at Delson Dewey including grounding, fencing, foundations, etc.	WI			Planned	$1,248,000.00	Y		Y	A
A	West	GRE	599	753	12/1/2010	Crooked Lake	Enterprise Park	1	115		142		MN		3.5	Planned	$3,600,000.00			Y	A
A	West	GRE	600	1078	12/1/2009	Baxter	Southdale	1	115		224	New line	MN		9	Planned	$5,400,000.00			Y	A
A	West	GRE	601	641	10/1/2008	Mud Lake	Wilson Lake	1	115		142		MN	12		Under Construction	$8,500,000.00			Y	A
A	West	GRE	1026	752	6/15/2008	Linwood 230-69 kV	transformer	1	230	69	112		MN			Under Construction	$5,000,000.00			Y	A
A	West	GRE	1361	2264	5/1/2010	Badoura	Birch Lake	1	115		182		MN		16.03	Planned	$11,275,000.00			Y	A
A	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	$275,000.00			Y	A
A	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	$275,000.00			Y	A
A	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	$5,959,788.00	Y	Y	Y	A
A	West	ITCM	1287	2116	6/1/2009	Salem 345/161 kV	transformer	1	345	161	448/448	Larger Xfmr	IA			Planned	$5,650,000.00	Y		Y	A
A	West	ITCM	1288	2117	12/31/2010	Hazleton 345/161	transformer	1	345	161	335/335	Larger Xfmr	IA			Planned	$5,000,000.00	Y		Y	A
A	West	ITCM	1289	2118	12/31/2009	Marshalltown	Toledo	1	115		233/233	Rebuild	IA	16		Planned	$4,712,000.00			Y	A
A	West	ITCM	1289	2119	12/31/2009	Belle Plaine	Toledo	1	115		233/233	Rebuild	IA	18		Planned	$6,080,000.00			Y	A
A	West	ITCM	1289	2120	12/31/2010	Belle Plaine	Stoney Point	1	115		233/233	Rebuild	IA	27		Planned	$8,208,000.00			Y	A
A	West	ITCM	1342	2208	6/1/2009	Lewis Fields	Hiawatha	1	161		250	new line	IA		8.5	Planned	$2,550,000.00			Y	A
A	West	ITCM	1342	2209	6/1/2010	Lewis Fields	transformer	1	161	115		new transformer	IA			Planned	$2,000,000.00			Y	A
A	West	ITCM	1344	2212	6/1/2012	Beverly	transformer	1	345	161	335	new substation	IA			Proposed	$4,000,000.00			Y	A
A	West	ITCM	1344	2211	6/1/2012	Beverly Tap	Beverly	1	161		335	new line	IA		7.9	Proposed	$300,000.00			Y	A
A	West	ITCM	1473	1856	6/1/2009	Mason City Armor	Emery North	1	69		140/140	Rebuild existing line	IA	4.5		Planned	$975,000.00			NT	A
A	West	MDU	548	1576	11/1/2007	Bismarck Downtown	East Bismarck		115		160	Rebuild	ND			Planned	$363,000.00			Y	A
A	West	MDU	1008	1578	11/1/2009	S Mandan	Bismarck Downtown		115		180	Memorial Bridge circuit replacement	ND			Planned	$2,868,000.00			Y	A
A	West	MDU	1008	1577	11/1/2009	Heskett	NW Bismarck		115		180	Memorial Bridge circuit replacement	ND			Planned	$3,692,000.00			Y	A
A	West	MP	1	318	6/30/2008	Arrowhead 230-230 kV	Phase-Shifter	1	230	230	800		MN			Planned	$13,741,772.80			Y	A
A	West	MP	1	2039	6/30/2008	Arrowhead	Capacitor		230		2 x 75 Mvar		MN			Planned	$1,858,227.20			Y	A
A	West	MP	1	319	6/30/2008	Arrowhead 345/230 kV	transformer	1	345	230	800		MN			Planned	$10,400,000.00			Y	A
A	West	MP	277	579	5/1/2010	Pine River	Pequot Lakes	1	115		182	New Line	MN		8.9	Planned	$4,215,000.00	Y		Y	A
A	West	MP	277	2944	5/1/2010	Pine River	Substation Equipment	1	115			Substation Equipment	MN			Planned	$2,350,000.00			Y	A
A	West	MP	600	2943	12/1/2009	Scearcyville	switching station		115			new switching station	MN			Planned	$2,250,000.00			Y	A
A	West	MP	1025	2660	7/1/2012	Boswell 230	Swatara 230		230			Boswell to Swatara 34.6 Miles	MN			Planned	$34,069,591.00	Y		Y	A
A	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	$3,163,583.00	Y		Y	A
A	West	MP	1025	2662	7/1/2012	Blackberry 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Boswell	MN			Planned	$3,017,108.00	Y		Y	A
A	West	MP	1025	2661	7/1/2012	Swatara 230	Riverton 230		230			Swatara to Riverton 33.2 Miles	MN			Planned	$24,878,937.00	Y		Y	A
A	West	MP	1025	2663	7/1/2012	Swatara 230/115 kV	transformer		230	115		New 230/115 kV Swatara Substation	MN			Planned	$8,817,640.00	Y		Y	A
A	West	MP	1025	2664	7/1/2012	Riverton 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Riverton	MN			Planned	$2,372,682.00	Y		Y	A
A	West	MP	1286	2115	6/1/2008	Two Harbors	capacitor		115		25 Mvar	New Switching station & 25 MVAR cap	MN			Planned	$1,750,000.00			Y	A

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A	West	MP	1359	2260	6/30/2007	International Falls	Capacitor		115		1x20 Mvar	add new	MN			Planned	$245,000.00			Y	A
A	West	MP/GRE	277	2263	5/1/2009	Badoura	Pine River	1	115		182	New Line	MN		19.8	Planned	$10,030,000.00	Y		Y	A
A	West	MP/GRE	277	2946	5/1/2009	Badoura	Substation Equipment	1	115			Substation Equipment	MN			Planned	$2,100,000.00			Y	A
A	West	MP/GRE	277	2945	5/1/2010	Pequot Lakes	Substation Equipment	1	115			Substation Equipment	MN			Planned	$1,300,000.00			Y	A
A	West	MP/GRE	1021	2948	11/1/2009	Tower 115	New Substation	1	115			New Substation	MN		15	Under Construction	$1,000,000.00			Y	A
A	West	MP/GRE	1021	2947	11/1/2009	Embarrass 115	New Substation	1	115			New Substation	MN		15	Under Construction	$2,800,000.00			Y	A
A	West	MP/GRE	1021	1590	11/1/2009	Embarrass 115	Tower 115	1	115		182	New 115 kV line	MN		15	Under Construction	$7,314,000.00			Y	A
A	West	MP/GRE	1022	1591	5/1/2009	Badoura 115	Long Lake 115	1	115		182	New 115 kV line	MN		17	Under Construction	$8,621,000.00	Y		Y	A
A	West	MPC/XEL/O	279	3584	7/1/2012	Cass Lake 230 kV	Cass Lake 115 kV	1	230	115	187 MVA	Add a 230/115 kV Transformer at Cass Lake	MN			Proposed		N		Y	A
A	West	MPC/XEL/O	279	1098	7/1/2012	Boswell	Wilton	1	230		495	Add a new 230 kV line between Boswell and Wilton	MN		72	Proposed	$72,360,000.00	Y		Y	A
A	West	MRES	755	3032	6/1/2008	Alexandria Switching Station	Capacitors		115		25 Mvar	Add a 1 x 25 MVAr capacitor bank at the Alexandria Switching Station	MN			Under Construction	$530,000.00			Y	A
A	West	OTP	274	2598	8/1/2008	Dawson Tap	Dawson	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	1		Planned	$68,000.00			Y	A
A	West	OTP	274	2266	8/1/2008	Louisurg	Dawson Tap	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	14.4		Under Construction	$954,580.00			Y	A
A	West	OTP	274	2267	8/1/2008	Louisburg	transformer	1	115	12.5	10	Convert an existing 41.6 kV line to 115 kV	MN			Planned	$300,000.00			Y	A
A	West	OTP	274	2268	8/1/2008	Dawson	transformer	1	115	12.5	20	Convert an existing 41.6 kV line to 115 kV	MN			Planned	$300,000.00			Y	A
A	West	OTP	274	377	8/1/2008	Appleton	Louisburg	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	6.9		Under Construction	$458,020.00			Y	A
A	West	OTP	275	378	8/1/2008	Dawson Tap	Canby	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	21.1		Under Construction	$519,400.00			Y	A
A	West	OTP	1462	2516	10/1/2009	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. The basic requirement for this upgrade would be to add additional 230	ND			Planned	$705,931.00	Y		Y	A
A	West	OTP	1462	2515	10/1/2009	Rugby	bus		230			The Transmission Owner Interconnection Facilities consist of the radial bus 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. The basic	ND			Planned	$104,809.00			Y	A
A	West	OTP	1462	2514	10/1/2009	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	$88,000.00			Y	A
A	West	XEL	56	310	12/31/2010	Shafer	Lawrence Creek	1	115		310	small amount new ROW	MN	6.2		Planned	$3,500,000.00			Y	A
A	West	XEL	56	306	12/31/2010	Lindstrom	Shafer	1	115		310	New line	MN	2.8		Planned	$5,800,000.00			Y	A
A	West	XEL	56	303	12/31/2010	Lawrence Creek	St Croix Falls	1	161		371	New 161 kV line	MN		2.05	Planned	$9,080,000.00			Y	A
A	West	XEL	56	301	12/31/2010	Chisago	Lindstrom	1	115		310	New 115 kV line	MN	7		Planned	$10,100,000.00			Y	A
A	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	$6,000,000.00			Y	A
A	West	XEL	56	1088	12/31/2010	Lawrence Creek 115-69 kV	transformer	1	115	69	70		MN			Planned	$1,631,000.00			Y	A
A	West	XEL	385	2283	6/1/2009	Brookings Co	White	2	345		2085	New 345 kV line	SD/MN			Planned				Y	A
A	West	XEL	385	975	12/31/2009	Nobles Co 345-115 kV	transformer	2	345	115	672	New transformer	MN			Planned	$5,792,804.96			Y	A
A	West	XEL	1457	2565	12/31/2009	Nobles County	substation		345			345 kV substation upgrades	MN			Planned	$344,270.00	Y	Y	Y	A

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A	West	XEL	1457	2552	12/31/2009	Fenton County	substation		115			Substation upgrades	MN			Planned	$776,000.00	Y		Y	A
A	West	XEL	1457	2303	12/31/2009	Nobles County	Fenton	2	115		620	New 115 kV line plus permitting and ROW	MN			Planned	$13,560,000.00	Y		Y	A
A	West	XEL	1457	2550	12/31/2009	Nobles County	substation		115			Substation upgrades	MN			Planned	$11,992,730.00	Y		Y	A
A	West	XEL	1457	2551	12/31/2010	Hazel Creek	substation		115			New Substation and in-and-out taps to transmission	MN			Planned	$10,962,000.00	Y		Y	A
A	West	XEL	1457	2301	12/31/2010	Hazel Creek	Capacitor and SVC		115		53 & 33 Mvar	Capacitor 53 Mvar, SVC 33 Mvar	MN			Planned	$0.00	Y		Y	A
A	West	XEL	1457	2494	12/31/2009	Nobles	feeders		34.5			four new 50 MW 34.5 kV feeders and all associated equipment at Nobles County Sub.	MN			Planned	$1,100,000.00			NT	A
A	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	$7,120,000.00	Y		Y	A
A	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	$6,101,122.00	Y		Y	A
A	West	XEL	1458	2566	12/31/2009	Brookings Co	substation		345			Substation upgrades 4-345 kV CB	MN			Planned	$1,313,878.00	Y	Y	Y	A
A	West	XEL	1458	2299	12/31/2009	Yankee	Brookings County	2	115		620	New 115 kV line plus permitting and ROW	MN			Planned	$9,955,000.00	Y		Y	A
A	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	$5,290,000.00	Y		Y	A
A	West	XEL	1458	2496	11/30/2011	Yankee	feeders		34.5			four new 50 MW underground feeder lines and all associated equipment	MN			Planned	$2,202,000.00			NT	A
A	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	$2,425,500.00	Y	Y	Y	A
A	West	XEL	1489	2548	6/1/2009	Woodbury	Tanners Lake	1	115		256	Upgrade to 310 MVA	MN		3.5	Planned	$525,000.00			Y	A
A	West	XEL	1613	2653	5/30/2012	Hazel Run Substation			115			20 Mvar SVC	MN			Planned	$4,779,000.00	Y		Y	A
A	West	XEL	1614	2654	5/30/2012	Hazel Crk Substation			115			30 Mvar SVC	MN			Planned	$4,803,000.00	Y		Y	A
A	West	XEL (NSP)	1454	2485	10/1/2007	Yankee	feeder bays		34.5			Two 34.5 feeder bays terminating at dead-end switch structures ouside of Yankee Substation	MN			Planned	$581,280.00			NT	A
A	West	XEL (NSP)	1455	2488	5/1/2009	Riverside Generating Plant	breakers		115			IC to install 115 kV breakers on IC side of interconnection facilities as well as two sets of metering equipment	MN			planned	$165,000.00			Y	A
A	West	XEL (NSP)	1455	2489	5/1/2009	Riverside Generating Plant	Apache Substation		115		63 kA CB	IC to install three new 115 kV, 63 kA interrupting rating circuit breakers, six 115 kV switches, two 115 kV current coupling voltage transformers, as well as relocate the existing Apache 115 kV line to a new termination in the substation.	MN			Planned	$2,605,000.00			Y	A
A in MTEP08	Central	Ameren	1235	1934	6/1/2012	Fredericktown	AECI Fredericktown Tap	1	161		250	Increase ground clearance	MO	12		Proposed	$970,500.00			Y	B>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	$1,279,700.00			Y	C>B>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	C>B>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	$13,000,000.00			Y	C>B>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	C>B>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	$2,113,000.00			Y	C>B>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	$15,039,400.00	Y	Y	Y	C>B>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	$11,000,000.00	Y	Y	Y	C>B>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	$6,600,000.00	Y		Y	C>B>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	$553,000.00			Y	C>B>A

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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	C>B>A
A in MTEP08	Central	AmerenIP	1232	2219	1/1/2008	Tilden	Fayetteville	1				tap Tilden-Fayetteville (L1526) for construction power to Prairie State	IL			In Service	$2,602,000.00			Y	B>A
A in MTEP08	Central	AmerenIP	1351	1941	5/5/2008	Pana, North	Decatur Rt. 51 L1462	1	138		280	Replace 1200 A terminal equipment with 1600 A equipment at Pana	IL			In Service	$80,600.00			Y	B>A
A in MTEP08	Central	AmerenIP	1526	2603	3/14/2008	Midway	N. Staunton	1	138		280	Replace terminal equipment at N. Staunton	IL			In Service	$375,100.00			Y	B>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	$2,566,900.00			Y	C>B>A
A in MTEP08	Central	AmerenIP	1531	2608	1/1/2008	S. Bloomington	Clinton Rt. 54	1	138		125	Replace terminal equipment at S. Bloomington	IL			In Service	25000			Y	B>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	$744,800.00			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	$1,642,627.00	Y		Y	C>B>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	$230,000.00	Y		Y	C>B>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	$155,330.00	Y		Y	C>B>A
A in MTEP08	Central	AmerenMO	717	1408	6/1/2010	Conway	Orchard Gardens	1	138		240	increase ground clearance	MO			Proposed	$125,350.00			Y	B>A
A in MTEP08	Central	AmerenMO	718	1409	6/1/2010	Conway	Orchard Gardens	2	138		240	increase ground clearance	MO			Proposed	$125,350.00			Y	B>A
A in MTEP08	Central	AmerenMO	2061	3969	12/1/2010	Gray Summit	Tyson	1	345		1200	Replace Terminal Equipment at Tyson	MO			Planned	$0.00	Y		Y	C>B>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	$19,000,000.00	Y		Y	C>B>A
A in MTEP08	Central	AmerenMO	2061	3970	12/1/2010	Gray Summit	Tyson	2	345		1200	Replace Terminal Equipment at Tyson	MO			Planned	$0.00	Y		Y	C>B>A
A in MTEP08	Central	AmerenMO	2072	3975	10/1/2008	Brick House	Maline	2	138		382	Add Circuit Breaker at brick House in Brick House - Maline - 4 138 kV line	MO			Planned				Y	C>B>A
A in MTEP08	Central	AmerenMO	2072	3976	10/1/2008	Brick House		1	138	13.8	100	Add two 138 - 13.8 KV transformers at Brick House	MO			Planned				Y	C>B>A
A in MTEP08	Central	AmerenMO	2072	3974	10/1/2008	Brick House	Maline	1	138		382	Add Circuit Breaker at brick House in Brick House - Maline - 3 138 kV line	MO			Planned	$8,700,000.00			Y	C>B>A
A in MTEP08	Central	AMRN	2113	2836	9/30/2008	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				Planned	$1,880,000.00	Y		Y	C>B>A
A in MTEP08	Central	AMRN	2113	2837	12/1/2008	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			Planned	$364,000.00	Y		Y	C>B>A

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A in MTEP08	Central	CWLP	1552	2651	10/1/2009	Interstate	Holland/East Springfield	1	138		271	Loop Holland to East Springfield 1384 line through CWLP Interstate substation (Two New Tie Lines)	IL			Planned	$2,800,000.00			Y	B>A
A in MTEP08	Central	DEM	625	2568	6/1/2008	Pierce	Beckjord		138		500	Install new 138kV cir with a capacity approx 500MVA due to new 345/138 kV TB to Beckjord North bus	OH			Under Construction	$132,486.42			Y	C>B>A
A in MTEP08	Central	DEM	625	1301	6/1/2008	Pierce/Beckjord 345/138 kV	transformer	C	345	138	400	Add third 345/138kV xfr 400 MVA connected to Beckjord 138kV North Bus.	OH			Under Construction	$2,527,029.00			Y	C>B>A
A in MTEP08	Central	DEM	806	808	11/1/2007	Gwynneville	transformer	1	345	69	150	Add 150 MVA 345/69 kV xfr	IN			In Service	$5,175,365.00			Y	C>B>A
A in MTEP08	Central	DEM	806	809	11/1/2007	Gwynneville	Gwynneville 69108 Jct	1	69		153	New 69kV line Gwynneville to new Jct between Arlington Jct and Morristown. Deenergize section from 108 Jct to 166 Jct. Gwynneville-Jct-Arlington Jct	IN		4.1	In Service	$1,474,521.00			NT	C>B>A
A in MTEP08	Central	DEM	806	811	6/1/2008	Gwynneville	Gwynneville 69166 Jct	1	69		153	New 69kV line Gwynneville to new Jct between Arlington Jct and Morristown. Reconductor from Jct to Morristown. Gwynneville-Jct-Morristown.	IN	2	3.3	Planned	$1,173,812.00			NT	C>B>A
A in MTEP08	Central	DEM	810	1302	12/31/2007	Bloomington	transformer	5	230	69	200	Add 230/69kV Bk5	IN			In Service	$3,986,059.00			Y	C>B>A
A in MTEP08	Central	DEM	811	3061	12/31/2007	Evendale 1	Capacitor		69		21.6 MVAR	Add capacitor	OH			In Service	$390,805.00			NT	C>B>A
A in MTEP08	Central	DEM	811	814	12/31/2007	Evendale 2	Capacitor		69		21.6 MVAR	Add capacitor	OH			In Service	$390,805.00			NT	C>B>A
A in MTEP08	Central	DEM	828	3065	12/31/2007	Northgreen	Capacitor		69		14.4 MVAR	Add capacitor	OH			In Service	$406,671.00			NT	C>B>A
A in MTEP08	Central	DEM	830	3067	11/2/2007	Thorntown	Capacitor		69		28.8 MVAR	Add capacitor	IN			In Service	$456,723.00			NT	C>B>A
A in MTEP08	Central	DEM	834	3071	6/1/2012	Kingman	Capacitor		69		7.2 MVAR	Add capacitor	IN			Planned	$500,000.00			NT	C>B>A
A in MTEP08	Central	DEM	835	3072	6/1/2010	Pittsboro	Capacitor		69		14.4 MVAR	Add capacitor	IN			Planned	$500,000.00			NT	C>B>A
A in MTEP08	Central	DEM	841	820	6/1/2013	Westwood Bk1	transformer	1	345	138	412.9	Replace 1200A 138kV equipment with 2000A to allow full xfr rating.	IN			Planned	$554,000.00			Y	C>B>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	$439,844.75			NT	C>B>A
A in MTEP08	Central	DEM	1245	1959	6/1/2010	Potato Creek Switching Station			69			Construct 69kV switching station	IN			Planned	$1,007,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1245	1958	6/1/2010	Frankfort Jefferson	Potato Creek		69		153	69178 Build 2.7 miles of 954 ACSR 69kV	IN		2.7	Planned	$1,087,115.23			NT	C>B>A
A in MTEP08	Central	DEM	1265	1982	6/1/2010	Geist 2	Capacitor		69		36 MVAR	Add a second 69kV 36MVAR cap bank at Geist	IN			Planned	$500,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1266	1983	6/1/2009	Hortonville	Capacitor		69		36 MVAR	Install 69kV 36MVAR cap bank at Hortonville	IN			Planned	$500,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1501	2574	6/1/2012	Carmel 146th St	Capacitor 2		69		36 MVAR	Install a 2nd 69kV 36MVAR cap bank	IN			Planned	$624,145.00			NT	C>B>A
A in MTEP08	Central	DEM	1502	2575	12/1/2008	Tipton West 69kV	Tipton West Jct		69			IMPA to build new 69kV - 69191 line from Tipton West sub to new Tipton W. Jct.	IN		2.7	Proposed	$926,496.00			NT	C>B>A
A in MTEP08	Central	DEM	1502	2577	12/1/2008	Tipton West substation		1,2	230	69		Install two new 230/69kV - 75 MVA transformer w/assoc. switching and protective equipment.	IN			Planned	$9,297,000.00			Y	C>B>A
A in MTEP08	Central	DEM	1502	3778	12/1/2008	Getrag - Tipton Sub	Tipton West		69	12.5		IMPA to build sub and 69 lines: new 69185 ckt (2.2 miles) Tipton West and Alternate feed (2.5 miles) 69191 ckt. (ATO scheme) from tap between Tipton West (1.2 miles) and new Tipton West Jct (1.5 miles)	IN		4.7	Planned				NT	C>B>A

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A in MTEP08	Central	DEM	1502	2576	12/1/2008	Tipton West 230kV			230			Route 23008 line into new Tipton West Sub	IN			Proposed	$573,376.00			Y	C>B>A
A in MTEP08	Central	DEM	1502	3114	12/31/2008	Tipton	Tipton West Jct		69		100	Reconductor 69kV line between Tipton Muni sub and new Tipton West Jct w/954ACSR - FOG (1.2 miles) and install 1200A switch on Kokomo side of new junction; CO1 = change to 477ACSR	IN	1		Planned	$300,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1504	2579	12/1/2007	Honda			138			New substation for Honda in Greensburg	IN			In Service	$0.00			Y	B>A
A in MTEP08	Central	DEM	1505	2580	6/1/2008	HE Owensville North			138			Loop Gibson to Princeton 13863 line through new HE transmission sub	IN			In Service	$182,375.00			Y	B>A
A in MTEP08	Central	DEM	1506	2581	12/31/2007	Peru SE			69			Add 69kV ring breaker, line terminal and interconnection metering	IN			In Service				NT	C>B>A
A in MTEP08	Central	DEM	1507	2583	12/31/2007	Vectren Francisco			138			Reroute 138kV around proposed substation.	IN			In Service	$0.00			Y	B>A
A in MTEP08	Central	DEM	1510	2586	6/1/2008	Wabash River	TH Water St		138		191	Uprate conductor to 100C temperature	IN			Planned	$120,282.00			Y	B>A
A in MTEP08	Central	DEM	1512	2588	6/1/2010	Ashland	Rochelle		138			Install underground 138 kV circuit from Ashland to Rochelle. Requires a permanent in-line reactor.	OH		1.6	Proposed	$2,478,513.00			Y	C>B>A
A in MTEP08	Central	DEM	1512	2939	6/1/2010	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	$400,000.00			Y	C>B>A
A in MTEP08	Central	DEM	1513	2589	6/1/2010	Metea	Capacitor		69		14.4 MVAR	Install 14.4MVAR 69kV unit	IN			Planned	$568,653.00			NT	C>B>A
A in MTEP08	Central	DEM	1514	2590	6/1/2009	Wabash River	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			Planned	$0.00			Y	B>A
A in MTEP08	Central	DEM	1514	3776	6/1/2009	Wabash River Station	Burnett Jct	1	138			Partial reconductor of two sections of 13847 line to allow uprating of 23002 line overbuild. Wab Riv to Spelterville to Burnett Jct - No ratings change, just Z changes. Going from 6-wired 477acsr to 3-wired 954acsr.	IN			Planned	$255,173.00			Y	B>A
A in MTEP08	Central	DEM	1515	2591	6/1/2009	Speed	Relays		345			Replace Speed relays for the LGEE Trimble addition - moved from 702D5940 to this project (Speed Refurb Plan)	IN			Planned	$145,922.00			Y	B>A
A in MTEP08	Central	DEM	1519	2595	6/1/2011	Noblesville NE	Geist		69			Build a new 69kV line from Noblesville NE sub to tap the Fishers North - Geist 69kV line	IN			Planned	$2,640,107.00			NT	C>B>A
A in MTEP08	Central	DEM	1560	3111	6/1/2010	Edwardsport	capacitor		138		57.6 MVAR	Install a 138kV 57.6MVAR capacitor at Edwardsport.	IN			Planned	$500,000.00			Y	C>B>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	$399,579.80			Y	C>B>A
A in MTEP08	Central	DEM	1563	3115	10/15/2008	Todhunter	AK Steel	1	138		306	Replace F5686 existing conductor with 954ACSR @ 100C from Todhunter to AK Steel and replace any limiting terminal equipment at both ends	OH	2		Planned	$302,000.00			Y	B>A
A in MTEP08	Central	DEM	1564	3116	6/1/2009	Roseburg Switching Station	Capacitor		69		21.6 MVAR	Install 69kV 21.6MVAR std capacitor	IN			Planned	$500,000.00			NT	C>B>A

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A in MTEP08	Central	DEM	1568	3120	6/1/2010	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	$4,561,673.88			Y	B>A
A in MTEP08	Central	DEM	1569	3121	6/1/2010	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	$1,507,855.84			Y	B>A
A in MTEP08	Central	DEM	1570	3122	6/1/2010	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	$4,139,000.00			Y	B>A
A in MTEP08	Central	DEM	1648	3379	10/15/2008	Lafayette South	Lafayette Eli Lilly - Tippe Labs	1	138		179 / 306	Lafayette S to (new) Shadeland to Lilly Uprate 397.5ACSR to 100C - 4.13 miles - 13808 ckt; CO#1: Added costs to reconductor the 13808 line from Eli Lilly Tippecanoe Lab Substation to new Shadeland Substation with 954acsr@100C.	IN	4.1		Planned	$389,255.84			Y	C>B>A
A in MTEP08	Central	DEM	1650	3381	6/30/2012	Fairview	HE Fairview	1	138		306	Fairview to HE Fairview 13854 Reconductor with 954ACSR @ 100C	IN	3.3		Proposed	$1,236,383.93			Y	C>B>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		Proposed	$278,000.00			Y	C>B>A
A in MTEP08	Central	DEM	1878	3772	6/1/2009	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			Planned	$2,000,000.00			Y	B>A
A in MTEP08	Central	DEM	1881	3775	12/31/2009	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	$1,252,764.46			Y	C>B>A
A in MTEP08	Central	DEM	1886	3782	5/29/2009	Columbus West	line switches	1	69		143	Replace 69kV switches 1&2 with 1200 amp switches - (in the 69146 ckt)	IN			Planned	$82,847.17			NT	C>B>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	$2,418,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1889	3785	6/1/2009	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	$2,300,000.00			NT	C>B>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	$1,181,222.93			NT	C>B>A
A in MTEP08	Central	DEM	1891	3787	6/1/2009	North Manchester 69	N. Manchester Sw. Sta.	1	69		100	6923 ckt. reconductor from N. Manchester 69 sub to N. Manchester Sw Sta (0.53 mile) and a portion of the line section from N. Manchester 69 sub to Collamer along CR 1100N (1.03 miles), also replace transmission poles - new conductor will be 477ACSR@100C	IN	1.56		Planned	$618,143.02			NT	C>B>A

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A in MTEP08	Central	DEM	1892	3788	6/1/2009	Wabash 138 sub	Hopewell Jct.	1	69		100	69132 ckt. Reconductor 6.86 miles from Wabash to Hopewelll Jct. with 477ACSR	IN	6.86		Planned	$2,591,000.00			NT	C>B>A
A in MTEP08	Central	DEM	1893	3789	6/1/2011	Mitchell Lehigh Portland	Bedford 25th St	1	69		100	Reconductor 10.3 miles of 69kV - 6995 line with 477 ACSR	IN	10.3		Planned	$3,620,480.63			NT	C>B>A
A in MTEP08	Central	DEM	1895	3791	6/1/2011	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	4.2		Planned	$1,433,226.94			Y	C>B>A
A in MTEP08	Central	DEM	1896	3792	6/1/2010	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	$16,493.18			NT	C>B>A
A in MTEP08	Central	DEM	1897	3793	6/1/2010	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	$921,919.10			NT	C>B>A
A in MTEP08	Central	DEM	1899	3795	12/31/2010	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	$3,102,711.45			NT	C>B>A
A in MTEP08	Central	DEM	1901	3797	6/1/2011	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 (7.13 miles)	IN	7.13		Planned	$1,510,945.57			NT	C>B>A
A in MTEP08	Central	DEM	1902	3799	6/1/2012	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	$163,389.67			NT	C>B>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	$6,000,000.00			Y	C>B>A
A in MTEP08	Central	HE	1635	3299	12/1/2009	Ramsey Primary	345kV Ring Bus	1	345		2000 AMP	Rebuild	IN			Planned	$7,000,000.00			Y	B>A
A in MTEP08	Central	HE	1923	3802	9/1/2009	Spring Valley Junction	69lV Switching Station	1	69		2000 AMP	Rebuild	IN			Planned	$2,600,000.00			NT	C>B>A
A in MTEP08	Central	HE	1926	3805	9/1/2008	Gwyneeville Primary	Pioneer Substation	1	69		2000 AMP	New Construction	IN		8	Planned	$1,000,000.00			NT	C>B>A
A in MTEP08	Central	HE	1927	3806	9/1/2010	Hubbell Primary		1	138		2000 AMP	Rebuild	IN			Planned	$3,000,000.00			Y	C>B>A
A in MTEP08	Central	HE	1928	3807	9/1/2011	Fairview Primary		1	138		2000 AMP	Rebuild	IN			Planned	$1,500,000.00			Y	C>B>A
A in MTEP08	Central	HE	1929	3808	9/1/2012	Georgetown Primary		1	138		2000 AMP	Rebuild	IN			Planned	$1,250,000.00			Y	C>B>A
A in MTEP08	Central	HE	2082	3979	9/1/2009	Shelbyville Intel Park		1	138	12.5	2000 AMP	New Construction	IN			Planned	$750,000.00			Y	C>B>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	$250,000.00			Y	C>B>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	$500,000.00			NT	C>B>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	$250,000.00			NT	C>B>A
A in MTEP08	Central	HE	2084	3984	9/1/2009	Worthington Primary		1	161	138	250MVA	Replace Existing	IN			Planned	$4,500,000.00			Y	C>B>A
A in MTEP08	Central	HE	2095	3983	9/1/2008	Sandborn Primary	Carlisle Switch	1	69			New Construction	IN		9	Planned	$2,000,000.00			NT	C>B>A
A in MTEP08	Central	HE	2095	3982	9/1/2008	Sandborn Primary	Freelandville Switch	1	69			New Construction	IN		9.7	Planned	$2,000,000.00			NT	C>B>A

