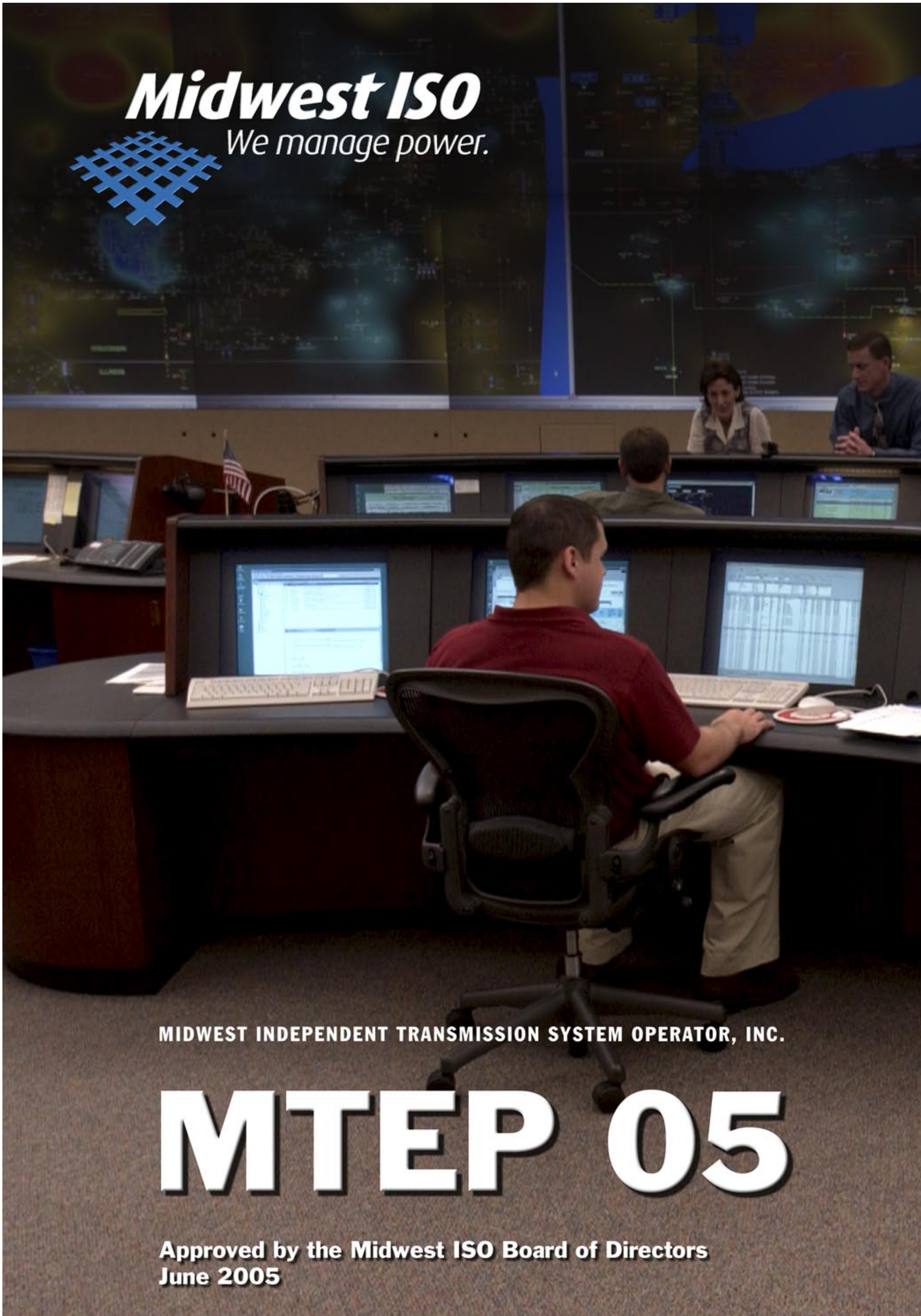

Midwest ISO
We manage power.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

# MTEP 05

**Approved by the Midwest ISO Board of Directors**
**June 2005**

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The following appendices are not public information. Please see the Midwest ISO web site for instructions on requesting copies of these appendices. Select Planning & Interconnections, then Expansion Planning from the navigation menus or use the following link http://www.midwestiso.org/plan_inter/expansion.shtml

Appendix A - 2004-2009 MISO Transmission Expansion Planning Map

Appendix D – Analysis Technical Details

# Section 1: Executive Summary

## 1.1 Introduction

This Midwest ISO Transmission Expansion Plan 2005 (MTEP 05) report describes the currently recommended transmission needs for the Midwest ISO transmission System. In accordance with the Transmission Owners' Agreement (TOA), approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities.

MTEP 05 has identified, through its Baseline Reliability study process, 615 planned or proposed facility additions or enhancements representing an investment of $2.91 billion through 2009, primarily to maintain reliability. In addition to these facilities, the report describes two other large scale "Exploratory" plans that continue to be evaluated by the Midwest ISO and stakeholders for their potential regional benefits. The results of the Baseline Reliability study of MTEP 05 indicate that the Midwest ISO Transmission System as projected for the year 2009 is expected to be able to perform in accordance with NERC Planning Standards for normal system conditions, events involving loss of a single transmission facility, and for most events involving loss of more than one facility. This performance will require that the ***Planned*** projects listed in Appendix A to this report go forward, and that the ***Proposed*** projects or suitable alternatives are in place. The more than 600 Planned or Proposed facility additions needed to enable the Transmission System to meet reliability standards are listed in Appendix A. This Midwest ISO Transmission Expansion Plan 2005 (MTEP 05) report is the second regional expansion plan produced by the Midwest ISO since start of operations in February 2001. The Midwest ISO Board of Directors approved the first regional plan, MTEP 03 in June 2003. The independent system reliability assessment contained in this MTEP 05 should be considered together with the commercial observations drawn in MTEP 03 and in Chapter 7 of MTEP 05. Together, these analyses indicate that the currently planned expansion to the Midwest ISO Transmission System are expected to result in a system that meets reliability requirements, but for which there is opportunity for additional regional expansion to further address congestion and to provide for access to new generation additions. The MTEP 05 work has established that the expansions in Appendix A will provide for a reliable system, but the Midwest ISO has not independently evaluated at this point in the developing expansion planning process whether these expansions are the most efficient solutions to reliability issues identified. The Midwest ISO will continue to work with stakeholders as the planning process evolves to identify and provide for the most efficient solutions to reliability issues, as well as the further identification of broader regional solutions to stakeholder needs.

This MTEP 05 comes at a time of significant transitions for the Midwest ISO. At the time of this writing, the Midwest ISO is at the start of operations of the Midwest Market Implementation, the transmission and energy market for the Midwest ISO region. This region spans 15 states, and 947,000 square miles from the Dakotas to Kentucky, and includes more than 119,000 Mw of demand, 97,000 miles of transmission and diverse generation resources.

This is a time of transition as well for the planning process that will support the implementation of the Midwest Market. Together with stakeholders, the Midwest ISO has been developing a transmission pricing policy and additions to the planning protocol that was established in the Transmission Owners' Agreement. This policy and protocol will enable the Midwest ISO to meet the needs of the market by planning for and promoting the development of system expansion needed to relieve constraints to the efficient delivery of energy from resources to load, and by providing increased certainty to the cost responsibility and recovery for these expansions.

MTEP 05 identifies expansion needed for a planning horizon extending through the peak season of 2009. These expansion plans are listed in Appendix A to this MTEP report, together with information about expected service dates, project owner, estimated project cost and other information. Continuing the project designations initiated with MTEP 03, projects are classified as either “Planned” or “Proposed”. Projects in Appendix A that are designated as Planned projects are recommended by the Midwest ISO to be completed by the service dates identified. Other projects listed in Appendix A as Proposed projects are tentative solutions to identified needs, and require additional planning before they are endorsed by the Transmission Owners or the Midwest ISO as the preferred solution. Of the $2.91 billion projected investment, $1.57 billion is for Planned facilities. In many cases, a “project” consists of a number of discrete facilities that are to be developed as a part of a single solution to the identified need. Appendix A includes 369 Planned facilities and 246 Proposed facilities.

This expansion plan report includes sections devoted to the following topics:

- Planning objectives and process of the Midwest ISO
- Midwest ISO system configuration, observations, and issues
- Review and status of the projects identified in MTEP 03
- Analyses of system performance against reliability standards
- Operational issues; constraints related to TLR, AFC, FTR
- Special regional projects with potential benefits
- Summary of transmission investment

## 1.2 The Midwest ISO Planning Objectives and Process

### 1.2.1 Objectives

The fundamental objective of the MTEP is to ensure the system can continue to be reliably operated into the future. Day-to-day operations ensure that the current system is reliably operated, but the system must be planned to continue to meet existing obligations into the future including load growth, to respond to changing external system configurations, and changes to the connected generation resources.

As a Transmission Provider, the Midwest ISO has an obligation to continue to provide for the reliable and efficient transmission service to the existing and forecast loads of Network Customers, along with any commitments to Point-to-Point Transmission Customers. Firm Transmission Service Customers expect that in exchange for their transmission service payments that increase over time with necessary additional transmission investment, they will be able to continue to reliably meet their Network Load from their Network Resources at just and reasonable rates. This requires that the planning process identify solutions to reliability issues that arise from the expected dispatch of Network Resources. These solutions should balance the costs of increasing the embedded cost of the grid through transmission expansions with the costs of redispatching the Network Resources (congestion cost) and other operational solutions to managing grid reliability.

The Midwest ISO's transmission owners are expected to make the investments necessary to implement the Planned Projects in this expansion plan, unless alternative funding is provided for under the tariff.

## 1.2.2 Process

The current planning process at the Midwest ISO integrates the ongoing planning processes that are responsive to new customer requests for system access, and the continuing but cyclic Baseline Reliability studies of the MTEP regional plan development. The graphic below depicts these processes.

Key elements of this process include the following:

- Roll-up of Transmission Owner Plans
- Inclusion of Plans from Interconnection and Delivery Services
- Development of Power Flow Base Case
- Review of System Reliability and Congestion
- Development of any Additional Expansion Needs
- Review of Additional Regionally Beneficial Expansions

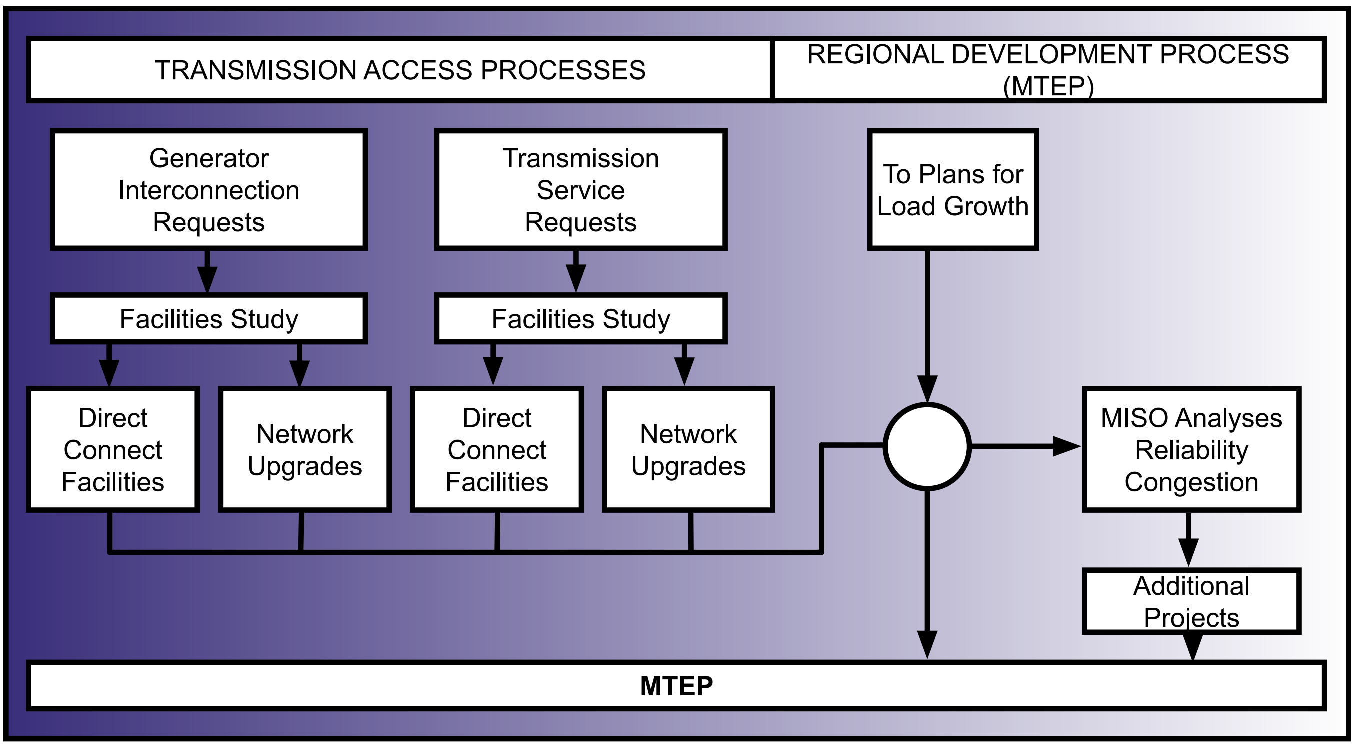



**Figure 1.2-1**

### 1.2.2.1 Assignment of Cost Responsibility

As noted above, it is expected that future MTEP will assign cost responsibility for most of the projects contained within the plan. These assignments will be in accordance with to-be-filed tariff provisions governing the cost assignment and recovery for Midwest ISO transmission facilities. At the time of completion of this MTEP 05, cost responsibility for load growth driven projects is in accordance with Attachment N to the tariff and the Transmission Owners Agreement, which, in general assigns the costs for such upgrades to the local Transmission Owner constructing the upgrade. Costs for generator interconnection driven upgrades are in accordance with Attachment X to the tariff and are determined at the time of execution of each individual interconnection agreement.

### 1.2.2.2 Plan Review

Once the Midwest ISO develops the regional plan in collaboration with the Transmission Owners, the Midwest ISO staff engages in several stages of stakeholder review of the plan. This review is intended to provide input to the staff as to the accuracy of the results of analyses in the plan and comment on the conclusions drawn from those analyses.

The plan is reviewed first by the Expansion Planning Group (EPG), and then by its parent committee the Planning Subcommittee (PS). The MTEP results are then discussed with the OMS and the Advisory Committee before being presented to the Midwest ISO Board of Directors for Approval. The Midwest ISO requests approval by the Board of the Planned projects in the MTEP, recognizing that the more tentative Proposed plans are more likely to undergo further development and modification before becoming Planned projects. Once approved by the Board, the regional plan is implemented in accordance with the Transmission Owners agreement. The Midwest ISO monitors the progress of projects in the plan as future MTEP are developed. It is understood that even Planned projects may be revised as system conditions change or as preferred projects may come to light. The Midwest ISO keeps track of and incorporates any such changes into future system models used to continually assess system performance.

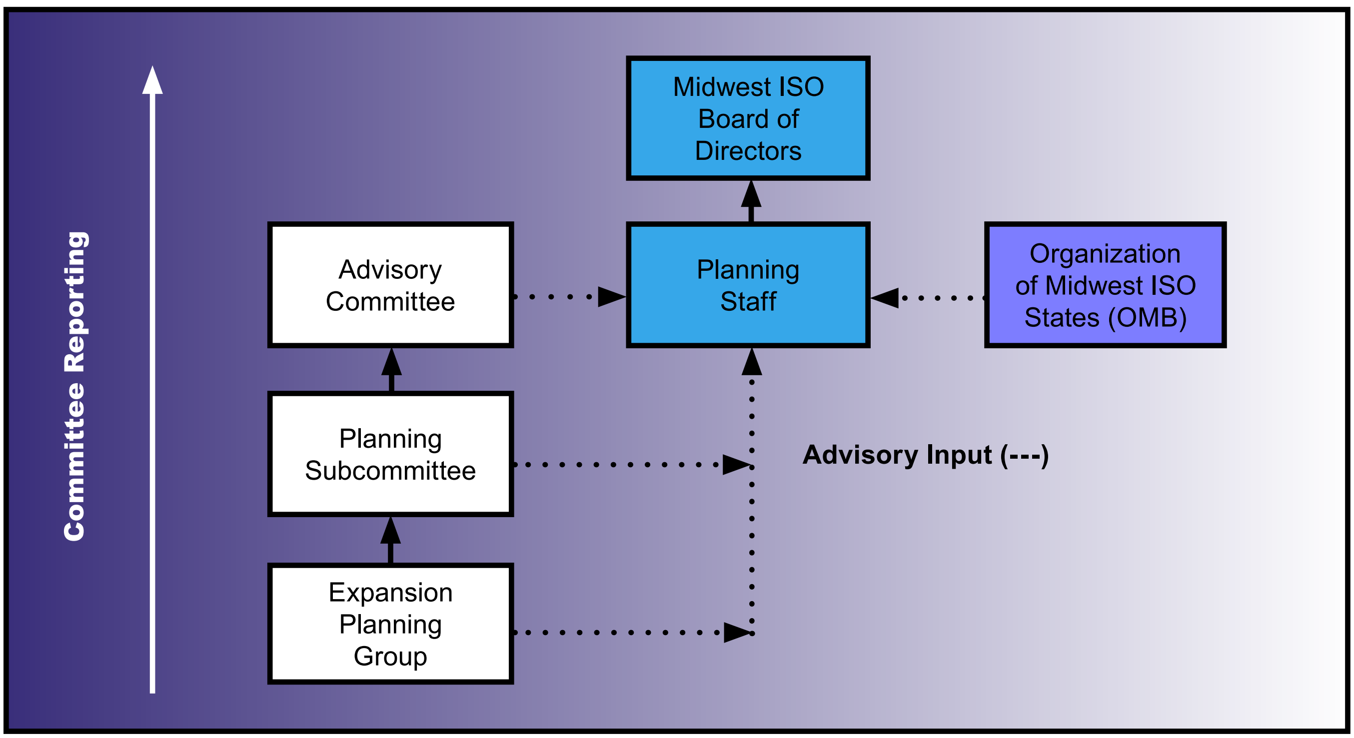



**Figure 1.2-2**

### 1.2.2.3 Organization of Midwest ISO States (OMS)

The Organization of Midwest ISO States (OMS) was formed in mid-2003. Since that time, the role of the OMS in the Midwest ISO planning process has been developing. Midwest ISO staff has discussed the first two regional plans with the OMS. These have been higher-level reviews intended to familiarize the OMS with the basic findings from the analyses and to discuss process issues.

For major projects proposed in the plan, that may need state certification, the Midwest ISO is prepared to support the Transmission Owners in describing the needs and benefits of the projects within the state siting and certification processes.

The OMS has formed a Planning and Siting Work Group, and in subsequent issues of the MTEP the Midwest ISO will seek input from this Work Group as well as from the OMS Board of Directors as to the planning process.

In addition, while the Midwest ISO does not seek nor expect endorsement of any aspect of the plan, it is the hope of the Midwest ISO that by engaging in dialogue with the OMS regarding aspects of the MTEP, particularly the development of regional or multi-state projects, as they may be developed over time, the Midwest ISO and our transmission owning members can gain insights that will help to maximize the value of the transmission grid.

## 1.3 Update on MTEP 03 Findings

The Transmission Planning responsibilities of the Midwest ISO include monitoring the progress and implementation of necessary system expansions identified in the MTEP. The MISO Board approved the first MISO expansion plan MTEP 03 on June 19, 2003.

MTEP 03 contained 407 Planned and Proposed facilities, of which 229 were Planned. As a whole, nearly all of the 229 Planned facilities included in MTEP 03 are on track

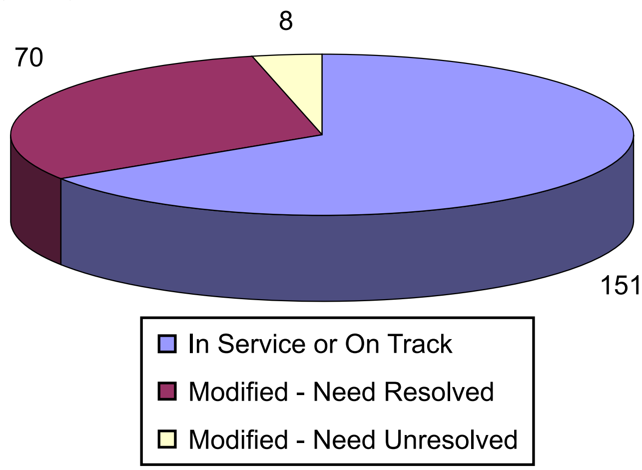



**Figure 1.3-1**
**Status of 229 MTEP 03 Planned Facilities**

Planning is a dynamic process and the Midwest ISO expects that as a normal part of developing the most cost effective plans, there should be modifications to plans where appropriate to meet changing system conditions. Review of the projects identified in MTEP 03 has shown that many projects have undergone some modification, delay, substitution, or even cancellation. Typical reasons for these changes involve

- Load growth less than anticipated
- Generation or transmission service plans changing
- Development of alternative solutions such as system operating guides or alternative projects

After considering the circumstances of each project, there remain at this time 21 projects, about 5%, from MTEP 03 for which the need apparently continues to exist and the projects have been delayed beyond the desired service date for reasons predominantly of regulatory delays or construction delays. The Midwest ISO has documented these projects in Section 4 and will incorporate review of the critical conditions driving these projects into seasonal operating reviews of the system to develop operational steps if required to ensure the security of the system until the projects are installed.

### 1.3.1 New Projects Added in MTEP 05

As noted previously, there where 407 itemized facilities in the 2002-2007 period of MTEP 03. MTEP 05 expands the planning horizon through 2009. There are a total of 542 new facilities now planned or proposed through the 2009 period that have been identified with the MTEP 05 effort (where not identified in MTEP 03). Appendix A contains now a total of 615 planned and proposed facilities.

### 1.3.2 Impact on Reliability of Changing Project Status

Notwithstanding the natural modifications of the overall plan on a continuing basis, the results of the Baseline Reliability analyses that have been performed for the first time in this MTEP 05 and will be included in subsequent MTEPs, along with other supporting studies performed by the Transmission Owners provided the indication as to whether the currently identified projects in the Appendix A to MTEP 05 form a sufficient set to maintain system reliability. The results of these analyses are described in Section 6 to this MTEP report.

## 1.4 MTEP 05 - Focus on Reliability

This second Midwest ISO regional plan has a substantial reliability focus. MTEP 03 was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 that was underway by the Transmission Owners at the time of startup of MISO operations and shortly thereafter. This MTEP 05 extends the work of MTEP 03 and provides a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 time horizon. This evaluation is referred to as the Baseline Reliability Study.

The Baseline Reliability Study provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the year 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to determine if these proposed additions are sufficient to meet NERC planning standards for reliability. This assessment is accomplished through modeling analyses of the transmission system's steady-state power flow, dynamic system performance, small-signal perturbation simulation, load deliverability assessment, and voltage-stability. This analysis was performed by MISO staff and reviewed in an open Stakeholder process.

The purpose of the MTEP Baseline Reliability Study is to determine system expansions that are needed to reliably meet the ongoing needs of existing transmission customers. Projects that are identified in the Baseline Reliability Study are recognized as needed as a part of the base system and are not expected to be the responsibility of new transmission service or interconnection customers that seek access to the transmission system, unless otherwise identified in Appendix A as related to such a request.

The planning horizon studies performed in the MTEP process are coordinated with the seasonal (summer and winter) reliability studies performed by the Midwest ISO. This coordination entails comparison of critical conditions in the near term seasonal assessments and in the further out planning horizon of the MTEP. This comparison ensures that issues identified in the planning horizon will be addressed before they become problems in the operating horizon, and conversely, that planned solutions are being implemented for nearer term issues.

## 1.5 Key Findings for 2009

The following sections describe key findings from the MTEP 05 Baseline Reliability study.

### 1.5.1 System Performance with Planned and Proposed Projects

The results of the Baseline Reliability study of MTEP 05 indicate that the Midwest ISO Transmission System as projected for the year 2009 is expected to be able to perform within standards for normal system conditions, events involving loss of a single transmission facility, and for most events involving loss of more than one facility. This performance will require that the Planned projects go forward, and that the Proposed projects or suitable alternatives are in place. The more than 600 Planned or Proposed facility additions needed to enable the Transmission System to meet reliability standards are listed in Appendix A. Projects that are needed to meet the more significant reliability concerns identified by the Midwest ISO are described in section 1.5.2 below.