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A in MTEP08	Central	IPL	1634	3298	1/1/2008	Petersburg	Vincennes Jct	1	138		249	Change CT Ratio At Petersburg to 1200A	IN			In Service	$2,500.00			Y	B>A
A in MTEP08	Central	IPL	1639	3301	6/1/2013	Various Locations	capacitors					Add capacitors to IPL General Distribution System	IN			Planned	$50,000.00			NT	C>B>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	$5,000,000.00	Y		Y	C>B>A
A in MTEP08	Central	Vectren	995	1559	12/31/2012	Mount Vernon	transformer	1	138	69	67/76	add 2nd transformer from reserve equipment	IN			Proposed	$80,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1001	1565	5/31/2009	Oak Grove 138/69 kV	transformer	1	138	69	168/176	new transformer	IN			Planned	$8,950,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1002	1566	5/31/2009	Northeast	Oak Grove	77	138		287/287	new line	IN		5	Planned	$2,800,000.00			Y	B>A
A in MTEP08	Central	Vectren	1002	1567	5/31/2009	Oak Grove	Culley	77	138		287/287	new line	IN		10	Planned	$5,700,000.00			Y	B>A
A in MTEP08	Central	Vectren	1023	1968	5/31/2009	Scott Township 138/69 kV	Substation		138	69	168/176	new substation with one 138/69 kV transformer and 138 & 69 kV tie ins	IN			Planned	$10,000,000.00			Y	B>A
A in MTEP08	Central	Vectren	1023	1969	5/31/2009	Scott Township	Elliott	74	138		287/287	new line	IN		6	Planned	$3,900,000.00			Y	B>A
A in MTEP08	Central	Vectren	1258	1974	5/31/2008	Pigeon Creek 138	substation development	1	138			greater 100 kV substation work	IN			Planned	$5,100,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1258	2760	5/31/2008	Pigeon Creek 138/69 kV	transformer	1	138	69	168/176	new transformer with tie ins for 138 kV and 69 kV lines	IN			Planned	$5,600,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1779	3569	6/1/2009	Aventine	Substation	1	69	12.47	16/20	New sub and 69kv line work	IN			Planned	$2,715,000.00			NT	C>B>A
A in MTEP08	Central	Vectren	1780	3570	6/1/2009	Aventine Ph II	Substation	1	69	12.47	16/20	2nd XFMR	IN			Planned	$1,325,000.00			NT	C>B>A
A in MTEP08	Central	Vectren	1781	3571	6/1/2009	Abengoa Substation	Substation	1	138	12.47	16/20	New sub and 138kv line work	IN			Planned	$2,750,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1782	3572	6/1/2009	Northeast Sub Bus reconfig	Substation	1	138			Rebuild existing straight bus with more reliable breaker and half scheme	IN			Planned	$3,300,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1783	3573	6/1/2009	Princeton Area Load Growth	Substation	1	69	12.47	16/20	2nd XFMR at Kings	IN			Planned	$400,000.00			NT	C>B>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	$1,250,000.00			NT	C>B>A
A in MTEP08	Central	Vectren	1785	3575	6/1/2008	Z83 Upgrade NE	Z83 Upgrade NW	83	138			Upgrade terminal equipment at NE and NW.	IN			Planned	$100,000.00			Y	C>B>A
A in MTEP08	Central	Vectren	1786	3576	6/1/2008	Z98 Upgrade AB Brown	Z98 Upgrade Point	98	138			Upgrade terminal equipment at AB Brown and Point	IN			Planned	$100,000.00			Y	C>B>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	$3,300,000.00			NT	C>B>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	$2,600,000.00			NT	C>B>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	$1,400,000.00			NT	C>B>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	$1,500,000.00			NT	C>B>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	$300,000.00			NT	C>B>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	$7,680,032.00	Y		Y	C>B>A
A in MTEP08	East	FE	1589	2672	6/1/2010	West Medina	Substation	1	138	69	90/120 MVA	New 138/69 kV transformer	OH			Planned	$4,131,000.00			Y	C>B>A
A in MTEP08	East	FE	1591	2674	6/1/2009	Newton Falls	Substation Upgrades	3	138	69	100/134 MVA	Replace 138/69 kV transformer	OH			Planned	$2,034,365.00			Y	C>B>A

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A in MTEP08	East	FE	1596	2679	10/1/2009	Lakeview Substation	Capacitor Bank		34.5			Capacitor Bank Addition	OH			Planned	$451,100.00			Y	C>B>A
A in MTEP08	East	FE	1599	2686	6/1/2009	Lemoyne	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	10.1		Planned				Y	B>A
A in MTEP08	East	FE	1599	2190	6/1/2009	Wallbridge Junction	Maclean	1	138		308/375 MVA	Line Reconductor	OH	0.5		Proposed	$247,900.00			Y	B>A
A in MTEP08	East	FE	1599	2685	6/1/2009	Frey	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	3.9		Planned				Y	B>A
A in MTEP08	East	FE	1599	2684	6/1/2009	Lemoyne	Oregon	1	138		286/286 MVA	New Line from 3 terminal lines.	OH	11.8		Planned	$1,020,000.00			Y	B>A
A in MTEP08	East	FE	1600	2687	6/1/2014	Beaver	Wellington	1	138		161/194 MVA	New Line	OH	23		Proposed	$5,000,000.00			Y	C>B>A
A in MTEP08	East	FE	1601	2688	6/1/2010	Chamberlin	Shalersville	1	138		260/309 MVA	New Line	OH	12		Planned	$3,669,000.00			Y	C>B>A
A in MTEP08	East	FE	1609	2701	6/1/2009	Tangy	Substation	5	345	138	382/473 MVA	New 345/138 kV Transformer	OH			Planned	$7,300,000.00	Y		Y	C>B>A
A in MTEP08	East	FE	1610	2702	6/1/2009	Avon	Substation	92	345	138	505/664 MVA	New 345/138 kV Transformer	OH			Planned	$8,459,634.00	Y		Y	B>A
A in MTEP08	East	FE	1905	3864	6/1/2008	Salt Springs #2 Failed unit	#2 Failed TR replace	1	138	69	90 MVA	Rewind/replace transformer	OH	0		In Service	$2,226,000.00			Y	C>B>A
A in MTEP08	East	FE	1907	3866	6/1/2008	Brookside	Hale	1	69			New Line	OH	0	0.89	In Service	$769,000.00			Y	C>B>A
A in MTEP08	East	FE	1908	3867	6/1/2008	Cook	Galion	1	69			reconductor line	OH	5.4		In Service	$2,000,000.00			Y	C>B>A
A in MTEP08	East	FE	1909	3868	6/1/2010	Davis Besse	sub reconfiguration		345			substation breaker additions	OH			Planned	$3,345,000.00			Y	C>B>A
A in MTEP08	East	FE	1911	3870	11/1/2010	Fayette	substation addition		138	69		add transformer and breakers	OH			Proposed	$4,000,000.00			Y	C>B>A
A in MTEP08	East	FE	1911	3871	11/1/2010	Fayette	Bryan/Stryker	1	69			New Line	OH		5	Proposed	$8,000,000.00			Y	C>B>A
A in MTEP08	East	FE	1912	3872	12/31/2009	Cardington	Tangy	1	69			reconductor line	OH	16.8		Planned	$2,400,000.00			Y	C>B>A
A in MTEP08	East	FE	1918	3878	6/1/2010	Dale	Jackson	1	69			New Line	OH	3.9		Planned	$2,700,000.00			Y	C>B>A
A in MTEP08	East	FE	1921	3883	6/1/2012	Chittenden	Darrow	1	69			New Line	OH		3.87	Planned	$3,275,000.00			Y	C>B>A
A in MTEP08	East	FE	2096	3988	1/1/2010	Stacy	distribution transformer	1	138	36		New 138-36kV Distribution transformer	OH			Planned	$0.00			Y	C>B>A
A in MTEP08	East	FE	2096	3987	1/1/2010	Stacy	substation	1	138			New 138kV substation	OH			Planned	$3,000,000.00			Y	C>B>A
A in MTEP08	East	FE	2096	3985	1/1/2010	Ashtabula Q-4	Stacy	1	138			New line extension from current 138kV Line	OH	12		Planned	$4,500,000.00			Y	C>B>A
A in MTEP08	East	FE	2096	3986	1/1/2010	Mayfield Q-4	Stacy	1	138			New line extension from current 138kV Line	OH	12		Planned	$4,500,000.00			Y	C>B>A
A in MTEP08	East	ITC	1660	3426	1/21/2008	Horn	Jefferson 120 kV		120			substation with in and out to existing Jefferson - trenton line	MI			In Service	$1,350,000.00			Y	C>B>A
A in MTEP08	East	ITC	1660	3425	1/21/2008	Horn 120 kV	Trenton Channel PP 120 kV		120			substation with in and out to existing Jefferson - trenton line	MI			In Service	$1,350,000.00			Y	C>B>A
A in MTEP08	East	ITC	1661	3427	5/28/2008	Axle 120 kV	St Clair 120 kV	1	120			substation with in and out to existing St Clair - Cypress line	MI			In Service	$800,000.00			Y	C>B>A
A in MTEP08	East	ITC	1661	3428	5/28/2008	Axle 120 kV	Cypress 120 kV	1	120			substation with in and out to existing St Clair - Cypress line	MI			In Service	$800,000.00			Y	C>B>A
A in MTEP08	East	ITC	1661	3429	10/1/2008	St Clair	Remer	2	120			new line	MI			Under Construction	$800,000.00			Y	C>B>A
A in MTEP08	East	ITC	1662	3431	10/1/2008	Square Lake 120 kV	Lily 120 kV	1	120			substation with in and out to existing Bloomfiel - Lily line	MI			Under Construction	$1,100,000.00			Y	C>B>A

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A in MTEP08	East	ITC	1662	3430	10/1/2008	Square Lake 120 kV	Bloomfield 120 kV	1	120			substation with in and out to existing Bloomfiel - Lily line	MI			Under Construction	$1,100,000.00			Y	C>B>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	$4,000,000.00			Y	C>B>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	$1,130,000.00			Y	C>B>A
A in MTEP08	East	ITC	1857	3746	6/1/2011	Jewell	St. Clair	2	120			Break up 3-ended line	MI			Proposed	$550,000.00			Y	C>B>A
A in MTEP08	East	ITC	1857	3745	6/1/2011	Adams	Spokane	1	120			Break up 3-ended line	MI			Proposed	$850,000.00			Y	C>B>A
A in MTEP08	East	ITC	1866	2887	12/31/2008	Anti-galloping project	Throughout System						MI			Under Construction	$3,000,000.00			Y	C>B>A
A in MTEP08	East	ITC	1870	3757	5/1/2009	ClydeTP	Placid	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI	11.5		Planned				Y	C>B>A
A in MTEP08	East	ITC	1870	3758	5/1/2009	ClydeTP	Durant	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI	6.6		Planned				Y	C>B>A
A in MTEP08	East	ITC	1870	3759	12/1/2009	ClydeTP	Clyde	1	120		343 MVA	Clyde taps the Placid-Durant 120kV circuit	MI		3.3	Planned	$2,750,000.00			Y	C>B>A
A in MTEP08	East	ITC	1871	3760	12/1/2009	Hurst	Durant	1	120		343 MVA	Hurst taps the Genoa-Durant 120kV circuit	MI	8.2	0.5	Planned	$1,050,000.00			Y	C>B>A
A in MTEP08	East	ITC	1871	3761	12/1/2009	Hurst	Genoa	1	120		343 MVA	Hurst taps the Genoa-Durant 120kV circuit	MI	11.9	0.5	Planned	$1,050,000.00			Y	C>B>A
A in MTEP08	East	ITC	1873	3765	6/1/2010	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	$2,800,000.00			Y	C>B>A
A in MTEP08	East	ITC	1874	3767	11/3/2007	Cosmo Tap	Bad Axe	1	120		200 MVA	Install Fiber Optic cable on the 3 -ended Arrowhead-Harvest Wind-Bad Axe 120 kV circuit	MI	3.1		In Service		Y		Y	C>B>A
A in MTEP08	East	ITC	1874	3768	11/3/2007	Cosmo Tap	Arrowhead	1	120		222 MVA	Install Fiber Optic cable on the 3 -ended Arrowhead-Harvest Wind-Bad Axe 120 kV circuit	MI	15.6		In Service	$2,352,131.00	Y		Y	C>B>A
A in MTEP08	East	ITC	1874	3766	11/3/2007	Cosmo Tap	Harvest Wind	1	120		351 MVA	Install Fiber Optic cable on the 3 -ended Arrowhead-Harvest Wind-Bad Axe 120 kV circuit, and install a new pole top switch outside the Harvest wind station	MI	10		In Service		Y		Y	C>B>A
A in MTEP08	East	ITC	1875	3771	5/31/2009	Bad Axe	Wyatt	2	120		343 MVA	Builds a second Bad Axe - Wyatt 120 kV circuit	MI		2.95	Planned	$5,894,687.00	Y		Y	C>B>A
A in MTEP08	East	ITC	1875	3769	5/31/2009	Leppek	Wyatt	1	120		222 MVA	Creates a new 120 kV Leppek Substation, and cuts in the existing Wyatt - Sandusky 120 kV circuit (line tap only)	MI	14.9		Planned	$967,275.00	Y		Y	C>B>A
A in MTEP08	East	ITC	1875	3770	5/31/2009	Leppek	Sandusky	1	120		185 MVA	Creates a new 120 kV Leppek Substation, and cuts in the existing Wyatt - Sandusky 120 kV circuit (line tap only)	MI	14.87		Planned	$967,275.00	Y		Y	C>B>A
A in MTEP08	East	METC	480	1336	6/1/2009	Brickyard Jct.	Felch Road	1	138			Reconductor	MI	13		Planned	$10,000,000.00	Y		Y	C>B>A
A in MTEP08	East	METC	1389	2392	11/3/2007	Beecher 138 kV	Samaria 138 kV	1	138			Install aTap Pole and Switches (Midwest Grain Processor)	MI			In Service	$360,000.00			Y	C>B>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			Proposed	$100,000.00			Y	C>B>A
A in MTEP08	East	METC	1448	2452	6/1/2013	Simpson 138kV			138	12.5		Install a second distribution transformer at Simpson (Simpson)	MI			Proposed	$2,200,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3434	11/23/2007	Tittabawassee 345 kV	Breaker 36F7		345				MI			In Service	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3388	3/28/2008	Cornell 138 kV	Breaker 377		138				MI			In Service	$160,000.00			Y	C>B>A

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A in MTEP08	East	METC	1655	3396	6/14/2008	Kenowa 345 kV	Breaker 31R8		345				MI			In Service	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3392	6/27/2008	Kenowa 345 kV	Breaker 29F7		345				MI			In Service	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3407	12/31/2008	Weadock 138kV	Breaker 588		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3405	12/31/2008	Weadock 138kV	Breaker 488		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3397	12/31/2008	Ludington 345 kV	Breaker 26F7		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3406	12/31/2008	Weadock 138kV	Breaker 500		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3408	12/31/2008	Weadock 138kV	Breaker 688		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3404	12/31/2008	Weadock 138kV	Breaker 388		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3403	12/31/2008	Weadock 138kV	Breaker 288		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3401	12/31/2008	Weadock 138kV	Breaker 148		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3398	12/31/2008	Ludington 345 kV	Breaker 26R8		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3395	12/31/2008	Kenowa 345 kV	Breaker 31F7		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3394	12/31/2008	Kenowa 345 kV	Breaker 29R8		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3393	12/31/2008	Kenowa 345 kV	Breaker 29H9		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3391	12/31/2008	Twining 138kV	Breaker 288		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3390	12/31/2008	Twining 138kV	Breaker 188		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3389	12/31/2008	Twining 138kV	Breaker 177		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3387	12/31/2008	Alma 138 kV	Breaker 577		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3386	12/31/2008	Cornell 138 kV	Breaker 177		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3385	12/31/2008	Alma 138 kV	Breaker 477		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3402	12/31/2008	Weadock 138kV	Breaker 188		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3399	12/31/2008	Marquette 138kV	Breaker 5070		138				MI			Planned	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1655	3400	12/31/2008	Battle Creek 345 kV	Breaker 32H9		345				MI			Planned	$300,000.00			Y	C>B>A
A in MTEP08	East	METC	1656	3414	12/31/2008	Hampton	Thetford	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3413	12/31/2008	Hampton	Thetford	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3412	12/31/2008	Argenta	Tompkins		345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3670	12/31/2008	Ludington	Tallmadge	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3415	12/31/2008	Livingston	Tittibawassee		345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A

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A in MTEP08	East	METC	1656	3416	12/31/2008	Palisades	Vergennes		345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3417	12/31/2008	Thetford	Tittibawassee	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3671	12/31/2008	Kenowa	Ludington	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3409	12/31/2008	Argenta	Battle Creek		345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3411	12/31/2008	Argenta	Palisades	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3672	12/31/2008	Kenowa	Ludington	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3410	12/31/2008	Argenta	Palisades	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3676	12/31/2008	Ludington	Tallmadge	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3675	12/31/2008	Keystone	Ludington	2	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3674	12/31/2008	Keystone	Ludington	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1656	3673	12/31/2008	Ludington	Pere Marquete	1	345			relay upgrade	MI			Planned	$611,111.00			Y	C>B>A
A in MTEP08	East	METC	1793	3600	12/31/2009	Argenta 138 kV	Circuit Breaker		138			New Breaker	MI			Planned	$1,100,000.00			Y	C>B>A
A in MTEP08	East	METC	1793	3599	12/31/2009	Argenta 345 kV	Circuit Breaker		345			New Breaker	MI			Planned	$1,100,000.00			Y	C>B>A
A in MTEP08	East	METC	1794	3603	6/1/2009	Argenta	Verona	1	138			Remove sag limits	MI			Under Construction	$160,000.00			Y	C>B>A
A in MTEP08	East	METC	1796	3605	6/1/2011	Twining	Almeda	1	138			Reconductor	MI	22		Planned	$19,500,000.00	Y		Y	C>B>A
A in MTEP08	East	METC	1797	3606	5/31/2010	Almeda	Saginaw River	1	138			Reconductor	MI	25		Planned	$21,000,000.00	Y		Y	C>B>A
A in MTEP08	East	METC	1798	3607	6/1/2010	Campbell	Black River	1	138			New Line	MI		15	Planned	$0.00	Y		Y	C>B>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	$21,000,000.00	Y		Y	C>B>A
A in MTEP08	East	METC	1798	3609	6/1/2010	Black River	Circuit Breaker		138			New Breaker	MI			Planned	$0.00	Y		Y	C>B>A
A in MTEP08	East	METC	1799	3610	6/1/2011	Roosevelt	Tallmadge	1	345			Remove sag limits	MI			Proposed	$1,000,000.00			Y	C>B>A
A in MTEP08	East	METC	1813	3647	12/31/2009	Cobb	Sternberg	1	138			Rebuild line	MI	4		Planned	$3,500,000.00			Y	C>B>A
A in MTEP08	East	METC	1813	3646	12/31/2009	Cobb	Four Mile	1	138			Rebuild line	MI	4		Planned	$3,500,000.00			Y	C>B>A
A in MTEP08	East	METC	1813	3645	12/31/2009	Cobb	Tallmadge	2	138			Rebuild line	MI	4		Planned	$0.00			Y	C>B>A
A in MTEP08	East	METC	1813	3644	12/31/2009	Cobb	Tallmadge	1	138			Rebuild line	MI	4		Planned	$3,500,000.00			Y	C>B>A
A in MTEP08	East	METC	1813	3643	12/31/2009	Cobb	Brickyard	1	138			Rebuild line	MI	4		Planned	$3,500,000.00			Y	C>B>A
A in MTEP08	East	METC	1814	3648	12/31/2010	Tippy	Chase	1	138			Reconductor	MI	30		Planned	$30,000,000.00	Y		Y	C>B>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	$17,150,000.00	Y		Y	C>B>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	$7,750,000.00	Y		Y	C>B>A

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A in MTEP08	East	METC	1820	2872	12/31/2008	METC Communication and Relaying Upgrade	Throughout system						MI			Proposed	$10,000,000.00			Y	C>B>A
A in MTEP08	East	METC	1829	3677	6/1/2010	Leoni	Beecher	1	138			Increase Capacity	MI			Planned	$450,000.00			Y	C>B>A
A in MTEP08	East	METC	1832	3694	12/31/2008	Beals	Wealthy	1	138			Replace/Modify towers to mitigate MESC sag clearance violations	MI			Planned	$650,000.00			Y	C>B>A
A in MTEP08	East	METC	1832	3690	12/31/2008	Four Mile	Algoma Jct	1	138			Replace/Modify towers to mitigate MESC sag clearance violations, apply new sag limit and monitor	MI			Planned	$650,000.00			Y	C>B>A
A in MTEP08	East	METC	1832	3693	12/31/2008	Argenta	Riverview	1	138			Replace/Modify towers to mitigate MESC sag clearance violations	MI			Planned	$650,000.00			Y	C>B>A
A in MTEP08	East	METC	1832	3692	12/31/2008	Gaines	Stamping Plant	1	138			Replace/Modify towers to mitigate MESC sag clearance violations, apply new sag limit and monitor	MI			Planned	$650,000.00			Y	C>B>A
A in MTEP08	East	METC	1832	3691	12/31/2008	Battle Creek	Verona	2	138			Replace/Modify towers to mitigate MESC sag clearance violations	MI			Planned	$650,000.00			Y	C>B>A
A in MTEP08	East	METC	1834	3695	12/1/2008	Tirrell Road	Battle Creek	1	138			Tirrel Rd. taps the Battle Creek-Cochran 138kV circuit	MI			Planned	$100,000.00			Y	C>B>A
A in MTEP08	East	METC	1834	3696	12/1/2008	Tirrell Road	Cochran Jct.	1	138			Tirrel Rd. taps the Battle Creek-Cochran 138kV circuit	MI			Planned	$100,000.00			Y	C>B>A
A in MTEP08	East	METC	1835	3698	9/1/2008	Geddes	Claremont	1	138			Geddes. taps the Lawndale-Claremont 138kV circuit	MI			Under Construction	$87,500.00			Y	C>B>A
A in MTEP08	East	METC	1835	3697	9/1/2008	Geddes	Lawndale	1	138			Geddes. taps the Lawndale-Claremont 138kV circuit	MI			Under Construction	$87,500.00			Y	C>B>A
A in MTEP08	East	METC	1836	3699	6/1/2008	Riggsville	Substation Equipment	1	138			Modify Bus protection relay scheme	MI			In Service	$260,000.00			Y	C>B>A
A in MTEP08	East	METC	1837	3700	12/1/2008	Van Buren	Campbell	1	138			Van Buren taps the Campbell-Hager Park 138kV circuit	MI			Under Construction	$100,000.00			Y	C>B>A
A in MTEP08	East	METC	1837	3701	12/1/2008	Van Buren	Hager Park	1	138			Van Buren taps the Campbell-Hager Park 138kV circuit	MI			Under Construction	$100,000.00			Y	C>B>A
A in MTEP08	East	METC	1838	3703	9/1/2009	Meridian	Hagadorn Jct.	1	138			Meridian Loops into the Delhi-Hagadorn 138kV circuit	MI			Planned	$2,200,000.00			Y	C>B>A
A in MTEP08	East	METC	1838	3702	9/1/2009	Meridian	Delhi	1	138			Meridian Loops into the Delhi-Hagadorn 138kV circuit	MI			Planned				Y	C>B>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	C>B>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	$175,000.00			Y	C>B>A
A in MTEP08	East	NIPS	919	974	5/1/2008	Lagrange	Transformer	1	138	69	168	Replace existing 138/69 KV 112 MVA with 168 MVA transformer.	IN			Planned	$1,593,300.00			Y	B>A
A in MTEP08	East	NIPS	1551	2650	11/1/2008	Flint Lake	Tower Road	2	138		316	Add 2nd 138kV circuit	IN		5.5	Planned	$5,050,000.00	Y		Y	C>B>A
A in MTEP08	East	NIPS	1977	2767	12/1/2009	Leesburg	New 138/69 kV Substation		138	69		Install 138/69 kV Transformer and 2 69 kV Circuits at Leesburg Substation	IN			Proposed	$5,407,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1978	2768	12/1/2007	Goshen Jct	Goshen Jct	6976	69			Reconductor existing 20 Al. conductor on Goshen Jct. Cir. 6976, 2.1 miles	IN	2.1		Planned	$190,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1982	2772	12/1/2008	Various	Breakers		69	34.5		34.5 kV & 69 kV Breaker Replacement (Prog)	IN			Planned	$1,075,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1986	2776	6/1/2008	Green Acres	Transformer		138	69		Add new transformer	IN			Planned	$755,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1992	2782	4/1/2008	Starke	Transformer		138	69		Upgrade 138/69 kV Transformer Capacity. Add Pumps.	IN			Planned	$126,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1996	2786	5/1/2008	Angola	Switch #644	6980	69			Rebuild with 336 KCM ACSR	IN	15		Planned	$1,780,000.00			Y	C>B>A
A in MTEP08	East	NIPS	1997	2787	12/1/2008	Goshen Junction	Model Tap	6977	69			Reconductor 4/0 Cu. to 336.4KCM ACSR	IN	1.5		Planned	$71,000.00			Y	C>B>A

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A in MTEP08	East	NIPS	2004	2794	1/1/2008	Northeast	Capacitor		69			Add 69 KV Capacitors - (2) 10.8 MVAR	IN			In Service	$870,000.00			Y	C>B>A
A in MTEP08	East	NIPS	2006	2796	12/1/2008	Kenwood	Capacitor		69			Add two steps of 10.8 MVAR (each) Capacitor banks	IN			Planned	$983,000.00			Y	C>B>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	$1,000,000.00			Y	B>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	$4,000,000.00			Y	B>A
A in MTEP08	East	WPSC	1209	3847	12/31/2010	Hersey	Transformer Addition		69			Add 90/168MVA transformer to the Hersey Sub	MI			Planned	$2,500,000.00			Y	B>A
A in MTEP08	East	WPSC	1210	1905	12/31/2008	Lewiston	Breaker		69			Add Breaker at Lewiston	MI			Planned	$800,000.00			Y	B>A
A in MTEP08	East	WPSC	1211	1906	8/1/2009	Grand Traverse	Grawn		69		198/257.4	Rebuild Overloaded Line	MI	5.21		Planned	$2,500,000.00			Y	B>A
A in MTEP08	East	WPSC	1213	1908	12/31/2008	Vestaburg	6MVAR cap. Bank		69			Add 6MVAR at Vestaburg Sub.	MI			Planned	$300,000.00			Y	B>A
A in MTEP08	East	WPSC	1214	1909	7/1/2008	Garfield X	Grawn	1	69		198/257.4	Rebuild Overloaded line	MI	7.68		Proposed	$3,350,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1218	1913	12/31/2008	Atlanta	Transformer LTC upgrade		69			Replace existing transformer LTC	MI			Planned	$600,000.00			Y	B>A
A in MTEP08	East	WPSC	1219	2169	12/31/2009	Plains X	Star Lake		69		198/257.4	Rebuild Overloaded line	MI	7.02		Planned	$3,400,000.00			Y	B>A
A in MTEP08	East	WPSC	1219	1914	12/31/2009	Lake County	Star Lake		69		198/257.4	Rebuild Overloaded Line	MI	7.72		Planned	$2,700,000.00			Y	B>A
A in MTEP08	East	WPSC	1222	1917	12/31/2011	Lake County	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Planned	$2,500,000.00			Y	B>A
A in MTEP08	East	WPSC	1222	2129	12/31/2011	Lake County 138	Lake County 69		69		168MVA	Add 168MV transformer	MI			Planned	$3,500,000.00			Y	B>A
A in MTEP08	East	WPSC	1274	3257	12/31/2011	Allendale	Osipoff	1	69		198/257.4	Rebuild Overloaded line	MI	14.53		Planned	$5,100,000.00			Y	B>A
A in MTEP08	East	WPSC	1274	1996	12/31/2011	Allendale	Blendon		69		198/257.4	Rebuild Overloaded line	MI	2.11		Planned	$750,000.00			Y	B>A
A in MTEP08	East	WPSC	1276	1999	12/31/2011	Wayland	Goodwin		69		198/257.4	Rebuild Overloaded line	MI	4.58		Planned	$1,750,000.00			Y	B>A
A in MTEP08	East	WPSC	1276	1998	12/31/2011	Burnips	Goodwin		69		198/257.4	Rebuild Overloaded line	MI	13.09		Planned	$4,700,000.00			Y	B>A
A in MTEP08	East	WPSC	1311	2166	12/31/2012	Copemish	Karlin		69		198/257.4	Rebuild Overloaded line	MI	13.59		Planned	$4,800,000.00			Y	B>A
A in MTEP08	East	WPSC	1311	2167	12/31/2012	Grawn	Karlin		69		198/257.4	Rebuild Overloaded line	MI	6.61		Planned	$2,300,000.00			Y	B>A
A in MTEP08	East	WPSC	1313	3851	12/31/2010	Lincoln X	Baldwin	1	69		198/257.4	Rebuild Overloaded Line (Off peak case)	MI	16.47		Planned	$5,800,000.00			Y	B>A
A in MTEP08	East	WPSC	1313	2168	12/31/2010	Baldwin	Plains X		69		198/257.4	Rebuild Overloaded line (Off peak case)	MI	6.94		Planned	$2,400,000.00			Y	B>A
A in MTEP08	East	WPSC	1313	3850	12/31/2010	Hersey	Lincoln X	1	69		198/257.4	Rebuild Overloaded Line (Off peak case)	MI	3.05		Planned	$1,500,000.00			Y	B>A
A in MTEP08	East	WPSC	1315	2170	12/31/2009	Potter	Grand Traverse		69		198/257.4	Rebuild Overloaded line	MI	2.24		Planned	$1,100,000.00			Y	B>A
A in MTEP08	East	WPSC	1315	3258	12/31/2009	Potter	East Bay	1	69		198/257.4	Rebuild Overloaded line (light load)	MI	4.32		Planned	$2,200,000.00			Y	B>A
A in MTEP08	East	WPSC	1577	3129	12/31/2012	Copemish	Bretheren	1	69		198/257.4	Rebuild Overloaded line	MI	10.81		Proposed	$3,800,000.00			Y	B>A
A in MTEP08	East	WPSC	1577	3135	12/31/2012	Bretheren	Bass Lake	1	69		198/257.4	Rebuild Overloaded line	MI	18.11		Planned	$6,400,000.00			Y	B>A

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A in MTEP08	East	WPSC	1581	3853	12/31/2011	Advance Dist.	East Jordan X	1	69		198/257.4	Rebuild Overloaded Line	MI	4.66		Planned	$1,650,000.00			Y	B>A
A in MTEP08	East	WPSC	1581	3134	12/31/2011	Alba	Graves X	1	69		198/257.4	Rebuild Overloaded line	MI	4.72		Planned	$2,300,000.00			Y	B>A
A in MTEP08	East	WPSC	1581	3233	12/31/2011	East Jordan X	Graves X	1	69		198/257.4	Rebuild Overloaded line	MI	7.14		Planned	$3,500,000.00			Y	B>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	$500,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3140	12/31/2009	Gaylord	Kerridge	1	69		198/257.4	Rebuild Overloaded line	MI	0		Planned	$50,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3141	12/31/2009	Kerridge	Alpine	1	69		198/257.4	Rebuild Overloaded line	MI	3.41		Planned	$1,150,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3142	12/31/2009	Alpine	Elmira	1	69		198/257.4	Rebuild Overloaded line	MI	3.61		Planned	$1,300,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3143	12/31/2009	Elmira	Advance	1	69		198/257.4	Rebuild Overloaded line	MI	16.26		Planned	$5,700,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3147	12/31/2010	Hayes X	Petoskey	1	69		198/257.4	Rebuild Overloaded line	MI	10.48		Planned	$3,700,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3144	12/31/2010	Advance	Wilson	1	69		198/257.4	Rebuild Overloaded line	MI	4.7		Planned	$2,300,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3146	12/31/2010	Boyne City	Hayes X	1	69		198/257.4	Rebuild Overloaded line	MI	0		Planned	$50,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3148	12/31/2010	Petoskey	Petoskey Distribution	1	69		198/257.4	Rebuild Overloaded line	MI	0		Planned	$50,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3149	12/31/2010	Petoskey Distribution	Oden	1	69		198/257.4	Rebuild Overloaded line	MI	5.24		Planned	$1,800,000.00			Y	B>A
A in MTEP08	East	WPSC	1586	3145	12/31/2010	Wilson	Boyne City	1	69		198/257.4	Rebuild Overloaded line	MI	3.04		Planned	$1,450,000.00			Y	B>A
A in MTEP08	East	WPSC	1587	3150	12/31/2010	Gaylord 138	Oden 138	1	138		396.1/514.9	Build lines from Gaylord to Advance to Oden, scheduled to be rebuilt, to double circuit.	MI		46.74	Proposed	$5,000,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1964	3855	12/31/2009	Tap METC Island Rd. line	Chester 138kV	1	138		396.1/514.9	Build new 138kV line to connect to a new 138/69kV transformer	MI	5		Planned	$2,300,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1964	3854	12/31/2009	Chester 138	Chester 69	1	138		168MVA	Add 168MV transformer and substation	MI			Planned	$5,700,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1965	3856	12/31/2008	Gray 138	Gray 69	1	138		168MVA	Add 168MV transformer and substation	MI			Planned	$6,600,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1967	3859	12/31/2010	Middleville X	Superior	1	69		198/257.4	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	19.73		Planned	$6,905,500.00			Y	C>B>A
A in MTEP08	East	WPSC	1967	3858	12/31/2010	Wayland	Middleville X	1	69		198/257.4	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	10.69		Planned	$3,741,500.00			Y	C>B>A
A in MTEP08	East	WPSC	1967	3861	12/31/2010	Odesa	Sebewa	1	69		198/257.4	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	3.37		Planned	$1,179,500.00			Y	C>B>A
A in MTEP08	East	WPSC	1967	3860	12/31/2010	Superior	Odessa	1	69		198/257.4	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	0.06		Planned	$21,000.00			Y	C>B>A
A in MTEP08	East	WPSC	1967	3862	12/31/2010	Sebewa	Portland	1	69		198/257.4	Rebuild Overloaded Line (Poles have reached the end of their useful life)	MI	6.85		Planned	$2,397,500.00			Y	C>B>A
A in MTEP08	East	WPSC	1968	3863	12/31/2008	Weswood	New Sub		69			Construct a new 69kV substation to sectionalize the exising Alba to Kalkaska line.	MI			Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	East	WPSC	2110	2827	10/28/2007	Cadillac	Leroy	1	138			Transmission line taps for 138 kV Loop-in Line Work (Dead end structure and line drop in from dead end structure.)	MI			Planned	$44,300.00	Y		Y	C>B>A
A in MTEP08	East	WPSC	2110	2826	12/28/2007	G566 Substation	new substation	1	138	34.5		New 138 kV Three Breaker Ring Bus Sub on Cadillac - Leroy 138 kV line.	MI			Planned	$1,938,900.00	Y		Y	C>B>A

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A in MTEP08	East	WPSC	2121	2906	12/31/2008	Gaylord Sub		1	69			The existing lightning protection at the Gaylord Substation was found to be inadequite, this project will upgrade the protection.	MI			Planned	$350,000.00			Y	C>B>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			Proposed	$4,986,995.20	Y		Y	B>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	Proposed	$174,094,863.00	Y	Y	Y	B>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			Proposed	$15,020,589.89	Y	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			Proposed	$4,986,995.20	Y		Y	B>A
A in MTEP08	West	ATC LLC	356	3384	6/1/2013	Cardinal (formerly West Middleton)	substation		345			new 345 substation	WI			Proposed	$30,966,868.00	Y	Y	Y	B>A
A in MTEP08	West	ATC LLC	574	858	6/1/2012	Council Creek	Petenwell	1	138		293 MVA SE	uprate	WI	32		Proposed	$200,000.00			Y	B>A
A in MTEP08	West	ATC LLC	574	1269	6/1/2012	Monroe County (XEL)	Council Creek (ATC)	1	161		577 MVA SE		WI	20		Proposed	$19,200,000.00			Y	B>A
A in MTEP08	West	ATC LLC	574	1370	6/1/2012	Council Creek 161-138 kV	transformer	1	161	138	280 MVA SE		WI			Proposed	$2,500,000.00			Y	B>A
A in MTEP08	West	ATC LLC	879	877	8/1/2006	Forward Energy Center	South Fond du Lac		138		293	loop line into new generation site and relay upgrades	WI			Planned	$594,171.63			Y	C>B>A
A in MTEP08	West	ATC LLC	879	876	8/1/2006	Butternut	Forward Energy Center		138		293	new 138-kV interconnection substation	WI			Planned	$2,720,829.40			Y	C>B>A
A in MTEP08	West	ATC LLC	881	880	6/1/2006	Forest Junction	Cypress (new generation site)		345		488	new 345-kV Cypress Interconnection substation	WI			Planned	$6,139,366.22			Y	C>B>A
A in MTEP08	West	ATC LLC	881	881	6/1/2006	Cypress (new generation site)	Arcadian		345		488	loop Forest Junction-Arcadian into new Cypress generation site, relay upgrades	WI			Planned	$997,420.30			Y	C>B>A
A in MTEP08	West	ATC LLC	1268	1986	6/1/2009	Artesian	Capacitor bank				49	install 2x 24.5 Mvar capacitor banks	WI			Proposed	$630,000.00			Y	B>A
A in MTEP08	West	ATC LLC	1268	1987	6/1/2009	Kilbourn	Capacitor bank				49	install 2x 24.5 Mvar capacitor banks	WI			Proposed	$630,000.00			Y	B>A
A in MTEP08	West	ATC LLC	1279	2105	6/1/2009	North Beaver Dam 138			138		49 Mvar		WI			Proposed	$2,500,000.00			Y	B>A
A in MTEP08	West	ATC LLC	1280	2106	6/1/2008	South Lake Geneva 69			69		16.33 Mvar	new capacitor	WI			Planned	$1,251,336.07			Y	B>A
A in MTEP08	West	ATC LLC	1553	3101	6/1/2009	Hiawatha	Capacitor bank		138		16.33 MVAR		MI			Planned	$615,283.00			Y	B>A
A in MTEP08	West	ATC LLC	1555	3103	6/1/2009	Perkins	Capacitor banks		138		2x16.33 MVAR		MI			Planned	$1,395,185.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1665	3435	7/1/2008	Atlantic	Osceola	1	69		48 MVA SE	Rebuild Atlantic-Osceola 69 kV line (Laurium #1)	MI	13.7		Planned	$7,953,102.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1666	3437	6/1/2008	Winona	Atlantic	1	69		46 MVA SE	Uprate Winona-Atlantic 69 kV line clearance to 185 deg F	MI			Planned				Y	C>B>A
A in MTEP08	West	ATC LLC	1666	3436	6/1/2008	Mass	Winona	1	69		46 MVA SE	Uprate Mass-Winona 69 kV line clearance to 185 deg F	MI			Planned	$903,202.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1667	3438	1/1/2008	Pine River 69 kV ring bus			69			Construct 69 kV ring bus at Pine River	MI			Proposed	$10,500,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1667	3439	9/1/2009	Pine River	Capacitor Bank		69		2x4.08 MVAR	Increase bank size from 5.4 to 8.16 MVAR	MI			Proposed				Y	C>B>A
A in MTEP08	West	ATC LLC	1668	3440	6/1/2008	Munising	Capacitor Bank		69		2x4.08 MVAR		MI			Proposed	$1,300,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1669	3441	6/1/2008	Roberts	Capacitor Bank		69		1x4.08 MVAR	Add a 4.08 Mvar Bank	MI			Proposed	$900,000.00			Y	C>B>A

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A in MTEP08	West	ATC LLC	1670	3442	6/1/2008	Empire	Forsyth	1	138		302 MVA SE	Upreate Empire-Forsyth 138 kV line to 302 MVA	MI			Planned	$2,500,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1671	3443	6/1/2008	Southwest Delevan	Bristol	1	69			New 138 kV line from Southwest Delevan-Bristol operated at 69 kV	WI		3.5	Under Construction	$6,765,459.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1672	3444	6/1/2008	Brick Church	Cobblestone	1	69		115 MVA	Uprate Brick Church-Cobblestone 69 kV line to 115 MVA	WI			Proposed	$1,400,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1673	3445	1/1/2008	Eden	Spring Green	1	138		234 MVA SE	Uprate X-17 Eden-Spring Green 138 kV line to 167 degrees F	WI			In Service	$1,200,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1674	3446	6/1/2008	Portage		1	138	69	143 MVA SE	Uprate Portage 138/69 kV transformer to 143 MVA	WI			Planned	$1,400,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1675	3447	6/1/2008	Sister Bay			24.9		2x1.2 MVAR	Install 2 1.2 MVAR distribution capacitor banks at Sister Bay 69 kV	WI			Proposed	$62,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1676	3448	6/1/2009	L'Anse			69		1x4.08 MVAR	Install one 4.08 MVAR 69 kV capacitor bank at L'Anse substation	MI			Proposed	$600,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1677	3449	6/1/2009	Chandler	Cornell	1	69		167 deg F	Uprate Chandler-Cornell 69 kV line clearance from 120 to 167 deg F	MI			Proposed	$900,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1678	3450	12/14/2007	9 Mile			69		2x8.16 MVAR	Install two 8.16 MVAR 69kV capacitor banks at 9 Mile substation	MI			In Service	$1,440,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1679	3451	6/1/2009	Richland Center Olson			69		5.4 to 8.1 MVA	Expand the existing 69 kV capacitor bank from 5.4 to 8.1 MVAR at Richland Center Olson substation	WI			Proposed	$1,770,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1679	3452	6/1/2009	Brewer			12.4		1x7.8 MVAR	Install one 7.8 MVAR capacitor bank at Brewer substation	WI			Proposed				Y	C>B>A
A in MTEP08	West	ATC LLC	1680	3453	6/1/2010	Walworth	North Lake Geneva	1	69		69 MVA	Uprate Walworth-North Lake Geneva 69 kV line to 69 MVA	WI	2.25		Proposed	$370,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1681	3454	6/1/2009	North Lake Geneva	Lake Geneva	1	69		115 MVA	Uprate North Lake Geneva-Lake Geneva 69 kV line to 115 MVA	WI	2.25		Proposed	$1,300,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1682	3456	6/1/2009	Crivitz			69			Loop 69 kV line from Sandstone-Pioneer into Crivitz sub	WI			Planned				Y	C>B>A
A in MTEP08	West	ATC LLC	1682	3457	6/1/2009	Crivitz	High Falls	2	69		52 MVA SE	Rebuild Crivitz-High Falls 69 kV line	WI	13.8	0.7	Planned	$20,733,935.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1682	3455	6/1/2009	Crivitz	High Falls	1	69		52 MVA SE	Rebuild Crivitz-High Falls 69 kV line	WI	13.8		Planned				Y	C>B>A
A in MTEP08	West	ATC LLC	1683	3458	6/1/2009	Sunset Point	Pearl Ave	1	69			Rebuild 2.37 miles of 69 kV from Sunset Point-Pearl Ave with 477 ACSR	WI	2.37		Proposed	$1,759,714.33			Y	C>B>A
A in MTEP08	West	ATC LLC	1684	3460	6/1/2009	Pleasant Valley			138			Construct a 138 kV bus at Pleasant Valley substation to permit second distribution transformer interconnection	WI			Proposed	$2,160,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1734	3527	6/1/2008	Berlin			69		1x10.8 MVAR	Upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at Berlin 69 kV substation	WI			Under Construction	$200,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1734	3526	6/1/2008	Berlin			69		1x8.2 MVAR	Upgrade the 4.1 MVAR capacitor bank to 8.2 MVAR at Berlin 69 kV substation	WI			Under Construction				Y	C>B>A
A in MTEP08	West	ATC LLC	1735	3528	12/1/2007	St. Martins			138		2000A	Upgrade St. Martins 138 kV bus to 2000A	WI			In Service	$200,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1736	3529	12/1/2007	St. Lawrence			138		1200A	Upgrade St. Lawrence 138 kV bus	WI			In Service	$6,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1930	3809	12/20/2007	Straits	transformer	2	138	69	100 MVA SE	Install a 2nd Straits 138-69 kV Transformer and a 138-kV bus tie breaker	WI			In Service	$3,000,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1931	3810	4/1/2008	North Appleton	Fox River	1	345		1541 MVA SE	Increase ground clearance for North Appleton-Fox River 345-kV to 200/230 deg F	WI	11.1		Planned	$1,057,339.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1933	3812	6/1/2008	Lakehead Delevan Tap	Lakehead Delevan	1	138		169 MVA SE	Uprate Lakehead Delevan Tap to Lakehead Delevan radial-138 kV due to 2nd distribution transformer addition	WI	1		Proposed	$166,050.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1942	3821	6/1/2009	Atlantic	transformer	1	138	69	64 MVA SE	Replace limiting relay equipment on the Atlantic Transformer	MI			Proposed	$418,035.50			Y	C>B>A

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A in MTEP08	West	ATC LLC	1943	3822	6/1/2009	M38	transformer	1	138	69	64 MVA SE	Replace limiting relay equipment on the M38 Transformer	MI			Proposed	$418,035.50			Y	C>B>A
A in MTEP08	West	ATC LLC	1945	3824	9/7/2009	Sheepskin	Capacitor Bank		69		+5.4 Mvar	Upgrade Sheekskin Capacitor 69-kV Bank from 10.8 Mvar to 16.2 Mvar	WI			Proposed	$272,268.00			Y	C>B>A
A in MTEP08	West	ATC LLC	1951	3832	1/10/2008	Hiawatha	transformer	2	138	69	100 MVA SE	Install a 2nd Hiawatha 138-69 kV Transformer and a 69-kV breaker on the Hiawatha-Roberts line	MI			In Service	$3,000,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	2057	3944	3/31/2010	Warrens			69		56 MVA SE	Construct a new Warrens distribution substation				Proposed	$3,185,000.00			Y	C>B>A
A in MTEP08	West	ATC LLC	2057	3945	3/31/2010	Warrens	WarrensTap	1	69		56 MVA SE	Construct a 5 mi 69 kV line to a new Warrens substation from a tap of the Ocean Spray Tap-Tunnel City line			5	Proposed				Y	C>B>A
A in MTEP08	West	ATC LLC	2102	2809	1/1/2008	N. Madison	Huiskamp	1	138			Projected in-service 2008,estimated $6,500,000	WI			Planned				Y	C>B>A
A in MTEP08	West	ATC LLC	2104	2812	6/8/2008	Rubicon	Horicon	1	138			Proposed completion 6/2008				Planned				Y	C>B>A
A in MTEP08	West	ATC LLC	2104	2813	6/8/2008	Horicon	transformer	1	138	69		Proposed completion 6/2008				Planned				Y	C>B>A
A in MTEP08	West	GRE	2086	642	6/1/2008	Wilson Lake 115-69 kV	transformer	1	115	69	84					Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	West	GRE	2087	644	11/1/2007	Liberty (Becker) 115-69 kV	transformer	1	115	69	140		MN			Planned	$3,500,000.00			Y	C>B>A
A in MTEP08	West	GRE	2088	754	6/1/2009	Enterprise Park 115-69 kV	transformer	1	115	69	84		MN			Planned	$1,800,000.00			Y	C>B>A
A in MTEP08	West	GRE	2097	2802		Elk River	Andover	1	69		45.5	Elk River - Anoka - Andover	MN			Planned				NT	C>B>A

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A in MTEP08	West	GRE	2097	2800	1/1/2009	Bunker Lake Bulk	Bunker Lake Distribution	1	69		92 MVA	Upgrade of Bunker Lake Substation to Bunker Lake Distribution 69 kV to at least 92 MVA.	MN	0.19		Planned	$132,896.00	Y		NT	C>B>A
A in MTEP08	West	GRE	2097	2801	1/1/2009	Elk River	RDF	1	69		78 MVA	Upgrade of Elk River - RDF 69 kV to at least 78 MVA	MN	1.1		Planned	$438,349.00	Y		NT	C>B>A
A in MTEP08	West	GRE	2097	2803	1/1/2009	Elk River #14 substation	substation redesign & reconfiguration	1	230			The redesigned and reconfigured 230 kV portion of the substation	MN			Planned	$3,911,678.00	Y		Y	C>B>A
A in MTEP08	West	GRE	2101	2808	6/1/2008	Dotson	Dotson	1	69			Planned upgrade to CT and relaying to be completed in 2008	MN			Planned				NT	C>B>A
A in MTEP08	West	GRE,XEL,O	286	1105	7/1/2012	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	$267,250,000.00	Y	Y	Y	B>A
A in MTEP08	West	GRE,XEL,O	286	2640	7/1/2012	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	$75,216,500.00	Y	Y	Y	B>A
A in MTEP08	West	GRE,XEL,O	286	2976	7/1/2012	Quarry (St. Cloud)	345/115 transformer	1	345	115	448	new transformer and terminal works	MN			Planned	$7,367,000.00	Y		Y	B>A
A in MTEP08	West	GRE,XEL,O	286	2641	7/1/2012	Alexandria SS	Transformer	1	345	115	448	new transformer and terminal works	MN			Planned	$6,500,000.00	Y		Y	B>A
A in MTEP08	West	GRE,XEL,O	286	1104	7/1/2012	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	$133,666,500.00	Y	Y	Y	B>A
A in MTEP08	West	GRE/OTP	1033	587	6/1/2011	Silver Lake 230/41.6 kV	transformer	1	230	41.6	50		MN			Planned	$1,840,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1337	2184	12/31/2009	Rose Hollow Substation	transformer	1	161	69	84		IA			Planned	$4,160,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1340	2205	12/31/2011	Lore	substation	1	345	161	335	new 345 sub & transformer to existing 161 sub	IA			Planned	$10,200,000.00			Y	B>A
A in MTEP08	West	ITCM	1340	2543	12/31/2011	Lore	Hazleton	1	345		2000	new line	IA		60.05	Planned	$99,082,500.00			Y	B>A
A in MTEP08	West	ITCM	1340	2542	12/31/2011	Salem	Lore	1	345		2000	new line	IA		16	Planned	$27,720,000.00			Y	B>A
A in MTEP08	West	ITCM	1340	2974	6/1/2011	Salem	345 termination		345		2000A	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	$2,280,000.00			Y	B>A
A in MTEP08	West	ITCM	1340	2973	6/1/2011	Hazelton	345 termination		345		2000A	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	$1,080,000.00			Y	B>A
A in MTEP08	West	ITCM	1341	2206	12/31/2008	Hazleton	transformer	1	161	69	74.7	replace transformer	IA			Planned	$900,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1341	2207	6/1/2009	Hazleton	transformer	2	161	69	74.7	replace transformer	IA			Planned	$900,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1345	2546	6/1/2009	Quad Cities	Rock Creek	1	345		1246	upgrade limiting equipment	IA			Proposed	$125,000.00			Y	B>A

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A in MTEP08	West	ITCM	1345	2547	6/1/2009	Rock Creek	Salem	1	345		1246	upgrade limiting equipment	IA			Proposed	$125,000.00			Y	B>A
A in MTEP08	West	ITCM	1346	2214	6/1/2009	Rock Creek	transformer	1	345	161	448	upgrade limiting equipment	IA			Planned	$100,000.00			Y	B>A
A in MTEP08	West	ITCM	1522	2599	6/1/2009	6th Street	Beverly	1	161		326	new line	IA		6.2	Planned	$7,200,000.00	Y		Y	B>A
A in MTEP08	West	ITCM	1618	2720	12/31/2009	Heron Lake	Lakefield Jct	1	161		440	Rebuild	MN	17		Planned	$9,250,000.00	Y		Y	B>A
A in MTEP08	West	ITCM	1619	2725	12/31/2009	East Calamus T	Maquoketa	1	161			remove model branch	IA			Planned				Y	B>A
A in MTEP08	West	ITCM	1619	2724	12/31/2009	East Calamus	Maquoketa	1	161			remove model branch	IA			Planned				Y	B>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	B>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	$502,208.00			Y	B>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	$1,905,500.00			Y	B>A
A in MTEP08	West	ITCM	1636	3290	12/31/2009	Waterbury breaker station			69				MN			Planned	$1,000,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1640	2737	12/1/2009	Iowa Falls	Franklin	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	4.5	0	Planned	$1,800,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2732	12/31/2013	Marshalltown	Wellsburg	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	27	0	Planned	$5,600,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2745	12/31/2013	Eldora	transformer	1	161	34	20 MVA	Retire Eldora Sub	IA			Planned	$3,000,000.00			Y	C>B>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	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2733	12/31/2013	Wellsburg	Eldora	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	11.5	0	Planned	$4,600,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2735	12/31/2013	Iowa Falls Industrial Tap	Iowa Falls	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	11.59	0	Planned	$4,600,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2736	12/31/2013	Iowa Falls Industrial Tap	Iowa Falls Industrial	1	161		262/262 MVA	Operate at 161kV	IA	1.54	0	Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2738	12/31/2013	Marshalltown	Wellsburg	1	115			REMOVE model branch	IA	27	0	Planned	$0.00			Y	C>B>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	$0.00			Y	C>B>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	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2734	12/31/2013	Eldora	Iowa Falls Industrial Tap	1	161		326/326 MVA	Rebuild 115kV to 161kV line	IA	1.21	0	Planned	$480,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2744	12/31/2013	Franklin	transformer	1	161	115	50 MVA	REMOVE transformer branch	IA			Planned	$50,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2754	12/31/2013	Wellsburg	transformer	1	115	69	50 MVA	REMOVE transformer branch	IA			Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2746	12/31/2013	Iowa Falls Industrial	transformer	1	161	69	35 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$1,500,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2747	12/31/2013	Iowa Falls	transformer	1	161	69	20 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2748	12/31/2013	Iowa Falls	transformer	2	161	69	20 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2749	12/31/2013	Wellsburg	transformer	1	161	69	50 MVA	Upgrade 115kV xfmr to 161kV	IA			Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2750	12/31/2013	Eldora	transformer	1	115	34	20 MVA	REMOVE transformer branch	IA			Planned	$0.00			Y	C>B>A

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A in MTEP08	West	ITCM	1640	2751	12/31/2013	Iowa Falls Industrial	transformer	1	115	69	35 MVA	REMOVE transformer branch	IA			Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2752	12/31/2013	Iowa Falls	transformer	1	115	69	20 MVA	REMOVE transformer branch	IA			Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2753	12/31/2013	Iowa Falls	transformer	2	115	69	20 MVA	REMOVE transformer branch	IA			Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2743	12/31/2013	Iowa Falls	Franklin	1	115			REMOVE model branch	IA	4.5	0	Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1640	2739	12/31/2013	Wellsburg	Eldora	1	115			REMOVE model branch	IA	11.5	0	Planned	$0.00			Y	C>B>A
A in MTEP08	West	ITCM	1641	2755	12/31/2009	Ottumwa Generating Station	Cap Bank	1	161		50 MVAR	new 161kV Cap Bank	IA			Planned	$800,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1643	2757	12/31/2009	Anita	Cap Bank	1	161		24 MVAR	new 161kV Cap Bank	IA			Proposed	$650,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1644	2758	12/31/2009	Grand Junction	Cap Bank	1	161		24 MVAR	new 161kV Cap Bank	IA			Proposed	$650,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1645	2759	12/31/2009	Leon	Cap Bank	1	69		7.2 MVAR	new 69kV Cap Bank	IA			Proposed	$150,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1739	3535	12/31/2009	Dysart	Washburn	1	161		446/446 MVA	Rebuild existing line	IA	19.3		Planned	$7,774,000.00			Y	C>B>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	$4,120,000.00			Y	C>B>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	$7,720,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1744	3546	12/31/2010	Maquoketa	Grand Mound	1	161		326/326 MVA	Reconductor	IA	14.5		Planned	$4,400,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1747	3555	6/1/2010	Elk	transformer	2	161	69	84 MVA	Upgrade transformer	MN			Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1747	3554	6/1/2010	Elk	transformer	1	161	69	84 MVA	Upgrade transformer	MN			Planned	$2,000,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1748	3556	12/31/2010	Emery	Lime Creek	1	161		326/326 MVA	Reconductor	IA	13		Proposed	$4,000,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1749	2818	10/31/2008	Hazelton	substation	1	345			345 kV relay modifications. The relays on the Hazelton to Adams 345 kV line were upgraded in 2005, and therefore no relay change-outs will be required. The relay settings will need to be re-done as a result of the new switch station.	IA			Planned	$28,800.00	Y	Y	Y	C>B>A
A in MTEP08	West	ITCM	1749	2817	10/31/2008	Adams	Hazelton	1	345			Line loop into new switch station. This upgrade will include the install of two new 90 degree steel H-frame structures and two wood H-frame tangent structures to facilitate entry of the line into the substation at right angles.	IA			Planned	$615,750.00	Y	Y	Y	C>B>A
A in MTEP08	West	ITCM	1749	2816	10/31/2008	G172 Mitchell County Switch Station	new switching station	1	345	34.5		New three-breaker 345 kV switch station in a configuration allowing future expansion to four position ring bus. Two line positions will allow for looping the Adams-Hazelton line into the switch station for interconnection of G172	IA			Planned	$5,889,474.00	Y		Y	C>B>A
A in MTEP08	West	ITCM	1749	4029	10/31/2008	microwave equipment						microwave equiment at Mitchell County switch station	IA			Planned	$190,000.00	Y		Y	C>B>A
A in MTEP08	West	ITCM	1750	2853	12/31/2008	Goose Pond	3 terminal 161kV switching station		161			3 terminal 161kV switching station along the Palmyra-Twin Rivers 161kV line.				Proposed	$1,400,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1751	3557	12/31/2008	Jefferson County	transformer	1	161	69	100 MVA	Upgrade transformer	IA			Planned	$1,600,000.00			Y	C>B>A

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A in MTEP08	West	ITCM	1752	3558	12/31/2008	Jefferson County	Cap Bank	1	69		31.2 MVAR	Install 2 new 15.6 MVAR Caps	IA			Planned	$1,400,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1753	3559	12/31/2008	Winnebago Jct	transformer	1	161	69	75MVA	Upgrade transformer	IA			Planned	$1,400,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1754	2854	12/31/2010	Emery	Lime Creek (Road Move)		161			Rebuild a portion of the Emery-Lime Creek 161kV line (about 1 mile) Road Move	IA	1		Proposed	$365,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1755	3562	12/31/2008	Washington	Kalona Tap	1	69		77/77 MVA	Rebuild existing line	IA			Planned	$1,570,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1755	3564	12/31/2008	North Crane Tap	Hills	1	69		77/77 MVA	Rebuild existing line	IA			Planned	$1,340,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1755	3563	12/31/2008	Kalona Tap	North Crane Tap	1	69		77/77 MVA	Rebuild existing line	IA			Planned	$1,440,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1756	2855	12/31/2008	Dyersville	Peoasta		69			Rebuild the 69kV line from Dyersville-Farley-Epworth-Peosta.				Proposed	$1,550,000.00			NT	C>B>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	$2,100,000.00			NT	C>B>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		Planned	$1,570,000.00			NT	C>B>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		Planned	$336,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1759	2856	12/31/2008	Pelican sub	69kV line taps		69			69kV line work require t accommodate the new CBPC 69kV Pelican switching station near Spirit Lake.				Proposed	$80,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1760	2857	12/31/2008	New Wilder Jct	Windom		69			Build a new Wilder jct-Windom 69kV line. The new Heron Lake-Wilder-Windom 69kV line & Windom-Wilder-Lakefield 69kV will be tied N.O. at Wilder Jct.				Proposed	$1,400,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1761	3568	12/31/2008	Readlyn	Tripoli	1	69		50/50 MVA	Rebuild existing line	IA	2.4		Planned	$816,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1762	2858	12/31/2008	Dyersville Ethanol 69kV tap	Liberty-Pfeiler REC 69kV		69			Build a new 1.75 mile 69kV tap from the Liberty-Pfeiler REC 69kV to a new ethanol plant			1.75	Proposed	$327,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1769	2864	12/31/2008	Belle Plaine	Hwy 30					Rebuild 1.4 miles		1.4		Proposed	$110,000.00			Y	C>B>A
A in MTEP08	West	ITCM	1770	2865	12/31/2008	Postville	W Union		69			Rebuild 0.65 miles of the Postville-Wunion 69kV line		0.65		Proposed	$167,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1772	3560	12/31/2009	North Centerville	Cap Bank	1	69		7 MVAR	Install new 7 MVAR Cap	IA			Planned	$1,400,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1773	3561	12/31/2008	Excel	Cap Bank	1	69		13.2 MVAR	Install new 13.2 MVAR Cap	IA			Planned	$1,400,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1776	2869	12/31/2009	Thompson	Dexter		69			Build a new 6 mile 69kV line fromThompson-Menlo Rec & Rebuild the 7.5 miles from Menlo REC-Dexter 69kV line.		7.5	6	Planned	$2,700,000.00			NT	C>B>A
A in MTEP08	West	ITCM	1972	2890	12/31/2008	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		Proposed	$203,000.00			NT	C>B>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	$1,702,346.00	Y		Y	C>B>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	$56,848.00	Y		Y	C>B>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	$103,650.00	Y		Y	C>B>A

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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	$56,848.00	Y		Y	C>B>A
A in MTEP08	West	ITCM	2108	4030	12/31/2009	Microwave communication network						Upgrade Transmission Owner's microwave communication network	IA			Planned	$200,000.00	Y		Y	C>B>A
A in MTEP08	West	MDU	1479	2240	11/1/2007	Cabin Creek	Switchyard & 115/60 kV xfmr		115	60	90 MVA	Tap on Baker - Glendive 115 kV line	MT			In Service	$3,200,000.00			Y	B>A
A in MTEP08	West	MP	1481	2259	12/1/2007	Platte River 115/34.5	Transformer		115	34.5	39	new sub	MN			In Service	$1,900,000.00			Y	C>B>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			Proposed	$3,500,000.00			Y	C>B>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	$165,000.00			Y	C>B>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	$125,000.00			Y	C>B>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	$265,000.00			Y	C>B>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	$350,000.00			Y	C>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	$538,000.00			Y	C>B>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	$175,000.00			Y	C>B>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	$500,000.00			Y	C>B>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	$500,000.00			Y	C>B>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	$100,000.00			Y	C>B>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	$250,000.00			Y	C>B>A
A in MTEP08	West	NWE	2018	3999	6/12/2008	Balsam Lake	Centuria		69	12.47		Build new 69KV line to Centuria and build Distribution Sub	WI	0	4	Proposed	$750,000.00			Y	C>B>A
A in MTEP08	West	OTP	1792	3590	10/1/2008	Mapleton 115 kV	Casselton Ethanol 115 kV	1	115		329	A new 115 kV line from Mapleton to Casselton Ethanol.	ND		14.2	Planned	$2,885,000.00			Y	C>B>A
A in MTEP08	West	OTP	1792	3591	10/1/2009	Buffalo 115 kV	Casselton Ethanol 115 kV	1	115		329	A new 115 kv line from Casselton Ethanol to Buffalo	ND		17	Planned	$3,780,000.00			Y	C>B>A
A in MTEP08	West	OTP	2090	3582	11/1/2008	Cass Lake 115 kV	switched capacitor bank		115		30 Mvar	Addition of 2 x 15 Mvar capacitor at the Cass Lake 115 kV bus	MN			Planned	$630,000.00			Y	C>B>A
A in MTEP08	West	OTP	2092	3585	7/1/2009	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	$900,000.00			Y	C>B>A
A in MTEP08	West	OTP/MPC	971	235	12/31/2010	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	$3,715,350.84			Y	B>A
A in MTEP08	West	OTP/MPC	2091	3583	7/1/2009	Cass Lake 115 kV	Cass Lake 69, 41.6 kV	1	115	41.6	55 MVA	Replace existing transformer at Cass Lake with a 55 MVA 115/69/41.6 kV transformer	MN			Planned	$2,000,000.00			NT	C>B>A