### 1.5.2 Key Projects

There are numerous key projects that have been identified as needed to maintain system reliability through the 2009 period. Table 1.5-1 lists projects of member systems for the 2004-2009 planning horizon that have estimated costs of $15 Million or more. These major projects account for $1,093 million, or about 70% of the total cost of all planned projects for the 2004-2009 period. Section 6 of this report contains descriptions of these and other major projects. Appendix A contains a listing of all Planned and Proposed projects.

| Table 1.5-1 Planned Projects $15 Million and Above | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Project** | **Description** | **Planning Region** | **Map Grid Location** | **Driver** | **Service Date** | **Project Cost (millions)** | **Project Status** |
| Arrowhead–Gardner Park 345 kV line | Build 220 miles of 345 kV line, 23 miles of 115 kV line, two 345-115 kV transformers, one 800 phase angle regulating transformer, one 345-230 kV transformer, reactive compensation | Central | I4 - J6 | Load & Trans. Service | 2008 | $422 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 10 % |
| Buffalo Ridge 825 MW of Generation Outlet | Build 94 miles of 345 kV line, 345 / 115 kV transformer, 34 miles of 161 kV, and 26 miles new 115 kV, 15 miles rebuild 115 kV | Northwest | G6 - H7 | Generation | 2007 | $130 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Final permits pending, IA contracts under negotiation<br>• Delay Risk: Low<br>• Construction: 10 % |
| Chisago–Apple River | Build 4.5 miles and rebuild 20.6 miles of 161 kV, rebuild 16 miles of 115 kV, and one 161-115 kV transformer | Northwest | I5 | Load | 2007 | $58 | • Category Reviewing Alternatives<br>• Budget Status: Pending<br>• External Approvals: Pending<br>• Delay Risk: High<br>• Construction: 0 % |
| Plains–Amberg–Stiles 138 kV line rebuild | Rebuild 131 miles of 138 kV line | Central | K5 - K6 | Load | 2006 | $45 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 15 % |
| Prairie State Power Plant transmission outlet | Build 35 miles of 345 kV line | Central | J11 - K11 | Generation | 2009 | $39 | • Category Planned<br>• Budget Status: Pending<br>• External Approvals: Pending<br>• Delay Risk: Medium<br>• Construction: 0 % |
| Rosser–Silver 230 kV line | Build 65 miles of 230 kV line | Northwest | F2 | Load | 2005 | $34 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 10 % |
| Callaway–Franks 345 kV line | Build 54 miles of 345 kV line | Central | I10 | Load | 2006 | $29 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 20 % |
| Thumb Loop Rebuild | Rebuild 70 miles of 120 kV line | East | N6 | Load & Other | 2006 | $27 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 60 % |
| Ponton 230 kV | 150 / 0 MVAR Static VAR Compensator | Northwest | F2 | Generation | 2005 | $25 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 98 % complete, in-service July 2005 |
| Thompson Birchtree | 150 / -20 MVAR Static VAR Compensator | Northwest | O3 | Generation | 2010 | $25 | • Category Planned<br>• Budget Status: Obtained<br>• External Approvals: Waiting for environmental permits for associated Wuskwatim generator connection project<br>• Delay Risk: Medium<br>• Construction: Not Available |

| Table 1.5-1 Table 1.5-1 Planned Projects $15 Million and Above (continued) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Project | Description | Planning Region | Map Grid Location | Driver | Service Date | Project Cost (millions) | Project Status |
| Jefferson City Area Development | Build 15 miles of 345 kV line, build 25 miles of 161 kV line | Central | I11 | Load | 2007 | $25 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Medium<br>• Construction: 10 % |
| West Marinette–Menominee–Rosebush–Amberg 138 kV line | Rebuild 43 miles of 138 kV line | Central | K5 | 60 % Load<br>20 % TSR<br>20 % Other | 2005 | $25 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 20 % |
| Columbia–North Madison 345 line | Convert 17 miles to 345 kV line, replace two 345 / 138 kV transformers | Central | K7 | Load & Trans. Service | 2006 | $25 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Low<br>• Construction: 60 % |
| Buffalo Ridge 425 MW of Generation Outlet | Build 24 miles of 161 kV line, rebuild 63 miles of 115 kV line | Northwest | G6 - H7 | Generation | 2006 | $68 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained, IA contracts under negotiation<br>• Delay Risk: Low<br>• Construction: 70 % |
| Wagener–NW68th & Holdrege 345 | Build 28 miles of 345 kV line | Northwest | F9 | Load | 2008 | $22 | • Category Planned<br>• Budget Status: Approved<br>• External Approvals: Obtained<br>• Delay Risk: Medium, some possibility of not being completed in 2008<br>• Construction: 5 % complete |
| St. Vital–Steinbach 230 | Build 35 miles of 230 kV line | Northwest | F1 | Load | 2010 | $21 | • Category Deferred by Alternative for 2007 Project is changed from planned to proposed as it was deferred to 2020. Higher load growth in the Steinbach area required a new plan. This plan consists of a second 230-66 kV transformer bank at Richer, which is planned to be in-service in 2007. The second bank provides for immediate load serving needs and defers the need for the 230 kV line. The budget for the alternative transformer bank has been approved and design is underway. |
| Rock River–Bristol–Elkhorn conversion to 138 kV | Converts 28 miles of 69 kV to 138 kV line, convert five 69 substation to 138 kV | Central | K7 | Load | 2008 | $20 | • Category Reviewing<br>• Budget Status: Pending<br>• External Approvals: Pending<br>• Delay Risk: High<br>• Construction: 0 % |
| Lenox Station | Rebuild 28 miles of 345 kV line, rebuild 47 miles of 120 kV line, one 345 / 120 kV transformer | East | O7 | Other | 2007 | $15 | • Category Planned<br>• Budget Status: 2005 portion approved, 2006 portion is pending approval. 2006 budget approval is expected<br>• External Approvals: Pending<br>• Delay Risk: Low<br>• Construction: 0 % |

In addition to these more significant projects in terms of cost, there are a number of projects of lesser cost that are required to relieve significant loading or low voltage conditions. Some of these include the following and additional detail may be found in Section 6 and the Appendices to this report:

### Wisconsin

- Skanawan-Highway 8 rebuild to double circuit 115 kV
- Port Washington–Saukville 138 kV rebuilds
- The second Wempletown–Paddock 345 kV line

### North Dakota

- Bismarck Downtown–East Bismarck 115 kV upgrade to 160 MVA
- Maple River–Red River 115 kV line upgrade to 310 MVA

### Iowa

- Upgrade Salem 345/161 kV Tr to 550 MVA; replace Hazelton Tr with existing Salem Tr.

### Minnesota

- Prairie Island–Red Rock 345 kV # 2 line upgrade to 1198 MVA
- Monticello–Sherco–Salida 115 kV line upgrade to 310 MVA, and Sherco 345/115 ckt 1 to 448 MVA
- Granite City 115 kV 2x40 MVAR capacitor addition
- Aldrich–St. Louis Park 115 kV line upgrade to 310 MVA
- St. Cloud Tap–I94Industrial–Salida 115 kV line upgrade to 310 MVA

### Missouri

- Joachim 345/138 kV 560 MVA transformer

### Ohio

- Star substation reconfiguration, each 345/138 transformer has independent breaker
- Galion substation reconfiguration, each 345/138 transformer has independent breaker

### Indiana

- Westwood 2nd 345/138 kV Transformer & Dequine–Westwood 345 kV line
- Cayuga–Veedersburg 230 kV rebuild
- Hanna–Southeast 138 kV breaker CT changes

### Michigan

- Campbell–Hudsonville 138 kV sag limit removed
- Tippy–Hodenpyl 138 ckt 1, reconductor 795 ACSS
- Croton–Felch Rd. 138 kV line reconductor
- North Belding–Sanderson–Eureka reconductor to 795 ACSS and N Beld CT Tap to 1200 A
- Weeds Lake 345/138 substation addition
- Garfield–Hemphill 138 line rebuild
- 36 MVAR Gallagher Capacitor
- 54 MVAR Placid Capacitor addition
- Bismarck–Golf 120 kV project create a 120 kV bus group at Golf and building a new 120 kV line from Bismarck to Golf

### 1.5.3 Reliability Issues Needing Resolution

The Midwest ISO identified certain conditions for which some facilities could be outside of design limits or for which voltages could be below standards by the year 2009. In all but a few cases these conditions involved multiple elements forced out of service. These multiple contingency events are somewhat rare under peak load conditions, and the current NERC Standards of performance for such events permit such excursions beyond limits provided that system operators can take action to remedy these conditions before they can propagate to an uncontrolled loss of load. For such conditions, it is important that the Midwest ISO as Reliability Coordinator understand the operating steps that can be implemented, including any plans for controlled shedding of load that may be needed to contain the events. For some of these multiple contingency events, not all of the necessary operating steps have been identified by the Midwest ISO to ensure the reliability of the system for these events. These events needing further resolution are tabulated in Section 6 of this report. The Midwest ISO will continue to work with the Transmission Owners to identify all necessary operating steps or other solutions needed to resolve these events.

### 1.5.4 Operational Issues

The MTEP is a forward looking expansion plan, the objectives of which include ensuring the future system can be operated safely, reliably and efficiently through the planning horizon year. One indication of future system performance are the results of the contingency studies of the planning horizon year, 2009. Another indicator of system performance is the current operational experience, and the relationship between constraints that routinely occur and planned expansions. Many system constraints are revealed as limits to the efficient operation of the system. Transmission customers desiring to make economical transactions request transmission service and are denied service due to the inability of the system to reliably accommodate the desired transactions. This is the result of low Available Flowgate Capability (AFC). Firm transactions are curtailed through the NERC Transmission Loading Relief (TLR) procedure due to unexpected system conditions, or less than perfect coordination amongst transmission providers. Nominations of Financial Transmission Rights (FTR) associated with physical transmission rights (transmission service) may be less than fully feasible. These real-time and near-term issues are referred to in this MTEP as operational issues. Each of these operational issues presents a reliability concern unless a generation redispatch is performed as an operating adjustment to the desired dispatch that would otherwise occur. The planning philosophy of the Midwest ISO is to seek resolution to these reliability issues in the least cost manner, through either a transmission system switching operation, a generation redispatch, or an expansion to the system.

In section 6.4.1 we have reviewed recent incidence of very low AFC, frequent TLR, or constraints to full FTR allocations. That Section draws correlations between Planned and Proposed expansion projects and constraints causing low AFC, high incidents of TLR, or pro-rated FTR allocations. The expansions in this MTEP 05 will address many but not all of these operational issues identified. The Midwest ISO will continue in subsequent expansion plans to review these constraints and identify expansions as appropriate to resolve such reliability concerns in the most efficient manner.

## 1.5.5 Other Potentially Beneficial Regional Projects

In the first Midwest ISO Transmission Expansion Plan, MTEP 03, the Midwest ISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal and wind generation, as well as gas generation based the interconnection queues at the time. This study is available on the Midwest ISO web site. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

Among the dozen potentially regionally beneficial expansion concepts reviewed in MTEP 03, two have been addressed further in this MTEP 05, because of the potential benefits that the preliminary analyses showed, and because of significant stakeholder interest in these two concepts. These two expansion concepts are referred to as 1) the Northwest Exploratory Project, and 2) the Iowa–Southern Minnesota Exploratory Project. Both projects would provide enhanced access by coal and wind resources to load centers in the Midwest ISO.

It is the intention of the Midwest ISO to continue the development of these regional expansion projects through further evaluation of the nature, value, and beneficiaries of these plans. The Midwest ISO intends to recommend such plans as these to the Midwest ISO Board of Directors at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made, consistent with the Midwest ISO tariff and the Transmission Owners Agreement.

The Northwest Exploratory study involves generation in the Dakotas and transmission upgrades from the Dakotas to Minnesota. The Iowa-Southern Minnesota Exploratory study involves generation in northern Iowa, southern Minnesota, and South Dakota and transmission upgrades from generation to major load centers in Minnesota, Iowa, and Wisconsin. Both studies are in progress and results to date and future work efforts are described in this report.

## 1.5.6 Total Expected Investment Through 2009

The total estimated direct cost of the Planned and Proposed facilities plus the facilities that went into service since 2003 is $2.91 billion for the six-year period 2004-2009 periods. This is substantially above the **$1.96 billion** that was estimated for the six-year period 2002-2007 in MTEP 03. Of these projects, **$204 million** were In Service by 2004, $1,565 million are considered Planned, and $1,144 million are considered Proposed and will continue to be reviewed.

The cumulative expected spend over the 2004-2009 period is shown in Figure 1.5-1 below.

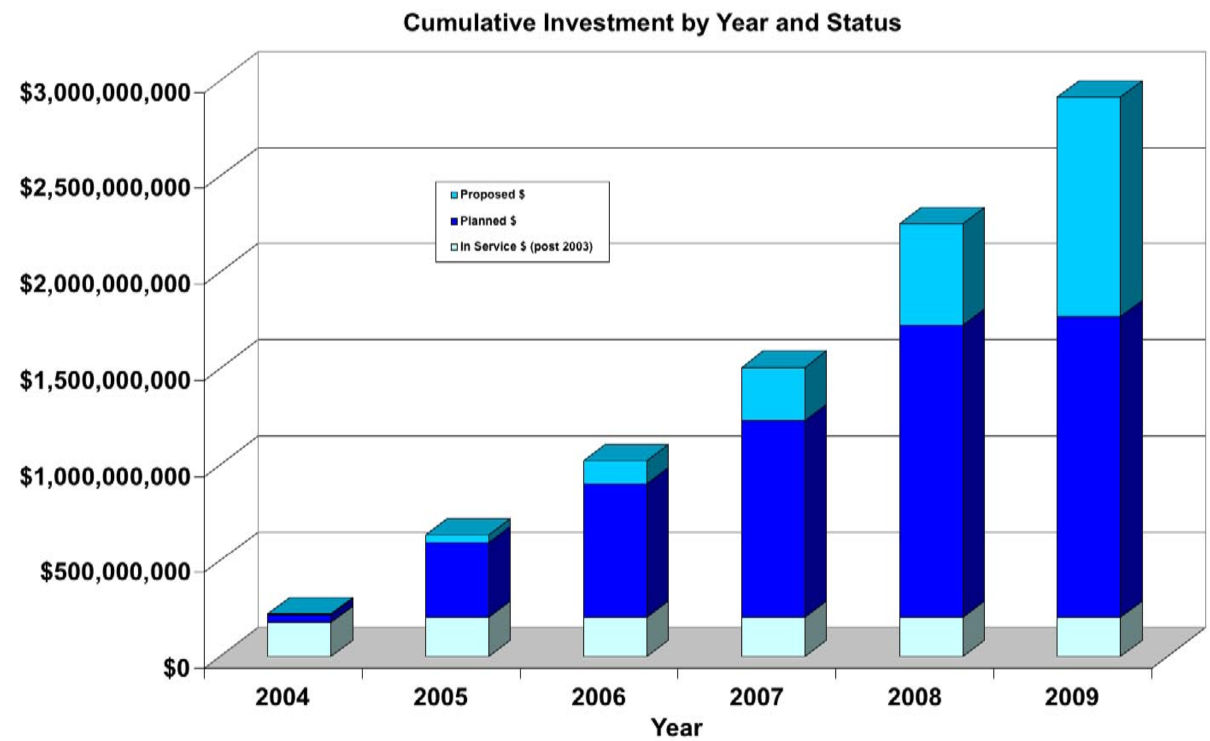



Figure 1.5-1 Cumulative Projected Spending All Projects

About 5,123 miles of transmission line upgrades are projected through 2009 which is about 4.6% of the approximately 112,000 miles of line existing throughout the Midwest ISO area. Less than 2%, however, involve lines on new transmission corridors.

About 59 % of the expected total transmission line and substation enhancements are at 230 kV and above.

Larger projects, with estimated costs of $5,000,000 and higher have been summarized below in Figure 1.5-2. This table shows a comparison of expected spend grouped by NERC region within the Midwest ISO for the out years of 2007 through 2009. For the purposes of this summary, groupings are as follows:

**MAPP:** Xcel Energy, Otter Tail Power, Montana Dakota Util., Minnesota Power, Manitoba Hydro, Great River Energy, Lincoln Electric Systems, Aquila, Alliant West

**MAIN:** American Transmission Co., AmerenIP, AmerenCILCO, Southern Illinois Power Coop, City Water Light and Power, City of Columbia

**ECAR**: Cinergy, International Transmission Co Michigan Electric Transmission Co, Louisville Gas and Electric Corp, Hoosier Energy, Indianapolis Power and Light, Vectren Energy, Northern Indiana Public Service Co., FirstEnergy

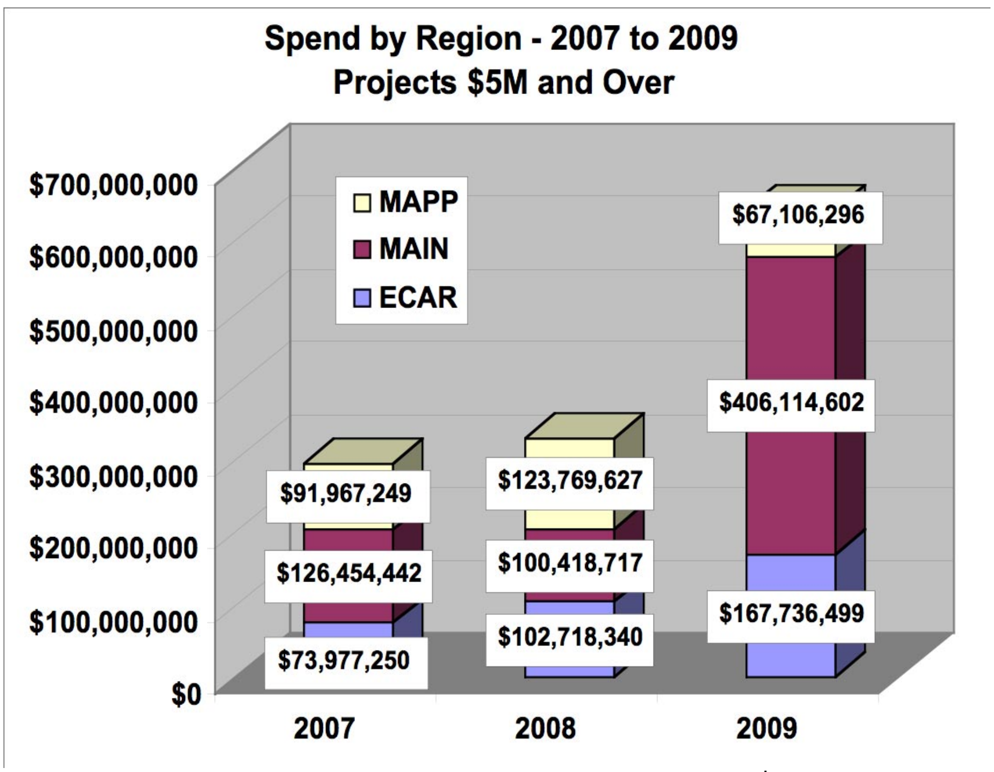



**Figure 1.5-2 Spend by Year by Region ($)**

This summary shows that of the $1,260,263,022 expected to be spent over the three-year period about 51% is projected for the year 2009. In addition, projected spending is relatively balanced between the three areas for 2007 and 2008, while in 2009 the MAIN areas entities project spending of about 63% of the 2009 total with ECAR 26% and MAPP 11%. This summary has excluded two significant projects with a combined cost of $552,000,000: the Arrowhead–Garden Pk Project of ATC LLC and the Buffalo Ridge Area Generation Outlet Project of Xcel Energy. The jurisdictional regulatory authorities already have approved these projects.

## 1.6 Implementation and Follow-Up

The Midwest ISO will monitor progress on all projects identified in this MTEP 05, and will support the need for and development of projects defined as Planned projects that are part of the approved MTEP.

The MTEP will be subject to change, as system conditions change. Changes in load growth, changes in usage patterns, development of new generation interconnections, changes in projected service dates of interconnection plans, delays in regulatory approvals of transmission projects, or ongoing development of preferred plans, all could cause changes to the overall MISO plan. The MTEP will be updated as needed to incorporate the impacts of such changes on the overall regional plan.

# Section 2: Midwest ISO Planning Objectives and Process – Update

## 2.1 Overview

The Midwest ISO Transmission Expansion Plan (MTEP) is produced in accordance with the requirements of RTO regional planning as set forth in the FERC Order 2000, and with the Agreement of the Midwest Transmission Owners to Organize the Midwest ISO (“Transmission Owners Agreement”, or “TOA”). As part of the ongoing responsibilities delineated in the TOA, the Midwest ISO develops transmission expansion plans to address the reliability of the Transmission System that is under its operational and planning control. In addition, the MTEP is to identify system expansion options that are beneficial in supporting the competitive supply of electric power by this system. The MTEP process is to consider all market perspectives, including demand-side options, generation location, and transmission expansion alternatives.

Together with stakeholders, the Midwest ISO has been developing a transmission pricing policy and additions to the planning protocol that was established in the TOA. This policy and protocol will enable the Midwest ISO to meet the needs of the market by planning for and promoting the development of system expansions needed to relieve constraints to the efficient delivery of energy from resources to load, and by providing certainty to the cost responsibility for these expansions. In this MTEP 05, the cost responsibility for the Planned (expected to go forward as planned) and Proposed (expected to be needed but other solutions under evaluation) projects identified in the regional plan are not yet explicitly described. These plans have been identified under the license-plate pricing policy in place at the start of Midwest ISO operations. Under this policy, projects needed to be constructed by a Transmission Owner in the pricing zone of that Owner are funded by that Owner and costs are recovered from customers taking service in the zone, through the zonal rates established through Attachment O to the tariff, unless a specific Transmission Customer has otherwise been assigned cost responsibility consistent with the policies of the FERC. In future versions of the MTEP, it is expected that projects in the plan will have specific cost responsibility delineated in accordance with the comprehensive pricing policy in development at the time of this MTEP 05.

The MTEP consolidates the transmission needs of the region into a single plan. A bottom-up, top-down approach is used to provide both detail at the local level and wide area analysis and optimization at the RTO-wide level. The Midwest ISO planning process is an open planning process that facilitates communication of ideas and concepts. The collaborative process coordinated through the Midwest ISO provides an opportunity for inputs from all stakeholder groups. This plan has been developed by Regional Study Groups formed from the Expansion Planning Group (EPG), and has been discussed with the parent committee to the EPG the Planning Subcommittee. Finally, it has been discussed with the Organization of Midwest ISO States (OMS) and with the Advisory Committee of the Midwest ISO before being brought before the Midwest ISO Board of Directors.

MTEP 05 is the second issue of a Midwest ISO regional transmission expansion plan. The first, MTEP 03 was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 plan year that was underway at the time of startup of Midwest ISO operations and shortly thereafter. It also provided in-depth analyses of the potential for regional transmission expansions to provide for lower customer energy costs by reducing congestion and by enabling the entry and delivery of new low cost generation.

This MTEP 05 extends the work of MTEP 03 by:

1. Tracking the progress of plans identified in MTEP 03
2. Continuing the development work on several of the most promising “Exploratory” regional projects identified as potentially beneficial in MTEP 03
3. Performing a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 horizon
4. Identifying the expansion necessary to maintain system performance within standards, and
5. Updating the expansion plan through the year 2009

## 2.2 Baseline Reliability

With MTEP 05, the Midwest ISO prepared the first "Baseline Reliability Study" for the RTO. Such a baseline is important in determining the system expansion needs through the planning horizon that are driven by existing service commitments. These service commitments include the forecast load growth of Network Customers, and firm transmission service commitments, a representation of which has been reflected through the modeled base-case generation dispatch. Expansions driven by these existing commitments form the "baseline" system from which new requests for transmission services, including interconnection service are evaluated.

The Baseline Reliability study performed for MTEP 05 provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the years 2004 through 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to determine sufficient and necessary projects to meet NERC and regional planning standards for reliability. This analysis was performed using traditional pre-market dispatch assumptions. The overall assumptions applied to this MTEP development are discussed in Chapter 5. Chapter 6 of this report provides a description of the analyses and results performed, and additional detail is included in Appendix D. In an effort to address recommendations for increased levels of contingency analysis from NERC in the aftermath of the August 2003 blackout, the Midwest ISO has performed an extensive analysis of the reliability of the Transmission System. These analyses are detailed in Chapter 6 and Appendix D and include in addition to first contingency steady state analyses, multiple contingency cascading outage analysis, transient stability simulations, small signal stability analyses, multiple contingency voltage stability screening, and load area loss-of-load expectation also referred to as Load Deliverability studies. This single study, however cannot evaluate all possible contingent conditions that could occur. The planning process is a continual one, and even as this MTEP 05 is distributed the planning staff is preparing a review of the planned 2011 system, and operational studies for the summer and winter 2005 seasons.The Baseline Reliability studies of the MTEP coordinate with the seasonal assessments performed by the Midwest ISO. Summer assessments were performed for the summers of 2003 and 2004. The summer assessment in 2004 expanded on the traditional first-contingency transfer analyses typically performed in NERC regional summer assessments, and explored the ability of the system to withstand additional levels of contingency, with a focus on voltage stability limits. The seasonal analyses provide Midwest ISO system operators with valuable information about proximity to limiting conditions should real-time events exceed usual first or second contingency planning criteria conditions. Information from the seasonal studies can help to target areas of the system for analysis in the planning horizon to ensure that plans are developing in a timely manner to avoid any weaknesses identified. Similarly, areas that are identified to be near or exceeding limits in the planning horizon in the MTEP 05 studies will be reviewed in the current year seasonal assessment for any operational concerns that may exist.

The Midwest ISO also draws information about system performance in both the operating and planning horizons through participation in NERC regional assessments of system performance.

## 2.3 Load Deliverability Studies

The Midwest ISO performs area import capability versus need studies, also referred to as Load Deliverability studies as a part of the determination of resource reliability for the Midwest ISO market. Resource reliability is maintained by 1) ensuring that market participants with load service responsibility maintain sufficient firm capacity to meet reserve requirements 2) ensuring that Network Resources identified by load serving entities are deliverable without "bottling" each other up if called upon together with other Network Resources to meet load demand, and 3) ensuring that the transmission system has sufficient capacity such that load areas can import needed supplies during times of deficiency of resources within the load area. Import needs are based on Loss of Load Expectation (LOLE) analyses.

At the present time the Midwest ISO requires that its load service entities maintain the reserve requirements prescribed by their respective NERC Regional Councils. Generator deliverability studies are performed on an ongoing basis as new Network Resources connect to the grid or request network resource status. Load Deliverability is evaluated as a part of the annual MTEP Baseline Reliability studies. MTEP 05 contains the first Midwest ISO Load Deliverability Study. The details of this study are contained in Section 6 to this report.

The planned 2009 Transmission System was found to be adequate in terms of its ability to deliver to load areas sufficient capacity to meet loss of load expectations of one day in ten years, with the exception of delivery to the ITC load area. The Midwest ISO, the State of Michigan and International Transmission Company continue to investigate alternatives to meet the target loss of load expectation in that part of the system.

## 2.4 Operational Concerns

MTEP 05 also looked at the operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests and future available transfer capability(AFC) values. There is industry debate as to the extent to which incidence of Transmission Loading Relief and unavailability of transmission capacity for sale are indicative of unreliable grid conditions or are commercial issues. The Midwest ISO planning process monitors flowgates that are associated with the most incidents of TLR and those that are most limiting to sale of transmission service. In many instances, transmission projects designed to relieve identified reliability criteria violations also relieve constraints associated with TLR and low AFC values. This is indicative that although the system may be capable of performing within strict reliability standards in areas of the system near constrained flowgates, high incidence of TLR and persistently low AFC values are often indicative of lower reliability margins. As the Midwest ISO market operation commences, it is expected that congestion management by TLR will be the exception to congestion management via the security constrained economic dispatch of the LMP-based energy market. The Midwest ISO planning philosophy is, in general, to expand the system when it is more economical to do so as compared to redispatching the system, or other operational steps, as resolution to a reliability criteria violation. This must include suitable consideration for the availability of the assumed operational steps, and the extent to which reliance on increasing levels of operating steps can pose an increased reliability risk. These considerations are only a part of the art of planning the system that is applied along with the science of engineering analyses by experienced Midwest ISO planners and operators, working in collaboration with our Transmission Owner planners and operators and other stakeholders.

The planning staff is also monitoring constraints that are binding in the allocation of Financial Transmission Rights. Not surprisingly, these binding constraints are many of the same constraints associated with TLR and low AFC values. Again, many of these constraints have planning solutions in the works as a means of maintaining system reliability. We will be looking at those constraints that are unresolved and developing proposed plans that could resolve them. Additional discussion and results of these analyses are in Chapter 6 of this MTEP 05 report.

## 2.5 Areas of Heightened Interest

While the Baseline Reliability analysis applied NERC reliability standards comprehensively across the entire Midwest ISO footprint, there are several areas of the system where conditions have caused concern for stakeholders in the recent past. Some of these areas of concern are discussed below.

### Michigan West-to-East Interface

Prior to the summer of 2004, a network customer in eastern Michigan requested firm transmission service for the peak months of 2004. The requested service was to source in Michigan Electric Transmission Company (METC). Only about two-thirds of these firm transmission service requests could be accepted on a firm basis.

The network transmission customer expressed concern to the Michigan PUC that these transfer restrictions were impacting reliability of supply to its load responsibilities.

The Midwest ISO performed an analysis of the in-state constraints to west-to-east transfers in Michigan, and reviewed this study with METC and the International Transmission Company (ITC). The report concluded that the transmission interface between METC and ITC systems has become a bottleneck as the result of the increasingly west-to-east intra-state power flows due to a combination of AES [Alternative Energy Suppliers] sourcing preferences, location of merchant generators in Michigan and the attractiveness of the Ontario wholesale power market. The analysis determined that two-thirds of the proposed new generation in Michigan is locating on the METC side of the interface and that required purchases into ITC's territory are expected to increase. ITC moved to address these issues in July of 2004 by approaching Midwest ISO with a plan to increase the Michigan west-to-east intra-state transfer capability as well as the AFC on flowgates impacted by transfers from METC to ITC.Midwest ISO lead a joint study effort of the ITC plan with participation from both METC and ITC. As a result of these analyses, the following set of upgrades have been proposed by ITC, METC & Midwest ISO and are included in Appendix A as a part of the regional plan:

**Table 2.5-1: Proposed Upgrades**

| Upgrade | System | Estimated Cost |
|---|---|---|
| Genoa 138/120kV Transformer | ITC | $1.2M |
| Atlanta 138/120kV Transformer | ITC | $1.3M |
| Hemphill to Hunters Creek Line Reactor | ITC end of METC-ITC tie | $1.6M |
| Pontiac-Hampton 345kV Line Wavetrap | ITC end of METC-ITC tie | $0.1M |
| Oakland to Dean Road 138 kV Line Relay adjustments and Hemphill Relay Upgrades | METC | $0.2M |
| **Cost Estimate Total:** | | **$4.4M** |

The impact of these upgrades will be to provide an estimated increase of 317 MW in FCITC for METC to ITC transfers. An AFC analysis also indicates that these upgrades would increase AFC on key limiting flowgates from 424 MW to 891 MW. These upgrades will benefit the load centers in the ITC pricing zone by increasing the capacity available for power transfer into this zone and are expected to be in service by summer 2005 (a little over a year from when the issue first arose.).

## Michigan Macomb and "Thumb" Area

The Midwest ISO performed a 2004 summer assessment. In that assessment, two areas in the 120 kV transmission system north of the Detroit area showed some weakness to contingencies.

The Macomb 120 kV bus could become critical for select transmission contingencies. Voltage and reactive margin at Macomb was studied under various conditions. V-Q curves were generated for base case and contingency conditions.

The prior outage of one of the St. Clair 120 kV generating units connected to the St Clair 123 bus in addition to the loss of the Stephens–Macomb 120 kV line results in a reactive margin of 10 MVar which is not sufficient to accommodate a possible load forecast variation of 5% and remain stable. Other more severe contingencies such as the loss of both the Stephens line and the double circuit supply to Macomb from St. Clair result in an unstable condition at the Macomb bus at forecast peak load levels.

The unstable conditions found in this area considered is expected to be local in nature in that the critical voltage at Macomb is sufficiently low (.76 pu) at the unstable point such that local motor load would likely trip off-line due to the motor protection devices. ITC has a planned project to bring an additional 120 kV line into the area (Bismarck–Golf 120 kV) that provides a path into the area that acts as a parallel path to the critical Stephens–Macomb path. In addition, Lenox substation (formerly called New Haven) is planned that includes the addition of a 345 / 120 kV transformer that strengthens the 120 kV network in the area. Finally, a 120 kV capacitor is planned to be added at Macomb. The new line, substation and capacitor will provide voltage support during contingency operation and eliminate this area of concern.

A separate area of relative weakness was found to be the Bad Axe area in the Michigan Thumb. There is known weakness in the supply to this area. The loss of the Harbor Beach generator and a single line or transformer supplying the area can result in localized voltage instability.

ITC has a planned project to support this area that includes installing high speed switching dynamic Var devices (Dvars) at two different locations in the Thumb and converting single circuit line construction to double circuit line construction which will enable bringing another 120 kV circuit through the west part of the thumb. In addition, ITC has a proposed project to add a substation at Saratoga. Saratoga, as proposed, will greatly reduce the likelihood that Greenwood generation in the thumb will be forced off due to a transmission event and provide another 345-120 kV transformer that will support the lower portions of the thumb.

These solutions are included in MTEP 05 Appendix A as:

**Macomb Area Solutions**

- Bismarck–Golf 120 kV , planned project, form 1 project group #518
- Lenox Substation, planned project, form 1 project group #518
- Macomb Capacitor, planned project, form 2 device #87

**Thumb Area Solutions**

- West Thumb Rebuild, planned project, form 1 branch IDs #529-533
- Bad Axe and Lee Substation DVARs, form 2 device #100 and 101
- Saratoga Substation, proposed project, form 1 project group #ITC9

The Midwest ISO will continue to work with ITC towards resolution to these voltage concerns and will continue to monitor the areas in seasonal assessments so that operating personnel are prepared to take remedial action if necessary.

### Michigan–Northern Lower Peninsula

Outage of the 345 kV Ludington–Keystone circuit in the METC northern Michigan area can cause heavy loadings on several underlying 138 kV lines. This condition has worsened over the past few years as area loads have increased. Peaking generation at Gaylord and Livingston has been dispatched during heavy load periods to mitigate potential overloads. MISO has established a flowgate at Tippy to monitor loading and re-dispatch area generation to maintain security. With forecasted growth for 2005, operation of the peakers would no longer be adequate to relieve potential overload conditions. To resolve this condition METC planned several line projects to be completed in the 2005-2009 period. The most critical of these projects are under construction and scheduled to be completed before the summer of 2005. The 13.2 mile Farr Road to Tippy 138 kV line has been rebuilt from 266 ACSR to 795 ACSS conductor this spring. Station terminal upgrades associated with the project are to be completed before June, 2005. A new 20 mile 138 kV line is also being constructed from Pere Marquette to Stronach. The new line is being built along a new route to allow the existing line to remain energized while the new line is being built. This allowed construction of both of these projects to be under construction simultaneously this spring. The new Pere Marquette–Stronach line is also scheduled to be energized before summer 2005. In the fall of 2005 rebuild of the 10.4 mile Tippy to Hodenpyl 138 kV line will begin. This rebuild is scheduled to be completed before summer, 2006. The Stover to Clearwater and Clearwater to Keystone 138 kV lines are also proposed to be rebuilt in 2007 and 2008. Completion of this multiphase 138 kV line rebuild project in the northern lower peninsula of Michigan provides a much needed boost to the capacity and reliability of this growing area.

### Michigan–Grand Rapids Area EHV Transformers

The Grand Rapids area is the fastest growing area served by the METC system. This growth has caused increased loading on the 345/138 kV transformers at the three EHV substations that surround the city. The Tallmadge substation serves northern Grand Rapids, the Gaines substation feeds into the rapidly growing area south of the city and Vergennes substation feeds into the developing area east of town. Studies indicated that with growth forecast for 2005, outage of a 345/138 kV transformer at either Gaines or Vergennes would cause the other to overload. Also 138 kV lines in the area were subject to overload for transformer outages. Loss of two of the four transformers serving the area would cause widespread load loss throughout the area. To resolve this condition METC has added a second transformer at both Gaines and Vergennes and located a spare transformer at Tallmadge. The Gaines transformer went in service in 2004 and the Vergennes transformer was energized in March 2005. The Tallmadge spare transformer is also being energized temporarily this spring while one of the existing Tallmadge transformers is undergoing major testing and overhaul. Addition of these transformers has provided the capacity needed to serve this growing area.

### Southern and Southeastern Wisconsin

Two areas in southeast Wisconsin area were also identified in the 2004 summer assessment as areas to monitor for potential voltage instability.

One area of concern is the area south of Milwaukee around Racine and Kenosha. The loss of Pleasant Prairie-Racine 345 kV circuit significantly weakens the Racine 345 kV bus. For load increases above forecast of 105%, or for load power factors 1% or more below expected, reactive power margins could become critical. An operating plan to operate the Germantown units as synchronous condensers could add about 30 MVar of reserve to the critical Racine 345 kV bus under the high load scenario.

For normal summer peak load projections, the Racine and Kenosha areas are expected to be stable for single line or single generator contingencies. Multiple outages, or single outages under certain levels of variation in load or load power factor could result in critical reactive margin levels.

ATC LLC has stated that distribution load switching may be available to provide some relief with respect to the Racine 345 kV bus voltage. The mitigation of the Milwaukee area voltage concerns is expected to begin by the summer of 2005 with the planned installation of 54 Mvar of capacitors at Moorland (Appendix A Device ID #2050) and the availability of the expanded capacity of the Port Washington generation facility. An additional 90 Mvar of capacitors are planned to be installed in 2006, with 54 Mvar scheduled to be installed at Burlington (Appendix ID #2059), and 36 MVars at Hartford (Appendix A Device ID # 2082).

The other area to monitor is the Madison area. The Columbia units are important in maintaining voltage stability for Madison area. With one of these units out, the North Madison area is observed to be sensitive to load level changes and power factor changes without local generation redispatch. Normal operation for the prior outage of Columbia Unit 1 at peak load is to bring on other off-line generation in the area. ATC LLC is considering a longer-term solution to provide increased support to the area that involves additional 345 kV supply to the Madison Area. Projects related to this additional support are listed in Appendix A with Branch IDs 139,148,149.

## Eastern Iowa

The Alliant Energy transmission system of eastern Iowa is comprised mainly of 69 kV and 161 kV facilities, but also includes 34.5 kV , 115 kV and 345 kV .

Prior to the latter part of the 1990's, the transmission system in this region was primarily used for load serving purposes. With the advent of the open access energy market and significant generation additions in Illinois, this system is under significant additional stress. Alliant Energy has documented line loading difficulties in this area and has presented these results before the NERC standing committees.

Although the MTEP 05 studies have not identified reliability standard violations in this area under expected firm transactions, some multiple contingency conditions identified result in overload conditions.

**Table 2.5-2: Multiple Contingency Conditions**

| System | Limiting Facility | Rating | Contingency | Loading % or P.U | Mitigation Plans |
|---|---|---|---|---|---|
| Iowa | Salem 345/161 kV Transformer | 336 | Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV Beaver Channel Generator | 101% | Upgrade Salem Tx. to 550 MVA and replace Hazelton Tx. with old Salem Tx of 336 MVA |
| | Hazelton 345/161 kV Transformer # 1 | 223 | Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers | 112% | |

Further, Midwest ISO TLR information shows that four of the top 22 flowgates in TLR are in this area:

**Table 2.5-3: Four of the Top 22 Flowgates in TLR**

| MTEP- 05 TLR Rank | Flowgate (NERC ID Number) | Pending Improvement (As of MTEP-05) | Year |
|---|---|---|---|
| 5 | Poweshiek–Reasnor 161 for Montezuma–Bondurant 345 (NERC 3704) | Reconductor of Poweshiek–Reasnor 161 kV line to 326 MVA Appendix A Branch ID # 187 | 2005 |
| 10 | Arnold–Vinton 161 for D.Arnold–Hazelton 345 (NERC 3724) | None identified at this time | - |
| 14 | Montezuma–Bondurant 345 kV (NERC 6086) | None identified at this time | - |
| 21 | Arnold-Hazelton 345 for loss of Wemp–Paddock 345 (NERC 3705) | ATCo's Wempleton–Paddock 345 kV cct #2 and long term proposal of Salem–Spring Green 345 kV Appendix A Branch ID # 344, 1266, 1267 | 2006 & 2014 |

It is known that the Salem 345/161 kV transformer (ALTW), an existing Midwest ISO flowgate is sensitive to south-to-north and east-to-west transfers. The base case flow on this transformer has increased since the 2003 summer. This is primarily due to an increased south-to-north bias. Changes in local line impedances due to system upgrades and an increased ALTW load since the 2003 summer also contributed to the increase. A Salem Operating Guide (ALTW) has been developed that calls for opening the Salem 161 kV bus tie (ALTW); however, its implementation would overload the Asbury-Lore 161 kV line (ALTW). ALTW plans to re-conductor this line prior to the 2005 summer season. The Salem guide will be available for the 2004/05 winter season.

Alliant Energy and Midwest ISO have been charged by NERC (via the NERC Alliant West TLR Task Force) with ensuring that planning studies are performed to identify transmission facilities needed to be upgraded or added to accommodate known firm uses of the system and to ensure reliability in this area. An Eastern Iowa study group has been formed and is commencing a detailed study of this area that will consider historical levels of parallel path flows in this area. For additional details on this area see Chapter 6 and Appendix D.

## South Central Illinois

The Prairie State 1500 MW coal-fired generating plant is planned to interconnect to the AmerenIP system in south central Illinois by 2009. This large base-load plant will tap coal resources in the area and is expected to provide capacity and energy for a number of Midwest ISO Network Customers, once it is established as a deliverable Network Resource. Considerable upgrades are needed to interconnect the plant reliably and provide for adequate delivery service. One of the major upgrades identified so far is the addition of a 26-mile Baldwin–Rush Island 345 kV line. It is possible that a number of transmission system expansions to this area of the Midwest ISO Transmission System could provide for more economical delivery of the output from plants in the area by reducing possible congestion on the system, particularly if other large plants were developed in this area. Analysis performed for MTEP 03 released in June 2003 postulated various expansion options to this system and found some of them effective in relieving congestion that could exist if additional coal plants were added in this area to take advantage of the available coal supplies, or if generation of other fuel sources were added. Several of the postulated expansions in MTEP 03 are included as long-term proposed projects in this MTEP 05 Appendix A and include Newton – Merom 345-kV, St. Francois–Fletcher 345-kV, and Albion–Norris City 345-kV. The Midwest ISO will continue to work with Ameren to evaluate the need for and benefits of these and other projects.

## Eastern Kentucky

The Midwest ISO has been advised by Eastern Kentucky Power Cooperative, a non-member of the Midwest ISO, that they are anticipating some significant configuration changes to their system that borders Midwest ISO member system LGEE. These changes are expected to occur by 2008 and involve building a 100 mile 161 kV transmission interconnection between EKPC and BREC to serve the load in WREC and the opening of the tie between TVA and EKPC. The Midwest ISO has been evaluating the impacts of these external system changes. Preliminary findings indicate that with these system changes there could be overloads on the Lake Reba Tap-Union City 138 kV line in the LGEE system under base conditions. Additional limiting facilities for n-1 contingencies were observed in the 2009 model in the LGEE system in the Fawkes/Lake Reba/Delvinta area. This is due to the additional output from the J K Smith power plant in support of service to the 447 MW load at WREC. We will continue to monitor these developing plans and their impact on Midwest ISO system expansion needs, and will report further on these impacts in MTEP 06 which is underway.

## South Dakota/ Minnesota

The proposed Big Stone II 600 MW coal-fired generating plant is planned to interconnect to the Otter Tail Power Company system in eastern South Dakota by 2011. This project would be constructed next to the existing 475 MW Big Stone I power plant located near Milbank, South Dakota. Generation capacity and energy from this project is expected to be delivered to both Midwest ISO network customers, as well as non-Midwest ISO network customers located in the MAPP region. Generation Interconnection and Delivery Service studies are underway and have identified two potential transmission alternatives that at a minimum will require construction of new 230 kV transmission facilities in eastern South Dakota and west-central Minnesota.

The next two sections describe exploratory transmission studies which are looking at moving large amounts of energy resources from the Dakotas, Minnesota, and Iowa to markets to the south and east. These studies both have proposed lines in the area of the Big Stone II project. The wider regional planning perspective of the Midwest ISO presents an opportunity to coordinate the development of transmission plans for the area which address both Big Stone II generator outlet requirements and the long-term development of energy resources in this area. The challenge is balancing the value of interconnection upgrades of least cost in the near-term and for current commitments, with the advantages of more expansive upgrades and their potential benefits over a longer term. This is the focus of the Exploratory regional plans discussed briefly below, and further in Chapter 7 of this report.

## Northwest Area

Midwest ISO identified in MTEP-03 potential plans for expansion of transmission in the Dakotas and into Minnesota with the goal to eliminate constraints in northwestern MAPP to the development and delivery of additional generation resources in the Dakotas. Since then, the Midwest ISO has been working with an active coalition of generation developers, government entities and utilities, the Upper Great Plains Transmission Coalition (UGPTC), interested in determining best plans to enable this development.

The Midwest ISO is leading studies to address this issue with the goal of selecting preferred projects for increasing the power delivery capability of the transmission system from the Dakota's. This study is ongoing at the time of this MTEP 05 distribution. It is expected that once studies are completed, the Midwest ISO will facilitate the implementation of these projects by identifying impacted and benefiting parties and applying newly developed Midwest ISO transmission pricing policies to recommend fair cost assignment and recovery for the projects.

Please see Charter 7 for further details on the current status and results from these studies.

## Southern Minnesota/ Northern Iowa

A study similar in some respects to the Northwest Area study is also being performed by the Midwest ISO in this area. The transmission system in this area has limited capacity to allow for significant development of additional wind generation projects. Because the northern Iowa and southern Minnesota area is a very good wind resource, there are a large number of generator interconnection requests in this area — literally thousands of megawatts of requests. This study will determine how to get 2,700 to 3,500 MW of wind generation to market in addition to existing and committed generation projects. The Rochester, Minnesota area; La Crosse, Wisconsin area; Worthington, Minnesota area and eastern Iowa area all have future load serving reliability concerns. The Minnesota–Wisconsin Stability Interface is a system constraint which can impact the ability of new generation to be sited in Minnesota and Wisconsin. The State of Minnesota also has a Renewable Energy Objective in which utilities in the state should have 10% of energy produced from renewable sources by 2015. This exploratory study will develop a transmission plan, which addresses these concerns at a preliminary level.

Progress on this plan development is contained in Chapter 7.

## 2.6 Planning Across Midwest ISO Seams

The Midwest ISO continues to develop and improve working arrangements with parties bordering the Midwest ISO region. The Midwest ISO is engaging these border entities in seams discussions and systems integration to permit the orderly conduct of energy transfer and related economic settlements that must occur, and of coordinated system expansion.

The development of these business arrangements is currently done under the collective title of Seams Coordination. The Midwest ISO has a filed Joint Operating Agreement (JOA) with PJM and has recently developed similar agreements with TVA (joint Midwest ISO/TVA/PJM), SPP, and is developing an agreement with the non-Midwest ISO members of MAPP.

Planning coordination with these entities through these JOAs involves close coordination on model development, data exchange, coordinated interconnection and transmission service impact studies, and development of joint regional plans. The Midwest ISO and PJM plan to develop the first joint regional plan by June of 2006. This plan will begin with the individual plans most recently created by each RTO and will develop an integrated view of the future super-regional system. Joint plans will include identification of expansion projects that are subject to cost sharing between the RTOs on the basis of cross-border cause and/or benefits, in accordance with procedures in development and to be filed by each RTO by mid-year 2005.

In addition, the Inter RTO/ISO Council is developing a draft scope and schedule for a combined inter-RTO/ISO expansion plan that will build from the various plans created on a seams interface basis to produce the first ever coordinated plan encompassing a majority of the nation's electrical grid. This activity is tentatively scheduled for release in 2007.

While these coordination agreements and procedures are in initial stages of implementation, this current MTEP 05 has taken advantage of the participation, data exchange, and review of individual transmission owner systems with seams with the Midwest ISO except AECI and SERC.

## 2.7 Process Overview

As stated above, the Midwest ISO develops the plan with the input and assistance of the following stakeholder groups including:

- The Expansion Planning Group
- The Planning Subcommittee
- The Advisory Committee
- The Organization of Midwest ISO States

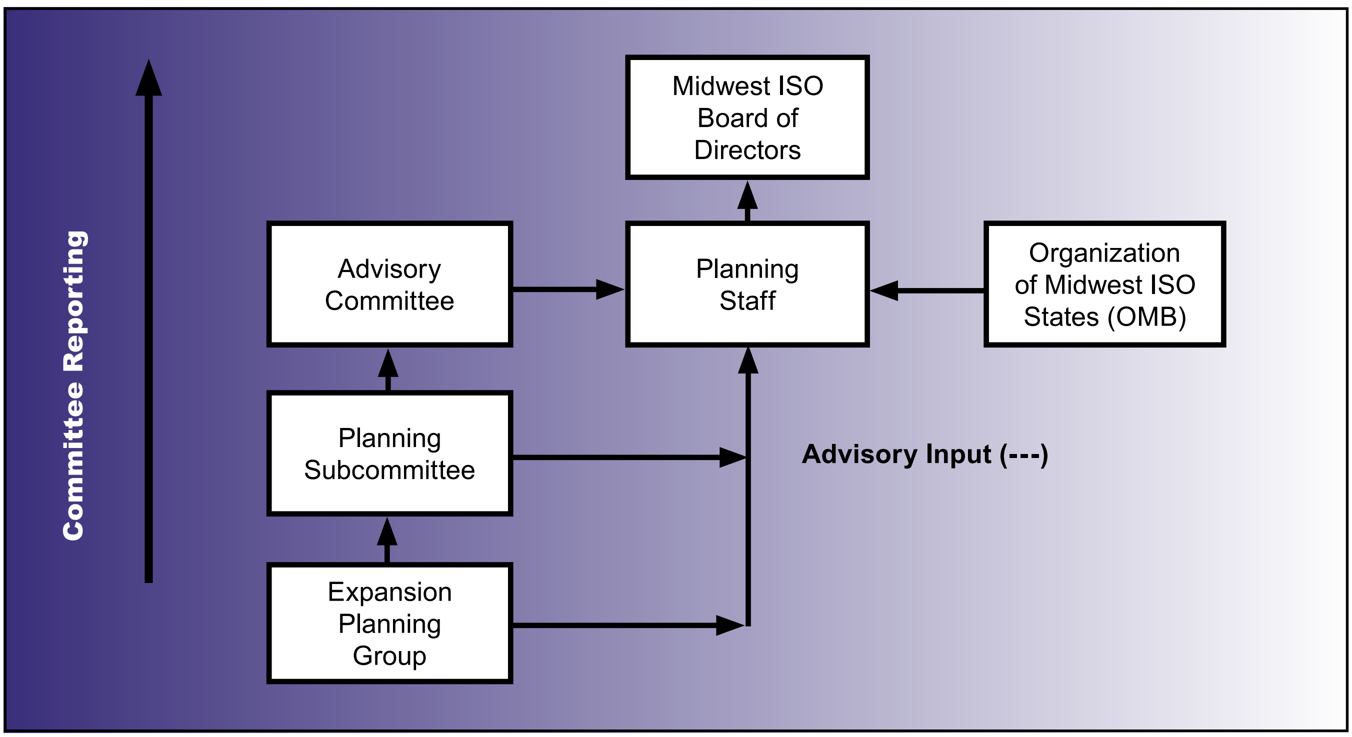



**Figure 2.7-1: Process Overview**

The current planning process at the Midwest ISO integrates the ongoing planning processes that are responsive to new customer requests for system access, and the continuing but cyclic Baseline Reliability studies of the MTEP regional plan development. The graphic below depicts these processes.

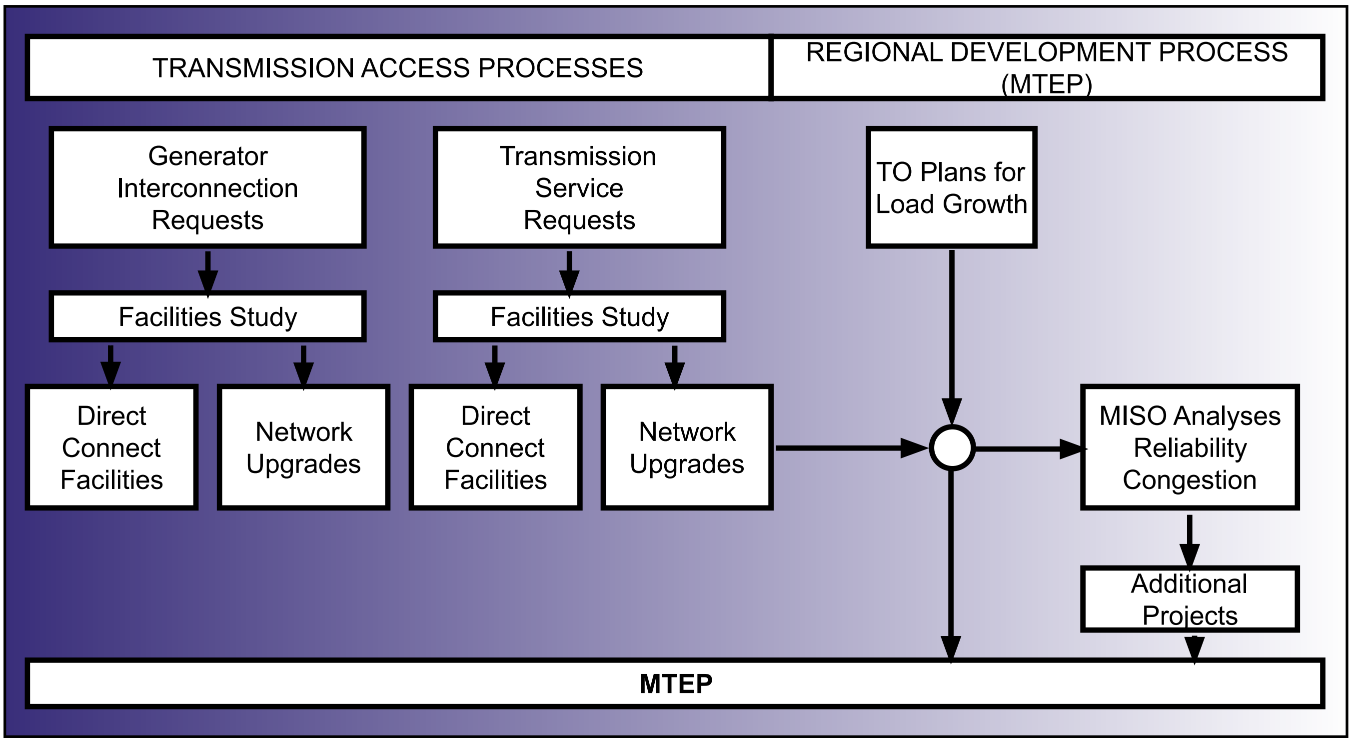



**Figure 2.7-2: Planning Process**

Key elements of this process include the following:

- Roll-up of Transmission Owner Plans
- Inclusion of Plans from Interconnection and Delivery Services
- Development of Power Flow Base Case
- Review of System Reliability and Congestion
- Development of any Additional Expansion Needs
- Review of Additional Regionally Beneficial Expansions

## Roll-up of Transmission Owner Plans

An essential part of the Midwest ISO regional expansion plan is the roll-up of the local area plans of the Transmission Owners. The Midwest ISO Transmission Owners Agreement establishes the ongoing responsibility of the Transmission Owners to plan for the continued reliable operation of their systems. The Midwest ISO and the Transmission Owners collaborate on a daily basis in reliability studies related to requested uses of the system for new delivery service rights, and for new generator interconnections. However, the many Transmission Owners are continually evaluating their systems often independent of each other for their local area needs. The roll-up and testing of the integrated developments from these various processes is essential to ensure the efficient long-term reliable operation of the Midwest ISO system. The roll-up of plans is the integration process, and provides the initial Midwest ISO plan for various study purposes.

## Reliability Review of the Planned System

As described above, parallel planning processes coexist within the Midwest ISO region as Transmission Owners continually plan their systems for their local area needs. Some of these localized planning processes are more coordinated than others, depending on the NERC region to which the Transmission Owner is a member. The Midwest ISO must perform comprehensive reliability reviews of the integrated plans of the Transmission Owners. This is in order to ensure that these local processes are sufficient to meet reliability needs, are coordinated and do not result in either inefficient plans or parallel path flow changes that could infringe on the rights of existing transmission customers, or in certain tightly interconnected areas, possibly endanger the reliability of the system.

The reliability review process has several embedded steps as depicted below, the objectives of which are to expand the system where necessary to address reliability needs in the most economical manner.