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A in MTEP08	West	SMP	1367	3261	10/30/2008	Lake City Sub	capacitor		69			Increasing to 18MVAR	MN			In Service				NT	C>B>A
A in MTEP08	West	SMP	1367	3260	10/30/2008	Lake City Sub	circuit breakers		69			Addition 4 circuit breakers	MN			In Service				NT	C>B>A
A in MTEP08	West	SMP	1367	3259	10/30/2008	Lake Ciity	Zumbro Falls	1	69		84	new line	MN		16	In Service				NT	C>B>A
A in MTEP08	West	SMP	1633	3296	6/30/2008	Rutland Sub	Capacitor		161		1x31.5 MVAR	Addition 31.5MVAR	MN			In Service				Y	C>B>A
A in MTEP08	West	SMP	1633	3295	6/30/2008	Rutland Sub	transformer	2	161	69	84	Addition of 84 MVA	MN			In Service				Y	C>B>A
A in MTEP08	West	SMP	1633	3297	6/30/2008	Rutland Sub	10th St (Fairmont)	1	69			Rebuild 4.0 miles existing line	MN	4		In Service	$6,245,340.00			NT	C>B>A
A in MTEP08	West	XEL	552	1685	6/1/2009	Ironwood 92/34.5 kV	transformer	2	92	34.5		new transformer	WI			Proposed	$300,000.00			NT	C>B>A
A in MTEP08	West	XEL	675	1364	6/1/2011	Westgate	Scott County	1	115		194 MVA	upgrade line	MN	20.1		Proposed	$14,000,000.00			Y	B>A
A in MTEP08	West	XEL	751	3019	12/1/2007	Nobles Co	Reactor #1		34.5		-50 Mvar	New reactor	MN			In Service	$200,000.00			NT	B>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	Proposed	$18,800,000.00	Y		Y	B>A
A in MTEP08	West	XEL	1367	3276	10/30/2008	Lake City Sub	circuit breakers		69			Addition (4) breakers	MN			Under Construction				NT	C>B>A
A in MTEP08	West	XEL	1368	2288	5/1/2009	Three Lakes	Roberts	1	69		-	New substation on existing Kinnickinnic - Roberts 69 kV line	WI			Proposed				NT	C>B>A
A in MTEP08	West	XEL	1368	2287	5/1/2009	Kinnickinnic	Three Lakes	1	69		-	New substation on existing Kinnickinnic - Roberts 69 kV line	WI			Proposed				NT	C>B>A
A in MTEP08	West	XEL	1368	2289	5/1/2009	Pine Lake	Three Lakes	1	115		-	New substation on existing Pine Lake - Willow River 115 kV line	WI			Proposed				Y	C>B>A
A in MTEP08	West	XEL	1368	2290	5/1/2009	Three Lakes	Willow River	1	115		-	New substation on existing Pine Lake - Willow River 115 kV line	WI			Proposed				Y	C>B>A
A in MTEP08	West	XEL	1368	2291	5/1/2009	Three Lakes	Transformer	1	115	69	112 MVA	New transformer at Three Lake sub	WI			Proposed	$7,000,000.00			Y	C>B>A
A in MTEP08	West	XEL	1369	2292	5/1/2009	Osceola	Sand Lake	1	69		84	Reconductor	WI			Proposed	$400,000.00			NT	C>B>A
A in MTEP08	West	XEL	1370	2294	5/1/2009	Rush River	Crystal Cave	1	161		-	Relocate the 69 kV rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI			Proposed				Y	B>A
A in MTEP08	West	XEL	1370	2293	5/1/2009	Pine Lake	Rush River	1	161		-	Relocate the 69 kV rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI			Proposed				Y	B>A
A in MTEP08	West	XEL	1370	3277	5/1/2009	Rush River	transformer	1	161	23.9		New distribution substation	WI			Proposed	$10,000,000.00			Y	B>A
A in MTEP08	West	XEL	1371	2295	6/1/2009	Black Dog	Wilson	2	115		310	Reconductor	MN			Planned	$900,000.00			Y	B>A
A in MTEP08	West	XEL	1373	2298	6/1/2010	West New Ulm	New Ulm	1	69		84	Reconductor	MN			Planned	$300,000.00			NT	B>A
A in MTEP08	West	XEL	1373	2297	6/1/2010	Ft. Ridgeley	West New Ulm	1	115		620	new Line	MN			Planned	$1,200,000.00			Y	B>A
A in MTEP08	West	XEL	1375	2302	12/31/2009	Lake Yankton	SW Marshall	1	115		310	New 115 kV line	MN			Planned	$5,000,000.00			Y	B>A
A in MTEP08	West	XEL	1375	2300	6/1/2010	Hazel Creek	Minnesota Valley	1	115		310	New 1115 kV Line	MN			Proposed	$5,000,000.00			Y	B>A
A in MTEP08	West	XEL	1486	2282	6/1/2009	Mary Lake	City of Buffalo	1	69		116	New 115 kV line operated at 69 kV	MN			Planned	$2,190,000.00			NT	C>B>A
A in MTEP08	West	XEL	1487	2306	12/1/2010	Somerset	Stanton	1	69		84	New 69 kV line	WI			Proposed	$9,247,500.00			NT	C>B>A

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A in MTEP08	West	XEL	1545	2624	12/1/2009	South Bend	Wilmarth	1	115		139	Line terminations at Wilmarth and South Bend	MN			Planned	$280,000.00			Y	B>A
A in MTEP08	West	XEL	1546	2630	10/1/2008	Hyland Lake	Dean Lake	1	115		370	Upgrade 3.2 miles of 115 kV line with 2-795 ACSR.	MN			Planned	$1,057,000.00			Y	B>A
A in MTEP08	West	XEL	1547	2631	6/1/2008	Ironwood bus upgrade	terminal equipment		115		160	Replace capacity-limiting terminal equipment	WI			Planned	$450,000.00			Y	C>B>A
A in MTEP08	West	XEL	1548	2632	6/1/2009	La Crosse	Capacitor Bank		161		60 MVAR	Install capacitor banks to maintain contingent voltage	WI			Planned	$2,300,000.00			Y	C>B>A
A in MTEP08	West	XEL	1548	3278	6/1/2009	Monroe County	Capacitor		161		2x30 MVAR	capacitor banks	MN			Planned				Y	C>B>A
A in MTEP08	West	XEL	1549	2635	6/1/2009	Wheaton	Eau Claire		161		335	Terminate Wheaton - Presto Tap 161 kV Line at Eau Claire Substation	WI			Planned	$1,065,000.00			Y	C>B>A
A in MTEP08	West	XEL	1549	2638	6/1/2009	Wheaton	Eau Claire		161		434	Reconductor 4.3 Miles of 161 kV line with 795 ACSS conductor	WI	4.3		Planned	$645,000.00			Y	C>B>A
A in MTEP08	West	XEL	1549	2636	6/1/2010	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	$2,902,000.00			Y	C>B>A
A in MTEP08	West	XEL	1549	2637	6/1/2010	50th Avenue	substation		161	69	70	Construct 161/69 kV Substation with two 70 MVA transformers	WI			Planned	$10,700,000.00			Y	C>B>A
A in MTEP08	West	XEL	1549	2633	1/1/2011	Eau Claire	Hallie		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Substation to 161 kV	WI	1.5		Planned	$2,425,000.00			Y	C>B>A
A in MTEP08	West	XEL	1549	2634	6/1/2011	Hallie	50th Avenue		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Substation to 161 kV	WI	2.5		Planned	$2,865,000.00			Y	C>B>A
A in MTEP08	West	XEL	1749	2819	10/1/2008	Adams	substation	1	345			345 kV relay upgrades. This relay upgrade will include replacing the existing line protection relays and panels with a new panel containing relays for a directional comparison unblocking (DCUB) system.	IA			Planned	$150,000.00	Y	Y	Y	C>B>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			Proposed	$5,264,000.00	Y		Y	C>B>A
A in MTEP08	West	XEL	1954	3835	12/1/2010	Cherry Creek	Split Rock	1,2	115			Separate the double circuit line to two single circuits	MN			Proposed	$1,189,200.00			Y	C>B>A
A in MTEP08	West	XEL	1955	3836	12/1/2009	Bangor switching station			69			New three 69 kV switching station at Bangor tap	WI			Proposed	$900,000.00			NT	C>B>A
A in MTEP08	West	XEL	1956	3837	12/1/2009	Lakefield	Blue Lake	1	345		1364 MVA	Phase raise.	MN			Proposed	$1,904,600.00			Y	C>B>A
A in MTEP08	West	XEL	1957	3839	12/1/2012	new sub	London - Madison tap	1	69		84 MVA	Rebuild 69 kV line from London/Madison Tap to new substation	WI			Proposed	$0.00			NT	C>B>A
A in MTEP08	West	XEL	1957	3841	12/1/2012	new sub	Burnswick	1	69		84 MVA	Construct 69 kV line from new substation to DPC Brunswick Substation	WI			Proposed	$0.00			NT	C>B>A
A in MTEP08	West	XEL	1957	3838	12/1/2012	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			Proposed	$7,080,000.00			Y	C>B>A
A in MTEP08	West	XEL	1957	3840	12/1/2012	new sub	Union (DPC)	1	69		84 MVA	Construct 69 kV line from new substation to DPC Union Substation	WI			Proposed	$0.00			NT	C>B>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			Proposed	$0.00			Y	C>B>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			Proposed	$19,270,980.00			Y	C>B>A
A in MTEP08	West	XEL	1959	3846	12/1/2010	Yankee Doodle	Pilot Knob	1	115		310 MVA	115 kV line from Yankee Doodle to Pilot Knob	MN			Proposed	$3,765,200.00			Y	C>B>A
A in MTEP08	West	XEL	1960	3844	12/1/2010	Traverse	St. Peter	1	69		84 MVA	Upgrade to 84 MVA	MN			Proposed	$720,000.00			NT	C>B>A

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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			Proposed	$507,200.00			Y	C>B>A
A in MTEP08	West	XEL	2100	2807	6/1/2008	Cannon Falls	Meisville Tap	1	69		84.3	Upgrade is planned by June 2008 to a 84.3 MVA Normal, +10% Emergency rating (Cannon Falls-Lake Byllesby-Meisville Tap 69kV)	MN			In Service				NT	C>B>A
A in MTEP08	West	XEL	2100	2806	6/1/2008	Traverse (NSP)	Traverse (GRE)	1	69		67.5	Upgrade is planned by June 2008 to a 67.5 MVA Normal, +10% Emergency rating	MN			In Service				NT	C>B>A
A in MTEP08	West	XEL	2100	2805	6/1/2008	Cannon Falls	Northfield	1	69		136.5	Upgrade is planned by June 2008 to a 136.5 MVA Normal, +10% Emergency rating	MN			In Service				NT	C>B>A
A in MTEP08	West	XEL	2105	2815	6/1/2009	Wilmarth	Johnson Tap	1	69			Upgraded to 84 MVA	MN	1.7		Planned	$360,000.00			NT	C>B>A
A in MTEP08	West	XEL	2109	2825	7/31/2007	G609 Flambeau Hydro	generator	1	34.5			Interconnect existing hydro generators at Flambeau Hydro Paper Mill to Xcel's 34.5 kV system, requires switch poles and gang operated air break switch	WI			Planned	$34,200.00	Y		Y	C>B>A
A in MTEP08	West	XEL	2119	2851	7/28/2008	Scott County	Shakopee	1	69			A 69 kV switch structure (3-steel poles) on line 0716 with a 3-way manually operated disconnect switch and a 400' two-span tap transmission line to the customer's proposed substation.	MN			Planned	$259,000.00	Y		NT	C>B>A
A in MTEP08	West	XEL,RPU,SI	1024	2983	12/15/2015	Hampton Corner and North Rochester	substation	1	345			new substation	MN			Planned	$7,600,000.00			Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	1673	12/15/2015	Hampton Corner	North Rochester	1	345		2050	new line	MN		36	Planned	$57,560,000.00			Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	1675	12/15/2015	North Rochester	Transformer	1	345	161	448	new transformer and terminal works	MN			Planned	$15,650,000.00	Y		Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	1676	12/15/2015	North La Crosse	Transformer	1	345	161	448	new transformer and terminal works	WI			Planned	$9,500,000.00	Y		Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	2984	12/15/2015	North Rochester	substation	1	345			new substation, 50% of not shared cost	MN			Planned	$4,986,500.00	Y		Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	1678	12/15/2015	North Rochester	Chester	1	161		400	new line	MN		14	Planned	$9,009,000.00			Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	1677	12/15/2015	North Rochester	Northern Hills	1	161		400	new line and termial works	MN		12.6	Planned	$18,661,000.00	Y		Y	B>A
A in MTEP08	West	XEL,RPU,SI	1024	2647	12/15/2015	North Rochester	North La Crosse	1	345		2050	new line and termial works	MN		82	Planned	$237,033,500.00	Y	Y	Y	B>A
A in MTEP08	West	XEL/GRE	1380	2314	5/1/2010	Scott County	West Waconia	1	115		310		MN		25	Proposed	$13,600,000.00			Y	C>B>A
A in MTEP08	West	XEL/GRE	1545	2625	12/1/2009	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	$4,300,000.00			Y	B>A
A in MTEP08	West	XEL/GRE	1545	2626	12/1/2009	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	$950,000.00			Y	B>A
A in MTEP08	West	XEL/GRE	1545	2627	12/1/2009	Pohl tap	Pohl	1	115		310	Upgrade the existing 69 kV line from Pohl - Pohl tap to 115 kV	MN			Planned				Y	B>A
A in MTEP08	West	XEL/GRE	1545	2628	12/1/2009	Pohl	Eastwood	1	115		194	Reterminate the existing 69 kV line from Pohl - Eastwood tap into Eastwood substation. Operate the line at 115 kV.	MN			Planned	$440,000.00			Y	B>A
A in MTEP08	West	XEL/GRE	1545	2629	12/1/2009	Pohl Substation						Upgrade the Pohl substation from 69 kV to 115 kV	MN			Planned	$540,000.00			Y	B>A

Appendix A: Project Facility Table

Target Appendix	Region	Rep Source	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 MTEP08	West	XEL/GRE	1545	2623	12/1/2009	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	$6,405,000.00			Y	B>A

Appendix A-1: MTEP08 Appendix A Project Cost Allocations by Pricing Zones

Values shown below are subject to change depending on actual project costs [1]

	Proj ID	ISD	Zone	Total Shared Cost[2]	Pricing Zone																								Tot Proj Cost with 100% GIP[3]
					FE	HE	CIN	VECT	IPL	NIPS	METC	ITC	ITCM	CWLD	AMMO	AMIL	MI13AG	MI13ANG	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total	
East	2110 GIP	2008	METC	991,600							991,600																	991,600	1,983,200
East	1874 GIP	2008	ITC	1,176,066								1,176,066																1,176,066	2,352,131
East	1551	2008	NIPS	5,050,000						5,050,000																		5,050,000	5,050,000
East	1875 GIP	2009	ITC	3,914,619							5,872	3,908,746																3,914,619	7,829,237
East	1610	2009	FE	8,459,634	8,459,634																							8,459,634	8,459,634
East	1609	2009	FE	7,300,000	7,300,000																							7,300,000	7,300,000
East	1819	2009	METC	7,750,000							7,735,193							14,807										7,750,000	7,750,000
East	480	2009	METC	10,000,000							9,977,448							22,552										10,000,000	10,000,000
East	1797	2010	METC	21,000,000							21,000,000																	21,000,000	21,000,000
East	1798	2010	METC	21,000,000							20,771,682							228,318										21,000,000	21,000,000
East	1814	2010	METC	30,000,000							27,751,667							2,248,333										30,000,000	30,000,000
East	1818	2011	METC	17,150,000							17,045,715							104,285										17,150,000	17,150,000
East	1796	2011	METC	19,500,000							19,500,000																	19,500,000	19,500,000
East	East Total			153,291,918	15,759,634					5,050,000	124,779,177	5,084,812						2,618,295										153,291,918	159,374,202
Central	2113 GIP	2008	AMIL	1,122,000												1,122,000												1,122,000	2,244,000
Central	2116 GIP	2008	AMIL	1,013,979												1,013,979												1,013,979	2,027,957
Central	2061	2010	AMMO	19,000,000											19,000,000													19,000,000	19,000,000
Central	1970	2011	VECT	7,680,032		342,795	1,958,804	5,330,883	47,550																			7,680,032	7,680,032
Central	2068	2012	AMIL	15,039,400	394,960	19,000	376,117	35,534	89,096	102,739	240,744	319,397	96,345	8,051	242,924	12,247,243	16,642	4,318	23,590	12,720	368,191	292,156	59,408	8,961	34,762	25,605	20,898	15,039,400	15,039,400
Central	2069	2012	AMIL	17,600,000	288,879	13,897	263,454	25,990	65,166	75,144	176,083	233,611	70,468	5,889	177,678	15,503,155	12,172	3,158	83,524	9,304	269,299	213,686	43,451	6,554	25,425	18,728	15,285	17,600,000	17,600,000
Central	Central Total			61,455,411	683,839	375,691	2,598,375	5,392,406	201,812	177,883	416,826	553,008	166,813	13,940	19,420,602	29,886,377	28,815	7,476	107,113	22,024	637,490	505,842	102,859	15,514	60,188	44,333	36,182	61,455,411	63,591,389
West	2109 GIP	2008	NSP	17,100																		17,100						17,100	34,200
West	2119 GIP	2008	NSP	129,500																		129,500						129,500	259,000
West	2108 GIP	2009	ITCM	1,059,846									1,059,846															1,059,846	2,119,692
West	2097 GIP	2009	GRE	2,241,462																		29,071	2,183		2,210,208			2,241,462	4,482,923
West	1522	2009	ITCM	7,200,000									7,200,000															7,200,000	7,200,000
West	1618	2009	ITCM	9,250,000									3,419,125									5,830,875						9,250,000	9,250,000
West	1749 GIP	2009	ITCM	3,437,012	90,262	4,342	82,318	8,121	20,361	23,479	55,018	72,993	2,711,686	1,840	55,516	55,585	3,803	987	2,744	2,907	84,144	126,709	13,577	2,048	7,944	5,852	4,776	3,437,012	6,874,024
West	1953	2010	NSP	5,264,000									39,170									3,577,235	1,219,032		90,982	337,581		5,264,000	5,264,000
West	1285	2011	NSP	18,800,000									96,363									15,758,210	114,396		2,536,525	294,506		18,800,000	18,800,000
West	286	2012	GRE/NSP/OTP/MP	490,000,000	12,504,058	601,512	11,403,559	1,124,957	2,820,698	3,252,609	7,621,711	10,111,812	5,839,153	254,892	7,690,745	7,700,218	526,877	136,705	380,160	402,708	14,954,224	254,156,365	46,200,124	283,682	15,124,634	80,236,760	6,671,837	490,000,000	490,000,000
West	356	2013	ATC	230,056,310	5,779,734	278,036	5,271,052	519,987	1,303,807	1,503,449	3,522,973	4,673,969	2,972,643	117,818	3,554,883	3,559,262	243,538	63,189	175,721	186,143	189,865,088	4,275,328	869,354	131,126	508,699	374,701	305,808	230,056,310	230,056,310
West	1024	2015	NSP	216,250,265	4,793,174	230,577	4,371,320	431,229	1,081,256	1,246,821	2,921,626	3,876,155	21,412,672	97,708	2,948,089	2,951,720	201,968	52,403	145,726	154,370	31,452,234	115,335,444	3,303,877	15,507,187	3,170,358	310,743	253,609	216,250,265	216,250,265
West	West Total			983,705,495	23,167,228	1,114,467	21,128,249	2,084,294	5,226,123	6,026,358	14,121,329	18,734,929	44,750,660	472,258	14,249,232	14,266,785	976,186	253,284	704,351	746,128	236,355,690	399,235,837	51,722,542	15,924,043	23,649,349	81,560,143	7,236,030	983,705,495	990,590,414
Total				1,198,452,824	39,610,701	1,490,158	23,726,624	7,476,700	5,427,935	11,254,241	139,317,332	24,372,749	44,917,473	486,198	33,669,834	44,153,162	1,005,001	2,879,055	811,464	768,152	236,993,180	399,741,680	51,825,401	15,939,557	23,709,536	81,604,477	7,272,212	1,198,452,823	1,213,556,005

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 08 RECB Cost Allocation Summaries

Table A-2.1: MTEP08 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-Servicce Dates, and actual Fixed Charge Rates

Year	Annual Charges (Allocation * FCR)	FE	HE	CIN	VECT	IPL	NIPS	METC	ITC	ITCM	CWLD	AMMO	AMIL	MI13AG	MI13ANG	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
2008	1,900,049	-	-	-	-	-	1,010,000	198,320	235,213	-	-	-	427,196	-	-	-	-	-	29,320	-	-	-	-	-	1,900,049
2009	14,022,563	3,169,979	868	16,464	1,624	4,072	1,014,696	3,753,026	1,031,561	2,878,131	368	11,103	438,313	761	7,669	549	581	16,829	1,226,651	3,152	410	443,630	1,170	955	14,022,563
2010	33,275,363	3,169,979	868	16,464	1,624	4,072	1,014,696	17,657,696	1,031,561	2,885,966	368	3,811,103	438,313	761	502,999	549	581	16,829	1,942,098	246,958	410	461,827	68,687	955	33,275,363
2011	45,901,370	3,169,979	69,427	408,224	1,067,801	13,582	1,014,696	24,966,839	1,031,561	2,905,238	368	3,811,103	438,313	761	523,856	549	581	16,829	5,093,740	269,837	410	969,132	127,588	955	45,901,370
2012	150,429,250	5,807,559	196,309	2,816,850	1,305,097	608,574	1,700,794	26,574,547	3,164,525	4,106,431	54,134	5,433,373	7,528,436	111,899	552,693	98,003	85,528	3,135,172	56,026,182	9,530,434	60,249	4,006,096	16,183,807	1,342,559	150,429,250
2013	196,440,512	6,963,505	251,916	3,871,061	1,409,094	869,336	2,001,484	27,279,141	4,099,319	4,700,960	77,698	6,144,349	8,240,288	160,607	565,330	133,148	122,756	41,108,189	56,881,247	9,704,305	86,474	4,107,836	16,258,747	1,403,721	196,440,512
2014	196,440,512	6,963,505	251,916	3,871,061	1,409,094	869,336	2,001,484	27,279,141	4,099,319	4,700,960	77,698	6,144,349	8,240,288	160,607	565,330	133,148	122,756	41,108,189	56,881,247	9,704,305	86,474	4,107,836	16,258,747	1,403,721	196,440,512
2015	239,690,565	7,922,140	298,032	4,745,325	1,495,340	1,085,587	2,250,848	27,863,466	4,874,550	8,983,495	97,240	6,733,967	8,830,632	201,000	575,811	162,293	153,630	47,398,636	79,948,336	10,365,080	3,187,911	4,741,907	16,320,895	1,454,442	239,690,565

Notes:

1. The annual cumalative 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%. 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 orginate in a zone and those projects that orginate 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 08 Appendix A Projects

	FE	HE	CIN	VECT	IPL	NIPS	METC	ITC	ITCM	CWLD	AMMO	AMIL	MI13AG	MI13ANG	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
Total Shared Project Costs	15,759,634			7,680,032		5,050,000	127,391,600	5,090,684	20,946,858		19,000,000	34,775,379					230,056,310	436,460,865	78,400,000		139,441,462	78,400,000		**1,198,452,824**
Project Cost Allocation to Others				(2,349,149)			(2,618,295)	(5,872)	(6,556,201)			(4,889,001)					(40,191,222)	(47,487,011)	(32,199,876)		(122,106,621)	1,836,760		**(256,566,487)**
Project Cost Allocation from Others	23,851,067	1,490,158	23,726,624	2,145,817	5,427,935	6,204,241	14,544,028	19,287,937	30,526,815	486,198	14,669,834	14,266,785	1,005,001	2,879,055	811,464	768,152	47,128,092	10,767,826	5,625,277	15,939,557	6,374,695	1,367,716	7,272,212	**256,566,487**
Net Project Cost	39,610,701	1,490,158	23,726,624	7,476,700	5,427,935	11,254,241	139,317,332	24,372,749	44,917,473	486,198	33,669,834	44,153,162	1,005,001	2,879,055	811,464	768,152	236,993,180	399,741,680	51,825,401	15,939,557	23,709,536	81,604,477	7,272,212	**1,198,452,823**
Net Transmission Plant in Service per Attachment O - June 2008	653,501,633	82,628,163	882,465,988	154,795,406	90,596,480	403,742,858	353,081,000	781,107,000	397,094,695	14,388,591	366,947,941	390,917,600	n/a	n/a	22,917,043	24,349,058	1,954,686,636	1,182,007,041	106,882,979	97,474,384	329,568,010	113,382,069	52,199,676	

Table A-2.3: State Comparison of RECB Cost Allocation for MTEP 08 Appendix A Projects

	IA	IL	IN	MI	MN	MO	ND	OH	SD	WI	Total
Total State Shared Project Costs	10,637,012	34,775,379	12,730,032	132,482,284	695,420,015	19,000,000		15,759,634		277,648,468	**1,198,452,824**
Project Cost Allocation to Other States	(736,258)	(4,759,563)	(979,402)	(10,510,012)	(184,679,538)					(54,901,715)	**(256,566,488)**
Project Cost Allocation from Other States	15,263,452	15,716,963	28,322,896	37,710,149	40,481,201	15,156,032	41,839,635	41,044,916	7,070,609	13,960,634	**256,566,487**
Net State Project Cost	25,164,206	45,732,778	40,073,526	159,682,421	551,221,678	34,156,032	41,839,635	56,804,550	7,070,609	236,707,388	**1,198,452,823**

Appendix A-3: MTEP 06 thru MTEP 08 RECB Cost Allocation Summaries

Table A-3.1: MTEP06 thru 08 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-servicce Dates, and actual Fixed Charge Rates

Year	Annual Charges (Allocation * FCR)	FE	HE	CIN	VECT	IPL	NIPS	METC	ITC	ITCM	CWLD	AMMO	AMIL	MI13AG	MI13ANG	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
2008	55,460,497	3,613,039	454,401	5,596,418	4,572,713	93,626	2,350,922	9,236,053	14,033,369	668,004	5,090	168,607	2,520,309	-	-	7,950	8,378	9,918,730	2,076,646	50,083	6,220	49,296	17,099	13,546	55,460,497
2009	128,074,490	7,520,018	493,863	6,524,744	4,643,568	270,841	2,813,982	20,170,284	15,558,903	4,568,356	19,538	647,490	3,208,848	761	7,669	30,523	32,075	46,876,515	10,394,009	3,090,448	23,865	569,887	556,402	51,898	128,074,490
2010	165,891,190	7,582,047	498,270	8,212,210	4,649,398	285,437	2,834,709	34,161,510	25,085,663	5,532,810	20,711	7,103,043	3,308,598	761	502,999	815,296	34,020	46,935,688	12,970,139	3,944,762	25,315	605,686	727,082	55,035	165,891,190
2011	223,251,675	8,712,290	998,677	14,693,269	9,605,683	1,465,338	3,130,279	43,652,958	48,803,950	5,855,736	42,158	7,926,457	5,084,873	761	523,856	848,926	102,369	48,013,536	16,933,829	4,141,340	51,731	1,693,008	858,394	112,258	223,251,675
2012	350,841,710	11,349,870	1,125,558	17,101,895	9,842,979	2,060,330	3,816,378	45,260,666	50,936,914	7,120,479	95,924	9,558,519	12,174,997	111,899	552,693	946,380	187,315	51,975,783	75,632,200	21,717,915	111,570	5,062,118	22,629,724	1,469,603	350,841,710
2013	397,960,372	12,505,816	1,181,165	18,156,105	9,946,976	2,321,091	4,117,068	45,965,260	51,871,708	7,963,829	119,488	10,282,635	12,886,849	160,607	565,330	981,525	224,544	90,753,476	76,528,030	21,891,786	137,795	5,163,858	22,704,665	1,530,764	397,960,372
2014	397,960,372	12,505,816	1,181,165	18,156,105	9,946,976	2,321,091	4,117,068	45,965,260	51,871,708	7,963,829	119,488	10,282,635	12,886,849	160,607	565,330	981,525	224,544	90,753,476	76,528,030	21,891,786	137,795	5,163,858	22,704,665	1,530,764	397,960,372
2015	441,210,425	13,464,451	1,227,281	19,030,369	10,033,222	2,537,343	4,366,432	46,549,586	52,646,939	12,246,363	139,029	10,872,253	13,477,193	201,000	575,811	1,010,670	255,418	97,043,923	99,595,119	22,552,561	3,239,233	5,797,930	22,766,813	1,581,486	441,210,425
Total	441,210,425	13,464,451	1,227,281	19,030,369	10,033,222	2,537,343	4,366,432	46,549,586	52,646,939	12,246,363	139,029	10,872,253	13,477,193	201,000	575,811	1,010,670	255,418	97,043,923	99,595,119	22,552,561	3,239,233	5,797,930	22,766,813	1,581,486	441,210,425

Notes:

1. The annual cumalative 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%. 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 orginate 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 08 Appendix A Projects

	FE	HE	CIN	VECT	IPL	NIPS	METC	ITC	ITCM	CWLD	AMMO	AMIL	MI13AG	MI13ANG	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
Total Shared Project Costs	34,599,634		31,775,533	110,080,032		12,169,614	200,148,408	278,839,943	31,731,858		32,381,100	45,259,579			3,914,650		507,509,877	508,670,055	158,962,971		143,759,106	106,249,766		**2,206,052,124**
Project Cost Allocation to Others	(1,835,590)		(2,077,648)	(62,918,840)		(955,686)	(7,786,411)	(41,170,706)	(7,505,945)		(299,719)	(5,292,503)					(81,354,100)	(50,797,882)	(53,744,086)		(123,905,452)	(151,246)		**(439,795,815)**
Project Cost Allocation from Others	34,558,212	6,136,404	65,453,960	3,004,919	12,686,713	10,618,231	40,385,932	25,565,459	37,005,903	695,147	22,279,884	27,418,890	1,005,001	2,879,055	1,138,699	1,277,088	59,063,838	40,103,421	7,543,923	16,196,164	9,135,995	7,735,546	7,907,431	**439,795,815**
Net Project Cost	67,322,256	6,136,404	95,151,845	50,166,111	12,686,713	21,832,159	232,747,928	263,234,697	61,231,816	695,147	54,361,265	67,385,965	1,005,001	2,879,055	5,053,349	1,277,088	485,219,615	497,975,594	112,762,807	16,196,164	28,989,649	113,834,066	7,907,431	**2,206,052,124**
Net Transmission Plant in Service per Attachment O - June 2008	653,501,633	82,628,163	882,465,988	154,795,406	90,596,480	403,742,858	353,081,000	781,107,000	397,094,695	14,388,591	366,947,941	390,917,600	n/a	n/a	22,917,043	24,349,058	1,954,686,636	1,182,007,041	106,882,979	97,474,384	329,568,010	113,382,069	52,199,676	