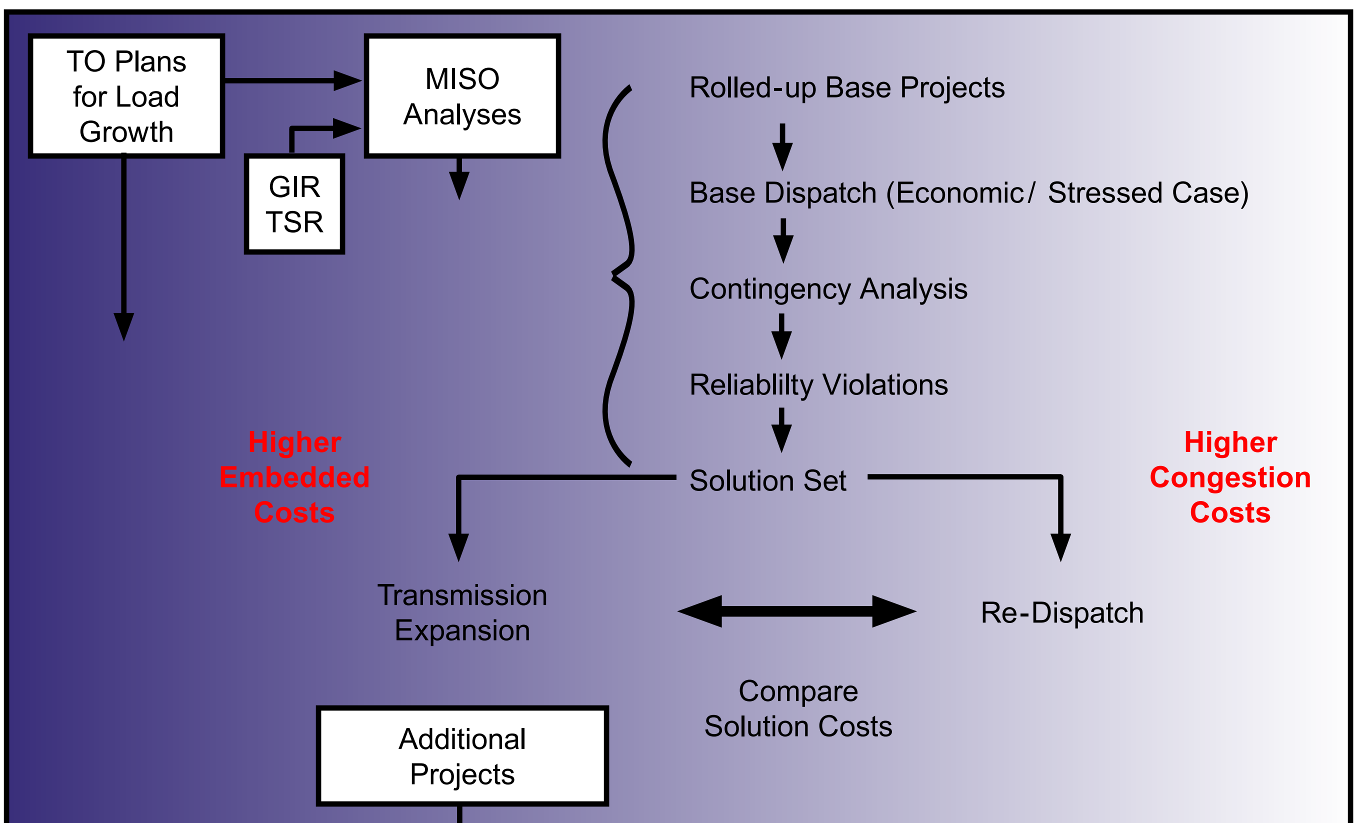



**Figure 2.7-3: Reliability Review Process**

### Review of Additional Regionally Beneficial Expansions

One of the key aspects of the MTEP begun with MTEP 03 is the study of the ability of the planned transmission system to provide low cost electricity to customers into the future. The MTEP process will continue to solicit stakeholder input as to regionally beneficial expansions that while not essential to maintaining reliable supply from currently committed and planned resources, provide benefits that are favorable relative to their costs. Such benefits could involve enabling access to low cost resources, providing for economic development in an area, or furthering energy policy such as achieving renewable energy targets.

## 2.8 The Importance of Appendix A

Appendix A is a spreadsheet listing of the Planned and Proposed projects that are a part of MTEP 05. The listing includes much information about the nature, location, expected service date, need, driver, estimated cost, and other information about the Baseline projects needed in the region. Appendix A is a living document that is updated twice annually in February and in July and on that basis is a current listing of the expected development of the Midwest ISO Transmission System. Midwest ISO future system models are based on the projects contained in Appendix A.

## 2.9 Implementation and Follow-Up

The Midwest ISO will support the need for and track the development of projects defined as Planned projects that are part of the approved MTEP.

The MTEP will be subject to change, as system conditions change. Changes in load growth, changes in usage patterns, development of new generation interconnections, changes in projected service dates of interconnection plans, delays in regulatory approvals of transmission projects, or ongoing development of preferred plans, all may cause changes to the overall Midwest ISO plan. The MTEP will be updated as needed to incorporate the impacts of such changes on the overall Plan.

# Section 3: About Midwest ISO

## 3.1 Scope of the Midwest ISO System

On December 20, 2001, the Midwest ISO became the first FERC-approved RTO in the nation and began selling regional transmission service under its FERC-approved tariff on Feb. 1, 2002.

As a Regional Transmission Organization, the Midwest ISO provides non-discriminatory, open access to the transmission system under its operational control. This transmission system spans 15 states.

**Midwest ISO statistics:**

- 23 Transmission Owners
- 36 Control Areas in three regional reliability organizations
  - MAPP/MRO
  - MAIN
  - ECAR
- 119,000 Mw of peak load
- 131,000 Mw of generating capacity
- 97,000 miles of transmission lines
- 947,000 square miles in the Midwest ISO footprint
- 15.1 million customers
- 1,504 Generating units in the reliability footprint
- 2 Control Centers
  - Carmel, Indiana
  - St. Paul, Minnesota

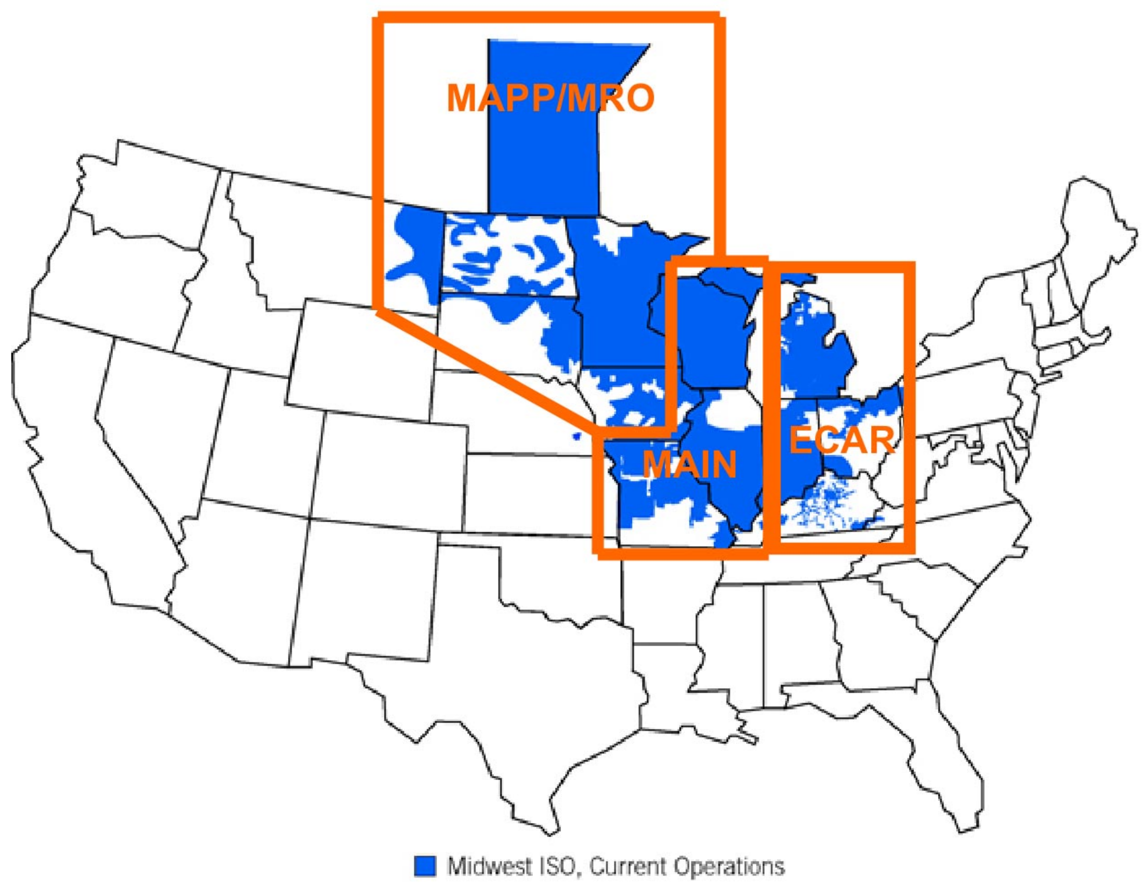



**Figure 3.2-1: The General Areas of the Three RSGs.**

## 3.2 Planning Regions

For the MTEP 05 study process, the studies were divided into three regions corresponding closely to the boundaries of the NERC regional reliability organizations MAPP, MAIN and ECAR. Each Regional Study Group (RSG) invited the non-Midwest ISO participants in the NERC region to participate in the Midwest ISO MTEP 05 reliability studies.

**ECAR RSG Participants**

- CINERGY
- FirstEnergy
- Grid America
- Hoosier Energy
- Indianapolis Power & Light
- International Transmission Company
- LG&E Energy
- Michigan Electric Transmission Company
- Northern Indiana Public Service Company
- VECTREN

**MAPP RSG Participants**

- Alliant Energy West
- Lincoln Electric System
- MidAmerican Energy Company - Non-Member
- Manitoba Hydro - Coordination Member
- Minnesota Power
- Montana-Dakota Utilities Co.
- Muscatine Power & Water - Non-Member
- Otter Tail Power Company
- Western Area Power Administration - Non-Member
- Xcel Energy North

**MAIN RSG Participants**

- Allegheny Energy Supply Co., LLC
- Alliant Energy Corporate Services
- Ameren
  (including the operating companies of)
  - AmerenUE
  - AmerenCIPS
  - AmerenCILCO
  - AmerenIP
- American Transmission Company, LLC
- Central Iowa Power Cooperative
- City Water, Light and Power
- Columbia (Missouri) Water & Light
- Commonwealth Edison Company
- Constellation Energy Commodities Group, Inc.
- Coral Power, LLC
- Duke Energy
- North America, LLC
- Edison Mission Marketing and Trading
- Electric Energy, Inc.
- GridAmerica LLC
- Illinois Municipal Electric Agency
- Madison Gas & Electric Company
- Midwest ISO
- Northern Indiana Public Service Co.
- NRG Energy, Inc.
- PJM Interconnection, L.L.C.
- PPL EnergyPlus, LLC
- Southern Illinois Power Co-operative
- Soyland Power Cooperative, Inc.
- Tenaska Power Services
- Wisconsin Electric Power Company
- Wisconsin Public Power Inc.
- Wisconsin Public Service Corporation.

## 3.3 Load and Generation Trends

The Midwest ISO does not currently prepare a long-term load forecast. Load projections are reported by Network Customers under the tariff, and are represented in planning models developed collaboratively between the Midwest ISO and our transmission-owning members. Members also provide load forecasts through the NERC regional reporting processes. Resource adequacy is established under the tariff by requiring load serving entities to report their Network Resources that will be used to meet State and NERC regional resource adequacy guidelines.

Estimates of load and resource additions through the 2009 period have been made below in Figure 3.3-1 by using the current Midwest ISO peak load measurements, aggregate load growth rate projections reported by members and non-members to NERC, and activity from the Midwest ISO generation interconnection queue.

At an estimated load growth rate of 1.9%, the peak load of Midwest ISO for 2009 would be about 131,000 Mw, which is about equal to the current installed capacity of 131,000 MW. There is about 11,554 Mw of generation in the current queue with executed interconnection agreements and service dates between 2004 and 2009 inclusive. There is an additional 17,521 MW of generation in the queue for service over this period that have not yet executed interconnection agreements.

Additional load and capacity projections for the wider Midwest region are available from the report "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council. This NERC report concluded that overall the three regions are expected to have adequate resources through 2013.

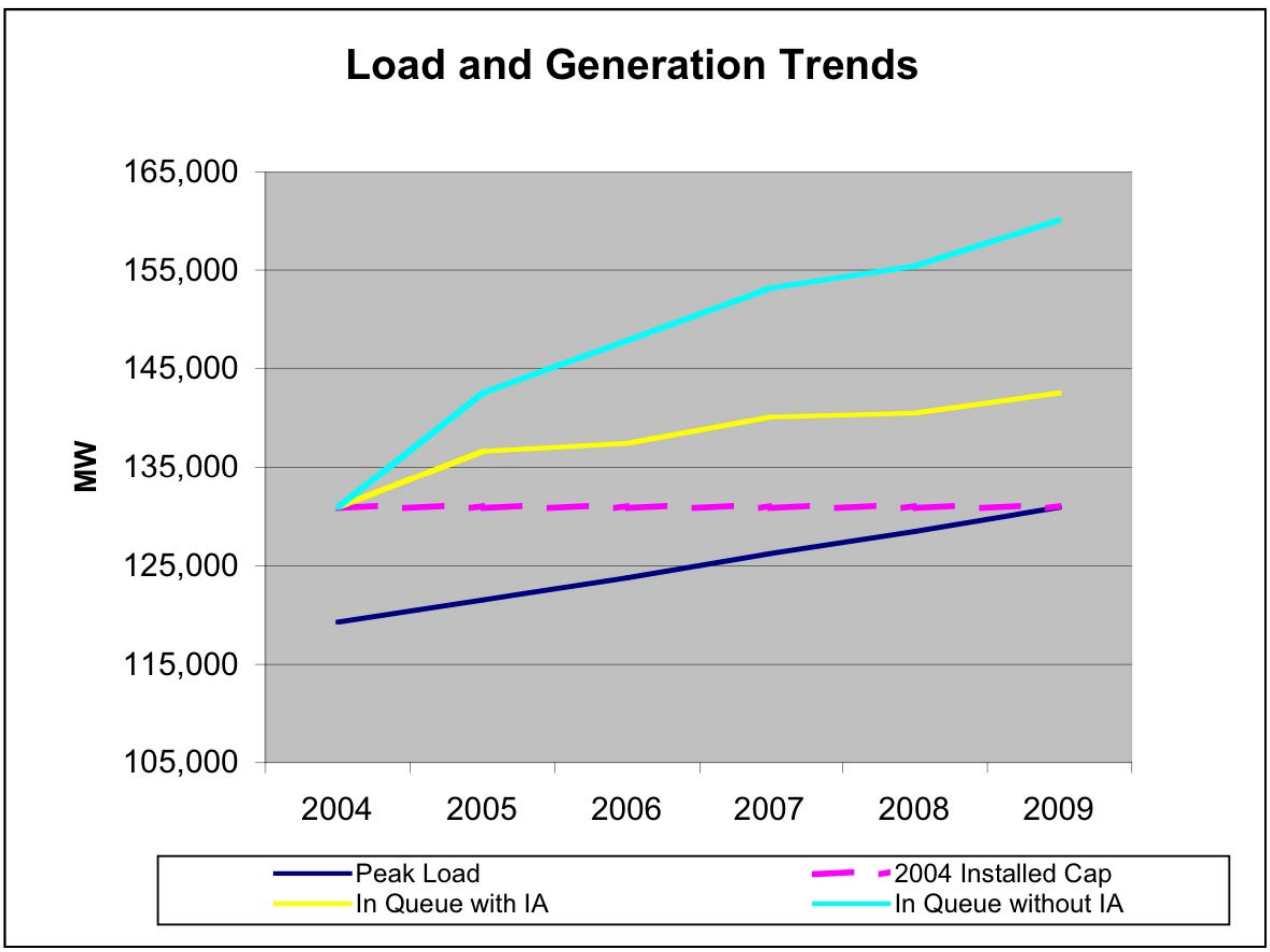
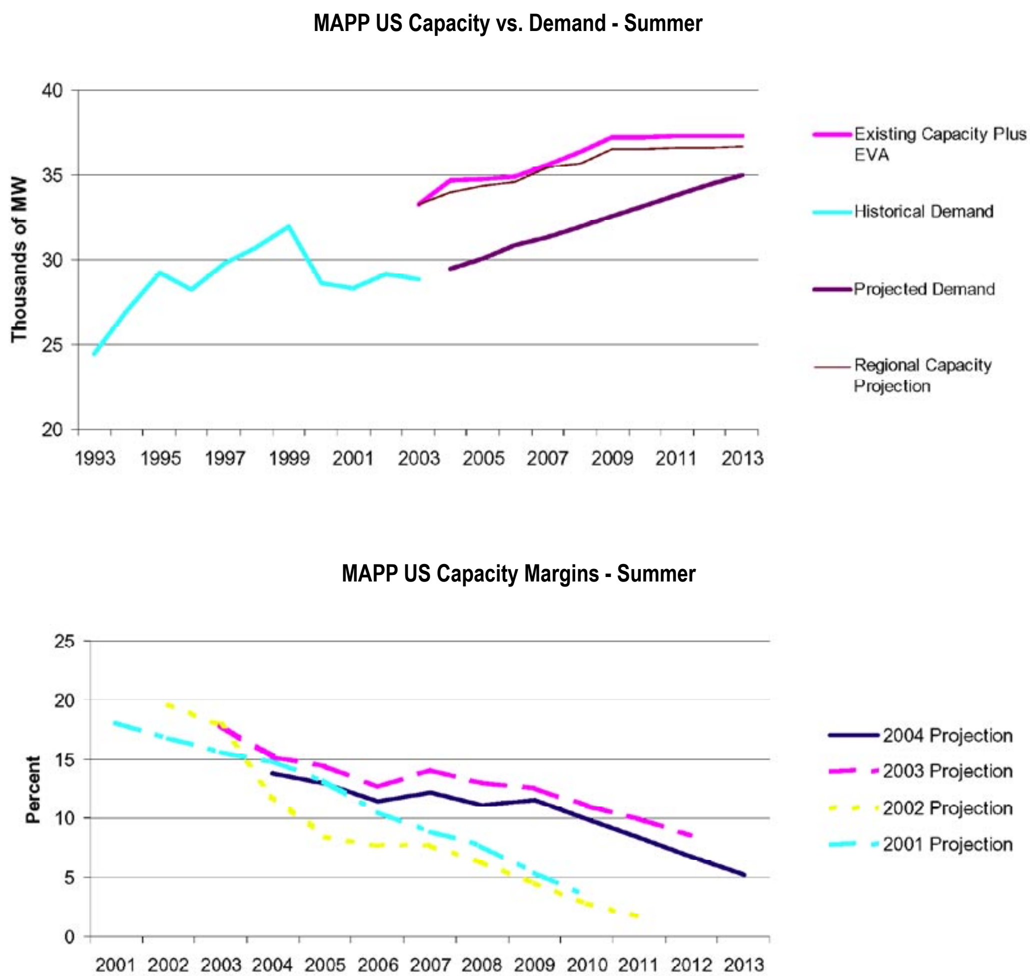


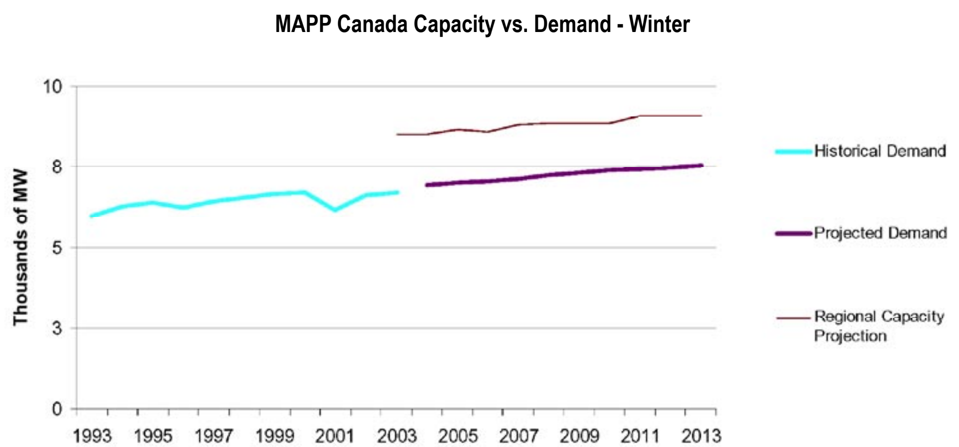

Figure 3.3-1

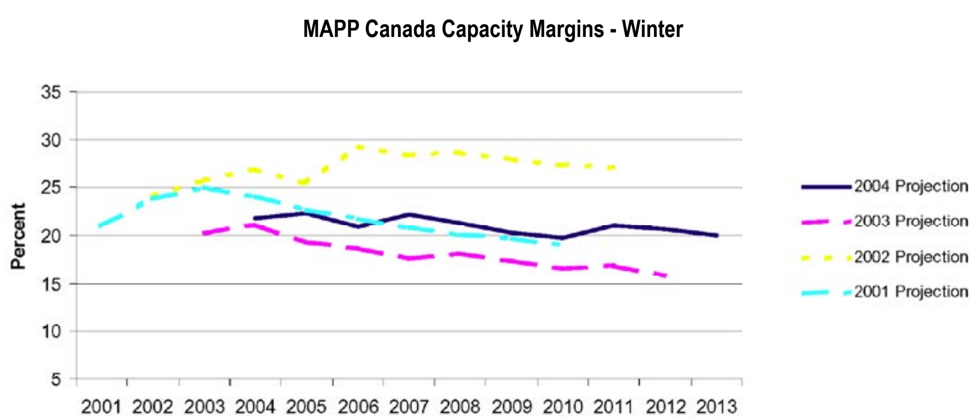
Figures 3.3-2 through 3.3-5 are from this NERC report and show the historical loads, the projected load forecasts under high, normal and low growth assumptions, the existing generation capacity and the projected generation in each region.




*Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.*

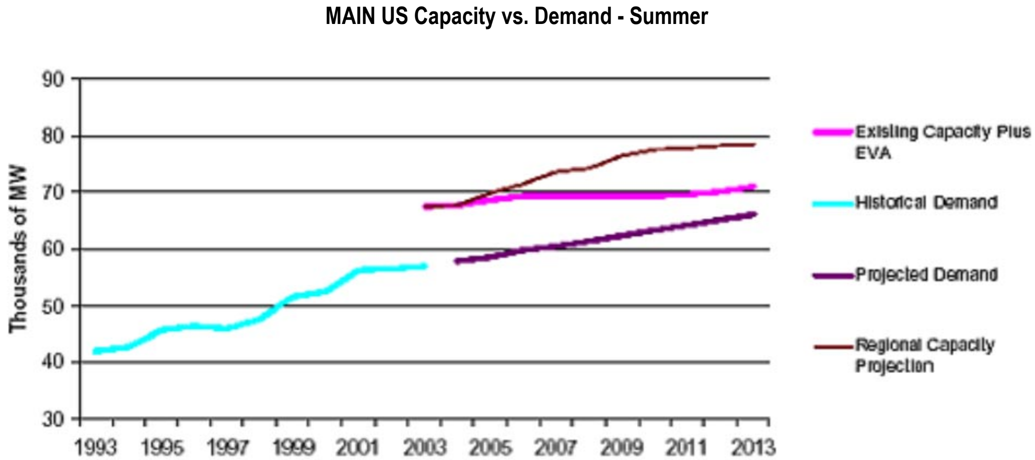
**Figure 3.3-2**

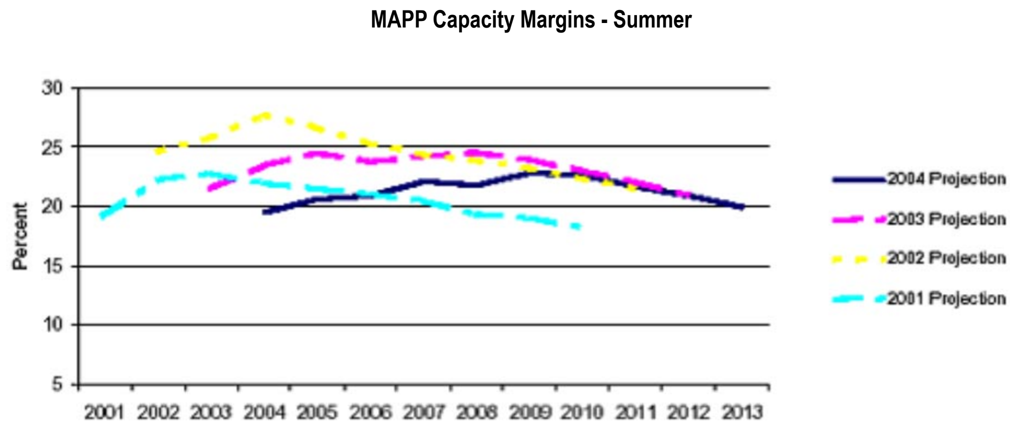



*Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.*

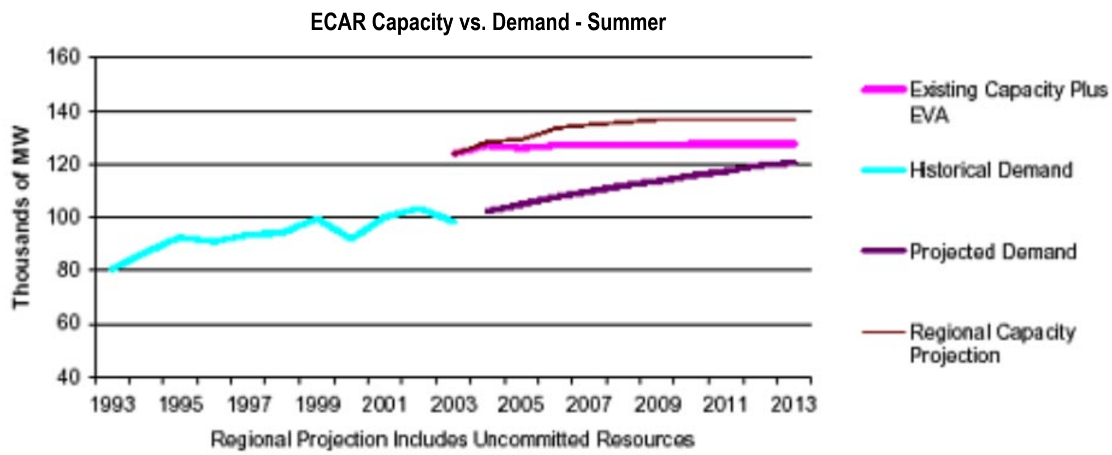
**Figure 3.3-3**

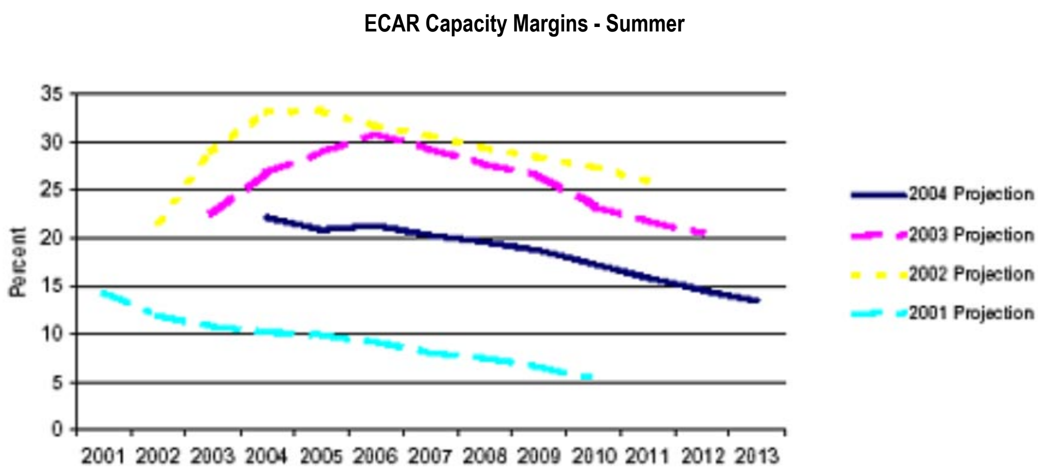



*Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.*

**Figure 3.3-4**




*Source: "2004 Long Term Reliability Assessment, The Reliability of Bulk System in North America" by the North American Electric Reliability Council.*

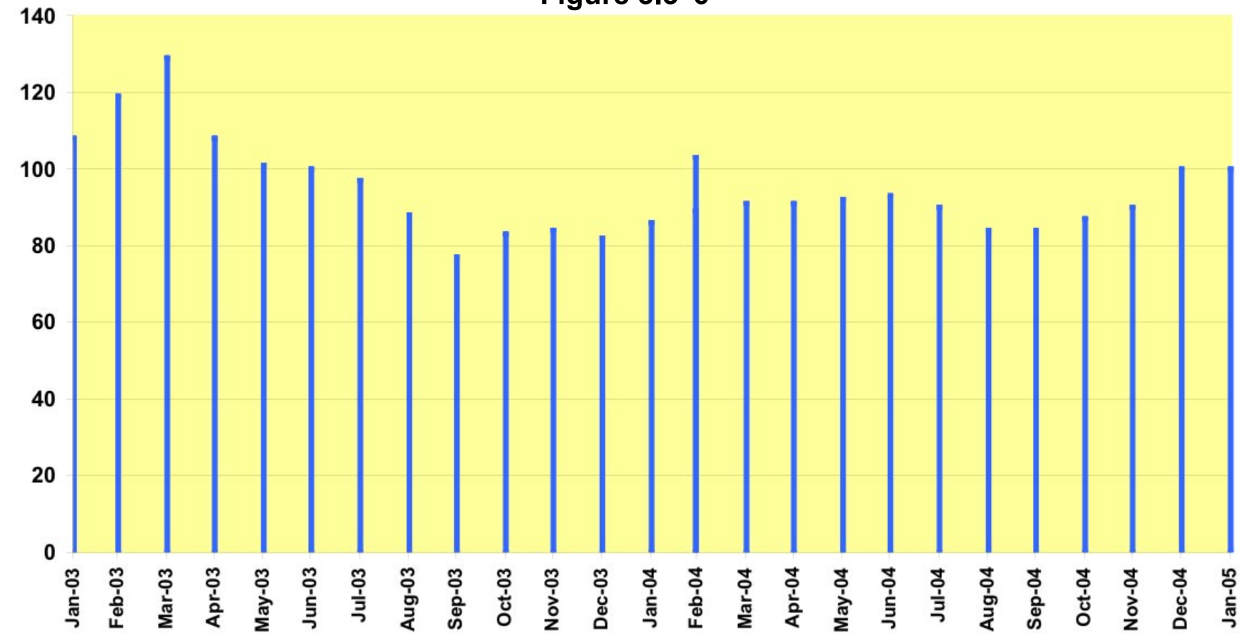
**Figure 3.3-5**

## 3.3.2 Midwest ISO Generation Interconnection Queue

Figure 3.3-6 below shows the active generation interconnection queue entries for the two-year period January 2003 to January 2005. The number of active entries has remained relatively stable between approximately 80 and 100. During this time, more than 150 new requests have entered the queue.

Number of Active Entries in Queue by Date

Figure 3.3-6



There has been a considerable shift in the type of requests the Midwest ISO is processing. As shown in Figure 3.3-7 below, 65% of current entries are for wind power, 18% for natural gas and 12% coal.

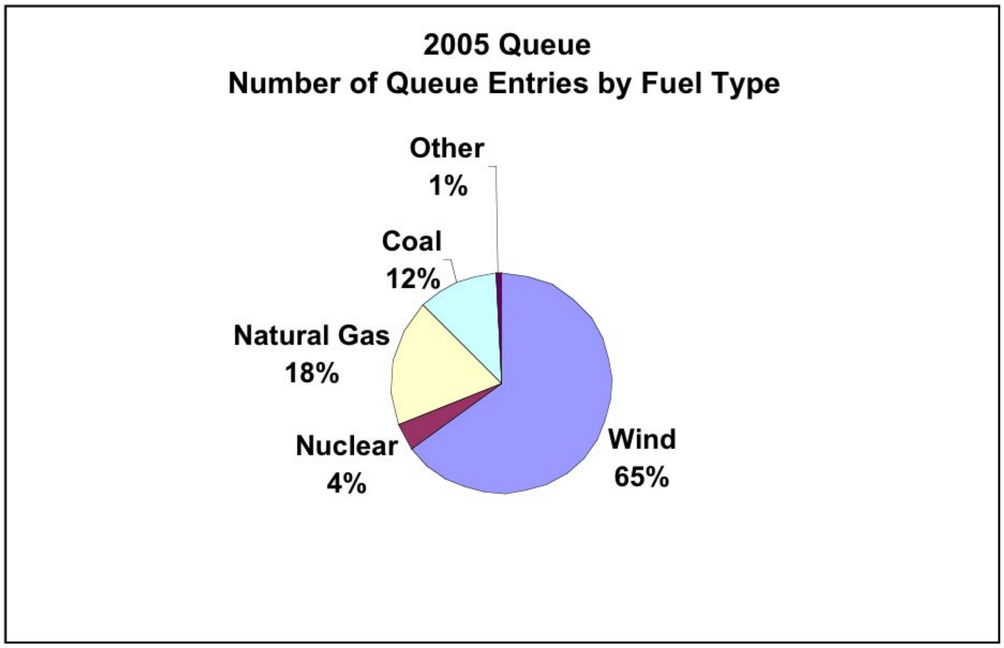



**Figure 3.3-7**

Compared to the entries in the 2003 queue shown in Figure 3.3-8 below, this is a 30% increase in wind requests, 50% increase in the number of coal requests and a 50% decrease in gas requests.

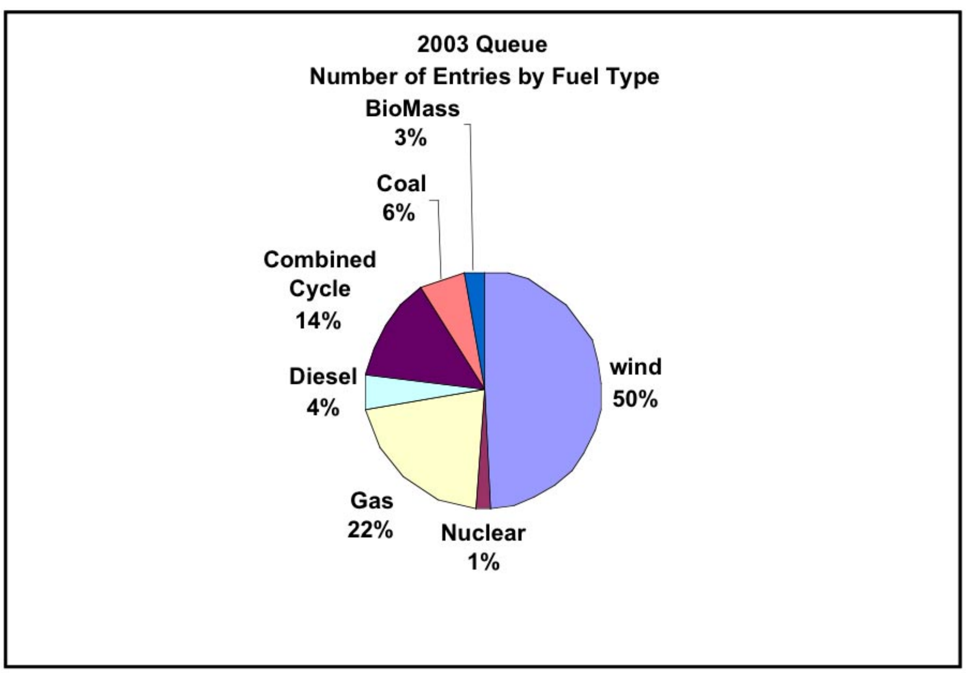



**Figure 3.3-8**

While the number of wind entries has increased significantly, in terms of capacity, the 2005 queue shows that the predominant fuel type is coal with 6700 MW, followed by wind with 5800 MW and gas with gas with 5000 MW.

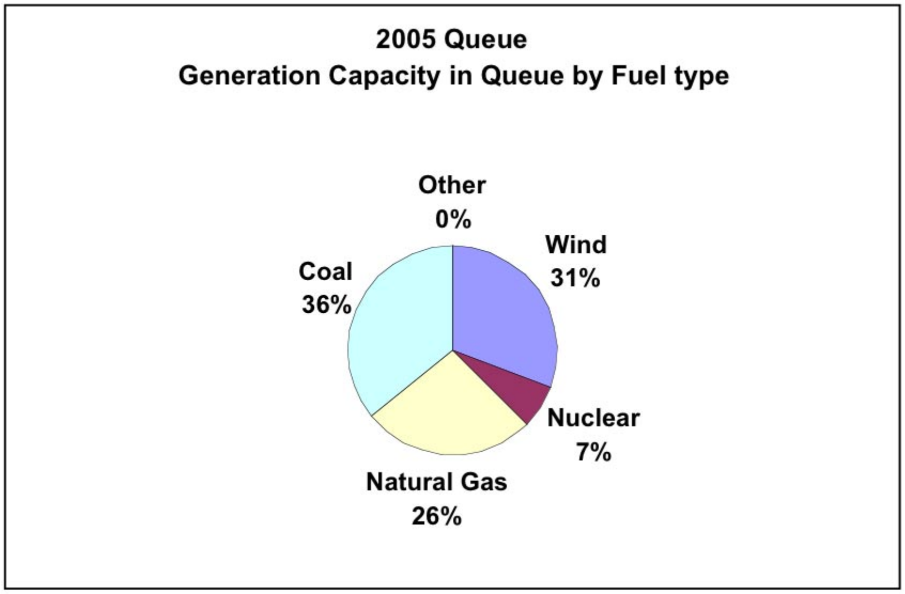



Figure 3.3-9

This compares to the 2003 queue shown in Figure 3.3-10, in which the overwhelming capacity of the queue was in natural gas plants. Most Combined Cycle plants are gas fired also.

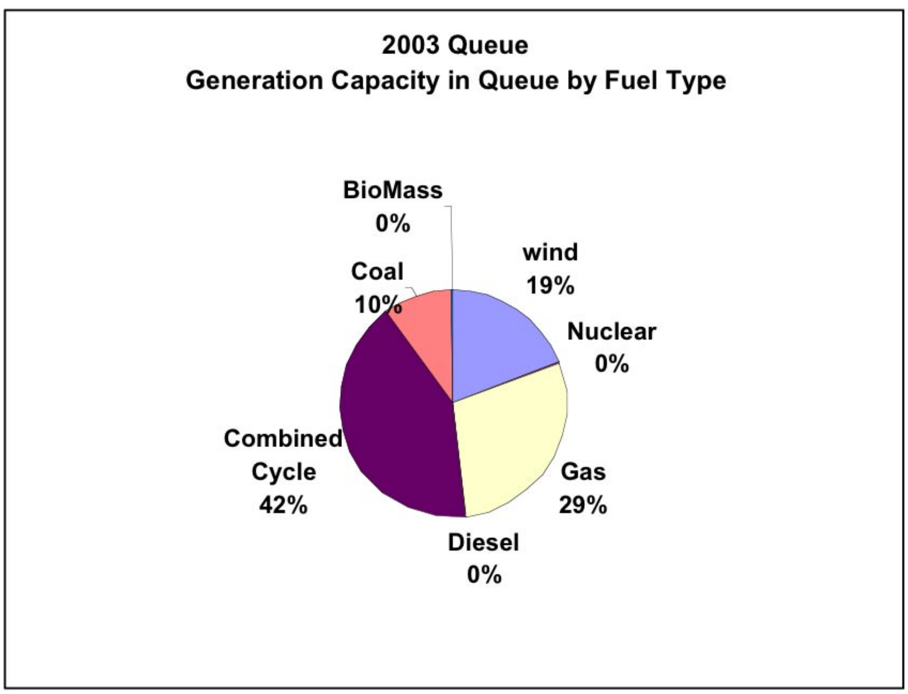
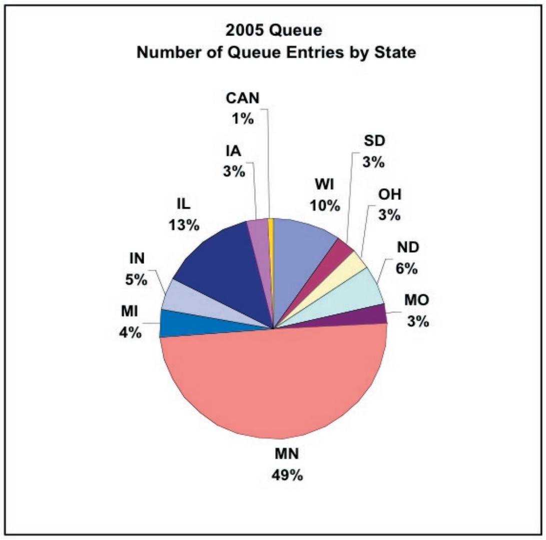



Figure 3.3-10

The higher price of natural gas over the past two years may be a primary factor in more coal and wind being proposed for the future, and for the expectation of reduced energy production from existing gas plants.

The proposed locations of the Queue entries by requests and by fuel type are shown in Figure 3.3-11 below. The bulk of both the entries and the capacity is in Minnesota, and this is largely wind-powered capacity.



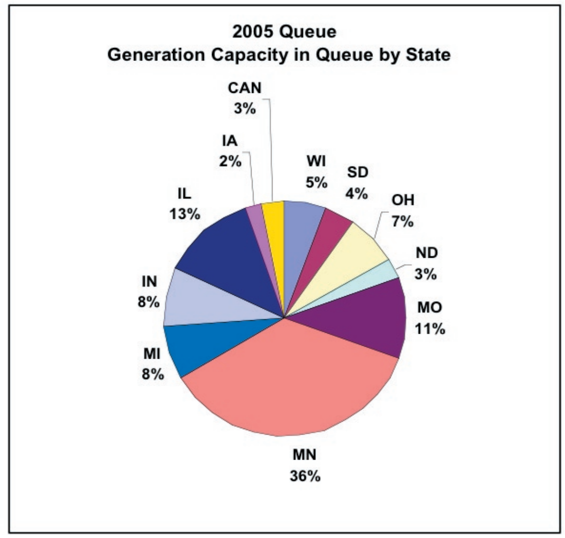




Figure 3.3-11

The plot below shows the geographic distribution of the queue entries.

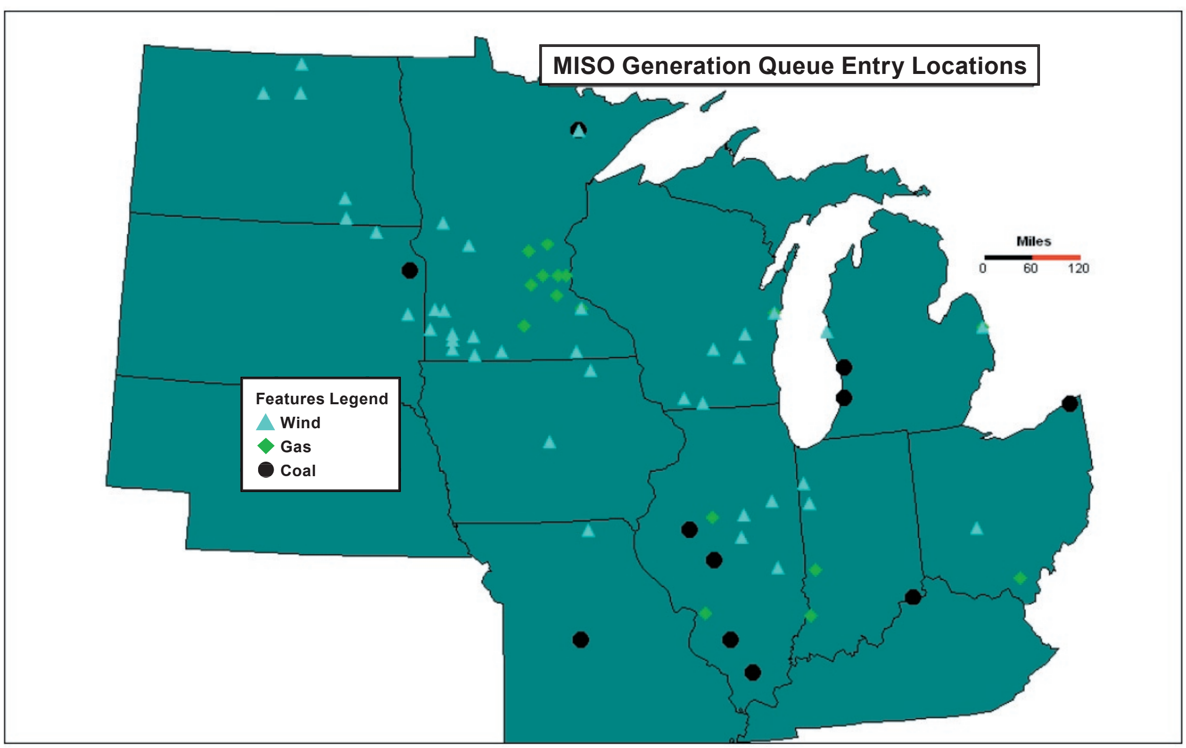



Figure 3.3-12

## 3.4 Midwest ISO Primary Energy Resource Opportunities

### 3.4.1 Coal

Midwest ISO has significant coal resources that are being mined in its footprint. North Dakota, Illinois, Indiana, Kentucky and Ohio have concentrations of coal-fired generation near mines. Other states are served by rail from the coalmines and from the Power River Basin mines in Wyoming. Figure 3.4-1 displays the location of sources of coal in the U. S.A. Michigan and Iowa coal beds are not major sources of commercially recoverable coal.

**Coal Sources in the United States**

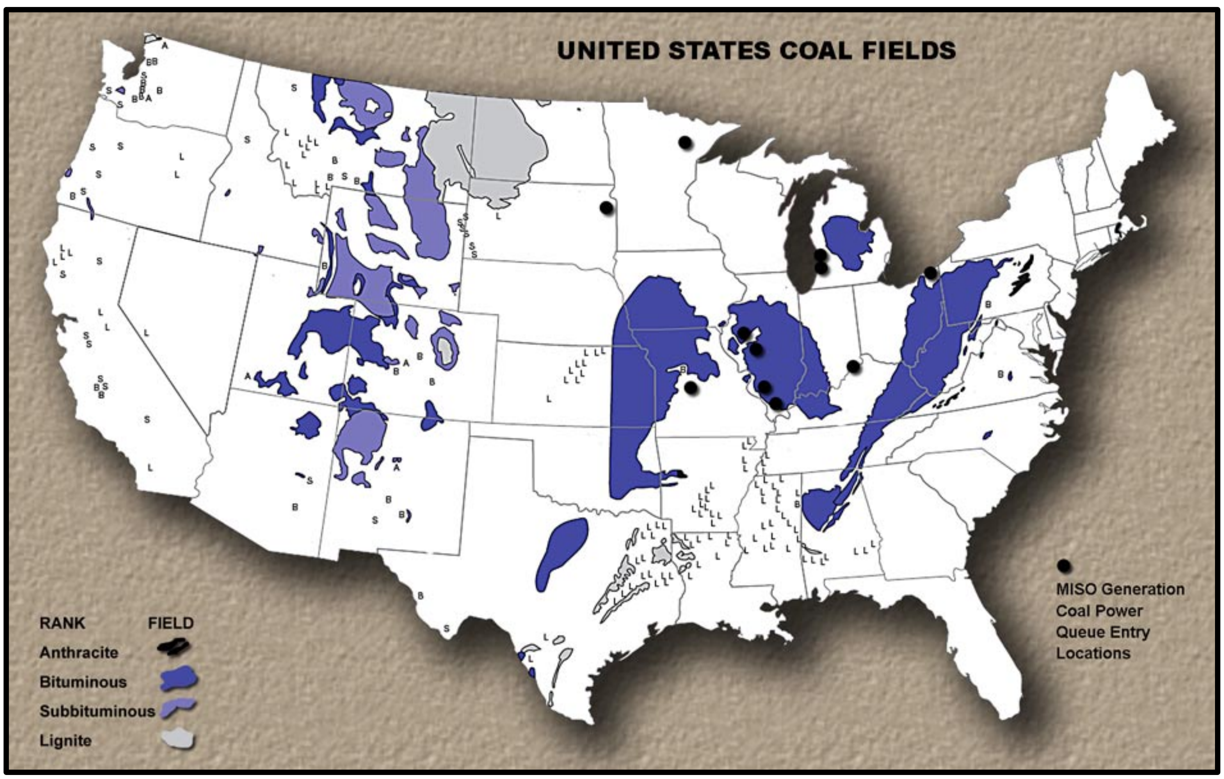
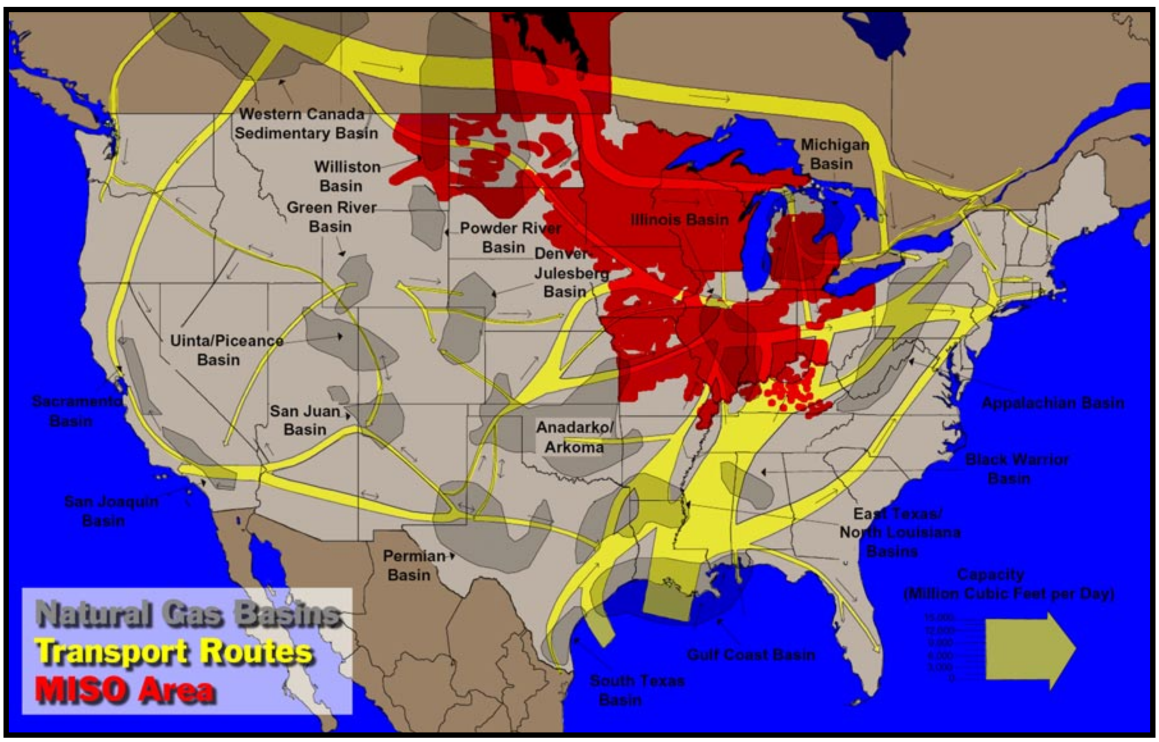



**Figure 3.4-1**

## 3.4.2 Gas

The Midwest ISO footprint also has an abundant gas supply available as indicated in the map in Figure 3.4-2. The paths of many of the major pipelines pass through the Midwest ISO footprint.




**Natural Gas Basins and Transport Routes**
**Source (DOE/EIA 0618(98):**
**Energy Information Administration– Deliverability on the Interstate Natural Gas Pipeline System**

**Figure 3.4-2**

### 3.4.3 Wind

Wind generation is increasingly a potential source of economic energy. The map in Figure 3.4-3 shows the locations of the major sources of wind energy in the U.S. Class 4 wind areas, with Good wind energy development potential, are shown as blue on the map. The Buffalo Ridge, in southwestern Minnesota, northwestern Iowa and the Dakotas has considerable wind energy development proceeding. A few wind farms have been developed in the Class 3 areas.

The time required to build higher voltage lines of 345-kv or higher is in the range of five to seven years. Wind generation can be developed in two years. Transmission congestion in the Buffalo Ridge area currently limits wind generation output; however, short-term solutions for lower voltage transmission lines are being designed to provide an increase in transmission capacity in the Buffalo Ridge area.

The 5,000 MW of wind generation is a significant amount, but it is small compared to the total potential outlined in Table 3.4-1.