Appendix B: Project Table

Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	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	6/1/2012	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				$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	9/30/2008	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	AmerenMO	720	Page 138/34 kV Substation	Page 138/34 kV Substation - Replace 3-138 kV Breakers	MO			Excluded	$587,500	12/1/2008	Planned	138		B	Y
B	Central	AmerenMO	1233	Cahokia-Ashley-2 138 kV	Replace bus conductor and retap CTs	MO				$116,300	6/1/2012	Proposed	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				$7,541,500	6/1/2011	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				$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				$113,000,000	5/1/2011	Proposed	345		B	Y
B	Central	DEM	1557	Wheatland to Bloomington to Pritchard to Franklin to Hanna 345	Wheatland to Bloomington to Pritchard to Franklin to Hanna 345	IN				$95,140,000	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				$11,435,000	5/1/2011	Proposed	345		B	Y
B	Central	DEM	1566	Todhunter to AK Steel 138KV reconductor of F5682	Replace F5682 existing conductor with 954ACSR @ 100C from Todhunter substation to AK Steel.	OH				$227,000	11/15/2008	Planned	138		B	Y
B	Central	DEM	2050	Dresser 345/138kV Bank 3 addition	Add a 3rd 345/138kV transformer at Dresser Sub	IN				$3,500,000	6/1/2012	Proposed	345	138	C>B	Y
B	Central	IPL	2053	Petersburg 345/138kV East and West Autotransformers	Replace and upgrade existing East and West 345/138kV autotransformer at Petersburg Substation	IN				$8,000,000	6/1/2012	Proposed	345	138	C>B	Y
B	East	FE	1612	Begin right-of-way research, substation siting and initial contacts for Cranberry 500/138kV Sub	Construct a 500/138kV Sub with four exits in the Cranberry/Adams Township area.	PA				$39,600,000	6/1/2011	Proposed	500	138	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				$4,900,000	6/1/2011	Proposed	345		C>B	Y
B	East	METC	646	Edenville Jct. - Warren 138kV	Edenville Jct.-Warren: Rebuild 15 miles of 336 ACSR to 795 ACSR (pre-build to 230kV)	MI				$10,765,000	6/1/2010	Planned	138		C>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					6/1/2011	Planned	138		B	Y

Appendix B: Project Table *Project Information from Facility table*

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
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	6/1/2018	Proposed	345	138	B	Y
B	West	ATC LLC	174	Canal-Dunn Road 138 kV	Canal - Dunn Road 138 ckt , Sum rate 400	WI				$9,056,048	6/1/2012	Planned	138		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) - 2007 Relocate 69 kV Rexton tap to 69 kV Hiawatha-Pine River line (6909) - 2009 Relocate 69 kV Trout Lake tap to 69 kV Hiawatha-Pine River line (6909) - 2009 Construct Mackinac 138 kV substation additions (portions may be earlier for maintenance issues) - 2009 Rebuild Hiawatha-Pine River-Mackinac 69 kV to 138 kV - 2009 Construct 138 kV bus and install one 138/69 kV, 50 MVA transformers at Pine River - 2009 Convert rebuilt Hiawatha-Indian Lake circuit (operated at 69 kV) to 138 kV - 2009 Construct 138 kV ring bus at Hiawatha SS - 2009 Install 138 kV substation modifications at Indian Lake SS - 2009	WI			Excluded	$12,140,000	5/1/2009	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	6/1/2018	Proposed	345	138	B	Y
B	West	ATC LLC	434	Butternut 28.8 MVAR capacitor bank	Butternut 138, 28.8 MVAR Capacitor bank	WI				$1,050,000	6/1/2015	Proposed	138		B	Y
B	West	ATC LLC	544	Bluemound 200 MVAR capacitor bank	Bluemound 200 MVAR capacitors	WI				$3,300,000	6/1/2010	Proposed	138		B	Y
B	West	ATC LLC	569	White River T-D interconnection	South Lake Geneva - White River 138 kV line	WI				$4,473,000	6/1/2016	Proposed	138	69	B	Y
B	West	ATC LLC	573	North Madison-West Middleton 345 kV	North Madison - West Middleton 345 kV line	WI				$46,700,000	6/1/2016	Proposed	345		B	Y
B	West	ATC LLC	884	Spring Green 32 MVAR capacitor bank	Spring Green 32 MVAR capacitor bank	WI				$1,200,000	6/1/2010	Proposed	69		B	Y
B	West	ATC LLC	887	Bain 345 kV bus	Bain 345 kV bus	WI				$2,100,000	6/1/2011	Proposed	345		B	Y
B	West	ATC LLC	1269	Arcadian transformer replacement	Replace Arcadian 345/138kV transformer #3 with a 500MVA transformer.	WI				$3,500,000	6/1/2013	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				$800,000	6/1/2011	Proposed	138		B	Y
B	West	ATC LLC	1282	Add two 5.4 Mvar 69 kV Capacitor banks at the Osceola substation in Houghton County, MI	Add two 5.4 Mvar 69 kV Capacitor banks at the Osceola substation in Houghton County, MI	MI					6/1/2008	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				$4,181,904	6/1/2011	Proposed	138		B	Y
B	West	ATC LLC	1353	Hiawatha - Pine River 69	Hiawatha - Pine River 69 kV maintenance rebuild to 138kV standards	MI				$70,850,000	12/31/2009	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				$584,007	6/1/2010	Planned	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					6/1/2013	Proposed	138		B	Y

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B	West	ATC LLC	1624	Uprate X-67 Portage-Trienda 138 kv line	Increase clearance and uprate SS equipment	WI				$1,404,000	6/1/2014	Proposed	138		B	Y
B	West	ATC LLC	1626	Summit Capacitor Banks	Install two 34.2 MVAR 69kV capacitor banks at Summit substation	WI					6/1/2010	Proposed	138		C>B	Y
B	West	ATC LLC	1686	Brandon-Fairwater 69 kV line	Construct Brandon-Fairwater 69 kV line	WI				$1,730,000	6/1/2010	Proposed	69		C>B	Y
B	West	ATC LLC	1687	Metomen transformer replacement	Replace the 138/69 kV transformer at Metomen substation	WI				$1,798,000	6/1/2013	Proposed	138	69	C>B	Y
B	West	ATC LLC	1690	Rebuild Verona-Oregon 69 kV line	Rebuild the Verona-Oregon 69 kV line Y119	WI				$8,334,947	6/1/2011	Proposed	69		C>B	Y
B	West	ATC LLC	1691	Uprate McCue-Milton Lawns 69 kV line	Uprate McCue-Milton Lawns 69 kV line	WI					6/1/2011	Proposed	69		C>B	Y
B	West	ATC LLC	1698	Dunn Road 138/69 kV transformer	Install 60 MVA 138/69 kV transformer at Dunn Road	WI					6/1/2012	Proposed	138	69	C>B	Y
B	West	ATC LLC	1704	Uprate Sheepskin-Dana 69 kv line	Uprate Sheepskin-Dana 69 kv line to 95 MVA	WI				$726,000	6/1/2013	Proposed	69		C>B	Y
B	West	ATC LLC	1705	Bass Creek area upgrades	Install a 138/69 kV transformer at Bass Creek substation, Rebuild/reconductor Townline Road-Bass Creek 138 kV line	WI				$6,040,000	6/1/2013	Proposed	138	69	C>B	Y
B	West	ATC LLC	1950	2nd Kewaunee 345-138 kV Transformer	Add a 2nd Kewaunee 345-138 kV transformer	WI					4/1/2011	Proposed	345	138	C>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					6/1/2012	Proposed	138		C>B	Y
B	West	ATC LLC	2035	Uprate X23 Colley Rd Terminal	Uprate X23 Colley Rd Terminal (Colley Rd-Marine)	WI					6/1/2014	Proposed	138		C>B	Y
B	West	ATC LLC	2112	G546	Network upgrades for tariff service request	WI		GIP	In Suspension	$8,830,000	10/28/2009	Planned	138		C>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	1/1/2009	Planned	230		C>B	Y
B	West	GRE/ALTW	1354	Dotson -Storden 161 and Dotson - Searles 161	Dotson -Storden 161 and Dotson - Searles 161	MN				$37,890,000	12/31/2011	Planned	161	69	B	Y
B	West	GRE/XEL	603	Alexandria - West St. Cloud 115 kV line	Alexandria - West St. Cloud 115 kV line	MN				$36,954,688	9/1/2013	Planned	115		B	Y
B	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	ND				$11,000,000	11/1/2015	Planned	230	115	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				$400,000	6/1/2011	Proposed	115		B	Y
B	West	OTP	549	Jamestown Reactor Addition	Jamestown 115 kV 25 MVAR reactor	ND				$436,672	8/1/2010	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	6/1/2017	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			$149,045,000	1/1/2015	Planned	345	115	B	Y
B	West	XEL	1297	Reconductor Monticello - Oakwood - Hassan 115 kV line	Reconductor Monticello - Oakwood - Hassan 115 kV line with 795 ACSS	MN				$6,020,000	6/1/2011	Proposed	115		B	Y
B	West	XEL	1379	Pulaski - Linn Street - Becker - Liberty 69 kV to 115 kV upgrade	Pulaski - Linn Street - Becker 69 kV to 115 kV upgrade	MN				$4,600,000	6/1/2015	Proposed	115		C>B	Y

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Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
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
B	West	XEL/GRE	1203	Brookings, SD - SE Twin Cities 345 kV project	Brookings County -Lyon County-Franklin (Double Crt) - Helena-Lk Marion-Hampton Corner 9 (Single Crt) 345 kV; Hazel - Lyon County 345 kV line	MN	SD			$665,000,000	6/1/2014	Planned	345	69	B	Y

Appendices B: Project Facility Table

Target Appendix	Region	Rep Source	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	East	ITC	1856	3744	6/1/2011	Jewell	Belle River - Greenwood	1	345			Cut Pontiac-Greenwood-Belle River into Jewell creating Pontiac-Jewell and Jewell-Belle River-Greenwwod	MI			Proposed	$4,900,000.00			Y	C>B
B	Central	Ameren	720	1411	12/1/2008	Page Substation	Replace 3-138 kV Breakers		138			replace existing 138 kV breakers	MO			Planned	$587,500.00			Y	B
B	Central	Ameren	1233	1932	6/1/2012	Cahokia	Ashley	1	138		318	Replace bus conductor and retap CTs at Cahokia terminal	MO			Proposed	$116,300.00			Y	B
B	Central	AmerenIP	1234	1933	6/1/2012	Havana, South	Mason City, West	1	138		160	Increase ground clearance on 18.4 miles	IL	18.4		Proposed	$642,300.00			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	$100,000.00			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	$125,900.00			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	$2,069,600.00			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	$1,564,700.00			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	$200,000.00			Y	B
B	Central	AmerenIP	2114	2839	9/30/2008	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	$237,000.00	Y		Y	B
B	Central	AmerenIP	2114	2838	9/30/2008	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	$1,845,000.00	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	$1,661,464.00	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	$230,000.00	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	$5,426,258.00	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	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	DEM	1264	1981	6/1/2011	Speed			345	138	717	Replace existing 345/138 transformer at Speed with a new transformer rated at 3,000A or higher.	IN			Proposed	$7,541,500.00			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	$233,455.00			Y	B
B	Central	DEM	1556	3104	5/1/2011	Wheatland	Whitestown	1	345			New	IN		111	Proposed	$113,000,000.00			Y	B
B	Central	DEM	1557	3107	5/1/2011	Pritchard	Franklin	1	345			New	IN		24	Proposed				Y	B
B	Central	DEM	1557	3108	5/1/2011	Franklin	Hanna	1	345			New	IN		2.75	Proposed				Y	B
B	Central	DEM	1557	3105	5/1/2011	Wheatland	Bloomington	1	345			New	IN		61	Proposed	$95,140,000.00			Y	B
B	Central	DEM	1557	3106	5/1/2011	Bloomington	Pritchard	1	345			New	IN		15	Proposed				Y	B

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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	$6,420,000.00			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	$5,015,000.00			Y	B
B	Central	DEM	1566	3118	11/15/2008	Todhunter	AK Steel	1	138		306	Replace F5682 existing conductor with 954ACSR @ 100C from Todhunter substation to AK Steel.	OH	2		Planned	$227,000.00			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	$3,500,000.00			Y	C>B
B	Central	IPL	2053	3940	6/1/2012	Petersburg	West Autotransformer	W	345	138		New Autotransformer	IN			Proposed	$4,000,000.00			Y	C>B
B	Central	IPL	2053	3939	6/1/2012	Petersburg	East Autotransformer	E	345	138		New Autotransformer	IN			Proposed	$4,000,000.00			Y	C>B
B	East	FE	1612	3882	6/1/2011	Cranberry-Maple, Cranberry-Pine 138kV lines	(2) New 138kV lines	2	138			New line extensions from current 138kV Line	PA	3		Proposed				Y	B
B	East	FE	1612	2704	6/1/2011	Cranberry		1	500				PA			Proposed	$39,600,000.00			Y	B
B	East	FE	1612	2899	6/1/2011	Cranberry	Cabot	1	500			New Line looping from existing 500kV line	PA	0.1		Proposed				Y	B
B	East	FE	1612	2705	6/1/2011	Cranberry		1	500	138	600	New 500-138kV TR Bank	PA			Proposed				Y	B
B	East	FE	1612	3881	6/1/2011	Cranberry-Pine, Cranberry Hoytdale 138kV Lines	(2) New 138kV lines	2	138			New line extensions from current 138kV Line	PA	0.2		Proposed				Y	B
B	East	FE	1612	2898	6/1/2011	Wylie Ridge	Cranberry	1	500			New Line looping from existing 500kV line	PA	0.1		Proposed				Y	B
B	East	ITC	1856	3743	6/1/2011	Pontiac	Jewell	1	345			Cut Pontiac-Greenwood-Belle River into Jewell creating Pontiac-Jewell and Jewell-Belle River-Greenwwod	MI			Proposed				Y	C>B
B	East	METC	646	1329	6/1/2010	Edenville J.	Warren	1	138			Reconductor (230 kV construction, operate at 138 kV)	MI	14.8		Planned	$10,765,000.00			Y	C>B
B	East	METC	1815	3649	6/1/2011	Chase	Mecosta	1	138			Reconductor	MI	8		Planned				Y	B
B	West	ATC LLC	89	3246	6/1/2018	Mill Rd	Cypress	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3247	6/1/2018	Mill Rd	Arcadian	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3248	6/1/2018	Mill Rd	Bark River	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	103	6/1/2018	Mill Road (renamed, was Lannon Junction)	transformer		345	138	500	transformer	WI			Proposed	$29,200,000.00			Y	B
B	West	ATC LLC	89	3249	6/1/2018	Mill Rd	Germantown	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3251	6/1/2018	Mill Rd	Tamarack	1	138		252/301	TapSussex-Tamarack into Mill Rd	WI			Proposed				Y	B
B	West	ATC LLC	89	3250	6/1/2018	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 MVA SE		WI		7.64	Planned	$9,056,048.00			Y	B
B	West	ATC LLC	333	891	6/1/2007	Mackinac	Substation relocation		138			Straits substation rename/relocation	MI			Proposed	$11,740,000.00			Y	B
B	West	ATC LLC	333	474	5/1/2009	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	$200,000.00			Y	B
B	West	ATC LLC	333	596	5/1/2009	Hiawatha	Indian Lake (string second 138 kV circuit)	2	138		279	string 2nd 138 kV circuit	MI		40	Proposed	$200,000.00			Y	B
B	West	ATC LLC	341	893	6/1/2018	Concord	Bark River		345		815	new line	WI		19	Proposed	$50,300,000.00			Y	B
B	West	ATC LLC	341	894	6/1/2018	Bark River	transformer		345	138	500	transformer	WI			Proposed	$8,400,000.00			Y	B
B	West	ATC LLC	341	895	6/1/2018	Bark River	Mill Road		345		815	convert 138 to 345 kV	WI	11		Proposed	$800,000.00			Y	B
B	West	ATC LLC	341	483	6/1/2018	Rockdale	Concord (rebuild to dbl ckt 138/345)	1	345		1200	rebuild to dbl ckt 138/345	WI	22.6		Proposed	$22,200,000.00			Y	B
B	West	ATC LLC	341	477	6/1/2018	Concord 345/138 kV	transformer		345	138	500		WI			Proposed	$12,900,000.00			Y	B
B	West	ATC LLC	434	2063	6/1/2015	Butternut	Capacitor bank		138		28.8 Mvar		WI			Proposed	$1,050,000.00			Y	B
B	West	ATC LLC	544	898	6/1/2010	Bluemound	Capacitor bank		138		200 Mvar		WI			Proposed	$3,300,000.00			Y	B
B	West	ATC LLC	569	1251	6/1/2016	South Lake Geneva 138-69 kV	transformer	1	138	69			WI			Proposed	$1,973,000.00			Y	B
B	West	ATC LLC	569	1250	6/1/2016	South Lake Geneva	White River	1	138		355	line to new T-D substation	WI		3	Proposed	$2,500,000.00			Y	B
B	West	ATC LLC	573	1265	6/1/2016	North Madison	West Middleton	1	345		1200		WI		20	Proposed	$46,700,000.00			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	$1,200,000.00			Y	B

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B	West	ATC LLC	887	887	6/1/2011	Bain	New 345 kV bus		345			construct 345 kV bus	WI			Proposed	$2,100,000.00			Y	B
B	West	ATC LLC	1269	1988	6/1/2013	Arcadian 345-138kV	transformer	1	345	138	500	replace Arcadian 345/138kV transformer #2 & #3	WI			Proposed	$3,500,000.00			Y	B
B	West	ATC LLC	1270	1990	6/1/2011	Arcadian	Waukesha	1	138		426	Increase line clearance	WI	4		Proposed	$400,000.00			Y	B
B	West	ATC LLC	1270	1989	6/1/2011	Arcadian	Waukesha	2	138		426	Increase line clearance	WI	4		Proposed	$400,000.00			Y	B
B	West	ATC LLC	1282	2109	6/1/2008	Osceola 69			69		10.8 Mvar	Add two 5.4 Mvar 138 kV Capacitor banks at the Osceola substation in Houghton County, MI Proposed after MTEP06 Ph-2 review	MI			Proposed				Y	B
B	West	ATC LLC	1284	2113	6/1/2011	Albers	Somers	1	138		345/477		WI			Proposed				Y	B
B	West	ATC LLC	1284	2110	6/1/2011	Albers	Tie	1	138				WI			Proposed	$0.00			Y	B
B	West	ATC LLC	1284	2111	6/1/2011	Racine	Albers	1	138		345/477		WI	8		Proposed	$4,181,904.00			Y	B
B	West	ATC LLC	1284	2112	6/1/2011	Racine	Somers	1	138		345/477		WI			Proposed				Y	B
B	West	ATC LLC	1353	1993	12/31/2009	Hiawatha	Pine River	1	69		191 MVA SE	Maintenance rebuild of 69kV at 138kV standards	MI			Proposed	$70,850,000.00			Y	B
B	West	ATC LLC	1554	3102	6/1/2010	Indian Lake	Capacitor bank		138		16.33 MVAR		MI			Planned	$584,007.00			Y	B
B	West	ATC LLC	1622	3256	6/1/2013	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	$1,404,000.00			Y	B
B	West	ATC LLC	1626	3245	6/1/2010	Summit	Capacitor banks		138		2x34.2 MVAR		WI			Proposed				Y	C>B
B	West	ATC LLC	1686	3462	6/1/2010	Brandon	Fairwater	1	69			Construct a Brandon-Fairwater 69 kV line	WI		4	Proposed	$1,730,000.00			Y	C>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	$1,798,000.00			Y	C>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	$8,334,946.94			Y	C>B
B	West	ATC LLC	1691	3470	6/1/2011	McCue	Milton Lawns	1	69			Uprate McCue-Milton Lawns 69 kV line	WI			Proposed				Y	C>B
B	West	ATC LLC	1698	3477	6/1/2012	Dunn Road		1	138	69	60	Install 60 MVA 138/69 kV transformer at Dunn Road	WI			Proposed				Y	C>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	$726,000.00			Y	C>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	$6,040,000.00			Y	C>B
B	West	ATC LLC	1705	3487	6/1/2013	Townline Road	Bass Creek	1	138			Rebuild/reconductor Townline Road-Bass Creek 138 kV line	WI			Proposed				Y	C>B
B	West	ATC LLC	1950	3831	4/1/2011	Kewaunee	transformer	2	345	138	717 MVA SE	Add a 2nd Kewaunee 345-138 kV transformer	WI			Proposed				Y	C>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	C>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	C>B
B	West	ATC LLC	2112	2833	10/28/2009	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	$52,000.00			Y	C>B
B	West	ATC LLC	2112	2830	10/28/2009	Bowers Road	Line 6541	1	138			Connection of 138 kV line 6541 into Bowers Road Substation	WI			Planned	$754,000.00			Y	C>B
B	West	ATC LLC	2112	2831	10/28/2009	Sugar Creek Substation	substation	1	138			Replacement of the transceiver and related equipment for the Sugar Creek-Bowers Road 138-kV line.	WI			Planned	$52,000.00			Y	C>B
B	West	ATC LLC	2112	2832	10/28/2009	Burlington Substation	substation	1	138			Replacement of the transceiver and related equipment for the Burlington-Bowers Road 138-kV line.	WI			Planned	$52,000.00			Y	C>B

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B	West	ATC LLC	2112	2835	10/28/2009	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.	WI			Planned	$444,000.00			Y	C>B
B	West	ATC LLC	2112	2829	10/28/2009	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	WI			Planned	$4,591,000.00			Y	C>B
B	West	ATC LLC	2112	2834	10/28/2009	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	$2,885,000.00			Y	C>B
B	West	GRE	602	3885		Brownton	69 kV breaker station		69			new 69 kV breaker station near Brownton	MN			Proposed	$900,000.00			NT	B
B	West	GRE	602	802	6/1/2015	Brownton	McLeod	1	115				MN		9	Proposed	$4,675,000.00			Y	B
B	West	GRE	603	801	9/1/2013	Alexandria	West St. Cloud	1	115		310		MN		75	Planned	$36,954,688.00			Y	B
B	West	GRE	1354	2234	12/31/2010	Cobden	Dotson	1	69				MN		12	Proposed				NT	B
B	West	GRE	1354	2238	12/31/2011	Dotson Substation		2	161	69	56		MN			Proposed				Y	B
B	West	GRE	1354	2237	12/31/2011	Dotson Substation		1	161	69	56		MN			Proposed				Y	B
B	West	GRE	1354	2236	12/31/2011	Dotson	West New Ulm	1	161		434		MN		25	Proposed	$37,890,000.00			Y	B
B	West	GRE	2098	2804	1/1/2009	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	$4,894,756.00			Y	C>B
B	West	GRE	2098	2993	1/1/2009	RDF	Daytonport	1	69		78 MVA	Upgrade of RDF - Daytonport to at least 78 MVA	MN	3.7		Planned	$1,377,324.00			NT	C>B
B	West	MDU	1355	2241	11/1/2009	Heskett	Capacitor		115		30 MVAr		ND			Planned				Y	B
B	West	MDU	1355	2242	11/1/2015	Heskett	Additional 230/115 kV Switchyard		230	115	200 MVA	Switchyard in parallel w/ existing Heskett switchyard	ND			Proposed	$11,000,000.00			Y	B
B	West	MP	1292	2123	6/1/2011	ETCO	Forbes	1	115		122/134	Increase ground clearance	MN			Proposed	$400,000.00			Y	B
B	West	OTP	549	1530	8/1/2010	Jamestown	Reactor		115		25 Mvar	Add a 1 x 25 MVAr reactor at OTP Jamestown substation	ND			Proposed	$436,672.00			Y	B
B	West	OTP	585	589	6/1/2017	Pelican Rapids	Pelican Rapids Turkey Plant	1	115		85	Convert an existing 41.6 kV line to 115 kV	MN	2.5		Planned	$858,869.00			Y	B
B	West	OTP	973	3587	7/1/2010	Hankinson 230 kV	Wahpeton 230 kV	1	230		520	Rebuild existing 230 kV line.	ND	25.5		Planned	$15,565,000.00			Y	B
B	West	OTP	973	2950	11/1/2010	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	$39,750,000.00			Y	B
B	West	OTP	973	1523	11/1/2010	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	$6,100,000.00			Y	B
B	West	OTP	973	2949	11/1/2010	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	$1,500,000.00			Y	B
B	West	OTP	973	3589	6/1/2011	Toronto 115 kV			115		5 Mvar	Addition of 5 Mvar Capacitor Bank	SD			Planned				Y	B
B	West	OTP	973	1524	7/1/2011	Big Stone 230	Browns Valley 230 kV		230		390	Upgrade substation equipment at Browns Valley to achieve rating equal to thermal rating of line (Required Int. upgrade for Alts 1 and 2)	SD	38.7		Planned	$2,000,000.00			Y	B
B	West	OTP	973	2952	11/1/2011	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	$8,250,000.00			Y	B
B	West	OTP	973	2951	11/1/2011	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	$21,150,000.00			Y	B

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B	West	OTP	973	1525	6/1/2012	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	$6,100,000.00			Y	B
B	West	OTP	973	1518	6/1/2012	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	$3,000,000.00			Y	B
B	West	OTP	973	1517	6/1/2012	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	$9,400,000.00			Y	B
B	West	OTP	973	1515	11/1/2013	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	$2,400,000.00			Y	B
B	West	OTP	973	1516	11/1/2013	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	$15,100,000.00			Y	B
B	West	OTP	973	2953	1/1/2015	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	$6,500,000.00			Y	B
B	West	OTP	973	2957	1/1/2015	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	$250,000.00			Y	B
B	West	OTP	973	2956	1/1/2015	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	$2,100,000.00			Y	B
B	West	OTP	973	2955	1/1/2015	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	$250,000.00			Y	B
B	West	OTP	973	2954	1/1/2015	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	$6,500,000.00			Y	B
B	West	OTP/MDU	973	3586	7/1/2010	Browns Valley 230 kV	Hankinson 230 kV		230		390	Increase Clearance as required to realize thermal limit of conductor	SD/ND	33.5		Planned	$1,730,000.00			Y	B
B	West	OTP/MRES	973	3588	6/1/2011	Morris 115 kV	Grant County 115 kV	1	115		329	Rebuild the existing 115 kV line	MN	27		Planned	$1,400,000.00			Y	B
B	West	XEL	1297	2125	6/1/2011	Oakwood	Monticello	1	115		310/341	Reconductor line with 795 ACSS	MN	11.2		Proposed	$2,220,000.00			Y	B
B	West	XEL	1297	2126	6/1/2011	Oakwood	Hassan	1	115		310/341	Reconductor line with 795 ACSS	MN	19		Proposed	$3,800,000.00			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	1379	2312	6/1/2015	Linn Street	Becker	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed	$1,533,333.33			Y	C>B
B	West	XEL	1379	2313	6/1/2015	Becker	Liberty	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed	$1,533,333.33			Y	C>B
B	West	XEL	1379	2311	6/1/2015	Pulaski	Linn Street	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed	$1,533,333.33			Y	C>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	$5,930,926.00	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	$58,152.00	Y		Y	B

Appendices B: Project Facility Table

Target Appendix	Region	Rep Source	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	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	$4,305,000.00	Y		Y	B
B	West	GRE	1203	2649	9/1/2013	Franklin	Transformer	1	345	115	448	new transformer	MN			Planned	$4,000,000.00			Y	B
B	West	GRE	1203	1894	9/1/2013	Lake Marion	Transformer	1	345	115	448	new transformer	MN			Planned	$6,000,000.00			Y	B
B	West	GRE	1203	1893	9/1/2013	Lyon County	Transformer	1	345	115	448	new transformer	MN			Planned	$6,000,000.00			Y	B
B	West	GRE	1203	1895	9/1/2013	Hazel	Transformer	1	345	230	336	new transformer	MN			Planned	$6,000,000.00			Y	B
B	West	GRE	1203	1897	9/1/2013	Franklin	Transformer	1	115	69	70	Upgrade 47 MVA to 70 MVA	MN			Planned	$4,000,000.00			Y	B
B	West	GRE	1203	1896	6/1/2014	Hazel	Transformer	2	345	230	336	new transformer	MN			Planned	$4,000,000.00			Y	B
B	West	GRE	1203	1881	6/1/2009	Brookings County	Lyon County 345 kV	1	345		2066	new line	SD/MN		49	Planned	$107,650,865.84			Y	B
B	West	GRE	1203	1888	1/1/2011	Lyon County	Hazel	1	345		2066	new line	MN		22	Planned	$50,749,693.90			Y	B
B	West	GRE	1203	1883	9/1/2013	Lyon County	Franklin	2	345		2066	new line	MN		44	Planned	$48,333,041.81			Y	B
B	West	GRE	1203	1882	9/1/2013	Lyon County	Franklin	1	345		2066	new line	MN		44	Proposed	$96,666,083.61			Y	B
B	West	GRE	1203	1889	9/1/2013	Hazel	Minnesota Valley	1	230		388	new line	MN		8	Planned	$9,886,304.01			Y	B
B	West	GRE	1203	1887	9/1/2013	Lake Marion	Hampton Corner	1	345		2066	new line	MN		18	Planned	$39,545,216.02			Y	B
B	West	GRE	1203	1884	9/1/2013	Franklin	Helena	1	345		2066	new line	MN		67	Planned	$147,196,081.86			Y	B
B	West	GRE	1203	1885	9/1/2013	Franklin	Helena	2	345		2066	new line	MN		67	Planned	$73,598,040.93			Y	B
B	West	GRE	1203	1886	9/1/2013	Helena	Lake Marion	1	345		2066	new line	MN		16	Planned	$35,151,303.13			Y	B
B	West	GRE/XEL	1203	1899	6/1/2011	Willmar	Transformer	2	115	69	112		MN			Proposed	$3,000,000.00			Y	B
B	West	GRE/XEL	1203	1898	6/1/2011	Morris	Transformer	2	230	115	150	Upgrade 100 MVA to 150 MVA	MN			Proposed	$4,000,000.00			Y	B
B	West	GRE/XEL	1203	1891	6/1/2011	Brookings County	Toronto	1	115		310	new line	SD		20	Proposed	$19,223,368.90			Y	B

Appendix C: Project Table *Project Information from Facility table*

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	AmerenIL	143	Cahokia-Pinckneyville-1 230 kV	Cahokia - N. Coulterville section of Cahokia-Pinckneyville-1 230 kV - Increase ground clearance	IL				$644,600	6/1/2012	Proposed	230		C	Y
C	Central	AmerenIL	872	Mahomet-Champaign 138 kV Line 1592	Mahomet-Champaign 138 kV Line 1592 - Reconductor 1.55 miles of 477 kcmil ACSR from Mahomet Substation to Twr. 29	IL				$725,500	6/1/2009	Proposed	138		C	Y
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	B	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					6/1/2014	Proposed	138		C	Y
C	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				$1,139,000	6/1/2010	Proposed	138		C	Y
C	Central	AmerenIL	2063	North Coulterville - replace Transformer	North Coulterville 230/138 kV Substation Replace existing 140 MVA 230/138 kV transformer with spare (225 MVA or 252 MVA). Replace 138 kV wave trap in Tilden-Steeleville Line 1476 with minimum 1000 A SN capability	IL					6/1/2010	Proposed	230	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				$7,087,000	6/1/2012	Proposed	345	138	C	Y
C	Central	AmerenMO	1240	Reconductor Sioux-Huster-1 and -3 138 kV	Reconductor 15 miles of Sioux-Huster-1 and 13 miles of Sioux-Huster-3	MO				$4,996,000	6/1/2012	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	DEM	832	Lebanon 69kV Cap	Add 21.6 MVAR 69kV capacitor at Lebanon.	IN				$411,481	6/1/2008	Planned	69		C	NT
C	Central	DEM	840	Rushville 69kV Cap	Add 14.4 MVAR 69kV capacitor at Rushville.	IN				$510,845	6/1/2014	Planned	69		C	NT
C	Central	DEM	844	Newtown 138/69	Add new 138/69 kV TB at exsiting Newtown substation	OH				$4,198,021	6/1/2013	Planned	138	69	C	Y
C	Central	DEM	845	Stillwell 138/69	Construct new Stillwell 138/69 kV substation in the area served by Fairfield and Collinsville	OH				$8,525,369	6/1/2012	Planned	345	69	C	Y
C	Central	DEM	1248	Miami Fort GT 21.6MVAR 69kV capacitor	Install 21.6MVAR 69kV capacitor	OH				$551,247	6/1/2008	Planned	69		C	NT
C	Central	DEM	1249	Frankfort 230 36MVAR 69kV capacitor	Install 36 MVAR 69kV capacitor	IN				$632,358	12/31/2014	Planned	69		C	NT
C	Central	DEM	1260	Obannonville	60MVA 138/34kV substation loop 5489 into sub.	OH				$2,006,475	6/1/2008	Planned	138	34	C	Y
C	Central	DEM	1261	Lafayette Shadeland	22 MVA sub	IN				$1,306,341	6/1/2008	Under Construction	138	12	C	Y
C	Central	DEM	1500	Carmel 146th St 69kV Cap 1	Added one 36 MVAR 69kV capacitor at Carmel 146th St	IN				$492,860	12/1/2008	Planned	69		C	NT
C	Central	DEM	1509	Logansport South 69kV Cap	Install 69kV 36MVAR capacitor on the 69111 line terminal at Logansport South.	IN				$541,246	6/1/2008	Planned	69		C	NT
C	Central	DEM	1517	Jeffersonville Holman Ln 138/12	Construct a new Jeffersonville Holman Ln 138/12kV substation.	IN				$1,778,000	6/1/2010	Planned	138	13.8	C	Y