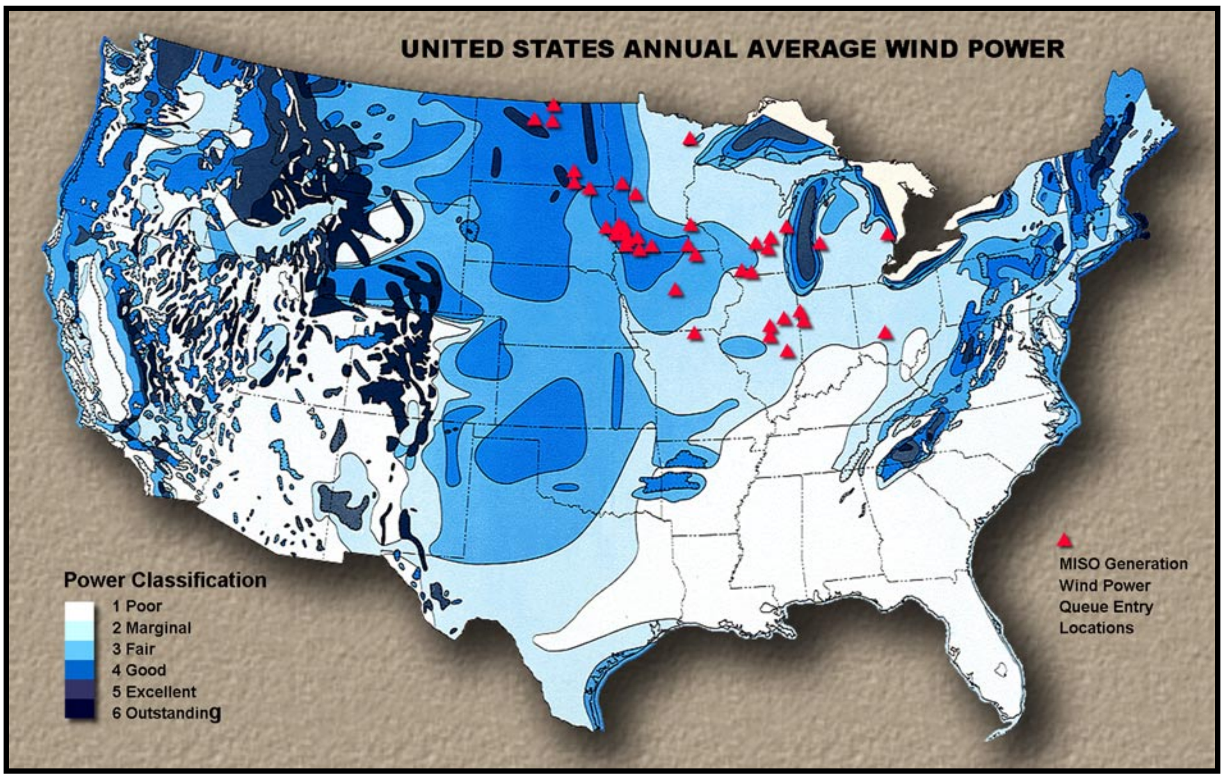



Figure 3.4-3

| Table 3.4-1: Wind Power (MW) | | |
|---|---|---|
| State | Existing [1] | Total Potential [2] |
| Illinois | 50 | 6980 |
| Iowa | 471 | 62900 |
| Minnesota | 563 | 75000 |
| Nebraska | 14 | 99100 |
| North Dakota | 66 | 138400 |
| South Dakota | 44 | 117200 |
| Wisconsin | 53 | 6440 |
| Total | 1261 | 506020 |

*Notes:*

*[1] Nameplate MW, American Wind Energy Association, January 2004.*

*[2] Average MW, circa 33% of nameplate capacity, sourced from "An Assessment of Windy Land Area and Wind Energy Potential", Pacific Northwest Laboratory, 1991.*

*Source: Wind on the Wires presentation on Net Environmental Impacts of Transmission Systems in the Midwest.*

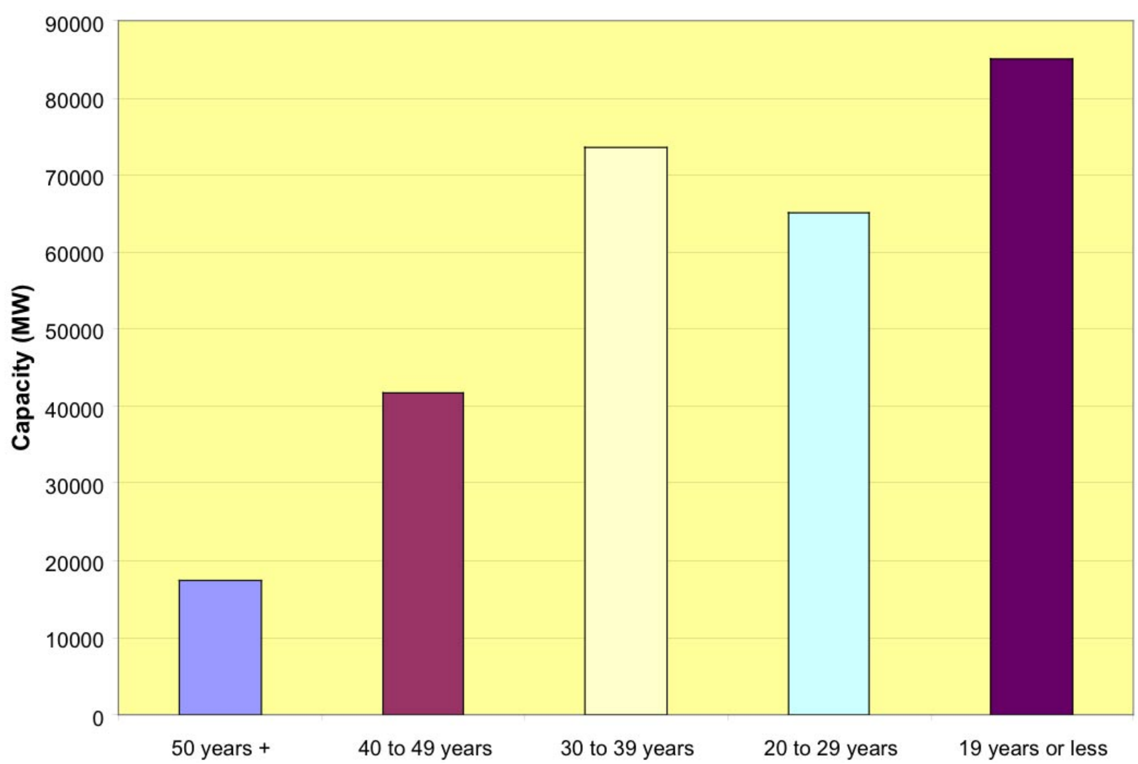
## 3.5 Regional Transmission to Access Generation Resources

Midwest ISO has engaged in forward transmission studies involving about 5,000 MW of wind generation in the Dakotas, Minnesota and Iowa. These studies are described further in Chapter 7. The Iowa–Southern Minnesota-Wisconsin Exploratory Study has up to 3,500 MW of wind generation included in a study to identify potential transmission that would be required in Southern Minnesota, Northern Iowa and Wisconsin areas. The Northwestern Exploratory Study coordinated with the Upper Great Plains Transmission Coalition determine scenarios for study. The Northwestern Exploratory study includes 500 MW of coal in North Dakota and 1,500 MW of wind generation at various sites in the North and South Dakota.

The Minnesota CAPX study is investigating the generation and the transmission alternatives that would be required to serve the loads in Minnesota for the 2020 study year. The CAPX study is incorporating the Iowa-Southern Minnesota-Wisconsin Exploratory Study and the Northwest Exploratory Study plus scenarios developed by the CAPX group. The CAPX study includes a 10% Renewable Energy Objective in the study scenario.

## 3.6 Retirement Possibilities of Older Generation

Figure 3.6-1 displays the age of generating plants in the United States. A substantial proportion of the total generation capacity is over forty years old. No indication of retirement of these facilities has been given, but one may expect some decisions as the market matures. In addition, the start of market operations within the Midwest ISO could impact retirement decisions. The amount of generation retirements and the location of new replacement generating resources will have a significant influence on how and where the transmission network may evolve in the longer term.




*Source: Energy Information Administration, Existing Electric Generating Units in the United States, 2003.*

**Figure 3.6-1**

## 3.7 Transmission Technologies

### 3.7.1 Conductor Technology

Various transmission conductor technologies have made it possible to increase the thermal loading characteristics of transmission lines on existing right-of-way (ROW). Midwest ISO members have installed some of the higher rated conductors and WAPA has a composite conductor being tested in North Dakota. Such technologies improve the use of existing ROW. Midwest ISO continues to investigate the potential use of these conductors in the planning process.

Xcel Energy has installed a ceramic composite conductor on some 115-kv lines in the Minneapolis area that increases the lines capacity without increasing the size of the transmission structures. 3M is the manufacture of the conductor.

This chart shows the experience in England and Wales in application of new conductor technologies to increase the capacity of a transmission tower line more than twofold.

**Ceramic Composite Conductor on 115 kV Line**

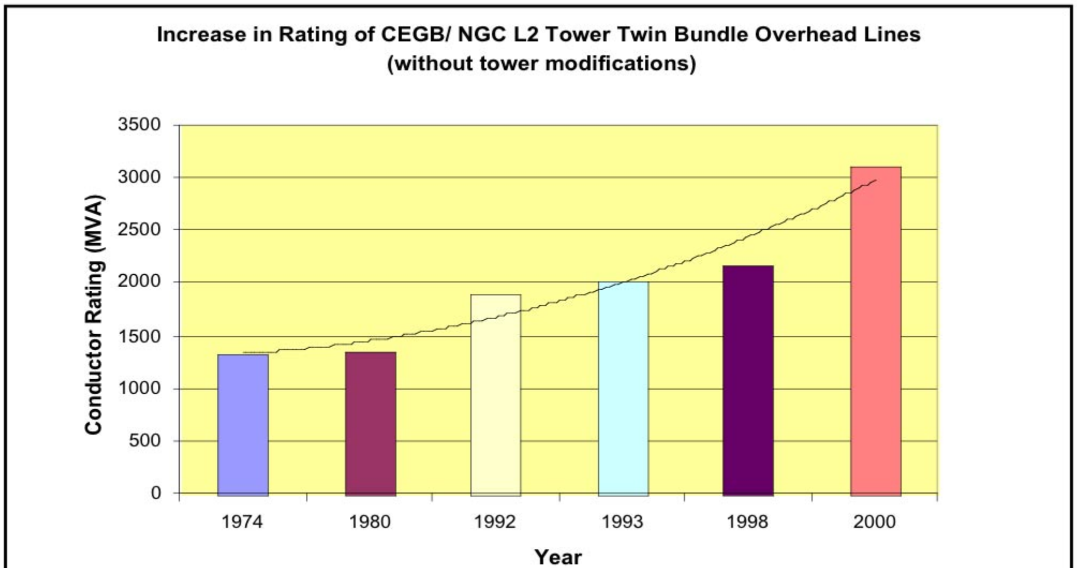


Figure 3.7-1

## 3.7.2 Long Distance Power Transfer

Midwest ISO held a seminar in St. Paul in 2004 for High Surge Impedance Loading Transmission Line technology. This technology enables the doubling the long distance power transfer capacity of a transmission line with a cost savings for construction of 30% per MW-mile of power transmitted while utilizing forty percent less ROW. The technology has been in use in Russia for about fifteen years. China and Brazil are installing 500-kv lines with the HSIL technology. The design experience and assistance for transmission line design is available to U.S. transmission owners.

Many of the transmission systems in the eastern part of Midwest ISO can be operated to thermal rating limits of the conductor. However, the long distance power transfer capability is very dependent upon the design of the line, or the surge impedance loading. HSIL addresses the impedance aspects of line design for long distance power transfer.

Transferring power from the coalfields, wind farms and to the southern and eastern markets are possible uses for HSIL technology.

### 3.7.3 FACTS Technology

Midwest ISO members have had HVDC , Static VAR Compensators, Statcoms, Series Capacitors and Phase Angle Regulators (PAR) operating in its transmission systems for some time. Midwest ISO members have experience with FACTS technology. Midwest ISO members consider FACTS technology solutions in their planning processes.

### 3.7.4 Load Technologies

Link and Sync™ technology is being investigated in the North Dakota area as a means of using a variable electric load to store heat in the floors of buildings for a delayed release as needed to heat a building. The goal is to modify the electric load of the transmission system such that the net energy available from wind generation more closely follows the load pattern required by the other load.

Telecommunications are used to cycle the electric heating elements according to a dispatching order similar to a generator dispatch order.

The load could also be used as a dynamic brake for generator stability considerations following a fault on the transmission system. The heat due to a braking event would be small even in the summer. Using dynamic braking may allow the transmission system to be loaded at higher levels pre-fault.

### 3.7.5 Eastern Interconnection Phasor Project

Midwest ISO is participating in a demonstration of concept for the Eastern Interconnection Phasor Project( EIPP). The EIPP is sponsored by the Department of Energy. The EIPP is a collection of highly accurate, GPS time synchronized power data monitoring units and computers that concentrate the data. A measurement from EIPP can be combined via digital communication links with other measurements in the Eastern Interconnection to determine the voltage magnitude and angle ( phasor) across the geographical distance between the measurement points. Knowing the value of two voltage phasors at the end of a transmission line allows an accurate estimate of the power flow on the line. State Estimators provide the data about the power system that allows the operators to make decisions about the way the transmission system is operated. EIPP receives data inputs up to 60 times faster than the Midwest ISO State Estimator receives inputs. EIPP has the potential to provide nearly a real time state estimate that is much faster than the present State Estimator.

The rate that data is received will allow the Midwest ISO control center to determine if the power system is oscillating and take corrective actions to stop the oscillation. Power oscillations are detrimental to successful operation of a power system

# Section 4: Status Update on Plans from MTEP 03

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 approved the first Midwest ISO expansion plan MTEP 03 on June 19, 2003. Following is a review of the Midwest ISO expansion facilities listed in the MTEP 03 report Appendix A, and their status. Appendix A is comprised of two tables – Form 1 listing transmission line and transformer facilities, and Form 2 listing device facilities such as capacitors and reactors. A transmission system upgrade project may be comprised of multiple branch and device facilities. Approximately half of the facilities in Appendix A are part of a multiple facility project.

Because the development of data for the pending MTEP 05 began in 2004, original MTEP 03 facilities that had not gone into service before January 1, 2004 are included in the new MTEP 05 Appendix A unless they have been cancelled due to replacement with a preferred project, have been delayed beyond the reporting period of the MTEP 05, or are no longer needed due to changing system conditions. The MTEP 05 Appendix A also includes new expansion facilities that have emerged since MTEP 03 as the planning horizon has been extended through 2009.

Of the 407 facilities in MTEP 03, 229 of them had a Planned status. The chart below shows the present status of the Planned facilities from MTEP 03.

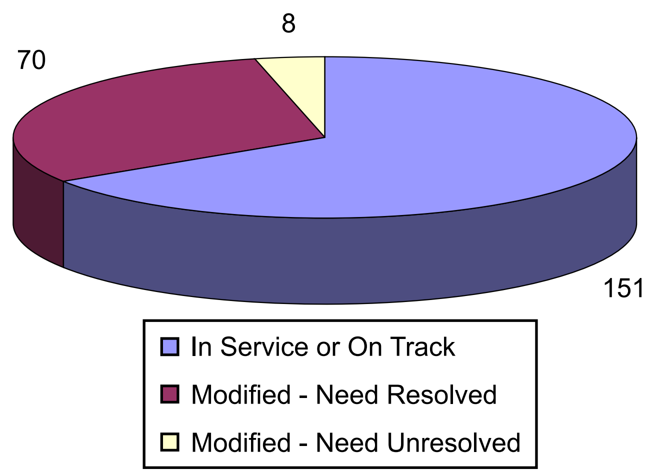



**Figure 4-1:**
**Status of 229 MTEP 03 Planned Facilities**

As a whole, nearly all of the 407 facilities included in MTEP 03 are on track or resolved. The chart below shows the present status of all Planned and Proposed facilities from MTEP 03.

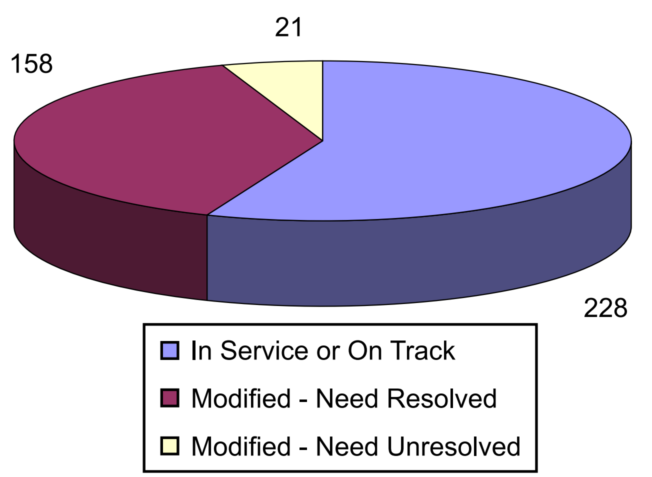



**Figure 4-2:**
**Status of 407 MTEP 03 Facilities**
**All Planning Status**

An initial comparison of planned or proposed facilities between the two plans showed that 179 or 44% of the original plans had been modified from the original plan. Midwest ISO staff inquiry into the reasons for these modifications indicated that for 158 of these facilities the modification is either appropriate due to changing conditions, or the modification is not significant. Appropriate modifications have occurred for a number of reasons such as:

- Load growth less than anticipated, and revised models show delay is appropriate
- Generation or transmission service plans of customers have changed
- Development of alternative solutions such as system operating guides or alternative facilities

Other modifications to the original projects occurred that are not significant to reliability for the following reasons:

- Project was delayed a short period, but is now in service
- Project was, or will be delayed a very short period (months) without significant increase in reliability risk
- Project had some delays but is expected in service by summer 2005

There were some delays in only component parts of a multifaceted project which do not impact overall project schedule

There remain at this time 21 facilities, about 5 %, from MTEP 03 for which the need apparently continues to exist and the facilities have been delayed beyond the desired service date for reasons predominantly of regulatory delays or construction delays. A number of these facilities are part of individual projects, so there are less than 21 projects with delays beyond the desired in-service date. The Midwest ISO has documented these facilities and will incorporate review of the critical conditions driving these facilities into seasonal operating reviews of the system to develop operational steps if required to secure the system until the facilities are installed. The 21 facilities are listed in the table on the following page.

## New Facilities Added in MTEP 05

As noted previously, there were 407 itemized facilities in the 2002-2007 period of MTEP 03. MTEP 05 expands the planning horizon through 2009. There are a total of 518 new facilities now planned or proposed through the 2009 period that have been newly identified with the MTEP 05 effort (where not identified in MTEP 03).

## Impact on Reliability of Changing Project Status

The Midwest ISO is committed to monitoring the implementation of facilities identified as necessary in the MTEP process. A part of this planning process involves the continuing assessment of project status. Changing conditions of the current and projected system will cause appropriate modifications to plans, and status changes as we have seen between MTEP 03 and MTEP 05 are expected.

The results of the Baseline Reliability analyses that have been performed for the first time in this MTEP 05 and that will be a part of subsequent MTEP, along with other supporting studies performed by the Transmission Owners are the indication as to whether the currently identified facilities in the Appendix A to MTEP 05 are sufficient to maintain system reliability. The results of these analyses are described in Section 6 to this MTEP report.

**Table 4-1: Projects With Delays Beyond the Desired In Service Date**

| MTEP 03 Expected In Service Date | MTEP 05 Expected In Service Date | From | To | Ckt | Voltage (kV) | MTEP 03 Status | Updated Status | Delay in Months | Reason For Change |
|---|---|---|---|---|---|---|---|---|---|
| 5/1/04 | 5/1/05 | 19th & Alvo | NW 12th & Arbor | 1 | 115 | Planned | Planned | 12 | One year delay in scheduled construction |
| 6/1/04 | 6/1/05 | Falls | Pioneer | | 138 | Proposed | Planned | 12 | Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties. |
| 6/1/04 | 6/1/05 | Morgan | Falls | | 138 | Proposed | Planned | 12 | Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties. |
| 6/1/04 | 6/1/05 | Pioneer | Stiles | | 138 | Proposed | Planned | 12 | Project changed from simple reconductor to line rebuild to allow for higher capacity and future uncertainties. |
| 6/1/04 | Dropped | Daytons Bluff | Battle Creek | 1 | 115 | Proposed | Dropped | n.a. | no longer planned |
| 6/1/04 | Dropped | Red Rock | Battle Creek | 2 | 115 | Proposed | Dropped | n.a. | no longer planned |
| 6/1/04 | Dropped | Red Rock | transformer | 1 | 345-115 | Proposed | Dropped | n.a. | no longer planned |
| 6/1/04 | Dropped | Red Rock | transformer | 2 | 345-115 | Proposed | Dropped | n.a. | no longer planned |
| 11/1/05 | 11/1/06 | Herblet Lake | Sherridon | 1 | 115 | Proposed | Planned | 12 | Budget constraints have resulted in a deferral as new lower cost alternatives are being evaluated. |
| 5/1/06 | 12/31/07 | Chisago | Lindstrom | 1 | 115 | Planned | Planned | 20 | Addressing local opposition concerns and change in state regulations. Also, after further review the 2nd Lawrence Creek 161-115 transformer (Row ID 305) can be cancelled |
| 5/1/06 | 12/31/07 | Lawrence Creek | St Croix Falls | 1 | 161 | Planned | Planned | 20 | Addressing local opposition concerns and change in state regulations. Also, after further review the 2nd Lawrence Creek 161-115 transformer (Row ID 305) can be cancelled |
| 5/1/06 | 12/31/07 | Lawrence Creek | transformer | 1 | 161-115 | Planned | Planned | 20 | Addressing local opposition concerns and change in state regulations. |
| 5/1/06 | 12/31/07 | Lindstrom | Shafer | 1 | 115 | Planned | Planned | 20 | Addressing local opposition concerns and change in state regulations. |
| 5/1/06 | 6/30/08 | Kelly | Whitcomb | | 115 | Proposed | Planned | 26 | Revised in-service date due to the need to re-apply for regulatory approval. Reapplication was primarily based on increased costs due to restrictions included in original application to the Public Service Commission of Wisconsin. |
| 9/1/06 | 7/1/07 | Fenton | Chanarambie | 1 | 115 | Planned | Planned | 10 | Part of wind outlet project. Total project has late 2007 in-service date. Shift due to construction scheduling. |
| 5/1/04 | Dropped | Elm Creek | Capacitor upgrade | 80>120 MVAR | 115 | Proposed | Dropped | n.a. | Additional study needed |
| 5/1/04 | Dropped | St. Louis Park | Capacitor | 60 MVAR | 115 | Proposed | Dropped | n.a. | Additional study needed |
| 5/1/05 | Cancelled | Wilson | Capacitor #2 | 120 MVAR | 115 | Planned | Cancelled | n.a. | Additional study needed |
| 5/1/05 | Dropped | Elm Creek | Capacitor #2 | 120 MVAR | 115 | Proposed | Dropped | n.a. | Additional study needed |
| 5/1/06 | Dropped | W River Road | Capacitor | 80 MVAR | 115 | Proposed | Dropped | n.a. | Additional study needed |
| 5/1/07 | Cancelled | Wilson | Capacitor #3 | 120 MVAR | 115 | Planned | Cancelled | n.a. | Additional study needed |

# Section 5: Overview of the MTEP 05 Study

## 5.1 Scope and Objectives

MTEP 05 is the second issue of a Midwest ISO regional transmission expansion plan. The first, MTEP 03, was issued in June of 2003. MTEP 03 provided foundational information on the scope of expansion planning through the 2007 plan year that was underway at the time of startup of Midwest ISO operations and shortly thereafter. It also provided in-depth analyses of the potential for regional transmission expansions to provide for lower customer energy costs by reducing congestion and by enabling the entry and delivery of new low cost generation.

MTEP 05 extends the work of MTEP 03 by updating the expansion plan through the year 2009, tracking the progress of plans identified in MTEP 03, continuing the development work on several of the most promising "Exploratory" regional projects identified as potentially beneficial in MTEP 03, performing a comprehensive top-down reliability evaluation of the expected baseline performance of the Transmission System through the 2009 horizon, and identifying the expansion necessary to maintain system performance within standards.

The Baseline Reliability Study provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the year 2009. This is accomplished through a series of evaluations of the 2009 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state powerflow, dynamic stability, small-signal stability, load deliverability, and voltage-stability analysis of the transmission system performed by Midwest ISO staff and reviewed in an open Stakeholder process. The current assessment of the 2009 system focused on performance of the system for summer peak operating conditions.

The Baseline Study was performed in two phases. Phase 1 of the Baseline Reliability Study determined if the Planned projects in the current transmission expansion plan provide adequate system reliability. NERC category A, B, and C events were analyzed with steady-state and dynamic stability analysis. Planning criteria violations (thermal overloads and low or high voltage) were flagged using local limit criteria, as Midwest ISO member's systems have been designed to different standards. Load deliverability was determined for control areas in Midwest ISO by calculation of Loss of Load Probability (LOLP) value. Category C events were evaluated for cascading by using a tripping proxy to gauge the severity of the event and if cascading may occur.

Phase 2 of the Baseline Reliability Study added to the Phase 1 model projects that the Transmission Owners have proposed to meet reliability needs through the period. The critical analyses were repeated to determine if the Planned and Proposed projects in the current transmission expansion plan provide adequate system reliability. The projects in the current transmission plan, which are the result of the transmission studies, are listed in Appendix A.

When Phase 2 of the Baseline Reliability Study was nearing completion, the RSG's reviewed operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests and future available flowgate capacity (AFC) values. Financial Transmission Rights (FTR) allocation binding constraints were also reviewed. Operational issues that will be addressed by the expansion plan were documented. A voltage stability screening of expected 2009 summer peak conditions was performed to determine areas that may have voltage stability issues and which are being further evaluated in continuing studies.

The Baseline Reliability Study determined how the system is expected to perform under peak load conditions with completion of present transmission plans. Any gaps in the transmission plans were identified and solutions proposed and tested. The end result is a Midwest ISO transmission expansion plan that is expected to meet reliability criteria once all identified solutions are implemented, unless changes to the plan are warranted. This expansion plan will undergo continuous review and will be formally reassessed in subsequent releases of MTEP. Near-term issues are also communicated to those within Midwest ISO performing seasonal assessments, establishing a feedback loop between Planning and Operating areas.

## 5.2 Baseline Reliability Study Inputs and Assumptions

The primary inputs and assumptions for the Baseline Reliability Study are:

1) The transmission system condition to be modeled and analyzed with associated load, generation and base interchange values

2) The contingencies and system events to be analyzed

3) The facilities monitored with respect to the Planning Criteria

4) The current transmission expansion plans from the planning process

### 5.2.1 Baseline Models

This Midwest ISO Transmission Expansion Plan study started in Fall of 2003. A 2004 year was selected for the near-term model that would be used to determine existing system deficiencies as a reference point. The 2009 model was selected to determine 5-year out transmission system performance with Planned transmission system improvements. The Midwest ISO Baseline study models for 2004 summer peak and 2009 summer peak were developed from NERC MMWG 2002 Series models. MAPP member data from the MAPP 2003 Series model was inserted and SPP member data from the most recent SPP Series model was inserted. Forecast network resources (generation) and loads were validated. The steady-state powerflow analysis examined the system performance for summer peak conditions with firm transfers modeled.

An assumption in the MTEP Baseline Reliability study was the inclusion of Planned transmission system upgrade projects in the Baseline models for Phase 1 of the analysis. Past planning studies have demonstrated the need for these projects; therefore, the inclusion of Planned projects would demonstrate how the current transmission plan performed in 2009. For Phase 2 of the analysis, the Proposed projects from Appendix A were also included in the model and any new proposals to address outstanding issues identified in Phase 1 which were identified prior to Phase 2 model development. The projects that comprise the current transmission plan are listed in Appendix A. As Appendix A is updated biennially, the projects which were Proposed when the models were developed, may now have a planning status of Planned. Therefore, Appendix A has two columns that indicate if a project was included in the Phase 1 or Phase 2 models.

#### MAIN Study Region Modeling Notes

At the start of the Study, many transmission owners requested model updates. In the MAIN region, the ATC and SIPC models were updated with complete inserts of their systems. AMEREN supplied updates to reflect changes in the information that was supplied in the MTEP Appendix A dated January 29, 2004. AMEREN also updated net load, and shunt data. CE, CILCO, IP, MEC, and CWLP also provided updates to the models.

### MAPP Study Region Modeling Notes

Load levels for the entire MAPP area were modeled at 100% peak summer load for the 2004 and 2009 base cases. No additional generation or load adjustments were made in the MAPP region. The table below shows the exports levels in the system intact base case models MAPP.

**Table 5.2-1: Base Case Area Export Levels**

| Case | MH-US | NDEX | MWSI | MNEX | SPC-BEPC (B10T) | MH-SPC | OH-MP (F3M) | MH-OH | OH E-W Ties | Quad City West | Cooper South |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2009 Summer Peak | 1346 | 634 | 170 | 212 | 150 S | 205 | 0 | 0 | 50 | 820 | 98 |

The above table shows that the real power flows across monitored interfaces are from the north to south and west to east.In recognition of the complexity of the integrated system that must be studied, the models must be as realistic as possible. Particular attention was given to the following features in the dynamic models:

- The machine and control system models were suitable for the duration of the real time period being examined in each case.
- Where load representation is critical, suitable detailed load models were used.
- Where large amounts of wind power are located, appropriate detail of interconnecting substations and maximum system outputs were modeled.
- HVdc system behavior was modeled in appropriate detail.
- Reactive control devices such as Static VAr Systems and fast switched shunt capacitors were modeled using standard models where possible, but with custom models where required.
- Out-of-step relays on the MH / SP / IMO ties to the U.S. were modeled to determine not only whether these relays will operate, but also the steady state and dynamic relay margins.

## 5.2.2 Planning Criteria - Contingencies and Limits

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 Study performed by the Midwest ISO staff in this plan 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.

Regional contingency files were developed by Midwest ISO Staff collaboratively with Transmission Owner with TO and regional study group inputs. NERC Category B and C contingency events at 100-kV and above were specified and analyzed. Over 10,000 NERC Category B (single line, transformer, or generator outage) contingency events and approximately 2,700 NERC Category C (double circuit tower, breaker fault / failure, bus fault and double element outage) contingency events were in the regional contingency files used for steady-state powerflow 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 member's systems. There is a huge number of possible NERC Category C events and it is not practical to analyze them all in any single study. 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. Approximately 140 NERC Category B and C events were specified and studied with dynamic stability simulations. The contingencies studied by each RSG are summarized below.

#### ECAR Region Contingencies

The ECAR RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5, ECAR Type 4), two independent single contingencies involving multiple terminal lines (C3, ECAR Type 5), automated double contingencies 200-kV and above (C3), and double contingencies which share a common bus at 138-kV level on METC system. Automated single contingencies (Category B) 100-kV and above were analyzed. ECAR region non-Midwest ISO member contingencies were included in automated contingency analysis. Dynamics simulations for 49 disturbances were performed.

#### MAIN Region Contingencies

The MAIN RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5) and selected breaker failures. The category B contingencies supplied by the RSG members were mostly those involving the outage of multi-terminal lines and multi-segment line outages. Automated single contingencies (Category B) 100-kV and above were analyzed. Non-Midwest ISO members, ComEd and MidAmerican, provided contingencies. Dynamics simulations of 15 disturbances were analyzed.

#### MAPP Region Contingencies

The MAPP RSG analyzed NERC category B events (single element) and the following types of NERC Category C events: double circuit tower outages (C5) and selected two independent single contingencies (C3), circuit breaker failures, bus faults for SGL and 3-phase with normal clearing or delayed clearing (stuck breakers), and bipolar block for DC lines. Automated single contingencies (Category B) 100-kV and above were analyzed. MAPP region non-Midwest ISO member contingencies were included in automated contingency analysis. Dynamics simulations of 63 disturbances were analyzed.

NERC Planning Standards allow for manual system adjustment and load shedding if necessary for Category C events. Because the contingency files typically contain the Category C forced outage event only, and not the allowable associated manual adjustments and / or load shedding, it may not be appropriate to say the Category C event is a criteria violation when flagged in this analysis. Therefore, in this report the results of Category C events that are outside the limit boundaries that were set are flagged as criteria exceptions, until the event can be analyzed according to NERC Planning Standards considering all input parameters. For example, a NERC Category C3 event is a single contingency, followed by operator adjustments, followed by another single contingency. The event is not modeled with operator actions in the contingency files and an overload is flagged in the analysis. However, with appropriate operator action after the first event, the overload would not occur after the second contingency occurs. That is why initial Category C event results were called criteria exceptions.

### 5.2.3 Monitored Elements

All system elements 100-kV and above within the Midwest ISO study 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 study region.

## 5.3 Baseline Reliability Study Process

### 5.3.1 Study Working Groups

To facilitate the Baseline Reliability Study, the Midwest ISO was divided into three Regional Study Groups (RSG). The regions selected used existing NERC regional reliability councils of Mid-Continent Area Power Pool (MAPP), Mid-America Interconnected Network (MAIN), and East Central Area Reliability Council (ECAR) to take advantage of existing working relationships and familiarity with regional criteria. A Midwest ISO Staff member was assigned to be the Lead for each RSG.

The RSG's were the primary work group which facilitated the technical studies. The RSG's documented the study criteria and defined study methodologies; reviewed and updated models; produced contingency and monitored element files; and were the first to review the results produced by Midwest ISO Staff. Note that transmission planning studies were conducted using an iterative process. If there was an issue with some of the results, the appropriate study input was corrected and analysis rerun.

The Expansion Planning Working Group (EPWG) facilitated the study process by providing input on the scope of work and methodology. If the RSG's had concerns they were brought to the EPWG for feedback and recommendations. The EPWG was also given periodic status reports on the study.

The flowchart below shows the iterative nature of transmission planning studies and how the RSG is a key part of the Baseline Reliability Study process.

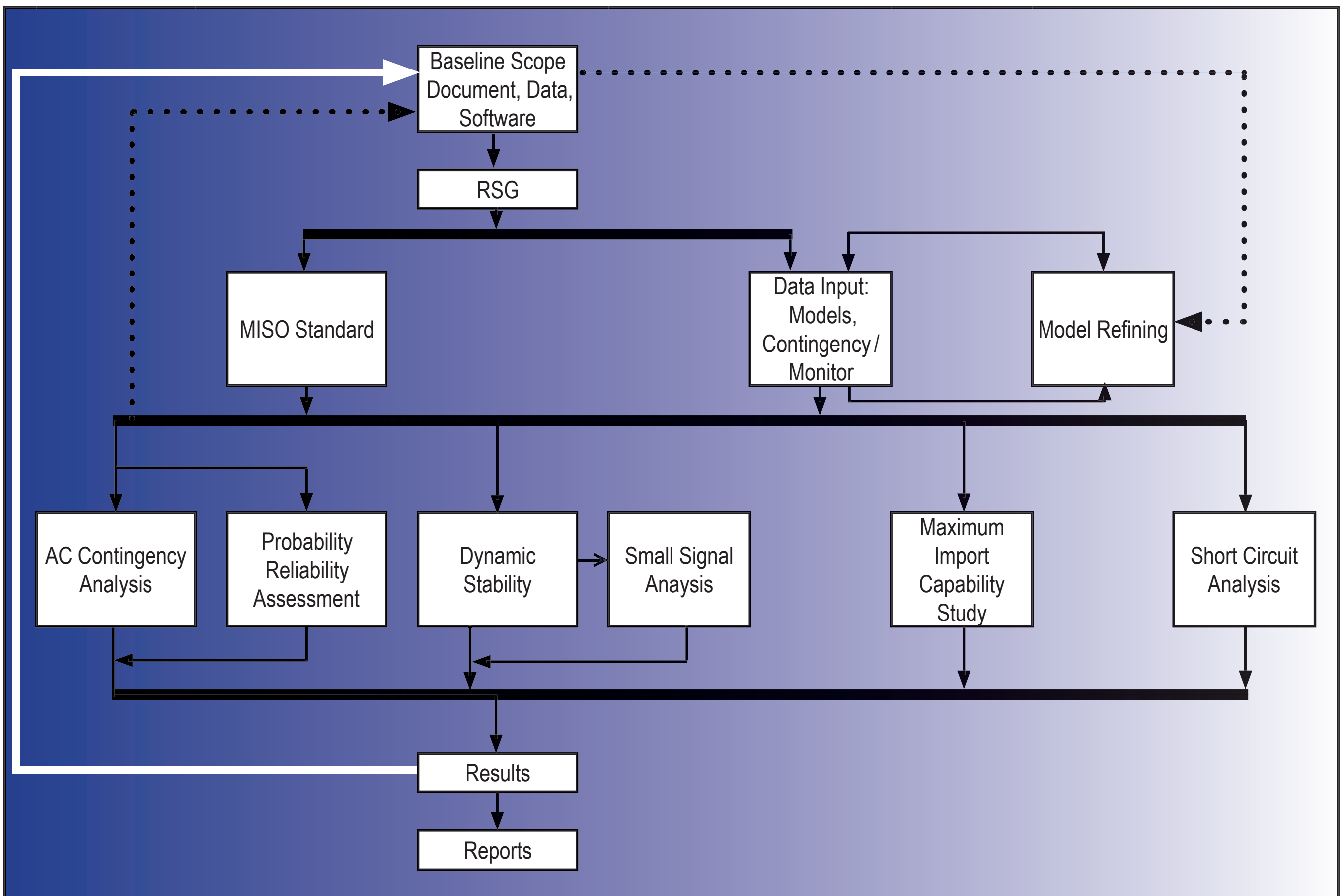



**Figure 5.3-1: Baseline Reliability Study Process Flowchart**

## 5.3.2 Baseline Study Process and Methodology

This section describes how the various tasks in this study were accomplished.

### 5.3.2.1 Steady-State Powerflow Analysis

The Study evaluated the thermal loadings of lines and transformers and bus voltages for the system above the 100 kV voltage level in the Midwest ISO including tie lines under both pre-contingency and post-contingency system conditions. The Study was conducted on 2009 summer peak cases using ShawPTI's PSS / E and MUST digital simulation programs. Although the primary focus of the study was on the future 2009 system performance, the 2004 summer peak condition was analyzed in Phase 1 as a reference point. The steady-state power analysis included the following tasks:

**Phase 1**

- Evaluate and document system intact (Category A) branch thermal loading and bus voltage limitations according to the local Transmission Owner (TO) flagging criteria.
- Evaluate and document contingent (Categories B and C) branch thermal loading and bus voltage limitations according to the local Transmission Owner (TO) flagging criteria.

**Phase 2**

- Map all system issues identified in Phase 1 to the Planned and Proposed facilities in Appendix A.
- Develop proposals (system upgrades) as necessary for Phase 1 issues without an identified Planned or Proposed solution in Appendix A or operating procedure.
- After all required proposals are developed, prepare a comprehensive list of all planned and proposed facilities (previous Appendix A plus any new projects).
- Create a Phase 2 powerflow base case with all Planned and Proposed facilities.
- Run contingency analysis to verify that all Planned and Proposed transmission system upgrades satisfy planning criteria. The end result of Phase 2 should be without planning criteria violations.
- If issues persist or Reliability Plan results in new issues, develop additional proposed upgrades or operating procedures as necessary.
- Analyze NERC Category C event exceptions to determine if event is a violation after allowed operator action has been taken. A system upgrade may be proposed if desirable to address the Category C issue. Document how Category C events will be addressed.
- Document all system upgrades and operating procedures which are necessary for reliable system performance.

In the past, review of operating procedures used to mitigate Category C events was not done in long-term planning study, but was done in short-term operating studies. However, it is beneficial to consider whether Category C events may merit transmission system upgrades by examining the effectiveness of the operating guides in the long-term. The next section discusses the Category C event cascade screening which is another part of reviewing of Category C events in the planning process.

### 5.3.2.2 Category C Event Cascade Screening

NERC Planning Standards require that Category C events do not exceed applicable ratings or result in uncontrolled cascading outages. Therefore, this Study screened the Category C events which resulted in criteria exceptions to determine if the event may be a criteria violation and warrant additional analysis. NERC Planning Standards do not provide an objective definition for cascading. Therefore, the desired outcome of the screening was to identify the approximate amount of MW of load which would be shed and / or the number of additional lines which would trip because of the event, to indicate cascading potential. The following screening procedure / guidelines were used:

i. Run Category C contingencies with all planned and proposed facilities modeled. Determine if issues remain and if voltages are below under-voltage load shed (UVLS) relay set points.

ii. Individually run contingencies with appropriate UVLS substation loads removed (status 0) from case. If branch loadings exceed Post-contingent Branch Tripping Guidelines (see section vii below), remove them from service and rerun the case. Repeat as necessary. Document the branches tripped (in addition to the Category C event) and the amount of load that is shed because of these trips.

iii. If initial load shedding does not address the issue or if the event appears to be cascading, develop an operating procedure or system upgrade.

iv. Run contingency with proposed operating procedure (generation re-dispatch, system reconfiguration, planned load shedding). Local re-dispatch or system swing re-dispatch may be used as appropriate.

v. Determine if the post-operating voltages and branch loadings are within applicable ratings. Divergent case solutions may indicate cascading potential.

vi. If criteria violations persist, modify procedure and try again.

vii. Post-Contingent Branch Tripping Guidelines: These tripping guidelines were to be used as a proxy for determining cascading outages. As Midwest ISO's members' systems were developed using different design standards, a common tripping proxy was not recommended. TO's were asked to provide input to determine if a wider area tripping proxy for transmission lines and transformers could be developed. A consensus was not reached by the EPWG participants. Consequently, Midwest ISO used TO provided tripping proxy to analyze possible cascading for that TO. If the TO did not respond to the tripping proxy survey, a default tripping proxy was used.

- The default transmission line tripping proxy was 100 % of emergency rating.
- Large Power Transformers tripping proxy. The default large power transformer tripping proxy is 100 % of emergency rating.
- Overhead transmission lines respond in a predictable manner to a contingent increase in current, assuming the line is conductor limited and not equipment limited. Pre-contingent and post-contingent flows can be used to determine a response time to reach the TO specified applicable rating. If the response time to reach the TO specified applicable rating is less than the time required for manual operator intervention, it is assumed that the line will trip. The table below gives a sample of response times for DRAKE conductor to reach its emergency rating (assumed to be 110 percent normal) from a given pre-contingent initial flow to the specified post-contingent flow on a 104F degree summer day. An overhead response time may be used. The default is no overhead conductor response time is used.

**Table 5.3-1: Overhead Conductor Response Times to Percent of Normal**

| Initial Flow Percent Normal | Post-Con. Percent Normal | Time Minutes |
|---|---|---|
| 50 | 110 | 18 |
| 60 | 110 | 17 |
| 70 | 110 | 15 |
| 80 | 110 | 11 |
| 90 | 110 | 6 |
| 50 | 130 | 9 |
| 60 | 130 | 8 |
| 70 | 130 | 6 |
| 80 | 130 | 5 |
| 90 | 130 | 2 |

If an event appears to result in cascading outages or exceeds applicable ratings, then a special protection scheme (SPS) may need to be implemented or a system upgrade proposed. Because this was a fast screening of cascading potential, any event which appears to be cascading should be reviewed using line specific tripping values which require a thorough review of design parameters and rights-of-way.

### 5.3.2.3 Dynamic Stability Analysis

The Study evaluated numerous system disturbances using ShawPTI's PSS / E Dynamics program. The dynamic simulations were performed on the Phase 1 summer peak models which contained Planned system upgrades. The dynamic stability analysis included the following activities:

- Create or modify channel definition, monitoring specification and fault definition files as necessary.
- Convert stability powerflow model to MAPP NMORWG User Interface Package compatibility (MAPP study region only).
- Create dynamic snapshots; compile user models and dynamic files for 2004, and 2009 summer peak base cases.
- Perform a steady state simulation analysis for 20 seconds with no disturbance and analyze voltage and transient voltage limitations according to the local Transmission Owner (TO) criteria for pre-disturbance.
- Perform fault scenarios including disturbances that conform to the NERC Planning Standards Table 1A Category B, C and D (monitor only) fault definitions. Evaluate voltage instability and transient limitations according to the local Transmission Owner (TO) criteria for post-disturbance.

### 5.3.2.4 Load Deliverability

Midwest ISO performed a Load Deliverability study for the 2004 and 2009 years. This study analyzed whether Midwest ISO areas have sufficient import capabilities to meet the industry criteria of 1 day in 10 year (0.1 day per year Loss Of Load Probability). Both the import capability needed to meet the reliability criteria and the actual import levels in 2004 and 2009 for all LOLE zones in this study were identified. Please see Section 6.4.2 Load Deliverability for complete discussion of how this analysis was performed and the results.

### 5.3.2.5 Small-Signal Stability

Midwest ISO performed a Small Signal Study Analysis (SSSA) study for the whole Midwest ISO footprint which included non-Midwest ISO MAPP members. The small signal analysis included the following activities:

- Development of a small signal stability (SSAT) case, including the whole Midwest ISO footprint, for the small signal study.
- Investigation of the 0.25Hz inter-area oscillation mode of MAPP region and participation factors.
- Evaluation of the settings of the SVCs and PSSs of the generators that contribute to the 0.25 Hertz inter-area mode.
- Identification of potential problem modes of oscillation in system intact 2004 and 2009 conditions.

Please see Section 6.4.3 Small Signal Stability for study assumptions and results.

### 5.3.2.6 Voltage Stability Screen 2009

The purpose of the voltage stability *screening* was to identify portions of the transmission system which may have reactive power resource limitations after loss of multiple system facilities, so that additional analyses can be focused on areas which have needs and not on areas which have adequate reactive supplies. The screening was performed on the MTEP 2009 Summer Peak cases (Phase 1 with Planned facilities and Phase 2 with Planned and Proposed facilities). The output of the screening was a list of buses whose controlling generators have depleted their reactive power supplies. Only buses whose voltages are controlled by generators ($V_{remote}$ buses) were monitored. Control area generator and switched shunt reactive reserves in the base case were documented. The Midwest ISO staff and the RSG's reviewed the raw output and recommended areas and contingencies which merit additional study. Continuing study tasks include determining the nature of the system response and, if necessary, obtaining a resolution to the reactive supply issue.

Detailed voltage stability analysis is computationally intensive. Therefore, a *screening* study was performed to identify portions of the transmission system which merit future study. The challenge for this voltage stability screening was determining a study technique which would be efficient and yet point us in the right direction. Midwest ISO determined that generators which are at their reactive output limits could be gleaned from monitoring the V buses of active generators with available reactive capability. If the $V_{remote}$ bus was below $V_{scheduled}$, then the generator had reached its reactive limit.

Specific analytical technique is described in Appendix D6. Specific study recommendations are located in Appendix D6. The raw output is available in Appendix D6 Voltage Stability Screen 2009.

### 5.3.2.7 Operational Issues

The Baseline Reliability Study also reviewed the operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests, future available flowgate capacity (AFC) values, and financial transmission rights (FTR) allocation binding constraints. This review was done after the majority of baseline study analysis had been completed. The FTR allocation binding constraints information was not available until early in February, 2005. Therefore, the expansion plans were already developed to address related known reliability issues and were not developed in MTEP05 to address these constraints.

Historical flowgate TLR data for January 2001 through December 2004 was documented. Expansion plans in place to address known TLR issues were subsequently documented.

Forward looking available flowgate capacity (AFC) for December 2004 through October 2007 was reviewed. Flowgates with negative AFC during the period were listed and compared against a security constrained economic dispatch (SCED) model to determine if the limitations may still exist under a market based dispatch. Flowgates with negative AFC and which were constrained in SCED were documented and existing expansion plans which may address potential future AFC issues were noted.

FTR allocation binding constraints from allocation process which occurred in January, 2005, were reviewed and facilities in the expansion plan which may address the constraint were noted.

# Section 6: Baseline Reliability Study Findings

## 6.1 Midwest ISO System - ECAR Region

### 6.1.1 System Description

The ECAR Regional Reliability Organization (RRO) includes several member systems that are also members of the Midwest ISO RTO. The ECAR RRO includes systems in Michigan, Indiana, Ohio, and Kentucky.

**Midwest ISO member systems in ECAR are:**

- First Energy (FE)
- Cinergy (CIN)
- Louisville Gas & Electric (LGEE)
- Northern Indiana Public Service Company (NIPSCO)
- Michigan Electric Transmission Company (METC)
- International Transmission Company (ITC)
- Hoosier Energy (HE)
- Indianapolis Power & Light (IPL)
- Vectren

**Non-Midwest ISO systems include:**

- American Electric Power (AEP)
- Dayton Power & Light (DPL)
- East Kentucky Power Cooperative (EKPC)
- Big Rivers Electric Cooperative (BREC)
- Ohio Valley Electric Corp. (OVEC)

In northern ECAR, two 138 kV transmission lines connect the METC transmission system in the Michigan lower peninsula to the transmission network in the Michigan upper peninsula operated by WUMS. ITC in southeastern Michigan interconnects with Hydro One (Ontario) by phase shifters. To the west, NIPSCO connects with the Commonwealth Edison and Ameren systems and Cinergy connects with the Ameren System. To the south, LGEE interconnects with the TVA system at 161 kV at several locations and at 500 kV at one location. FE, NIPSCO, METC, Cinergy and LGEE all connect with AEP system. AEP also has an extensive 765 kV system across the area.The Midwest ISO member systems in ECAR were modeled with the projected control area load and dispatched generation for 2009 summer as shown below.

The generation figures in table 6.1-1 are not indicative of available capacity to meet load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. Note that positive area interchange means the system is exporting power; negative area interchange is importing power. Contingencies came from ECAR database, TO provided lists, global single unit outage, global single transmission element outage which has both terminal voltages greater than 100 kV, global double transmission element outage which has both terminal voltages greater than 200 kV. Contingencies of ECAR Type 1-5 were tested for this study. ECAR Type 1-3 contingencies are single contingencies. ECAR Type 4 contingencies are double circuit tower outages. ECAR Type 5 contingencies are combination of any two single circuit outage. ITC system was also tested for double circuit tower outage of 100 kV and above system. METC system was tested for double outages which share a common bus at 138 kV level. All facilities within Midwest ISO ECAR footprint rated 100 kV and above were monitored for voltage and thermal violations for the above contingencies. The criteria used for determining violations are in Table 6.1-2.

**Table 6.1-1: ECAR 2009 Program**

| System | Modeled Load (MW) | Modeled Generation (MW) | Modeled Area Interchange (MW) |
|---|---|---|---|
| First Energy | 14,877 | 13,872 | -1,358 |
| Cinergy | 14,164 | 13,557 | -1,075 |
| Hoosier Energy | 680 | 1,654 | 935 |
| Vectren | 2,009 | 2,004 | -30 |
| LGEE | 8,356 | 8,019 | -530 |
| IP&L | 3,391 | 3,471 | 0 |
| NIPSCO | 3,497 | 2,651 | -892 |
| METC | 10,970 | 11,751 | 538 |
| ITC | 13,262 | 12,426 | -1,174 |
| **Total** | **71,205** | **69,405** | **-3,586** |

**Table 6.1-2: Thermal Violation Criteria**

| System | Thermal | Voltage | Voltage drop |
|---|---|---|---|
| No outages | 100 % normal | 0.95-1.05<br>0.97-1.05 (METC)<br>0.94-1.05 (LGEE) | n/a |
| Single outages | 100 % emergency | 0.90-1.05<br>0.92-1.05 (METC)<br>0.87-1.05 (ITC)<br>0.95-1.05 (IPL)<br>0.95-1.05 (Vectren) | 0.05 (345-kV and above)<br>0.10(100-kV–345-kV) |
| Multiple contingencies | 100 % emergency | 0.90-1.05 | 0.10 |

## 6.1.2 Summary of Baseline Study Results for ECAR Region Systems in Midwest ISO

Continuing the project designations initiated with MTEP 03, projects are classified as either "Planned" or "Proposed". Projects in Appendix A that are designated as Planned projects are recommended by the Midwest ISO to be completed by the service dates identified. Other projects listed in Appendix A as Proposed projects are tentative solutions to identified needs, and require additional planning before they are endorsed by the Transmission Owners or the Midwest ISO as the preferred solution. As described in Section 5 of this report, the Baseline study was performed in two phases. Phase 1 tested the system against reliability criteria with a set of "Planned" upgrades included in the model. It was anticipated that there might be certain conditions for which additional upgrades would be shown to be required. Phase 2 of testing included all expansions and enhancements "Planned" and "Proposed" by the Transmission Owners. Critical tests were then repeated for the system with this more complete set of upgrades.

The results of Phase 2 should show no violations of tested reliability criteria, or where violations remain additional solutions must be developed before 2009 if modeled conditions prevail.

## First Energy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**Table 6.1-3: First Energy Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| FE | 2009 | Crissinger–Tangy 138 kV | 182 | 107.40 % | B | Galion 345-138 #3 & #4 | PR2 | Crissinger–Tangy 138 kV circuit upgrade planned in 2006, BR_ID 1284 |
| | | Galion, Marion area 138 kV system | | 23 bus <0.9 pu | | | | Galion substation reconfiguration. BR_ID 1283 |
| FE | 2009 | Star 345-138 #1 | 151.3 | 102.30 % | B | Star 345-138 #2 & #3 | | Op procedure (switch back one transformer). Project to provide independent bus positions for each of the three transformers is scheduled for 2005 BR_ID 1282 |
| FE | 2009 | Division–CPP CL 138<br>Division–CPP LS 138<br>Lakeshore–CPP LS 138 | 165<br>165<br>287 | 143 %<br>154 %<br>118 % | C | Fox–Harding 345 #1 & Fox–Harding 345 #2 | n.a. | Op guide: trip CPP to Division ties. |
| FE | 2009 | Galion 345 kV , Galion, Cardington 138 kV | | 24 buses <0.90 pu, lowest of 0.867 pu | C | South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV | | |

PL – Planned Projects
PR – Proposed Projects
PL2 – New Planned Project in Phase 2
PR2 – New Proposed Project in Phase 2 study
CP2 – Conceptual Projects
N.A. – Not Avalable

**Table 6.1-4: First Energy - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| FE | 2009 | Crissinger–Tangy 138 | 182 | 106.80 % | B | Galion 345-138 #3 & #4 | PR2 | Crissinger–Tangy 138 kV circuit upgrade planned in 2006, BR_ID 1284 Galion substation reconfiguration to eliminate the contingency, BR_ID 1283 |
| | | Brookside–Beaver 138 | 135 | 98.50 % | | | | |
| | | Crissinger / Tangy area | | 24 buses <0.9 pu | | | | |
| FE | 2009 | Star 345-138 #1 | 300 | 102.40 % | B | Star 345-138 #2 & #3 | PR2 | Operating step is to switch back one transformer. Project to provide independent bus positions for each of the three transformers is scheduled for 2005 BR_ID: 1282 |
| FE | 2009 | Sammis–Highland 345 kV | 997 | 106 % | C | Mansfield–Highland 345 kV & Mansfield–Hoytdale 345 kV | PR2 | A project to increase rating of this line is scheduled for completion by summer 2005. |
| FE | 2009 | Lakeshore–CPP LS 138 | 287 | 118 % | C | Fox–Harding 345 #1 & Fox–Harding 345 #2 | | Operating guide, trip CPP to Division ties. |
| | | Division–CPP CL 138 | 165 | 143 % | | | | |
| | | Division–CPP LS 138 | 165 | 154 % | | | | |
| FE | 2009 | Crissinger–Tangy 138 | 182 | 108 % | C | South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV | PR2 | A project to increase the rating of this line is scheduled for completion prior to summer 2006. BR_ID 1284 |
| FE | 2009 | Star 345-138 #1 | 300 | 115 % | C | Breaker failure: Star–Juniper 345 & Star 345-138 #2 & #3 | PR2 | Operating step is to switch back one transformer. Project to provide independent bus positions for each of the three transformers is scheduled for 2005. BR_ID 1282 |
| FE | 2009 | Galion 345, Galion Cardington 138 kV | | 24 buses <0.90 pu, lowest at 0.867 pu | C | South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV | | |

**Table 6.1-5: First Energy - Phase 2 Outstanding Issues**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| FE | 2009 | Galion 345, Galion Cardington 138 kV | | 24 buses < 0.90 pu, lowest of 0.867 pu | C | South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV | | |

First Energy has two outstanding issues. One is simultaneous outages of two lines which may be potentially cascading. Additional information is provided in the ECAR Region study details appendix. Prior to summer 2005, FirstEnergy will be installing a system-wide UVLS scheme that will mitigate both the thermal and voltage impacts of this category C3 contingency. FirstEnergy is also investigating a project to get additional power source in the area, however this project is too preliminary to be defined as proposed. This area is to be monitored in 2005 Coordinated Summer Assessment.