Appendix C: Project Table

Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	DEM	1518	Curliss 138/69	Construct a new Curliss 138/69kV, 150 MVA substation. Install one 69 kV circuit.	OH				$4,675,000	6/1/2011	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				$7,000,000	6/1/2014	Planned	230	69	C	Y
C	Central	DEM	1562	Bloomington - new 138/12 kv sub	Build 22.4MVA 138/12kV sub w/ 2 12kV exits in Bloomington, IN near intersection of SR37 & Rockport Road. Tap 13837 line.	IN				$911,000	6/1/2009	Planned	138	12	C	Y
C	Central	DEM	1565	Carlisle to Hutchings 138kv line conversion	Convert existing 187 MVA - 69 KV line (DP&L - F6601) to 138 KV between Carlisle and DP&L Hutchings	OH				$2,315,946	12/31/2013	Proposed	138		C	Y
C	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				$2,297,455	11/1/2008	Planned	138	13.1	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				$2,980,000	6/1/2015	Planned	138		C	Y
C	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				$1,873,000	6/1/2009	Planned	138	13.1	C	Y
C	Central	DEM	1646	SCP Eastwood 34KV to 138KV conversion	Convert the existing 34KV SCP Rec Eastwood sub to 138KV - loop the new F8887 ckt through using 954ACSR	OH				$100,000	12/1/2008	Planned	138		C	Y
C	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				$10,000,000	6/1/2009	Proposed	69	12	C	NT
C	Central	DEM	1649	Oakley Phase 2 - Transmission	The above projects provide for the installation of two new 138-13.09 kV, 33.6 MVA transformers with LTC in Oakley Substation to re-supply the load presently supplied by the tertiaries of TB 9 and TB 10. A 138 kV circuit breaker will be installed in the Oakley 138 kV ring bus to establish a position to supply the two new transformers. Several existing 138 kV disconnect switches will be replaced.	OH				$2,929,138	12/31/2009	Planned	138	13.1	C	Y
C	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				$2,000,000	6/1/2010	Planned	138	13.2	C	Y
C	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				$1,996,986	6/1/2010	Planned	138	12	C	Y
C	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				$834,141	12/1/2008	Planned	69		C	NT
C	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				$97,057	12/31/2008	Planned	69		C	NT
C	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				$128,975	12/31/2008	Planned	69		C	NT
C	Central	DEM	1885	Todhunter to Carlisle 69kV - F5661 line uprate	Todhunter to Carlisle 69kV - Feeder 5661 Uprate to 100C	OH				$561,600	12/31/2008	Planned	69		C	NT
C	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				$5,160,000	6/1/2009	Planned	69	13.1	C	NT

Appendix C: Project Table

Project Information from Facility table

Target Appendix	Region	TO	PrjID	Project Name	Project Description	State	State2	Allocation Type per FF	Share Status	Estimated Cost	Expected ISD	Plan Status	Max kV	Min kV	App ABC	MISO Facility
C	Central	DEM	1898	Tipton IMPA Ethanol Plant	Add 69kV line switch just outside the Tipton Muni sub (new 69191) to feed radial tap to new Ethanol plant. 100% reimbursable by IMPA - IMPA to build line and sub	IN				$50,000	6/1/2010	Planned	69		C	NT
C	Central	DEM	1900	Avon Industrial Park 138-12kV new dist sub	Avon Industrial Park - Construct 138-12kV - 22.4 MVA sub and 2.6 mile - 138kV radial line from roughly the Avon South sub - AFTER 138KV CONVERSION	IN				$2,946,000	6/1/2011	Planned	138	12	C	Y
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				$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				$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				$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				$320,000	6/1/2016	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				$2,500,000	6/1/2012	Planned	138	69	C	NT
C	Central	DEM	2126	Martinsville SE Jct replace line switches	600A switches 1&2 to be replaced with 1200A switches in the 6903 line	IN				$100,000	6/1/2009	Planned	69		C	NT
C	Central	DEM	2127	Martinsville 69163-1 switch replacement	69163-1 switch replacement near tap to HE Cope with 1200A switch	IN				$50,000	6/1/2010	Planned	69		C	NT
C	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				$60,000	6/1/2009	Planned	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				$500,000	6/1/2014	Planned	69		C	NT
C	Central	DEM	2130	Summit Grove 69-12kV distribution sub	Construct new 22.4 - 69/12kV substation with one 12kV breaker in the 69117 line	IN				$1,300,000	3/31/2009	Planned	69	12	C	NT
C	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				$20,000	6/30/2010	Planned	69		C	NT
C	Central	DEM	2132	Frances Creek 69kV capacitor	Frances Creek Install 36MVAR 69kV capacitor bank	IN				$500,000	6/30/2010	Planned	69		C	NT
C	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				$1,550,000	6/1/2010	Planned	69		C	NT
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				$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				$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				$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				$0	6/30/2014	Planned	69		C	NT
C	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				$50,000	6/30/2014	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				$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				$1,377,500	6/30/2013	Planned	69		C	NT

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C	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				$1,269,000	12/31/2009	Planned	345	138	C	Y
C	Central	DEM	2142	Carmel 1st Ave 69/12kv New Sub	Construct sub with 22.4MVA Bk 1 w/o reg., and 3 12kv exits in 6966 line	IN				$3,764,000	6/1/2010	Planned	69	12	C	NT
C	Central	DEM	2143	Frances Creek 345/69kV Bank 2	Add Frances Creek 345/69kV Bank 2 - 200MVA with LTC	IN				$2,400,000	6/1/2012	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				$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				$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				$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				$1,376,000	6/30/2015	Planned	69		C	NT
C	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				$3,860,000	12/31/2009	Planned	69		C	NT
C	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				$1,040,000	6/1/2009	Planned	138		C	Y
C	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				$1,300,000	6/1/2010	Planned	69	12	C	NT
C	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				$690,000	6/1/2009	Planned	138		C	Y
C	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				$86,000	3/1/2009	Planned	69		C	NT
C	Central	DEM	2153	Mohawk to Lee Hanna 69kV reconductor	Mohawk to Lee Hanna 69kV reconductor 69130 ckt (5.27 mi) with 954acsr@100C	IN				$2,317,000	6/1/2010	Planned	69		C	NT
C	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				$100,000	6/1/2010	Planned	69	12	C	NT
C	Central	IPL	897	Thompson 345/138kV Autotransformer	Add new 345/138kV autotransformer at Thompson Substation	IN				$7,200,000	6/1/2012	Proposed	345	138	B	Y
C	Central	IPL	2051	Petersburg - Thompson 345 kV line Capacity Upgrade	Increase Capacity from 956 MVA to 1195 MVA	IN					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					6/1/2012	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	6/1/2014	Planned	138	69	C	Y
C	East	FE	1597	Galion - Add 138kV Cap Banks	Add (2) - 50 MVAR Cap Banks with breaker facilities to existing substation.	OH				$1,650,000	6/1/2014	Proposed	138		C	Y

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C	East	FE	1602	Begin Right-of-way research and initial contacts for potential "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				$15,000,000	6/1/2014	Proposed	138	69	C	Y
C	East	FE	1603	Begin Right-of-way research and initial contacts for potential 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				$15,000,000	6/1/2012	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	6/1/2014	Planned	138		C	Y
C	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				$6,400,000	6/1/2011	Proposed	345		C	Y
C	East	FE	1916	Mansfield: 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	12/31/2011	Planned	69		C	Y
C	East	FE	1919	Columbia Sub - Install 69 kV Cap Bank	Install a 14.4 MVAR capacitor bank and breaker at Columbia Substation.	OH				$623,600	6/1/2008	In Service	69		C	Y
C	East	FE	1920	New 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				$5,512,000	6/1/2011	Planned	138	69	C	Y
C	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				$4,000,000	6/1/2011	Planned	138	36	C	Y
C	East	ITC	694	Saratoga Station	Saratoga 345/120 kV switching station	MI				$29,600,000	12/31/2009	Proposed	345	120	C	Y
C	East	ITC	903	Stephens - Bismark	Creates a Bismark-Stephens 230 kV line with a 230/120 kV Xfmr at Stephens, and also builds a new Stephens-Redrun 120 kV	MI				$9,000,000	12/31/2008	Proposed	230	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	6/1/2014	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					6/30/2010	Proposed	120		C	Y

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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					5/31/2008	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					6/1/2012	Proposed	345	120	C	Y
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

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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	1850	Hancock 230/120kV Transformer	Cut the Wixom-Quaker 230kV circuit into Hancock Station, install a 230/120kV transformer similar to the one at Quaker.	MI					6/1/2016	Proposed	230	120	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	1860	Breaker Replacement Program 2009	Throughout System	MI					12/31/2009	Proposed			C	Y
C	East	ITC	1861	Breaker Replacement Program 2010	Throughout System	MI					12/31/2010	Proposed			C	Y
C	East	ITC	1862	Cable Termination Replacement 2009	Throughout System	MI					12/31/2009	Proposed			C	Y
C	East	ITC	1863	Cable Termination Replacement 2010	Throughout System	MI					12/31/2010	Proposed			C	Y
C	East	ITC	1864	Relay Betterment Program 2009	Throughout System	MI					12/31/2009	Proposed			C	Y
C	East	ITC	1865	Relay Betterment Program 2010	Throughout System	MI					12/31/2010	Proposed			C	Y
C	East	ITC	1868	Cato GIS replacement	Like for Like Replacement (Over $1 million)	MI					12/31/2010	Planned	120		C	Y
C	East	ITC	1872	Scio	Distribution Interconnection to add new 120/41kV transformer. Brings the Lark-Spruce 120kV circuit into the station.	MI					12/31/2008	Planned	120		C	Y
C	East	METC	240	Garfield-Hemphill 138kV	Swap a portion of this circuit with Thetford-Hemphill, thus utilizing much of the existing 795/1431 ACSR on that circuit. Rebuild the remaining portion into Garfield to 954 ASCR. Total amount of miles to be rebuilt TBD.	MI			Excluded		6/1/2014	Proposed	138		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

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C	East	METC	651	Stover - Clearwater 138 kV Line (Phase 2)	Rebuild Stover - Clearwater 138 kV line 8.8 miles to 795 ACSS	MI				$2,800,000	5/1/2018	Proposed	138		C	Y
C	East	METC	662	Weeds Lake	Tap the 345kV Argenta - Twin Branch circuit with a new 345/138kV EHV substation called Weeds Lake and loop in the two 138kV Argenta - Milham circuits into the new substation. Build 4 new (approximately 10 mile) 138kV circuits from the Argenta-Milham circuits to Weeds Lake. Also, replace 138kV breaker 6010 at Milham.	MI					6/1/2013	Proposed	345	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	6/1/2011	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	5/1/2015	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	6/1/2017	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	1658	138 kV Sag Clearance	throughout system	MI					12/31/2008	Planned			C	Y
C	East	METC	1795	David Jct. - Bingham 138kV	Rebuild 19 miles of 138kV 336.4 ACSR to 954 ACSR.	MI				$11,700,000	6/1/2010	Planned	138		C	Y
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	1806	Island Rd - Delhi 138kV	Rebuild 11 miles of 138kV 115 CU to 954 ACSR	MI					6/1/2015	Proposed	138		C	Y

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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-Hodenpyl 138kV circuit to 954 ACSR DCT. String second side of Hodenpyl-Tippy, creating a 2nd 138kV circuit from Keystone-Tippy. Prebuild to 230kV construction.	MI					6/1/2017	Proposed	138		C	Y
C	East	METC	1810	Iosco - Cottage Grove 138kV	Rebuild 23 miles of 138kV 115 CU to 954 ACSR. Prebuild to 230kV construction	MI					6/1/2018	Proposed	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	1821	Breaker Replacement Program 2009	Throughout system	MI					12/31/2009	Proposed			C	Y
C	East	METC	1822	Breaker Replacement Program 2010	Throughout system	MI					12/31/2010	Proposed			C	Y
C	East	METC	1823	Relay Betterment Program 2009	Throughout system	MI					12/31/2009	Proposed			C	Y
C	East	METC	1824	Relay Betterment Program 2010	Throughout system	MI					12/31/2010	Proposed			C	Y
C	East	METC	1826	Sag clearance 2009	Throughout system	MI					12/31/2009	Proposed			C	Y
C	East	METC	1827	Sag clearance 2010	Throughout system	MI					12/31/2010	Proposed			C	Y
C	East	METC	1828	Argenta-Palisades 345kV ckt. 1 & 2	Remove the SAG limit on Argenta-Palisades 345kV ckt 1& 2.	MI					6/1/2010	Planned	345		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	1833	Sag clearance 2011	Throughout system	MI					12/31/2011	Proposed			C	Y
C	East	METC	1839	Acme	New Bulk Power station served from Keystone-Stover 138kV circuit	MI					5/1/2009	Planned	138		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	7/1/2009	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	7/1/2009	Planned	69		C	NT

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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	7/1/2009	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	7/1/2009	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	7/1/2009	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	7/1/2009	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	7/1/2009	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	7/1/2009	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	7/1/2009	Planned	69		C	NT
C	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	12/1/2010	Proposed	138		C	Y
C	East	NIPS	1974	Liberty Park to Lake George - Upgrade Capacity	Increase circuit capacity between Liberty Park and Lake George (5.8 miles).	IN				$1,043,000	11/1/2009	Proposed	138		C	Y
C	East	NIPS	1975	Liberty Park to St. John - Upgrade Capacity	Increase circuit capacity between Liberty Park and St. John (2.3 miles).	IN				$586,000	12/1/2009	Proposed	138		C	Y
C	East	NIPS	1976	St. John - Add 2nd 345/138 kV transformer	Install 2nd 345/138 kV transformer, single 345 kV and single 138 kV breakers at St. John to increase substation capacity.	IN				$6,853,000	12/31/2011	Proposed	345	138	C	Y
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	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	12/1/2012	Proposed	138	69	C	Y
C	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	12/1/2012	Proposed	138	69	C	Y
C	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	12/1/2010	Proposed	69		C	Y
C	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	10/1/2009	Proposed	69		C	Y
C	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	10/1/2009	Proposed			C	Y
C	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	12/1/2011	Proposed	69		C	Y

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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	12/1/2011	Proposed	69		C	Y
C	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	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	Proposed	138	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	5/1/2011	Proposed	69		C	Y
C	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	6/1/2006	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	12/1/2009	Proposed	69		C	Y
C	East	NIPS	1999	Circuit 6907 reroute at Norway Gen Pland	Reroute existing 69 kV line around hydro dam.	IN				$99,000	12/1/2008	Planned	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	12/1/2008	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	12/1/2009	Proposed	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				$6,221,325	6/1/2016	Proposed	138		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	6/1/2013	Proposed	138		C	Y
C	West	ATC LLC	1623	Montrose Capacitor Banks	Install two 16.33 MVAR 69kV capacitor banks at Montrose substation	WI					6/1/2014	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	6/1/2018	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					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				$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					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					6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	1685	Hale 138 kV bus	Construct a 138 kV bus at Hale substation to permit third Brookdale distribution transformer interconnection	WI				$4,000,000	6/1/2009	Proposed	138		C	Y
C	West	ATC LLC	1688	Beardsley Street Circuit Breakers	Install two 69 kV breakers at Beardsley Street substation	WI					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					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				$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				$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				$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					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					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				$716,000	6/1/2015	Proposed	69		C	Y

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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					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					6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	1701	Blaney Park-Munising	Rebuild Blaney Park-Munising 69 kV to 138 kV	WI				$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				$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					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				$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				$56,300,000	6/1/2013	Proposed	138		C	Y
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				$4,162,000	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					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					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				$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					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				$1,550,000	6/1/2018	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				$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					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				$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					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				$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					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				$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				$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					6/1/2023	Proposed	69		C	Y

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C	West	ATC LLC	1725	Evansville-Brooklyn 69 kV line	Construct an Evansville-Brooklyn 69 kV line	WI				$8,120,000	6/1/2018	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				$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					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					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 230 F degree summer emergency ratings	MI						Proposed	138		C	Y
C	West	ATC LLC	1730	West Middleton-Blount 138 kV line	Construct a West Middleton-Blount 138 kV line	WI					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						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				$600,000	6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	1733	Boxelder temporary Capacitor bank	Install a temporary 24.5 MVAR 138-kV capacitor bank at Boxelder Substation	WI				$600,000	6/1/2008	Planned	138		C	Y
C	West	ATC LLC	1940	M38 capacitor bank	Install one 8.16 MVAR 138 kV capacitor bank at the M38 substation	MI					6/1/2009	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					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	1946	2nd Spring Green 138-69 kV Transformer	Install a 2nd Spring Green 138-69 kV Transformer	WI					6/1/2010	Proposed	138	69	C	Y
C	West	ATC LLC	1947	Uprate Black Earth-Stage Coach 69-kV	Uprate Black Earth-Stage Coach 69-kV						6/1/2010	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					6/1/2010	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					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					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	2020	Uprate Chandler Delta 69 kV #2	Increase line clearance to 167 deg F SE	MI					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	2021	Uprate Chandler-LakeheadTap-Masonville 69 kV	Increase line clearance to 167 deg F SN/SE	MI					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	2022	Uprate Delta-Mead-NorthBluff 69 kV	Increase line clearance to 167 deg F SN/SE	MI					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	2023	Uprate Masonville-Gladstone 69 kV	Increase line clearance to 167 deg F SN/SE	MI					6/1/2009	Proposed	69		C	Y
C	West	ATC LLC	2024	Uprate North Bluff-Gladstone 69kV	Increase line clearance to 167 deg F SN/SE	MI					6/1/2009	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					6/1/2009	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					6/1/2009	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					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					6/1/2010	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					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					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					6/1/2012	Proposed	69		C	Y
C	West	ATC LLC	2033	Uprate Bain-Kenosha 138-kV	Upgrade substation equipment at Bain & Kenosha	WI					6/1/2013	Proposed	138		C	Y
C	West	ATC LLC	2034	Add a 2nd Cap to Veron 69 kV	Add a 2nd 16.2 Mvar Cap to Veron 69 kV	WI					6/1/2014	Proposed	69		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					6/1/2014	Proposed	69		C	Y
C	West	ATC LLC	2037	Rebuild Dane-Okee 69 kV	Rebuild Dane-Okee 69 kV	WI					6/1/2015	Proposed	69		C	Y

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C	West	ATC LLC	2038	Spring Valley-S Lake Geneva 138 kV	Construct Spring Valley-Twin Lakes-S Lake Geneva 138 kV	WI					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					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					6/1/2016	Proposed	69		C	Y
C	West	ATC LLC	2041	Uiprate Forsyth 138-69 kV Tr	Address CT and/or relays limitations	MI					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					6/1/2017	Proposed			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					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					6/1/2018	Proposed	69		C	Y
C	West	ATC LLC	2045	Rebuild Victoria-Ontonagon 69 kV	Rebuild Victoria-Ontonagon 69 kV	MI					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					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					6/1/2019	Proposed	69		C	Y
C	West	ATC LLC	2048	Rebuild Victoria-Mass 69 kV	Rebuild Victoria-Mass 69 kV	MI					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					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						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					6/1/2014	Proposed	138		C	Y
C	West	ATC LLC	2103	A035	Network upgrades for tariff service request			TDSP	Direct Assigned	$96,650,282	1/1/2013	Planned	345	138	C	Y
C	West	ATC LLC	2161	Uprate Glenview-Shoto 138 kV	Increase line clearance to 200 deg F SN/SE	WI					6/1/2009	Proposed	138		C	Y
C	West	ATC LLC	2162	2nd McCue-LaMar 69 kV line	Construct a 2nd McCue-LaMar 69 kV line	WI					6/1/2017	Proposed	69		C	Y
C	West	ATC LLC	2163	Replace Ellinwood Tr #2	Replace Ellinwood 138-69 kv Tr #2	WI				$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				$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				$441,446	6/1/2010	Proposed	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	6/1/2001	Proposed	115		C	Y
C	West	ITCM	1343	Add a second Fairfax 161/69 kV transformer	Add a second Fairfax 161/69 kV transformer (250 MVA)	IA				$1,500,000	6/1/2011	Proposed	161	69	C	Y
C	West	ITCM	1738	Bertram-Hills 161kV Reconductor	Reconductor 33 miles of 161kV from Bertram to Hills, sum rate	IA					12/31/2012	Proposed	161		C	Y
C	West	ITCM	1740	Marshalltown-Boone 115 kV line rebuild	Marshalltown-Fernald-Ames-Boone Jct-Boone 115 kV line will be rebuilt/upgraded in 2011	IA					12/31/2011	Proposed	161		C	Y
C	West	ITCM	1741	Dotson - Storden	Network upgrades for GIA	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					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					12/31/2015	Proposed	161		C	Y
C	West	ITCM	1766	Lily Lake 69/34kV sub	Build a new 69/34kV sub near Amana. The sub will tie to the Crozier REC-Amana Refrigeration 69kV line	IA					12/31/2009	Proposed	69	34	C	NT
C	West	ITCM	1774	Truro 69/34kV Sub	Add a 69/34kV Xfmr in the Truro sub and reinsulate nearly 10 miles of 34kV to 69kV to serve the new sub.	IA					12/31/2009	Proposed	69	34	C	NT
C	West	ITCM	1775	Triboji-CBPC Milford 69kV	Rebuild the Triboji-Milford 69kV line.	IA					12/31/2009	Planned	69		C	NT
C	West	ITCM	1777	Solon Junction 161 & 34kV lines	0.75 miles of 161/34kV dbl ckt lines needed to tie to a new CIPCO owned 161/34kV Solon Jct sub	IA					12/31/2009	Proposed	161	34	C	Y
C	West	MDU	1356	Glenham - Reactors 230 115 Control high voltage on WAPA Bismarck - Oahe 230 kV line	Glenham - Reactors 230 115 Control high voltage on WAPA Bismarck - Oahe 230 kV line	ND					11/1/2012	Proposed	230	115	C	Y

Appendix C: Project Table

Project Information from Facility table

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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				$7,000,000	1/1/2010	Proposed	69	69	C	NT
C	West	SMP	2167	City of Redwood Falls, MN load serving upgrades	Adding approx 4.0 mimles of new 69kV transmission line and a new load serving substation (Estimated in service 2010)	MN				$2,500,000	1/1/2010	Proposed	69	69	C	NT
C	West	XEL	1376	Poplar Lake 161/69 sub on St Croix Falls - Apple River 161 kV line	Poplar Lake 161/69 sub on St Croix Falls - Apple River 161 kV line	WI				$3,000,000	5/1/2011	Planned	161	69	C	Y
C	West	XEL	1378	West St. Cloud - Granite City 115 Reconductor	West St. Cloud - Granite City 115 Reconductor	MN				$2,000,000	6/1/2011	Proposed	115		C	Y
C	West	XEL	2155	Monticello Transformer upgrade	Upgrade the Monticello 345/230 kV TR to 550 MVA	MN				$5,000,000	6/1/2011	Planned	345	230	C	Y
C	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				$17,000,000	6/1/2011	Planned	345	69	C	Y
C	West	XEL	2157	Douglas Co 2nd TR	2nd Douglas Co 115/69 kV transfromer	MN				$3,000,000	6/1/2011	Planned	115	69	C	NT
C	West	XEL	2158	Upgrade Sauk Center - Osakis 69 kV line	Upgrade Sauk Center - Osakis 69 kV line to a lower impedance.	MN				$4,440,000	6/1/2011	Planned	69		C	NT
C	West	XEL	2159	Nelson Cap Bank	Add 18 MVAR cap at Nelson substation	WI				$800,000	6/1/2010	Planned	69		C	NT
C	West	XEL	2160	Park Falls TR upgrade	Upgrade the Park Falls 115/34.5 kV TR to 47 MVA	WI				$3,000,000	6/1/2012	Planned	115	34.5	C	NT
C	West	XEL	2173	Hiawatha distribution substation	New distribution substation on Elliot Park - South Town 115 kB line	MN					6/1/2010	Planned	115	13	C	Y
C	West	XEL	2174	Mid Town Substation	New distribution substation in South Minneapolis	MN					6/1/2010	Planned	115	13	C	Y
C	West	XEL	2175	South Minneapolis	(1) New 345/115 kV substation at Hiawatha (2) new Highway 280 345 kV switching station on Terminal - Kohlman Lake 345 kV line (3) new 345 kv line from Highway 280 substation to Hiawatha substation	MN					6/1/2014	Proposed	345	115	C	Y
C	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					6/1/2012	Proposed	115	69	C	Y
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
C	West	XEL	2178	Regional Incremental Generation Outlet	(1) New 161 kV line from Pleasant Valley - Byron 161 kV line (2) Pleasant Valley - Willow Creek 161 kV line (3) Byron - Cascade Creek 2nd circuit (4) Pleasent Valley 2nd 345/161 kV line.	MN					6/1/2012	Proposed	345	161	C	Y
C	West	XEL/GRE	1952	Lester Prairie capacitor bank	This project is to add a 10 MVAR cap bank at Lester Prairie. 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					12/1/2011	Proposed	69		C	NT
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

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Project Information from Facility table

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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	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	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	Central	Midwest ISO	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	Midwest ISO	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	Midwest ISO	2234	MTEP08 Reference Future EHV Overlay - Palmyra to Meradosia	Build 345 kV circuit from Palmyra to Meradosia in Illinois	MO	IL			$75,000,000	8/1/2018	Conceptual	345	138	C	Y
C	Central	Midwest ISO	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	Midwest ISO	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	Midwest ISO	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	Midwest ISO	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	Midwest ISO	2239	MTEP08 Reference Future EHV Overlay - Rising to Sidney	Build 345 kV circuit from Rising to Sidney in Illinois	IL				$33,000,000	8/1/2018	Conceptual	345		C	Y
C	Central	Midwest ISO	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	Midwest ISO	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	Midwest ISO	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	Midwest ISO	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	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	Central	Midwest ISO	2248	MTEP08 Reference Future EHV Overlay - Ottumwa to Thomas Hill	Build 345 kV circuit from Ottumwa in Iowa to Thomis Hill in Missouri	IA	MO			$154,432,990	8/1/2018	Conceptual	345		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

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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	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	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	Manitol	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
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	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
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

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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

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Target Appendix	Region	Rep Source	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	143	56	6/1/2012	Cahokia	N. Coulterville	1	230		400	increase ground clearance	IL	45		Proposed	$644,600.00			Y	C
C	Central	Ameren	1240	1940	6/1/2012	Sioux	Huster	3	138		370	Reconductor 13 miles	MO	13		Proposed	$2,498,000.00			Y	C
C	Central	Ameren	1240	1939	6/1/2012	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15		Proposed	$2,498,000.00			Y	C
C	Central	Ameren	1539	2616	6/1/2015	Roxford	Stallings	1	345		1195	Install PCB at Roxford Substation	IL			Proposed	$1,200,000.00			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	$2,702,200.00			Y	C
C	Central	AmerenIL	2059	3967	6/1/2010	Centerville	South Belleville	1	138		160	Install 138 kV breaker at Centerville Substaion	IL			Proposed	$1,139,000.00			Y	C
C	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				Y	C
C	Central	AmerenIL	2063	3966	6/1/2010	North Coulterville	Tilden Tap	1	138		160	Replace terminal equipment at North Coulterville	IL			Proposed				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	$575,400.00			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	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	$7,087,000.00			Y	C
C	Central	AmerenIP	872	848	6/1/2009	Mahomet	Champaign	1	138		240	Reconductor 1.55 mile 477 kcmil ACSR from Mahomet Sub. To Twr. 29	IL	1.55		Proposed	$725,500.00			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	$171,600.00			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				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	$534,000.00			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	DEM	832	3069	6/1/2008	Lebanon	Capacitor		69		21.6 MVAR	Add capacitor	IN			Planned	$411,481.00			NT	C
C	Central	DEM	840	819	6/1/2014	Rushville	Capacitor		69		14.4 MVAR	Add capacitor	IN			Planned	$510,845.03			NT	C
C	Central	DEM	844	1310	6/1/2013	Newtown	transformer	1	138	69	150	Add new 138/69kV substation	OH			Planned	$4,198,021.00			Y	C
C	Central	DEM	845	1312	6/1/2012	Stillwell	substation	1	345	69	150	Stillwell Sub- Install new 345-69 kV capacity in area served by Fairfield and Collinsville	OH			Planned	$8,525,369.00			Y	C
C	Central	DEM	1248	1956	6/1/2008	Miami Fort GT	Capacitor		69		21.6MVAR	Install 21.6MVAR cap bk.	OH			Planned	$551,247.00			NT	C
C	Central	DEM	1249	1957	12/31/2014	Frankfort 230	Capacitor		69		36 MVAR	Install 36 MVAR 69kV capacitor	IN			Planned	$632,358.00			NT	C
C	Central	DEM	1260	1976	6/1/2008	Obannonville			138	34		60MVA 138/34kV substation loop 5489 into sub.	OH			Planned	$2,006,475.00			Y	C
C	Central	DEM	1261	1977	6/1/2008	Lafayette Shadeland			138	12		22 MVA sub	IN			Under Construction	$1,306,341.00			Y	C
C	Central	DEM	1500	2573	12/1/2008	Carmel 146th St	Capacitor 1		69		36 MVAR	Install a 69kV 36MVAR cap bank	IN			Planned	$492,860.00			NT	C
C	Central	DEM	1509	2585	6/1/2008	Logansport South	Capacitor		69		36 MVAR	Install 36 MVAR unit on 69111 line terminal	IN			Planned	$541,246.00			NT	C
C	Central	DEM	1517	2593	6/1/2010	Jeff Holman Ln			138	13.8		Build a std 138 13.8kV 22.4MVA sub with 2 138.8 kV UG exits at Jeffersonville	IN			Planned	$1,778,000.00			Y	C
C	Central	DEM	1518	2594	6/1/2011	Curliss	transformer		138	69		Install 138-69 kV, 150 MVA autotransformer. Install one 69 kV circuit.	OH			Planned	$4,675,000.00			Y	C
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	$7,000,000.00			Y	C
C	Central	DEM	1562	3113	6/1/2009	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			Planned	$911,000.00			Y	C
C	Central	DEM	1565	3117	12/31/2013	Carlisle	Hutchings (DP&L)	1	138		374	Convert existing 187 MVA - 69 KV line (DP&L - F6601) to 138 KV between Carlisle and DP&L Hutchings	OH	2.6		Proposed	$2,315,945.52			Y	C

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C	Central	DEM	1567	3119	11/1/2008	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	OH			Planned	$2,297,455.34			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	$2,980,000.00			Y	C
C	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			Planned	$1,873,000.00			Y	C
C	Central	DEM	1646	3377	12/1/2008	SCP Eastwood	substation		138			Convert the existing 34KV SCP Rec Eastwood sub to 138KV - loop the new F8887 ckt through using 954ACSR	OH		0.2	Planned	$100,000.00			Y	C
C	Central	DEM	1647	3378	6/1/2009	Carmel SE	69/12 substation		69	12	153	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		4	Proposed	$10,000,000.00			NT	C
C	Central	DEM	1649	3380	12/31/2009	Oakley	transformer		138	13.1		one new 138-13.09 kV, 33.6 MVA transformers with LTC and a 138 kV circuit breaker at Oakley Substation to re-supply the load presently supplied by TB 9. Several existing 138 kV disconnect switches will be replaced.	OH			Planned	$2,929,138.00			Y	C
C	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	$2,000,000.00			Y	C
C	Central	DEM	1880	3774	6/1/2010	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	$1,996,985.67			Y	C
C	Central	DEM	1882	3777	12/1/2008	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	$834,140.80			NT	C
C	Central	DEM	1883	3779	12/31/2008	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	$97,056.66			NT	C
C	Central	DEM	1884	3780	12/31/2008	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	$128,975.44			NT	C
C	Central	DEM	1885	3781	12/31/2008	Todhunter	Carlisle	1	69			Modify spans in 69 kV feeder 5661 Uprate to 100C	OH	1		Planned	$561,599.80			NT	C
C	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	Planned	$5,160,000.00			NT	C
C	Central	DEM	1898	3794	6/1/2010	Tipton	IMPA Ethanol Plant	1	69		100	Add 69kV line switch just outside the Tipton Muni sub (new 69191) to feed radial tap to new Ethanol plant. 100% reimbursable by IMPA - IMPA to build line and sub	IN		1	Planned	$50,000.00			NT	C
C	Central	DEM	1900	3796	6/1/2011	Avon Industrial Park	new dist sub	1	138	12	306	Avon Industrial Park - Construct 138-12kV - 22.4 MVA sub and 2.6 mile - 138kV radial line from roughly the Avon South sub - AFTER 138KV CONVERSION	IN		2.6	Planned	$2,946,000.00			Y	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	$455,228.77			NT	C

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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	$115,960.76			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	$2,300,000.00			NT	C
C	Central	DEM	2124	2909	6/1/2016	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	$320,000.00			NT	C
C	Central	DEM	2125	2910	6/1/2012	Centerton	transformer	1	138	69	120	Upgrade/replace existing 75MVA 138/69kV bank with 120MVA bank	IN			Planned	$2,500,000.00			NT	C
C	Central	DEM	2126	2911	6/1/2009	Martinsville SE Jct	switches		69		143	600A switches 1&2 to be replaced with 1200A switches	IN			Planned	$100,000.00			NT	C
C	Central	DEM	2127	2912	6/1/2010	Martinsville 69	69163-1 switch		69		143	69163-1 switch replacement near tap to HE Cope with 1200A switch	IN			Planned	$50,000.00			NT	C
C	Central	DEM	2128	2913	6/1/2009	Martinsville 69	Martinsville SE Jct	1	69		80	Uprate 6903 line's 336acsr to 100C operation	IN	4		Planned	$60,000.00			NT	C
C	Central	DEM	2129	2914	6/1/2014	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	$500,000.00			NT	C
C	Central	DEM	2130	2915	3/31/2009	Summit Grove	distribution sub		69	12		Construct new 22.4 - 69/12kV substation with one 12kV breaker in the 69117 line	IN			Planned	$1,300,000.00			NT	C
C	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	$20,000.00			NT	C
C	Central	DEM	2132	2917	6/30/2010	Frances Creek	capacitor		69		36 MVAR	Frances Creek Install 36MVAR 69kV capacitor bank	IN			Planned	$500,000.00			NT	C
C	Central	DEM	2133	2918	6/1/2010	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	$1,550,000.00			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	$2,712,500.00			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	$400,000.00			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	$0.00			NT	C
C	Central	DEM	2137	2922	6/30/2014	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	$0.00			NT	C
C	Central	DEM	2138	2923	6/30/2014	Greenwood HE Gilmore	switches		69		100	Greenwood HE Gilmore - Upgrade (2) 69kV line switches for 1200 amp capacity (or replace if required) in the 69102 line	IN			Planned	$50,000.00			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	$50,000.00			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	$1,377,500.00			NT	C

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C	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(1782 and 7481) wave traps with no resulting branch ratings changes	OH			Planned	$1,269,000.00			Y	C
C	Central	DEM	2142	2928	6/1/2010	Carmel 1st Ave	distribution sub		69	12		Construct sub with 22.4MVA Bk 1 w/o reg., and 3 12kv exits in 6966 line (name was previously changed from 3rd ave to 1st ave)	IN			Planned	$3,764,000.00			NT	C
C	Central	DEM	2143	2929	6/1/2012	Frances Creek	bank 2	2	345	69	200	Add Frances Creek 345/69kV Bank 2 - 200MVA with LTC	IN			Planned	$2,400,000.00			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	$424,000.00			NT	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	$2,400,000.00			Y	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	$2,400,000.00			Y	C
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	$420,000.00			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	$1,376,000.00			NT	C
C	Central	DEM	2148	2935	12/31/2009	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	$3,860,000.00			NT	C
C	Central	DEM	2149	2936	6/1/2009	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	$1,040,000.00			Y	C
C	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	$1,300,000.00			NT	C
C	Central	DEM	2151	2938	6/1/2009	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	$690,000.00			Y	C
C	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			Planned	$86,000.00			NT	C
C	Central	DEM	2153	2941	6/1/2010	Mohawk	Lee Hanna	1	69		71.7	Mohawk to Lee Hanna 69kV reconductor 69130 ckt (5.27 mi) with 954acsr@100C	IN			Planned	$2,317,000.00			NT	C
C	Central	DEM	2154	2942	6/1/2010	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			Planned	$100,000.00			NT	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	$7,200,000.00			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	FE	1593	2676	6/1/2014	Galion	Substation Upgrades	2	138	69	100/134 MVA	Replace 138/69 kV transformer	OH			Planned	$1,090,000.00			Y	C

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C	East	FE	1597	2680	6/1/2014	Galion 138kV	Capacitor Bank		138			Capacitor Bank Addition	OH			Proposed	$1,650,000.00			Y	C
C	East	FE	1602	2690	6/1/2014	Broadview	Substation	1	138	69	78/100 MVA	New 138/69 kV transformer	OH			Proposed				Y	C
C	East	FE	1602	2691	6/1/2014	Broadview	Substation	2	138	69	78/100 MVA	New 138/69 kV transformer	OH			Proposed				Y	C
C	East	FE	1602	2692	6/1/2014	Clark	Broadview	1	138		199/229 MVA	New Line	OH	11.3		Proposed				Y	C
C	East	FE	1602	2693	6/1/2014	Broadview	Urbana	1	138		276/309 MVA	New Line	OH	5.2		Proposed				Y	C
C	East	FE	1602	2694	6/1/2014	East Springfield	Broadview	1	138		199/241 MVA	New Line	OH	11.8		Proposed				Y	C
C	East	FE	1602	2695	6/1/2014	Broadview	Mill Creek	1	138		151/174 MVA	New Line	OH	36		Proposed				Y	C
C	East	FE	1602	2689	6/1/2014	Broadview	Substation		138			New Substation	OH			Proposed	$15,000,000.00			Y	C
C	East	FE	1603	2671	6/1/2012	Darby	Tangy	1	138				OH	18		Proposed				Y	C
C	East	FE	1603	2670	6/1/2012	London	Darby	1	138				OH	20.6		Proposed				Y	C
C	East	FE	1603	2669	6/1/2012	East Springfield	London	2	138				OH		15	Proposed	$15,000,000.00			Y	C
C	East	FE	1606	2698	6/1/2014	Barberton	South Akron	1	138		192/229 MVA	New Line	OH	8.1		Planned	$3,490,000.00			Y	C
C	East	FE	1607	2699	6/1/2011	Existing Chamberlin-Mansfield Line	Hanna	1	345		1504/1793 MV	New Line looping from existing line	OH	2		Proposed	$6,400,000.00			Y	C
C	East	FE	1916	3876	12/31/2011	New Mansfield	New 69kV Substation		69			New Substation	OH			Planned	$2,942,000.00			Y	C
C	East	FE	1919	3879	6/1/2008	Columbia Sub	capacitor bank	1	69			Capacitor Bank Addition	OH			In Service	$623,600.00			Y	C
C	East	FE	1920	3880	6/1/2011	New Shinrock/Johnson area	Substation	1	138	69		New Substation	OH			Planned	$5,512,000.00			Y	C
C	East	FE	2120	2903	6/1/2011	Q3-Northfield	Keystone	1	138			Loop in the exsting Q-3-Mayfield/Northfield circuit	OH	0.01		Planned				Y	C
C	East	FE	2120	2904	6/1/2011	Keystone		1	138			New 138kV substation	OH			Planned	$4,000,000.00			Y	C
C	East	FE	2120	2901	6/1/2011	Q-13-Eastlake/Lloyd	Keystone	1	138			New line extension from current 138kV Line	OH	0.01		Planned				Y	C
C	East	FE	2120	2900	6/1/2011	Q-12-Eastlake/Lloyd	Keystone	1	138			New line extension from current 138kV Line	OH	0.01		Planned				Y	C
C	East	FE	2120	2905	6/1/2011	Keystone		1	138	36		New 138-36kV Distribution transformer	OH			Planned				NT	C
C	East	FE	2120	2902	6/1/2011	Q3-Mayfield	Keystone	1	138			Loop in the exsting Q-3-Mayfield/Northfield circuit	OH	0.01		Planned				Y	C
C	East	ITC	694	1394	12/31/2009	Saratoga 345/120 kV	transformer	1	345	120	700		MI			Proposed	$5,000,000.00			Y	C
C	East	ITC	694	1393	12/31/2009	Saratoga 345 kV	Belle River 345	1	345		2259		MI	16.5	4.2	Proposed	$6,000,000.00			Y	C
C	East	ITC	694	1392	12/31/2009	Saratoga 345 kV	Pontiac 345 kV	1	345		1769		MI	42.9		Proposed	$600,000.00			Y	C
C	East	ITC	694	1391	12/31/2009	Saratoga 345 kV	Greenwood 345 kV	2	345		2552		MI		13.4	Proposed	$13,500,000.00			Y	C
C	East	ITC	694	1390	12/31/2009	Saratoga 345 kV	Greenwood 345 kV	1	345		2241		MI	13.4		Proposed	$600,000.00			Y	C
C	East	ITC	694	1388	12/31/2009	Saratoga 120 kV	Bunce Creek 120 kV	1	120		313		MI	12.5	0.6	Proposed	$700,000.00			Y	C
C	East	ITC	694	1385	12/31/2009	Saratoga 345/120 kV (sw sta provisions)	transformer		345	120			MI			Proposed	$1,100,000.00			Y	C
C	East	ITC	694	1387	12/31/2009	Saratoga 120 kV	Wabash 120 kV	1	120		299		MI	13.6	0.6	Proposed	$700,000.00			Y	C
C	East	ITC	694	1386	12/31/2009	Saratoga 120 kV	Robin 120 kV	1	120		444		MI	23.3	0.6	Proposed	$700,000.00			Y	C
C	East	ITC	694	1389	12/31/2009	Saratoga 120 kV	Burns 2 120 kV	1	120		313		MI	17.7	0.6	Proposed	$700,000.00			Y	C
C	East	ITC	903	922	12/31/2008	Bismark 230 kV	Stephens 230	1	230		657		MI		8.2	Proposed	$3,000,000.00			Y	C
C	East	ITC	903	923	12/31/2008	Stephens 230/120 kV	Transformer	1	230	120	693		MI			Proposed	$4,000,000.00			Y	C
C	East	ITC	903	924	12/31/2008	Stephens 120 kV	Redrun 120 kV	1	120		343		MI		5.4	Proposed	$2,000,000.00			Y	C
C	East	ITC	908	1580	5/30/2008	Lemoyne	Monroe 3-4	1	345		2000		MI	33.1	3	Proposed	$4,500,000.00			Y	C
C	East	ITC	908	3711	6/1/2014	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	1579	6/1/2014	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	938	6/1/2014	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

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C	East	ITC	908	935	6/1/2014	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	937	6/1/2014	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	936	6/1/2014	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	934	6/1/2014	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	6/30/2010	Quaker 120	Southfield 120	1	120		183/232	new line	MI		7.35	Proposed				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	$530,000,000.00			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	$25,000,000.00			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	$25,000,000.00			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	$10,000,000.00			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	$25,000,000.00			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	$400,000,000.00			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	$150,000,000.00			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	$225,000,000.00			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	$25,000,000.00			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	$10,000,000.00			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	$10,000,000.00			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	$600,000,000.00			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	$10,000,000.00			Y	C
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	$10,000,000.00			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	$10,000,000.00			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	$10,000,000.00			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	$400,000,000.00			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	$25,000,000.00			Y	C
C	East	ITC	1550	2639	5/31/2008	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	3718	6/1/2012	Menlo	Bunce Creek	1	120			reconductor line	MI	8.6		Proposed				Y	C
C	East	ITC	1842	3712	6/1/2012	Bunce Creek	Greenwood	1	230			New Line (existing ROW)	MI		36	Proposed				Y	C
C	East	ITC	1842	3713	6/1/2012	Bunce Creek 230/120 kV	Transformer	1	230	120		New Transformer	MI			Proposed				Y	C
C	East	ITC	1842	3714	6/1/2012	Greenwood 345/230 kV	Transformer	1	345	230		New Transformer	MI			Proposed				Y	C
C	East	ITC	1842	3715	6/1/2012	Greenwood	Kilgore	1	120			reconductor line	MI	0.34		Proposed				Y	C
C	East	ITC	1842	3716	6/1/2012	Kilgore	Lee	1	120			reconductor line	MI	10.3		Proposed				Y	C
C	East	ITC	1842	3717	6/1/2012	Lee	Menlo	1	120			reconductor line	MI	17		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

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C	East	ITC	1843	3719	6/1/2013	Essex	Waterman	1	230			New Cable	MI		8.5	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	1844	3721	6/1/2013	Essex	Mack (Voyager)	1	120			reconductor line	MI	2.4		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	3710	6/1/2013	Hemphill	Transformer	2	230	138		New Transformer	MI			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	3727	6/1/2014	Navarre	Waterman	1	230			Break up 3-ended line	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	1848	3728	6/1/2016	Bad Axe	Tuscola	1	120			New Line (existing ROW)	MI		34	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	1848	3729	6/1/2016	Tuscola	Arrowhead	1	120			reconductor line	MI	15.3		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	1850	3734	6/1/2016	Hancock 230/120 kV	Transformer	1	230	120		New Transformer	MI			Proposed				Y	C
C	East	ITC	1850	3732	6/1/2016	Hancock	Wixom	1	230			New Line resulting from Quaker-Wixom cut into Hancock	MI			Proposed				Y	C
C	East	ITC	1850	3733	6/1/2016	Hancock	Quaker	1	230			New Line resulting from Quaker-Wixom cut into Hancock	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	3740	6/1/2018	Riverview	Ironton	1	120			Replace Wave Trap	MI			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	3739	6/1/2018	Jefferson	Riverview	1	120			new line	MI		2.2	Proposed				Y	C
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	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	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	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	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	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	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	1860	2881	12/31/2009	Breaker Replacement Program 2009	Throughout System						MI			Proposed				Y	C
C	East	ITC	1861	2882	12/31/2010	Breaker Replacement Program 2010	Throughout System						MI			Proposed				Y	C
C	East	ITC	1862	2883	12/31/2009	Cable Termination Replacement 2009	Throughout System						MI			Proposed				Y	C
C	East	ITC	1863	2884	12/31/2010	Cable Termination Replacement 2010	Throughout System						MI			Proposed				Y	C

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C	East	ITC	1864	2885	12/31/2009	Relay Betterment Program 2009	Throughout System						MI			Proposed				Y	C
C	East	ITC	1865	2886	12/31/2010	Relay Betterment Program 2010	Throughout System						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	East	ITC	1872	3763	12/31/2008	ScioTP	Spruce	1	120		313 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI	0.23		Planned				Y	C
C	East	ITC	1872	3764	12/31/2008	ScioTP	Scio	1	120		343 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI		2.9	Planned				Y	C
C	East	ITC	1872	3762	12/31/2008	ScioTP	Lark	1	120		249 MVA	Scio Taps the Lark-Spruce 120kV circuit	MI	1.72		Planned				Y	C
C	East	METC	240	336	6/1/2014	Garfiled	Hemphill	1	138		521	Reconductor	MI	9.2		Proposed				Y	C
C	East	METC	642	1325	6/1/2017	Argenta	Hazelwood(Sag)	1	138			conductor sag	MI	0.1		Proposed	$50,000.00			Y	C
C	East	METC	651	1337	5/1/2018	Stover	Clearwater	1	138				MI	8.8		Proposed	$2,800,000.00			Y	C
C	East	METC	662	3592	6/1/2013	Weeds lake 345/138 kV	Transformer	1	345	138		new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI			Proposed				Y	C
C	East	METC	662	3594	6/1/2013	Weeds Lake	Milham	2	138			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI	10		Proposed				Y	C
C	East	METC	662	1350	6/1/2013	Weeds Lake 138 kV	New Switching Station		138			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI		10	Proposed				Y	C
C	East	METC	662	3598	6/1/2013	Weeds Lake Jct	Twin Branch	1	345			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI			Proposed				Y	C
C	East	METC	662	3597	6/1/2013	Weeds Lake Jct	Argenta	1	345			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI			Proposed				Y	C
C	East	METC	662	3596	6/1/2013	Weeds Lake	Argenta	2	138			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI	10		Proposed				Y	C
C	East	METC	662	3595	6/1/2013	Weeds Lake	Argenta	1	138			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI	10		Proposed				Y	C
C	East	METC	662	3593	6/1/2013	Weeds Lake	Milham	1	138			new switching station with both Argenta-Milham circuits cut in and Argenta-Twin Branch tapped with 345/138 kV transformer	MI	10		Proposed				Y	C
C	East	METC	984	1547	6/1/2011	Denver Station	New Station		345			New Station	MI			Proposed	$77,132,000.00			Y	C
C	East	METC	987	1550	6/1/2013	Emmet	Stover	1	138				MI			Proposed	$10,250,000.00			Y	C
C	East	METC	1225	1925	5/1/2015	Thompson Road	Tallman	1	138				MI	19.2		Proposed	$5,000,000.00			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	$6,000,000.00			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	$10,000,000.00			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	$20,000,000.00			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	$4,500,000.00			Y	C

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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	$14,000,000.00			Y	C
C	East	METC	1432	2436	6/1/2017	Withey Lake 138kV	Twining 138kV		138			Rebuild 0.2 miles of Withey Lake-Twining 138kV line	MI			Proposed	$100,000.00			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	1658	3418	12/31/2008	4 Mile	Englishville						MI			Planned				Y	C
C	East	METC	1795	3604	6/1/2010	David Jct.	Bingham	1	138			reconductor (removes sag limits)	MI	19		Planned	$11,700,000.00			Y	C
C	East	METC	1800	3611	6/1/2013	Argenta	Riverview	1	138			Remove sag limits	MI			Proposed				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	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	3619	6/1/2013	Stover	Livingston	1	138			Reconductor (230 kV construction, operate at 138 kV)	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	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	3624	6/1/2014	Emmet	Oden	2	138			new line (existing ROW)	MI			Proposed				Y	C
C	East	METC	1805	3621	6/1/2014	Livingston	Emmet	1	138			reconductor	MI			Proposed				Y	C
C	East	METC	1806	3625	6/1/2015	Delhi	Island	1	138			reconductor	MI	11		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	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	1808	3631	6/1/2017	Cowan Lake Jct	Four Mile	1	138			reconductor	MI	15.5		Proposed				Y	C
C	East	METC	1809	3633	6/1/2017	Keystone	Tippy	2	138			New line (existing ROW, 230 kV construction operate at 138 kV)	MI			Proposed				Y	C
C	East	METC	1809	3632	6/1/2017	Keystone	Tippy (Hodenpyl)	1	138			Reconductor (230 kV construction, operate at 138 kV)	MI			Proposed				Y	C
C	East	METC	1810	3634	6/1/2018	Cottage Grove	Iosco	1	138			reconductor	MI	23		Proposed				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
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	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	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	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	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

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C	East	METC	1812	2642	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	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	1816	3650	6/1/2013	Mecosta	Croton	1	138			Reconductor	MI	22		Proposed				Y	C
C	East	METC	1821	2873	12/31/2009	Breaker Replacement Program 2009	Throughout system						MI			Proposed				Y	C
C	East	METC	1822	2874	12/31/2010	Breaker Replacement Program 2010	Throughout system						MI			Proposed				Y	C
C	East	METC	1823	2875	12/31/2009	Relay Betterment Program 2009	Throughout system						MI			Proposed				Y	C
C	East	METC	1824	2876	12/31/2010	Relay Betterment Program 2010	Throughout system						MI			Proposed				Y	C
C	East	METC	1826	2878	12/31/2009	Sag clearance 2009	Throughout system						MI			Proposed				Y	C
C	East	METC	1827	2879	12/31/2010	Sag clearance 2010	Throughout system						MI			Proposed				Y	C
C	East	METC	1828	3602	6/1/2010	Argenta	Palisades	2	345			Remove sag limits	MI			Planned				Y	C
C	East	METC	1828	3601	6/1/2010	Argenta	Palisades	1	345			Remove sag limits	MI			Planned				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	3681	6/1/2018	Felch Road	Transformer	1	345	230		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	3683	6/1/2018	Tippy	Felch Road	1	230			New line (existing ROW)	MI		76	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	3687	6/1/2018	Livingston	Mio	1	230			New line (existing ROW)	MI		42	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	3689	6/1/2018	Mio	Tittabawassee	1	230			New line (existing ROW)	MI		79	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	1831	3685	6/1/2018	Tippy	Livingston	1	230			New line (existing ROW)	MI		79	Proposed				Y	C
C	East	METC	1833	2880	12/31/2011	Sag clearance 2011	Throughout system						MI			Proposed				Y	C
C	East	METC	1839	3705	5/1/2009	Acme	Stover	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned				Y	C
C	East	METC	1839	3704	5/1/2009	Acme	Keystone	1	138			Acme will be fed from a switching station cut into the Keystone-Stover 138kV circuit	MI			Planned				Y	C
C	East	MPPA	2073	3946	7/1/2009	Grand Traverse 1	South Airport Junction		69		108/140 MVA	Reconductoring	MI	1.14		Planned	$340,000.00			NT	C
C	East	MPPA	2074	3947	7/1/2009	South Airport Junction	Barlow Junction		69		108/140 MVA	Reconductoring	MI	2.15		Planned	$640,000.00			NT	C
C	East	MPPA	2075	3948	7/1/2009	Barlow Junction	Cass Road Junction		69		108/140 MVA	Reconductoring	MI	1.34		Planned	$395,000.00			NT	C
C	East	MPPA	2076	3949	7/1/2009	Cass Road Junction	Cass Road Sub		69		108/140 MVA	Reconductoring	MI	1.66		Planned	$490,000.00			NT	C
C	East	MPPA	2077	3950	7/1/2009	Cass Road Junction	Hall Street Sub		69		108/140 MVA	Reconductoring	MI	0.55		Planned	$170,000.00			NT	C
C	East	MPPA	2078	3951	7/1/2009	Gray Road Sub	Hall Street Sub		69		108/140 MVA	Reconductoring	MI	3.82		Planned	$1,130,000.00			NT	C
C	East	MPPA	2079	3952	7/1/2009	South Airport Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$70,000.00			NT	C
C	East	MPPA	2080	3953	7/1/2009	Barlow Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$200,000.00			NT	C
C	East	MPPA	2081	3954	7/1/2009	Cass Road Junction	Switches		69		1200 Amps	Upgrade switches from 600A to 1200A	MI			Planned	$150,000.00			NT	C
C	East	NIPS	1973	2763	12/1/2010	Leesburg	Northeast	1	138			Upgrade Connections and Circuit	IN	8.5		Proposed	$5,279,000.00			Y	C
C	East	NIPS	1974	2764	11/1/2009	Liberty Park	Lake George	1	138			Upgrade Connections and Circuit	IN	5.8		Proposed	$1,043,000.00			Y	C
C	East	NIPS	1975	2765	12/1/2009	Liberty Park	St. John	1	138			Upgrade Connections and Circuit	IN	2.3		Proposed	$586,000.00			Y	C
C	East	NIPS	1976	2766	12/31/2011	St. John	Transformer	1	345	138	560	Add 2nd transformer and breakers	IN			Proposed	$6,853,000.00			Y	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	$1,080,000.00			Y	C
C	East	NIPS	1980	2770	12/1/2011	Babcock	Capacitor		69			Add 2 to 3 - 9 .0 MVAR stages	IN			Proposed	$1,052,000.00			Y	C
C	East	NIPS	1981	2771	12/1/2011	Kreitzburg	Capacitor		69			Add 2 to 3 - 9 .0 MVAR stages	IN			Proposed	$1,052,000.00			Y	C
C	East	NIPS	1983	2773	12/1/2012	Dekalb	Transformer		138	69	70 MVA	Upgrade 138-69 Transformer	IN			Proposed	$1,700,000.00			Y	C
C	East	NIPS	1984	2774	12/1/2012	South Knox	138/69 kV Substation		138	69		New Substation	IN			Proposed	$12,568,000.00			Y	C
C	East	NIPS	1985	2775	12/1/2010	Wolcot	South Milford	6959	69			Upgrade Capacity of line.	IN	5.7		Proposed	$1,144,000.00			Y	C
C	East	NIPS	1987	2777	10/1/2009	Monticello	Oak Dale	6971	69			Upgrade Circuit 6972 Relays.	IN			Proposed	$95,000.00			Y	C

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C	East	NIPS	1988	2778	10/1/2009	Oak Dale	Chalmers	6972				Upgrade Circuit 6971 Relays.	IN			Proposed	$95,000.00			Y	C
C	East	NIPS	1989	2779	12/1/2011	South Milford	Helmer	6959	69			Upgrade Capacity of line.	IN			Proposed	$894,000.00			Y	C
C	East	NIPS	1990	2780	12/1/2011	Dekalb	Angola	6986	69			Upgrade Capacity of line.	IN			Proposed	$2,680,000.00			Y	C
C	East	NIPS	1991	2781	12/1/2010	East Winamac	Transformer		138	69		Upgrade 138/69 kV Transformer	IN			Proposed	$3,425,000.00			Y	C
C	East	NIPS	1993	2783	12/1/2012	South Valparaiso	138/69 kV Substation		138	69		New 138/69 kV Substation	IN			Proposed	$4,917,000.00			Y	C
C	East	NIPS	1994	2784	5/1/2011	Midway	Bristol	6977	69			Reconductor to 336.4 KCM ACSR.	IN	4.1		Proposed	$788,000.00			Y	C
C	East	NIPS	1995	2785	6/1/2006	Thayer	Liberty Park Ckt 6901		69			New Thayer Sub circuit.	IN		6	Proposed	$1,782,000.00			Y	C
C	East	NIPS	1998	2788	12/1/2009	East Winamac	Lawton	62&37	69			Rebuild old pole line. Ckts 6962 & 6937	IN	4.5		Proposed	$988,000.00			Y	C
C	East	NIPS	1999	2789	12/1/2008	Norway Gen Plant		6907	69			Reroute existing line.	IN			Planned	$99,000.00			Y	C
C	East	NIPS	2000	2790	12/1/2008	Goshen Junction	Model	6977	69			Reconductor to 336.4 KCM ACSR.	IN	0.5		Planned	$52,000.00			Y	C
C	East	NIPS	2003	2793	12/1/2009	Bruce Lake	Sw. 854	6937	69			Rebuild old pole line.	IN			Proposed	$359,000.00			Y	C
C	West	ATC LLC	575	1271	6/1/2016	Suamico	Sobieski	1	138				WI			Proposed	$1,510,893.00			Y	C
C	West	ATC LLC	575	1272	6/1/2016	Sobieski	Pioneer	1	138				WI			Proposed	$1,510,893.00			Y	C
C	West	ATC LLC	575	1270	6/1/2016	Pulliam (now Bayport)	Suamico	1	138				WI			Proposed	$3,199,539.00			Y	C
C	West	ATC LLC	1621	3239	6/1/2013	Birchwood	Lake Delton	1	138		383/478	Build a new line between Birchwood & Lake Delton	WI	5		Proposed	$5,806,000.00			Y	C
C	West	ATC LLC	1623	3240	6/1/2014	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	6/1/2014	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	3242	6/1/2014	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	1625	3243	6/1/2018	North Randolph	Columbia	1	345		1096/1096	Tap Columbia-South Fond du Lac into North Randolph	WI			Proposed	$9,718,000.00			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	$100,000.00			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	1685	3461	6/1/2009	Hale			138			Construct a 138 kV bus at Hale substation to permit a third Brookdale distribution transformer interconnection	WI			Proposed	$4,000,000.00			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	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	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	1692	3471	6/1/2011	North Mullet River			69			Replace the 400 amp metering CT at North Mullet River 69 kV substation	WI			Proposed	$404,242.68			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	$1,080,000.00			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	$1,190,000.00			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	$716,000.00			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

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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	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	$52,010,000.00			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	$1,958,000.00			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
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	$5,360,000.00			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	$56,300,000.00			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	$4,162,000.00			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	$2,810,000.00			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	$10,190,000.00			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	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	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	1714	3499	6/1/2018	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	$1,550,000.00			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	$248,000.00			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	$1,720,000.00			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	$1,720,000.00			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	$14,110,000.00			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	$1,440,000.00			Y	C

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C	West	ATC LLC	1721	3507	6/1/2015	Danz	Henry Street	1	69			Reconductor Danz-Henry Street 69 kV line	WI	1.5		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	1721	3509	6/1/2050	Pulliam	Danz	1	69			Reconductor Pulliam-Danz 69 kV line	WI	3		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	$1,160,000.00			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	$1,770,000.00			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	$1,770,000.00			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
C	West	ATC LLC	1725	3514	6/1/2018	Evansville	Brooklyn		69			Construct an Evansville-Brooklyn 69 kV line	WI		8	Proposed	$8,120,000.00			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	$790,000.00			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				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	3518		Straits	McGulpin	1	138		230 deg F	Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	MI			Proposed				Y	C
C	West	ATC LLC	1729	3519		Straits	McGulpin	3	138		230 deg F	Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	MI			Proposed				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		Blount	Ruskin	1	69			Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line	WI			Proposed				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	$600,000.00			Y	C
C	West	ATC LLC	1733	3525	6/1/2008	Boxelder			138		1x24.5	Install a temporary 24.5 MVAR 138-kV capacitor bank at Boxelder Substation	WI			Planned	$600,000.00			Y	C
C	West	ATC LLC	1940	3819	6/1/2009	M38	Capacitor Bank		138		1x8.16 Mvar	Install one 8.16 MVAR 138 kV capacitor bank at the M38 substation	MI			Proposed				Y	C
C	West	ATC LLC	1941	3820	6/1/2009	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	6/1/2010	Spring Green	transformer	2	138	69	100 MVA SE	Install a 2nd Spring Green 138-69 kV Transformer	WI			Proposed				Y	C
C	West	ATC LLC	1947	3826	6/1/2010	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	6/1/2010	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	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	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	2019	2891		Uprate Chandler Delta 69 kV #1			69			Increase line clearance to 167 deg F SE				Proposed				Y	C
C	West	ATC LLC	2019	3887	6/1/2009	Chandler	Delta	1	69		70 MVA SE	Increase line clearance to 167 deg F SE		5.5		Proposed				Y	C

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C	West	ATC LLC	2020	2892		Uprate Chandler Delta 69 kV #2			69			Increase line clearance to 167 deg F SE				Proposed				Y	C
C	West	ATC LLC	2020	3888	6/1/2009	Chandler	Delta	2	69		70 MVA SE	Increase line clearance to 167 deg F SE		7.65		Proposed				Y	C
C	West	ATC LLC	2021	2893		Uprate Chandler-LakeheadTap-Masonville 69 kV						Increase line clearance to 167 deg F SN/SE				Proposed				Y	C
C	West	ATC LLC	2021	3889	6/1/2009	Chandler	Lakehead Tap	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		8.65		Proposed				Y	C
C	West	ATC LLC	2021	3890	6/1/2009	Lakehead Tap	Masonville	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		2.96		Proposed				Y	C
C	West	ATC LLC	2022	2894		Uprate Delta-Mead-NorthBluff 69 kV			69			Increase line clearance to 167 deg F SN/SE				Proposed				Y	C
C	West	ATC LLC	2022	3892	6/1/2009	Mead	Bayview Tap	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		1.37		Proposed				Y	C
C	West	ATC LLC	2022	3891	6/1/2009	Delta	Mead	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		4.65		Proposed				Y	C
C	West	ATC LLC	2022	3893	6/1/2009	Bayview Tap	North Bluff	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		4.15		Proposed				Y	C
C	West	ATC LLC	2023	2895		Uprate Masonville-Gladstone 69 kV			69			Increase line clearance to 167 deg F SN/SE				Proposed				Y	C
C	West	ATC LLC	2023	3894	6/1/2009	Masonville	Gladstone	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		3.56		Proposed				Y	C
C	West	ATC LLC	2024	3895	6/1/2009	North Bluff	Gladstone	1	69		48 MVA SN/SE	Increase line clearance to 167 deg F SN/SE		2.06		Proposed				Y	C
C	West	ATC LLC	2025	3897	6/1/2009	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	6/1/2009	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	6/1/2009	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	3901	6/1/2010	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
C	West	ATC LLC	2028	3902	6/1/2010	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	3900	6/1/2010	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	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	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	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	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	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	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

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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	2034	3913	6/1/2014	Verona	capacitor		69		+1x16.2 Mvar	Add a 2nd 16.2 Mvar Cap to Veron 69 kV				Proposed				Y	C
C	West	ATC LLC	2036	3916	6/1/2014	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	6/1/2014	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	Okee	1	69		87/123 MVA S	Rebuild Dane-Okee 69 kV		4.39		Proposed				Y	C
C	West	ATC LLC	2038	3918	6/2/2015	Spring Valley	Twin Lakes	1	138		293/403 MVA	Construct Spring Valley-Twin Lakes 138 kV	WI		12	Proposed				Y	C
C	West	ATC LLC	2038	3919	6/2/2015	Twin Lakes	S Lake Geneva	1	138		293/403 MVA	Construct Twin Lakes-S Lake Geneva 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				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				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	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	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	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	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	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	2049	3935	6/1/2024	Verona	North Monroe	1	138		293/403 MVA	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				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		4.5		Proposed				Y	C
C	West	ATC LLC	2103	2810	1/1/2013	Oak Creek	Granville	1	345			String Oak Creek - Brookdale and Brookdale - Granville 345 kV Lines and Constuct an Oak Creek - St. Martins 138 kV Line and Brookdale - West Junction 138 kV Line	WI			Planned	$81,836,282.00			Y	C
C	West	ATC LLC	2103	2811	1/1/2013	Brookdale	transformer	1	345	138		Proposed 2013, 500 MVA	WI			Planned	$14,814,000.00			Y	C
C	West	ATC LLC	2161	4000	6/1/2009	Glenview	Shoto	1	138		128/173 SN/SI	Increase line clearance to 200 deg F SE	WI	23		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/SI	Replace Ellinwood 138-69 kv Tr #2	WI			Proposed	$2,012,243.00			Y	C
C	West	ATC LLC	2164	4003	2/1/2013	Nelson Dewey		2	161	138	210/286 SN/SI	Install a 2nd Nelson Dewey 161-138 kV Tr	WI			Proposed	$4,729,000.00			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	$441,446.00			Y	C

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C	West	ATC LLC		1877	6/1/2008	St Germain or Conover	capacitor		115			Install at least an 8 MVAR, 115kV Capacitor Bank at the St. Germain substation or an 8 MVAR, 138kV Capacitor Bank at the Conover substation.				Planned	$680,000.00			Y	C
C	West	GRE	1018	640	6/1/2001	Little Falls	CWP Little Falls	1	115		196	115 kv line operated at 34.5	MN	4		Proposed	$900,000.00			Y	C
C	West	ITCM	1343	2210	6/1/2011	Fairfax	transformer	2	161	69	250	add 2nd transformer	IA			Proposed	$1,500,000.00			Y	C
C	West	ITCM	1738	3536	12/31/2012	Bertram	Hills	1	161		446/446 MVA	Reconductor	IA	32.2		Proposed				Y	C
C	West	ITCM	1740	3537	12/31/2011	Marshalltown	Fernald	1	161		326/326 MVA	Rebuild existing line	IA	30.8		Proposed				Y	C
C	West	ITCM	1740	3539	12/31/2011	Ames	Boone Jct	1	161		326/326 MVA	Rebuild existing line	IA	13.1		Proposed				Y	C
C	West	ITCM	1740	3340	12/31/2011	Boone Jct	Boone	1	161		326/326 MVA	Rebuild existing line	IA	5.2		Proposed				Y	C
C	West	ITCM	1740	3538	12/31/2011	Fernald	Ames	1	161		326/326 MVA	Rebuild existing line	IA	6		Proposed				Y	C
C	West	ITCM	1741	3292	12/31/2010	Heron Lake	South Storden	1	161		440	Rebuild line to higher capacity	MN			Planned	$6,818,660.00	Y		Y	C
C	West	ITCM	1741	2235	12/31/2010	Storden (Cottonwood County)	Dotson	1	161		446	New line	IA	26		Planned	$16,379,839.00	Y		Y	C
C	West	ITCM	1741	4025	12/31/2010	Cottonwood County substation			161							Planned	$4,833,216.00	Y		Y	C
C	West	ITCM	1741	4028	12/31/2010	South Storden	Cottonwood County	1	161				MN			Planned	$4,092,575.00	Y		Y	C
C	West	ITCM	1741	4027	12/31/2010	Communication System Upgrades			161							Planned	$400,000.00	Y		Y	C
C	West	ITCM	1741	4026	12/31/2010	Heron Lake Substation			161							Planned	$4,195,530.00	Y		Y	C
C	West	ITCM	1742	3544	12/31/2010	Elk	Heron Lake	1	161		326/326 MVA	Rebuild existing line	IA	3.16		Proposed				Y	C
C	West	ITCM	1742	3543	12/31/2011	Magnolia	Elk	1	161		326/326 MVA	Rebuild existing line	IA	18.5		Proposed				Y	C
C	West	ITCM	1742	3542	12/31/2012	Split Rock	Magnolia	1	161		446/446 MVA	Rebuild existing line	IA	11		Proposed				Y	C
C	West	ITCM	1746	3549	12/31/2011	Fox Lake	Rutland	1	161		446/446 MVA	Rebuild existing line	MN	17		Proposed				Y	C
C	West	ITCM	1746	3550	12/31/2012	Rutland	Winnebago	1	161		446/446 MVA	Rebuild existing line	MN	14.6		Proposed				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				Y	C
C	West	ITCM	1746	3552	12/31/2014	Winnebago	Hayward	1	161		446/446 MVA	Rebuild existing line	MN	49.09		Proposed				Y	C
C	West	ITCM	1746	3553	12/31/2015	Hayward	Adams	1	161		446/446 MVA	Rebuild existing line	MN	36.39		Proposed				Y	C
C	West	ITCM	1766	2861	12/31/2009	Lily Lake 69/34kV sub	new 69/34kV sub near Amana		69	34		Build a new 69/34kV sub near Amana. The sub will tie to the Crozier REC-Amana Refrigeration 69kV line				Proposed				NT	C
C	West	ITCM	1774	2867	12/31/2009	Truro 69/34kV Sub	Add a 69/34kV Xfmr in the Truro sub		69	34		Add a 69/34kV Xfmr in the Truro sub and reinsulate nearly 10 miles of 34kV to 69kV to serve the new sub.		10		Proposed				NT	C
C	West	ITCM	1775	2868	12/31/2009	Triboji	Milford (CBPC)		69			Rebuild the Triboji-Milford 69kV line.	IA			Planned				NT	C
C	West	ITCM	1777	2870	12/31/2009	Solon Junction 161 & 34kV lines	for new CIPCO sub		161	34		0.75 miles of 161/34kV dbl ckt lines needed to tie to a new CIPCO owned 161/34kV Solon Jct sub			0.75	Proposed				Y	C
C	West	MDU	1356	2243	11/1/2012	Glenham	Reactors		230	115	30 MVAr	Control high voltage on WAPA Bismarck - Oahe 230 kV line	ND			Proposed				Y	C
C	West	SMP	2166	4005	1/1/2010	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	$7,000,000.00			NT	C
C	West	SMP	2167	4006	1/1/2010	Tap Existing Area Line	New Load Serving Sub at Redwood Falls	1	69	69	69	Add 4.0 Miles 69kV line and construct load serving substation at Redwood Falls	MN		4	Proposed	$2,500,000.00			NT	C
C	West	XEL	1376	2308	5/1/2011	Poplar Lake	Apple River	1	161		-	New sub tap on SCF-APP 161	WI			Proposed				Y	C
C	West	XEL	1376	2309	5/1/2011	Poplar Lake	Transformer	1	161	69	70 MVA	New 161/69 kV transformer at Popular Lake	WI			Proposed	$3,000,000.00			Y	C
C	West	XEL	1376	2307	12/31/2010	St Croix Falls	Border	1	161		-	New sub tap on SCF-APP 161	WI		4	Planned				Y	C
C	West	XEL	1378	2310	6/1/2011	West St. Cloud	Granite City	1	115		620	Reconductor	MN			Proposed	$2,000,000.00			Y	C
C	West	XEL	1952	3833	12/1/2011	Lester Prairie Cap Bank	Cap Bank		69		10 MVAR	New 10 MVAR cap bank at Lester Prairie	MN			Proposed				NT	C
C	West	XEL	2157	2966	6/1/2011	Douglas Co	Transformer	2	115	69	70	2nd 115/69 kV transformer at	MN			Planned	$3,000,000.00			NT	C
C	West	XEL	2158	2967	6/1/2011	Sauk Center	West Union	1	69		84	upgrade using lower impedance line	MN		9	Planned	$2,700,000.00			NT	C
C	West	XEL	2158	2968	6/1/2011	West Union	Osakis	1	69		84	upgrade using lower impedance line	MN		5.8	Planned	$1,740,000.00			NT	C
C	West	XEL	2159	2969	6/1/2010	Nelson	capacitor bank		69		18MVAR	New 18 MVAR cap at Nelson	WI			Planned	$800,000.00			NT	C
C	West	XEL	2160	2971	6/1/2012	Park Falls	Transformer	2	115	34.5	47	Upgrade the transformer to higher rating	WI			Planned	$1,500,000.00			NT	C
C	West	XEL	2160	2970	6/1/2012	Park Falls	Transformer	1	115	34.5	47	Upgrade the transformer to higher rating	WI			Planned	$1,500,000.00			NT	C

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C	West	XEL	2173	4007	6/1/2010	Hiawatha	distribution substation		115	13			MN			Planned				Y	C
C	West	XEL	2174	4008	6/1/2010	Mid Town	distribution substation		115	13			MN			Planned				Y	C
C	West	XEL	2175	4010	6/1/2014	Highway 280 substation	Hiawatha Substation	1	345			New 345 kv line from proposed Highway 280 substation to proposed Hiawatha substation.	MN			Proposed				Y	C
C	West	XEL	2175	4009	6/1/2014	Highway 280 substation	switching station		345	115	448	New 345/115 kV transfromer at proposed Hiawatha substation	MN			Proposed				Y	C
C	West	XEL	2176	4012	6/1/2012	Colville substation	Transfromer	1	115	69	112 MVA	New 115/69 kV transfromer at Colville	MN			Proposed				Y	C
C	West	XEL	2176	4013	6/1/2012	Colville substation	Byllesby	1	69		84 MVA	2 mile 69 kV line	MN			Proposed				Y	C
C	West	XEL	2176	4014	6/1/2012	Colville substation	Breaker reconfiguration					Reconfigure the 115 kV breakers at Colville substation.	MN			Proposed				Y	C
C	West	XEL	2176	4011	6/1/2012	Cannon Falls Substation	115 kV ring bus		115			Convert the existing 115 kV bus at Cannon Falls to Ring	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	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	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	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	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	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	2178	4022	6/1/2012	Pleasant Valley	Willow Creek	1	161		447 MVA	new 161 kV line from PV - Willow Creek	MN		20	Proposed				Y	C
C	West	XEL	2178	4021	6/1/2012	Pleasant Valley	Byron	1	161		447 MVA	new 161 kV line from PV to Byron	MN		25	Proposed				Y	C
C	West	XEL	2178	4023	6/1/2012	Byron	Cascade Creek	2	161		447 MVA	2nd 161 kV line from Byron - Cascade Creek	MN		9.8	Proposed				Y	C
C	West	XEL	2178	4024	6/1/2012	Pleasant Valley	new transformer	2	345	161	500 MVA	new 345/161 kV transformer at PV	MN			Proposed				Y	C
C	West	XEL		1871		Panther			230			Panther 230 kV line termination uprate (DKD thought it was GFA termination)	MN			Planned				Y	C
C	West	XEL		1870		Maynard	Capacitor		115		40 Mvar	New Capacitor	MN			Planned				Y	C
C	West	XEL		1872	12/1/2009	Split Rock	Capacitor				50 Mvar	New Capacitor (is this reactor?)	SD			Planned				Y	C
C	West	XEL/GRE	2155	2961	6/1/2011	Monticello	Transformer	6	345	230	550	Upgrade the 345/230 kV TR to 550 MVA	MN			Planned	$5,000,000.00			Y	C
C	West	XEL/GRE	2156	2965	6/1/2011	Lesueur Tap	substation		69			69 kV switching station at LeSueur	MN			Planned	$2,000,000.00			NT	C
C	West	XEL/GRE	2156	2964	6/1/2011	St. Thomas	substation	1	115	69	112	New 115/69 kV substation	MN			Planned	$4,000,000.00			NT	C
C	West	XEL/GRE	2156	2962	6/1/2011	Helena	Transformer	1	345	115	448	New 345/115 kV transformer at Helena substation	MN			Planned	$8,000,000.00			Y	C
C	West	XEL/GRE	2156	2963	6/1/2011	Helena	St. Thomas	1	115	115	318	New 6 mile 115 kV line	MN		6	Planned	$3,000,000.00			Y	C
C	Central	MISO	2194	4041	8/1/2018	Montgomery	Toledo	1	765		2640	new line	IA/MO		275	Conceptual	$871,000,000.00			Y	C
C	Central	MISO	2195	4042	8/1/2018	Montgomery	Coffeen	1	765		3576	new line	MO/IL		111	Conceptual	$343,000,000.00			Y	C
C	Central	MISO	2195	4071	8/1/2018	Coffeen	Transformer	1	765	345	2767.5	new transformer	IL			Conceptual	$15,000,000.00			Y	C
C	Central	MISO	2195	4063	8/1/2018	Montgomery	Transformer	1	765	345	2767.5	new transformer	MO			Conceptual	$15,000,000.00			Y	C
C	Central	MISO	2196	4062	8/1/2018	St. Francois	Transformer	1	765	345	2767.5	new transformer	MO			Conceptual	$15,000,000.00			Y	C
C	Central	MISO	2196	4040	8/1/2018	Montgomery	St Francois	1	765		3408	new line	MO		120	Conceptual	$372,000,000.00			Y	C
C	Central	MISO	2197	4061	8/1/2018	St. Francois	Rockport	1	765		2904	new line	MO/IL/IN		186	Conceptual	$599,000,000.00			Y	C
C	Central	MISO	2198	4038	8/1/2018	Rock Creek	Pontiac	1	765		3768	new line	IA/IL		108	Conceptual	$348,000,000.00			Y	C
C	Central	MISO	2198	4066	8/1/2018	Pontiac	Transformer	1	765	345	2767.5	new transformer	IL			Conceptual	$15,000,000.00			Y	C
C	Central	MISO	2199	4039	8/1/2018	Pontiac	Dequine	1	765		4368	new line	IL/IN		87	Conceptual	$265,000,000.00			Y	C
C	Central	MISO	2200	4050	8/1/2018	Dequine	South Chicago	1	765		5376	new line	IN		64	Conceptual	$161,000,000.00			Y	C
C	Central	MISO	2201	4073	8/1/2018	Dequine	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$15,000,000.00			Y	C
C	Central	MISO	2201	4072	8/1/2018	Dequine	Sullivan	1	765		4008	new line	IN		90.3	Conceptual	$294,000,000.00			Y	C
C	Central	MISO	2202	4074	8/1/2018	Dequine	Greentown	1	765		3576	new line	IN		117	Conceptual	$281,000,000.00			Y	C

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C	Central	MISO	2213	4087	8/1/2018	Buffington	Ghent	1	345		1000	new line	KY		33.2	Conceptual	$47,000,000.00			Y	C
C	Central	MISO	2215	4064	8/1/2018	Coffeen	Sullivan	1	765		3768	new line	IL/IN		100	Conceptual	$322,000,000.00			Y	C
C	Central	MISO	2232	4102	8/1/2018	Kewanee	East Moline	1	345		1000	new line	IL		30.6	Conceptual	$34,000,000.00			Y	C
C	Central	MISO	2232	4146	8/1/2018	Kewanee	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000.00			Y	C
C	Central	MISO	2233	4147	8/1/2018	Kewanee	Tazewell	1	345		1000	new line	IL		60	Conceptual	$85,000,000.00			Y	C
C	Central	MISO	2234	4103	8/1/2018	Meredosa	Palmyra	1	345		1000	new line	MO\IL		52.9	Conceptual	$65,000,000.00			Y	C
C	Central	MISO	2234	4148	8/1/2018	Meredosia	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000.00			Y	C
C	Central	MISO	2235	4149	8/1/2018	Meredosia	Ipava	1	345		1000	new line	IL		38.1	Conceptual	$54,000,000.00			Y	C
C	Central	MISO	2236	4150	8/1/2018	Meredosia	Pawnee	1	345		1000	new line	IL		54.5	Conceptual	$78,000,000.00			Y	C
C	Central	MISO	2237	4151	8/1/2018	Mt. Zion	Transformer	1	345	138	336	new transformer	IL			Conceptual	$10,000,000.00			Y	C
C	Central	MISO	2237	4104	8/1/2018	Mt. Zion	Pana	1	345		1000	new line	IL		29.1	Conceptual	$32,000,000.00			Y	C
C	Central	MISO	2238	4152	8/1/2018	Mt. Zion	Kansas	1	345		1000	new line	IL		51	Conceptual	$73,000,000.00			Y	C
C	Central	MISO	2239	4153	8/1/2018	Rising	Sidney	1	345		1000	new line	IL		23.3	Conceptual	$33,000,000.00			Y	C
C	Central	MISO	2240	4154	8/1/2018	Kansas	Sugar Creek	1	345		1000	new line	IL		23.7	Conceptual	$34,000,000.00			Y	C
C	Central	MISO	2241	4155	8/1/2018	Newton	Merom	1	345		1000	new line	IL		42	Conceptual	$60,000,000.00			Y	C
C	Central	MISO	2242	4156	8/1/2018	Norris City	Albion	1	345		1000	new line	IL		25.8	Conceptual	$37,000,000.00			Y	C
C	Central	MISO	2243	4157	8/1/2018	Baldwin	Joppa	1	345		872	new line	IL		86.8	Conceptual	$123,000,000.00			Y	C
C	Central	MISO	2246	4075	8/1/2018	Petersburg	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$20,000,000.00			Y	C
C	Central	MISO	2247	4076	8/1/2018	Gwynn	Transformer	1	765	345	2767.5	new transformer	IN			Conceptual	$20,000,000.00			Y	C
C	Central	MISO	2248	4160	8/1/2018	Ottumwa	Thomas Hill	1	345		740	new line	IA/MO		107	Conceptual	$154,432,990.00			Y	C
C	East	MISO	2203	4069	8/1/2018	Blue Creek	Greentown	1	765		6000	new line	IN		59	Conceptual	$191,000,000.00			Y	C
C	East	MISO	2204	4070	8/1/2018	Evans	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$20,000,000.00			Y	C
C	East	MISO	2204	4067	8/1/2018	Cook	Evans	1	765		4008	new line	MI		99	Conceptual	$299,000,000.00			Y	C
C	East	MISO	2205	4045	8/1/2018	Evans	Spreague	1	765		4008	new line	MI		95	Conceptual	$304,000,000.00			Y	C
C	East	MISO	2206	4048	8/1/2018	Spreague	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$15,000,000.00			Y	C
C	East	MISO	2206	4046	8/1/2018	Spreague	Bridgewater	1	765		6000	new line	MI		42	Conceptual	$120,000,000.00			Y	C
C	East	MISO	2207	4049	8/1/2018	Bridgewater	Transformer	1	765	345	2767.5	new transformer	MI			Conceptual	$15,000,000.00			Y	C
C	East	MISO	2207	4047	8/1/2018	Bridgewater	Blue Creek	1	765		3288	new line	MI		134	Conceptual	$432,000,000.00			Y	C
C	East	MISO	2208	4082	8/1/2018	Livingston	Dead River	1	345		488	new line	MI		232	Conceptual	$329,000,000.00			Y	C
C	East	MISO	2209	4068	8/1/2018	Bridgewater	South Canton	1	765		3024	new line	MI/OH		167	Conceptual	$538,000,000.00			Y	C
C	East	MISO	2244	4158	8/1/2018	Stillwell	Burr Oak	1	345		1000	new line	IN		19.3	Conceptual	$28,000,000.00			Y	C
C	East	MISO	2245	4159	8/1/2018	Avon Lake	Fox	1	345		1000	new line	OH		16.4	Conceptual	$24,000,000.00			Y	C
C	West	MISO	2179	4053	8/1/2018	Riel	Dorsey	1	500		2200	new line	Manitoba		25	Conceptual	$46,000,000.00			Y	C
C	West	MISO	2180	4031	8/1/2018	Riel	Maple River	1	500		2673	new line	Manitoba/ND		203	Conceptual	$344,000,000.00			Y	C
C	West	MISO	2180	4054	8/1/2018	Riel	Transformer	1	500	115	430	new transformer	Manitoba			Conceptual	$15,000,000.00			Y	C
C	West	MISO	2180	4055	8/1/2018	Maple River	Transformer	1	500	230	1200	new transformer	ND			Conceptual	$15,000,000.00			Y	C
C	West	MISO	2181	4056	8/1/2018	Blue Lake	Transformer	1	500	345	2000	new transformer	MN			Conceptual	$20,000,000.00			Y	C
C	West	MISO	2181	4032	8/1/2018	Maple River	Blue Lake	1	500		1540	new line	SD/MN		222	Conceptual	$381,000,000.00			Y	C
C	West	MISO	2182	4083	8/1/2018	Maple River	Watertown	1	345		600	new line	ND/SD		142	Conceptual	$202,000,000.00			Y	C
C	West	MISO	2183	4084	8/1/2018	Watertown	Split Rock	1	345		800	new line	SD		92.4	Conceptual	$131,000,000.00			Y	C
C	West	MISO	2184	4052	8/1/2018	Blue Earth	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000.00			Y	C
C	West	MISO	2184	4078	8/1/2018	Blue Earth	Split Rock	1	345		628	new line	SD/MN		130	Conceptual	$185,000,000.00			Y	C
C	West	MISO	2185	4059	8/1/2018	Hampton Corner	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000.00			Y	C
C	West	MISO	2185	4058	8/1/2018	Adams	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$15,000,000.00			Y	C
C	West	MISO	2185	4034	8/1/2018	Adams	Hampton Corner	1	765		4776	new line	MN		77	Conceptual	$247,000,000.00			Y	C
C	West	MISO	2186	4085	8/1/2018	Sherbourne County	Chisago County	1	345		1000	new line	MN		48.4	Conceptual	$69,000,000.00			Y	C
C	West	MISO	2187	4079	8/1/2018	SW Minneapolis	Sherbourne County	1	345		1000	new line	MN		47.9	Conceptual	$68,000,000.00			Y	C
C	West	MISO	2188	4035	8/1/2018	SW Minneapolis	Hampton Corner	1	765		4008	new line	MN		93	Conceptual	$260,000,000.00			Y	C
C	West	MISO	2189	4086	8/1/2018	Hampton Corner	Chisago County	1	345		972	new line	MN		72.2	Conceptual	$103,000,000.00			Y	C
C	West	MISO	2190	4077	8/1/2018	SW Minneapolis	Watertown	1	345		600	new line	SD/MN		148	Conceptual	$210,000,000.00			Y	C
C	West	MISO	2190	4051	8/1/2018	SW Minneapolis	Transformer	1	765	345	2767.5	new transformer	MN			Conceptual	$20,000,000.00			Y	C
C	West	MISO	2191	4036	8/1/2018	SW Minneapolis	Blue Earth	1	765		4776	new line	MN		73	Conceptual	$215,000,000.00			Y	C
C	West	MISO	2192	4033	8/1/2018	Blue Earth	Lehigh	1	765		4368	new line	MN/IA		85	Conceptual	$258,000,000.00			Y	C
C	West	MISO	2192	4057	8/1/2018	Lehigh	Transformer	1	765	345	2767.5	new transformer	IA			Conceptual	$15,000,000.00			Y	C
C	West	MISO	2193	4043	8/1/2018	Lehigh	Toledo	1	765		4008	new line	IA		97	Conceptual	$313,000,000.00			Y	C
C	West	MISO	2198	4065	8/1/2018	Rock Creek	Transformer	1	765	345	2767.5	new transformer	IA			Conceptual	$15,000,000.00			Y	C

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C	West	MISO	2210	4060	8/1/2018	Longwood	Chisago County	1	345		692	new line	MN/WI		116	Conceptual	$165,000,000.00			Y	C
C	West	MISO	2211	4037	8/1/2018	Longwood	Greenwood	1	345		1000	new line	WI		14	Conceptual	$200,000,000.00			Y	C
C	West	MISO	2212	4044	8/1/2018	Adams	Rock Creek	1	765		2808	new line	MN/IA		204	Conceptual	$627,000,000.00			Y	C
C	West	MISO	2214	4081	8/1/2018	Glenham	Transformer	1	345	230	336	new transformer	SD			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2214	4080	8/1/2018	Glenham	Ellendale	1	345		872	new line	SD/ND		86	Conceptual	$37,000,000.00			Y	C
C	West	MISO	2217	4109	8/1/2018	West Waconia	Blue Lake	1	345		2066	new line	MN		20	Conceptual	$25,000,000.00			Y	C
C	West	MISO	2217	4110	8/1/2018	West Waconia	Blue Lake	2	345		2066	new line	MN		20	Conceptual	$25,000,000.00			Y	C
C	West	MISO	2217	4088	8/1/2018	West Waconia	Hazel	1	345		800	new line	MN		92.3	Conceptual	$112,000,000.00			Y	C
C	West	MISO	2219	4115	8/1/2018	Ellendale	Transformer	1	345	230	336	new transformer	ND			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2219	4091	8/1/2018	Ellendale	Maple River	1	345		740	new line	ND		103	Conceptual	$229,000,000.00			Y	C
C	West	MISO	2220	4116	8/1/2018	Big Stone	Transformer	1	345	230	336	new transformer	SD			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2220	4092	8/1/2018	Big Stone	Ellendale	1	345		692	new line	ND\SD		114	Conceptual	$255,000,000.00			Y	C
C	West	MISO	2221	4117	8/1/2018	Big Stone	Watertown	1	345		1000	new line	SD		60	Conceptual	$140,000,000.00			Y	C
C	West	MISO	2222	4093	8/1/2018	West Waconia	McLeod	1	230		600	new line	MN		26	Conceptual	$78,000,000.00			Y	C
C	West	MISO	2222	4119	8/1/2018	McLeod	Panther	1	230		600	Rebuild Line	MN	28.2		Conceptual	$85,000,000.00			Y	C
C	West	MISO	2222	4121	8/1/2018	West Waconia	Transformer	2	345	230	448	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2222	4120	8/1/2018	West Waconia	Transformer	1	345	230	448	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2222	4118	8/1/2018	Minnesota Valley	Panther	1	230		600	Rebuild Line	MN	30.4		Conceptual	$91,000,000.00			Y	C
C	West	MISO	2223	4126	8/1/2018	Hayward	Transformer	1	345	161	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2223	4095	8/1/2018	Hayward	Winnebago	1	345		1000	new line	MN		50	Conceptual	$53,000,000.00			Y	C
C	West	MISO	2223	4096	8/1/2018	Hayward	Adams	1	345		1000	new line	MN		37	Conceptual	$40,000,000.00			Y	C
C	West	MISO	2223	4124	8/1/2018	Hayward	Adams	2	345		1000	new line	MN		37	Conceptual	$40,000,000.00			Y	C
C	West	MISO	2223	4094	8/1/2018	Winnebago	Lakefield	1	345		1000	new line	MN		55	Conceptual	$59,000,000.00			Y	C
C	West	MISO	2223	4127	8/1/2018	Adams	Transformer	2	345	161	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2223	4125	8/1/2018	Winnebago	Transformer	1	345	161	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2223	4123	8/1/2018	Hayward	Winnebago	2	345		1000	new line	MN		50	Conceptual	$53,000,000.00			Y	C
C	West	MISO	2223	4122	8/1/2018	Winnebago	Lakefield	2	345		1000	new line	MN		55	Conceptual	$59,000,000.00			Y	C
C	West	MISO	2224	4128	8/1/2018	Morris	Alexandria	1	345		1000	new line	MN		44	Conceptual	$93,000,000.00			Y	C
C	West	MISO	2224	4129	8/1/2018	Morris	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2224	4130	8/1/2018	Johnson Junction	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2224	4098	8/1/2018	Morris	Johnson Junction	1	345		1000	new line	MN		16	Conceptual	$34,000,000.00			Y	C
C	West	MISO	2224	4097	8/1/2018	Johnson Junction	Big Stone	1	345		1000	new line	SD\MN		32	Conceptual	$68,000,000.00			Y	C
C	West	MISO	2225	4133	8/1/2018	Crow River	Transformer	1	345	115	448	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2225	4101	8/1/2018	Crow River	Big Swan	1	345		1000	new line	MN		25.3	Conceptual	$54,000,000.00			Y	C
C	West	MISO	2225	4100	8/1/2018	Big Swan	Willmar	1	345		1000	new line	MN		40	Conceptual	$85,000,000.00			Y	C
C	West	MISO	2225	4099	8/1/2018	Willmar	Big Stone	1	345		972	new line	MN/SD		75	Conceptual	$159,000,000.00			Y	C
C	West	MISO	2225	4131	8/1/2018	Willmar	Transformer	1	345	230	336	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2225	4132	8/1/2018	Big Swan	Transformer	1	345	115	448	new transformer	MN			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2226	4136	8/1/2018	North Rochester	Byron	2	345		1000	new line	MN		10	Conceptual	$24,000,000.00			Y	C
C	West	MISO	2226	4134	8/1/2018	Adams	Pleasant Valley	2	345		1000	new line	MN		16.8	Conceptual	$39,000,000.00			Y	C
C	West	MISO	2226	4135	8/1/2018	Byron	Pleasant Valley	2	345		1000	new line	MN		16.3	Conceptual	$38,000,000.00			Y	C
C	West	MISO	2227	4137	8/1/2018	Monticello	Dickinson	1	345		1000	new line	MN		17.4	Conceptual	$25,000,000.00			Y	C
C	West	MISO	2227	4138	8/1/2018	Dickinson	Crow River	1	345		1000	new line	MN		3.8	Conceptual	$6,000,000.00			Y	C
C	West	MISO	2227	4139	8/1/2018	Crow River	West Waconia	1	345		1000	new line	MN		23.9	Conceptual	$34,000,000.00			Y	C
C	West	MISO	2227	4140	8/1/2018	West Waconia	Helena	1	345		1000	new line	MN		26	Conceptual	$37,000,000.00			Y	C
C	West	MISO	2230	4105	8/1/2018	Spring Green	Salem	1	345		1412	new line	WI		54	Conceptual	$69,000,000.00			Y	C
C	West	MISO	2230	4143	8/1/2018	Spring Green	West Middleton	1	345		1412	new line	WI		18	Conceptual	$23,000,000.00			Y	C
C	West	MISO	2230	4144	8/1/2018	Spring Green	Transformer	1	345	138	336	new transformer	WI			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2231	4107	8/1/2018	Hilltop	Transformer	1	345	138	500	new transformer	WI			Conceptual	$10,000,000.00			Y	C
C	West	MISO	2231	4106	8/1/2018	Hilltop	Columbia	1	345		1195	new line	WI		50	Conceptual	$68,000,000.00			Y	C
C	West	MISO	2231	4145	8/1/2018	Hilltop	LaCrosse	1	345		1195	new line	WI		80	Conceptual	$108,000,000.00			Y	C