The other outstanding issue is double 345 kV line outage South Berwick–Galion 345 kV & Ohio CT–Galion 345 kV which could cause low voltage at Galion area. The mitigation is under investigation.

## Hoosier Energy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**Table 6.1-6: Hoosier Energy - Phase I Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| HE-CIN | 2009 | Georgetown, Mill town 138 kV | | 0.86 pu | B | Georgetown–Gallagher 138 | | Change Georgetown transformers tap ratio |
| HE | | Owensburg–Worthington 138 kV | 129 | 109 % | | Worthington–Bloomington 345 | | Op procedure |
| HE-CIN | | Georgetown–Gallagher 138 kV | 133 | 104 % | | Whitefield–Edwardsport 138 | PR2 | Reconductor project BR_ID: 1311 |

For the Worthington–Bloomington 345 kV outage, there is an operating procedure. When the CTs at Worthington are in operation the breaker on the Worthington 345 / 138 kV transformer is opened. This policy was adopted as protection against line overloads on the 138 kV system out of Worthington in the event that a fault occurs on the Hoosier Energy Worthington–Bloomington 345 kV line. In Phase 2 analysis, the Worthington 345 / 138 kV transformer is set off, hence Owensburg–Worthington 138 kV is no longer overloaded.

**Table 6.1-7: Hoosier Energy - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| HE-CIN | 2009 | Georgetown–Gallagher 138 | 133 | 103.9 % | B | Whitfield–Edwardsport 138 kV | PR2 | Reconductor project. BR_ID: 1311 |
| | | Georgetown / Mill Town 138 kV | | 0.8637 | | Goergetown–Gallagher 138 kV | | Change Georgetown transformer tap ratio |

After inclusion of proposed projects, there is no outstanding issue.

## Cinergy

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**Table 6.1-8: Cinergy - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| CIN | 2009 | Five Points 230 kV | | 0.90 pu | B | Noblesville–Geist 230 | | Change LTC tap |
| CIN | 2009 | Geist 230 kV | | 0.87 pu | B | Noblesville–Geist 230 | | Change LTC tap |
| CIN | 2009 | Westwood 345-138 kV | 382.4 | 103 % | B | Dequine–Reynolds–Olive 345 kV / Reynold 345-138 | PR | Westwood–Dequine 345 kV line and Westwood 345 / 138 TX 2 BR_ID: 357,367. |
| | | | 382.4 | 100 % | B | Cayuga–Veedersburg 230 kV | | |
| CIN | 2009 | Georgetown–Gallagher 138 kV | 133 | 104 % | B | Whitefield–Edwardsport 138 | | |
| CIN | 2009 | Port Union–Hall 138 kV | 206 | 104 % | B | Hamilton–Port Union 138 kV | PL | Port Union– Hall 138 ckt 1, Sum rate 300 BR_ID: 594 |
| CIN | 2009 | Staunton–Greencastle–Lone Star–Greencastle | 95.6 | 103 % | B | Staunton–Greencastle Jct. 2–Cloverdale | | 69 kV configure change |
| CIN | 2009 | Beckjord–Tobasco 138 kV | 344 | 102 % | B | Beckjord–Clermont–Summerside–Port Union 138 kV | PL | Addition of Beckjord–Silver Grove 138 kV line BR_ID: 365 |
| CIN | 2009 | Ashland–Redbank 138 kV | 300 | 99.5 % | B | Red Bank–Terminal 345& Redbank 345 / 138 | | |
| CIN | 2009 | Crescent 138 bus tie | 382 | 101 % | B | Red Bank–Silver Grove-Zimmer 345 | In Service | 5 % reactor at Buffington–Florence 138 kV line DV_ID: 80 |
| | | Crescent 138 bus tie | 382 | 104 % | B | Pierce–Foster 345 kV | In Service | 5 % reactor at Buffington–Florence 138 kV line DV_ID: 80 |
| | | Crescent–W. End 138 | 273 | 99.5 % | B | | | |
| CIN | 2009 | Kokomo HP 230-138 kV | 75 | 98 % | B | Greentown–Jefferson 765 kV | PR | 2nd Kokomo 230 / 138 kV transformer BR_ID: 356 |
| CIN | 2009 | Todhunter 345 / 138 kV transformer and 138 kV lines | 478 | 106 % | C | Foster–Todhunter 345 & Todhunter 345 / 138 kV transformer | PL | Beckjord–Feldman 138 ckt 1, Sum rate 308 BR_ID: 363; Beckjord–Silver Grove 138 ckt 1, Sum rate 304 BR_ID: 365 |
| CIN | 2009 | Terminal 345 / 138 kV transformer and Terminal 138 kV lines | 478 | 111 % | C | Red Rank–Terminal 345 kV & Red Bank–Silver Grove-Zimmer 345 / Red Rank transformers and Silver Grove transformer | PL | Beckjord–Silver Grove 138 ckt 1, Sum rate 304 BR_ID: 365; Beckjord–Feldman 138 ckt 1, Sum rate 308 BR_ID: 363 |
| CIN | 2009 | Kokomo 230 / 138 transformer and 138 kV circuits | 75 | 144 % | C | Double circuit outages involving Greentown–Jefferson 765 kV circuit | PR | Kokomo–230 / 138 ckt 1, Sum rate 200 BR_ID: 356” |

**Table 6.1-8 (cont.): Cinergy - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| CIN | 2009 | Crawfordsville, CrawMU 138 kV | | 0.87 | C | Dequine–Westwood 345 kV / Westwood 345-138 & Lafayette–New London 138 kV | PR | Westwood–Dequine 345 kV line and Westwood 345/138 TX 2 BR_ID: 357,367 |
| | | Crawfordsville138 kV | | 0.9 | C | Dequine–Westwood 345 kV / Westwood 345-138 & Reynolds 345/138 transformer | | |
| | | Westwood 345-138 kV | 382.4 | 126 % | C | Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138 | | |
| | | Westwood 345-138 kV | 382.4 | 126 % | C | Dequine–Olive & Dequine–Reynolds 345 kV | | |
| | | Dequine–Westwood 345 kV | 409 | 118 % | C | Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138 | | |
| | | Dequine–Westwood 345 kV | 409 | 117 % | C | Dequine–Olive & Dequine–Reynolds 345 kV | | |
| CIN | 2009 | Northwest Tap–W. Lafayette 138 | 143 | 107 % | C | Dequine–Olive & Dequine–Reynolds 345 kV | PR | West Lafayette Purdue–Purdue NW Tap 138 ckt 1, Sum rate 179 BR_ID: 618 |
| | | | 143 | 105 % | C | Dequine–Olive & Dequine–Reynolds–Olive 345 kV & Reynold 345-138 | | |
| CIN | 2009 | Cayuga–Veedersburg-Attica–Lafayette 230 kV | 478 | 118 % | C | Eugene–Cayuga 345 kV & Cayuga–Nucor 345 kV | PR2 | 2006 proposed project to uprate the line to 496 MVA. BR_ID: 1296 |
| CIN | 2009 | Cloverdale–Stilesville–Plain 138 kV | 240 | 118 % | | | PR2 | Cloverdale–Plainfield South 138 kV is planned to be rebuilt in 2006. Rate 307 MVA. BR_ID: 1300 |
| CIN | 2009 | Cayuga–Frankfort 230 kV | 637 | 118 % | | | | |
| CIN | 2009 | Dresser 345-138 #2 | 478 | 113 % | C | Worthington–Bloomington 345 kV & Dresser 345-138 #1 | | |
| CIN | 2009 | Crescent 138 kV bus tie | 382 | 107 % | C | Foster–Pierce & Port Union–Zimmer | PL | Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5 % to 3 %) DV_ID: 81 |
| CIN | 2009 | Crescent-W. End 138 kV | 273 | 103 % | C | | | Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5 % to 3 %) DV_ID: 81 |
| CIN | 2009 | Crescent–W. End 138 kV | 273 | 101 % | C | E. Bend–Terminal & Miami Fort–Terminal | | Buffington–Florence 138, 337 MVA Reactor (change Impedance from 5 % to 3 %) DV_ID: 81 |
| CIN | 2009 | Miami Fort 345/138 transformer | 486 | 102 % | C | E. Bend–Terminal & Miami Fort–Terminal | PR | Miami Fort–345/138 ckt 2, Sum rate 450 BR_ID: 360 |
| CIN | 2009 | Bloomington 230-138 kV | 162.4 | 109.2 % | C | Gibson–Bedford & Bedford–Lost River 345 | n.a. | Operating guide and/or generation redispatch |

| Table 6.1-9: Cinergy - Phase 2 Results | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Area** | **Model Year** | **Limiter Element** | **Rating** | **Contingent Level (%, PU)** | **Con. Type** | **Contingency** | **Plan Status** | **Project to Address Limiter** |
| HE-CIN | 2009 | Georgetown–Gallagher 138 | 133 | 103.90 % | B | Whitfield–Edwardsport 138 kV | | Reconductor the line BR_ID: 1311 |
| CIN | 2009 | Ashland–Red Bank 138 | 300 | 102.20 % | B | Red Bank–Terminal 345 / Red Bank 345-138 | | |
| CIN | 2009 | Geist 230 kV | | 0.8709 | B | Geist–Noblesville 230 kV | | Lock LTC and add 35 MVAR capacitors at Geist 69 kV |
| HE-CIN | 2009 | Georgetown / Mill Town 138 kV | | 0.8637 | B | Goergetown–Gallagher 138 kV | | change Georgetown transformer tap ratio |
| CIN | 2009 | W. Lafayette–Cumberland 138 | 143 | 113.80 % | C | Dequine–Olive 345 & Dequine–Eugene 345 | PR2 | Replace 600 A switches, rate to 179 MVA, proposed project of 2007 BR_ID: 1307 |
| | | | | 103.10 % | | Cayuga–Nucor 345 & Lafayette–Attica–Veedersburg–Cayuga 230 | | |
| | | | | 100.90 % | | Nucor–Whitestown 345 & Lafayette–Attica–Veedersburg–Cayuga 230 | | |
| CIN | 2009 | Kokomo 230 / 138 transformer and 138 kV circuits | 75 | 135 % | C | Dumont–Greentown 765 & Greentown–Jefferson 765 | | |
| | | Carmel JT–Noblesville 230 | 319 | 112.20 % | | | | |
| CIN | 2009 | Kokomo Highland Park–Kokomo Delco 138 kV | 146 | 114.70 % | C | Clifty Creek–Pierce 345 #1 & #2 | PR2 | Proposed project of 2007; uprate line to 179 MVA. BR_ID: 1306 |
| CIN | 2009 | Kokomo Highland Park–Kokomo Chrysler 138 kV | 146 | 127.30 % | C | Clifty Creek–Pierce 345 #1 & #2 | PR2 | Proposed project of 2007; uprate to 179 MVA. R_ID: 1305 |
| CIN | 2009 | Carmel Jct.–Noblesville 230 kV | 319 | 112 % | C | Dumont–Greentown 765 kV & Greentown–Jefferson 765 kV | | |
| | | | | 115 % | C | Noblesville 345-230 kV & Noblesville–Geist 230 kV | | |
| CIN | 2009 | Noblesville–Geist 230 kV | 319 | 116 % | C | Noblesville 345-230 kV & Noblesville–Carmel Jct. 230 kV | | |
| | | | | 101 % | C | Whitestown–Guion 345 & Petersburg–Thompson 345 kV | | |
| | | | | 103 % | C | Clark-Columbus N 230 kV & Franklin–Columbus 230 kV | | |
| CIN | 2009 | Veedersburg–Attica 230 kV | 478 | 110 % | C | Eugene–Cayuga Sub 345 kV & Cayuga–Nucor 345 kV | | |
| | | | | 103 % | C | Eugene–Cayuga Sub 345 & Nucor–Whitestown 345 kV | | |
| CIN | 2009 | Veedersburg–Cayuga 230 kV | 478 | 98 % | C | DCT of Breed–Cassid 345 & Dequine–Eugene 345 | PR2 | 2006 proposed project to uprate the line to 496 MVA. BR_ID: 1296 |
| | | | | 119 % | C | Eugene–Cayuga Sub 345 & Cayuga–Nucor 345 | | |
| | | | | 112 % | C | Eugene–Cayuga Sub 345 & Nucor–Whitestown 345 | | |
| | | | | 101 % | C | Nucor–Cayuga 345 kV & Cayuga–Cayuga Sub 345 kV | | |

<table>
<tr><th colspan="9">Table 6.1-9 (cont.): Cinergy - Phase 2 Results</th></tr>
<tr><th>Area</th><th>Model Year</th><th>Limiter Element</th><th>Rating</th><th>Contingent Level (%, PU)</th><th>Con. Type</th><th>Contingency</th><th>Plan Status</th><th>Project to Address Limiter</th></tr>
<tr><td rowspan="4">CIN</td><td rowspan="4">2009</td><td>Lafayette–Attica 230</td><td>478</td><td>102.70 %</td><td rowspan="4">C</td><td rowspan="4">Eugene–Cayuga 345 kV & Cayuga–Nucor 345 kV</td><td rowspan="5">PL2</td><td rowspan="5">Cloverdale–Plainfield South 138 kV is planned to be rebuilt in 2006. Rate 307 MVA. BR_ID: 1300</td></tr>
<tr><td>Cayuga–Frankfort 230</td><td>637</td><td>104.80 %</td></tr>
<tr><td>Cloverdale–Stilesville 138</td><td>240</td><td>117.60 %</td></tr>
<tr><td>Stilesville-Plain 138</td><td>240</td><td>103.70 %</td></tr>
<tr><td>CIN</td><td>2009</td><td>Cloverdale–Stilesville 138 kV</td><td>240</td><td>100 %</td><td>C</td><td>Eugene–Cayuga 345 & Nucor–Whitestown 345 kV</td></tr>
<tr><td rowspan="2">CIN</td><td rowspan="2">2009</td><td rowspan="2">Dresser–Terre Haute S 138 kV</td><td rowspan="2">246</td><td>113 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga-Cayuga CT 345 kV</td><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td>107 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga CT-Sugar Creek 345 kV</td></tr>
<tr><td rowspan="3">CIN</td><td rowspan="3">2009</td><td rowspan="3">Dresser–Allendale–Amaxch–Stauton 138 kV</td><td rowspan="3">304</td><td>111 %</td><td>C</td><td>Merom-Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV</td><td></td><td></td></tr>
<tr><td>105 %</td><td>C</td><td>Merom-Worthington–Bloomington 345 kV & Cayuga CT–Sugar Creek 345 kV</td><td></td><td></td></tr>
<tr><td>113 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Wabash River-Stauton 230 kV</td><td></td><td></td></tr>
<tr><td>CIN</td><td>2009</td><td>Allendale–Margaret Ave. 138 kV</td><td>240</td><td>103 %</td><td>C</td><td>Merom–Worthington 345 kV & Cayuga–Cayuga CT 345 kV</td><td></td><td></td></tr>
<tr><td rowspan="4">CIN</td><td rowspan="4">2009</td><td>Worthington–Owen 138</td><td>135</td><td>119.80 %</td><td rowspan="4">C</td><td rowspan="4">Gibson–Bedford & Bedford–Lost River 345</td><td rowspan="4"></td><td rowspan="4"></td></tr>
<tr><td>Bloomington 230-138</td><td>162</td><td>107.90 %</td></tr>
<tr><td>Bedford–HE Owen 138</td><td>135</td><td>116.40 %</td></tr>
<tr><td>Bloomington NW-Bloomington 138 kV</td><td>143</td><td>123 %</td></tr>
<tr><td rowspan="2">CIN</td><td rowspan="2">2009</td><td rowspan="2">Dresser 345-138 #1</td><td rowspan="2">478</td><td>116.00 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV</td><td></td><td></td></tr>
<tr><td>109.90 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga–Sugar Creek 345 kV</td><td></td><td></td></tr>
<tr><td rowspan="3">CIN</td><td rowspan="3">2009</td><td rowspan="3">Dresser 345-138 #2</td><td rowspan="3">478</td><td>126 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Dresser 345-138 #1</td><td></td><td rowspan="3"></td></tr>
<tr><td>116 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga–Cayuga CT 345 kV</td><td></td></tr>
<tr><td>110 %</td><td>C</td><td>Merom–Worthington–Bloomington 345 kV & Cayuga CT–Sugar Creek 345 kV</td><td></td></tr>
</table>

| Table 6.1-9 (cont.): Cinergy - Phase 2 Results | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
| CIN | 2009 | Wabash River-Stauton 230 kV | 401 | 100 % | C | Worthington–Bloomington 345 kV & Lost River–Petersburg 345 kV | | |
| | | | | 100 % | C | Worthington–Bloomington 345 kV & Noblesville–Geist 230 | | |
| | | | | 101 % | C | Merom–Worthington 345 kV & Clinton–Wabash River 230 kV | | |
| | | | | 102 % | C | Merom–Worthington 345 kV & Kokomo–Thorntown 230 kV | | |
| | | | | 105 % | C | Merom–Worthington 345 kV & Bedford–Gibson 345 kV | | |
| | | | | 107 % | C | Merom–Worthington 345 kV & Nucor–Whitestown 345 kV | | |
| | | | | 108 % | C | Clinton–Wabash River 230 kV & Wabash River–Whitestown 230 kV | | |
| | | | | 109 % | C | Merom–Worthington–Bloomington 345 kV & Thorntown–Whitesville 230 kV | | |
| | | | | 112 % | C | Merom–Worthington-Bloomington 345 kV & Nucor–Cayuga 345 kV | | |
| | | | | 115 % | C | Merom–Worthington–Bloomington 345 kV & Wabash River–Whitesville 230 kV | | |
| CIN | 2009 | Gibson–Petersburg 345 | 1200 | 100 % | C | Bedford–Gibson 345 kV & Gibson–Duff 345 kV | | |
| CIN | 2009 | Pierce 345-138 kV | 302 | 102.80 % | C | East Bend–Terminal 345 & Pierce–Foster 345 | | |
| CIN | 2009 | Bloomington West–Whitehall 138 kV | 143 | 100.50 % | C | Merom–Worthington 345 kV & Columbus–Bedford 345 kV | | |
| CIN | 2009 | Ashland–Red Bank 138 kV | 300 | 115.40 % | C | Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie | | |
| | | | | 102.20 % | C | Red Bank 345 kV bus tie & Red Bank–Terminal 345 kV | | |
| CIN | 2009 | Augustine–Wilder 138 kV | 314 | 101.10 % | C | Clifty–Dearborn 345 kV & Red Bank–Silver Grove 345 kV | | |
| | | | | 104.00 % | C | Pierce–Foster 345 kV & Red Bank–Silver Grove 345 kV | | |
| | | | | 101.50 % | C | E Bend–Terminal 345 kV & Red Bank–Silver Grove 345 kV | | |
| | | | | 101.40 % | C | Foster–Hilcrest 345 kV & Red Bank–Silver Grove 345 kV | | |
| | | | | 102.50 % | C | Miami For–Terminal 345 kV & Red Bank–Silver Grove 345 kV | | |

| Table 6.1-9 (cont.): Cinergy - Phase 2 Results | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Area** | **Model Year** | **Limiter Element** | **Rating** | **Contingent Level (%, PU)** | **Con. Type** | **Contingency** | **Plan Status** | **Project to Address Limiter** |
| CIN | 2009 | Augustine–Wilder 138 kV | 314 | 100.70 % | C | Port Union–Terminal 345 kV & Red Bank–Silver Grove 345 kV | | |
| CIN | 2009 | Augustine–Wilder 138 kV | 314 | 104.50 % | C | Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie | | |
| CIN | 2009 | Augustine–Wilder 138 kV | 314 | 100.70 % | C | Red Bank–S. Grove 345 kV & Woodsdale–Madison 345 kV | | |
| CIN | 2009 | Beckjord–Tabasco 138 kV | 344 | 102.40 % | C | Red Bank–Terminal 345 kV & Red Bank–Silver Grove 345 kV | | |
| CIN | 2009 | Buffington–Hands 138 kV | 201 | 102.20 % | C | Port Union–Zimmer 345 & Red Bank-S. Grove–Zimmer 345 kV | PR2 | Uprate the line to 309 MVA in 2007. BR_ID: 1303 |
| CIN | 2009 | Buffington–Hands 138 kV | 201 | 99.10 % | C | Red Bank–Terminal 345 & Red Bank–S. Grove–Zimmer 345 kV | PR2 | Uprate the line to 309 MVA in 2007. BR_ID: 1303 |
| CIN | 2009 | Buffington–Hands 138 kV | 201 | 105.50 % | C | Red Bank–Terminal 345 & S.Grove–Zimmer 345 kV | PR2 | Uprate the line to 309 MVA in 2007. BR_ID: 1303 |
| CIN | 2009 | Red Bank 345-138 | 440 | 125.50 % | C | Port Union–Zimmer 345 kV & Red Bank 345 kV bus tie | | |
| CIN | 2009 | Terminal 345-138 #1 | 478 | 110.60 % | C | Red Bank–Terminal 345 kV & Red Bank-S. Grove–Zimmer 345 kV | | |
| CIN | 2009 | Terminal 138 kV bus tie | 478 | 107.80 % | C | Red Bank–Terminal 345 & Red Bank–S. Grove-Zimmer 345 | | |
| CIN | 2009 | Terminal 138 kV bus tie | 478 | 106.30 % | C | Red Bank-Terminal 345 & S. Grove–Zimmer 345 | | |
| CIN | 2009 | Terminal 345-138 #2 | 478 | 101.00 % | C | Red Bank–Terminal 345 & Red Bank-S. Grove-Zimmer 345 | | |
| CIN | 2009 | Terminal 345-138 #2 | 478 | 100.40 % | C | Red Bank–Terminal 345 & S. Grove-Zimmer 345 | | |
| CIN | 2009 | Todhunter 345-138 transformer and 138 kV bus tie | 478 | 105.80 % | C | Foster–Todhunter 345 & Todhunter 345-138 | | |
| CIN | 2009 | Todhunter–Woodsdale 345 kV #2 | 1315 | 110.90 % | C | Miami Fort–Terminal 345 kV & Todhunter–Woodsdale 345 kV #1 | | |
| CIN | 2009 | Five Points 230 kV | | 0.8868 | C | Eugene–Cayuga Sub 345 & Cayuga–Nucor 345 kV | | Change LTC tap |
| CIN | 2009 | Five Points 230 kV | | 0.8899 | C | Hanna–Francis–Petersburg 345 & Petersburg–Thompson 345 | | Change LTC tap |

With the Proposed projects or operating procedures implemented, most of the NERC Category B thermal violations were gone in the Indiana and Cincinnati area, except Ashland-Red Bank 138 kV facility. This facility is an underground cable so increasing capacity is a very expensive option. Cinergy is aware of this contingency overload and is currently evaluating solution alternatives with Midwest ISO.

For NERC Category C events, Phase 2 study not only included the events that were studied in Phase 1, but also included double contingencies that have terminal voltage 200 kV and above.

The outstanding issues in Cinergy include a NERC Category B violation and several NERC Category C violations.

Several NERC Category C events result in lines with contingeny loading over the cascading trip proxy. Tripping the overloaded line will result in no other loadings over the cascading trip proxy. These constraints will be reviewed in future studies by Midwest ISO and Cinergy. Additional information on these events is provided in the ECAR Region study details appendix.

Dresser 345-138 kV transformer - Project to replace limiting equipment (breakers and switches) to achieve full transformer rating will be included in next revision of Appendix A.

## VECTREN

The following table summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**VECTREN - Phase 1 Results**

There are no limiting facilities identified in Phase 1 study.

**Table 6.1-10: VECTREN - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Vectren | 2009 | Northwest–AB Brown 138 | 275 | 103.2 % | B | Northeast–AB Brown 138 | | Loading reduced to 98 % by bypassing AB Brown–Henderson reactor |

There is no outstanding issue after including Planned/Proposed facilities and operating procedure.

## LGEE

LGEE area includes Louisville metro area and Lexington area. Major new projects in LGEE area is the Trimble County #2 750 MW generator outlet which requires the construction of 43 miles of 345 kV line from the Mill Creek substation to the Hardin County substation, constructing three 138 kV lines Elizabethtown-Hardin, W. Frankfort-Tyron, and W. Lexington-Higby Mill.

The following tables summarize system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**Table 6.1-11: LGEE - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| LGEE | 2009 | Trimble County 345-138 kV | 258 | 109 % | C | Middletown–Bluelick 345 kV / Bluelick 345-138 kV & Middletown–Mill Creek 345 kV | | did not show in Phase 2 |

**Table 6.1-12: LGEE - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| LGEE | 2009 | Middletown–3842 Tap 138 | 287 | 105.90 % | B | Blue Lick–Middletown 345 / Blue Lick 345-138 | | |
| | | | | 101.20 % | B | Ashbottom–Grade 138 | PR2 | upgrade the terminal device |
| | | | | 106.30 % | B | Blue Lick 345-138 kV | | |
| LGEE | 2009 | Hardin 345-138 #1 | 344 | 104.50 % | B | Hardin 345-138 #2 | PR2 | upgrade the terminal device |
| LGEE | 2009 | Knob Creek / Pond Creek 138 kV | | 0.893 pu | B | Knob Creek–Mill Creek 138 kV | PR2 | add capacitors |
| LGEE | 2009 | Middletown-3842 Tap 138 | 287 | 102.50 % | C | Blue Lick–Middletown 345 & Blue Lick–Mill Creek 345 kV | PR2 | Upgrade the terminal device |
| LGEE | 2009 | Carrollton–Dow Corning 138 | 173 | 125.10 % | C | Ghent–W Lexington–Brown N 345 & Ghent-W Frankfort 345 / Frankfort 345-138 | | |
| | | Dow Corning–Dayton Walther 138 | 195 | 123.70 % | | | | |
| | | Dayton Walther–Nas 138 | 204 | 121.40 % | | | | |
| | | Carrollton–Lockport 138 | 172 | 106.80 % | | | | |
| | | Ghent–Nas 138 | 277 | 98.30 % | | | | |
| | | Owen County Tap–Scott Co. 138 | 194 | 112.20 % | | | | |
| LGEE | 2009 | Adams–Tyrone 138 | 139 | 101.50 % | C | Ghent-W Lexington–Brown N 345 & Ghent–Midway-W. Lexington 138 | | |
| | | OC Tap–Scott 138 | 194 | 98.90 % | | | | |

### LGEE - Outstanding Issues

LGEE proposed three projects in Phase 2 study, including: upgrading Middletown–3842 Tap 138 kV line terminal devices, upgrading Hardin transformer terminal devices and adding capacitors at Knob Creek / Pond Creek area. However these projects have not been submitted to MTEP Appendix A. Outage of multiple system elements may result in potential local area cascading and loss of load. Additional information is provided in the ECAR Region study details appendix.

For outage of Ghent–W. Lexington–Brown N 345 kV & Ghent–W. Frankfort 345 / W. Frankfort 345-138, there is no cascading after level 1 tripping. Dispatch Brown CT could alleviate overloading.

# IPL

## IPL - Phase 1 Results

IPL system was not documented in Phase 1 due to the lack of IPL participant in Midwest ISO RSG. The system was studied in Phase 2.

**Table 6.1-13: IPL - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| IPL | 2009 | South–Stouts 138 | 245 | 103.50 % | A | Base Case | | IPL manages internal 138 kV loads through internal area 216 switching |
| | | | | 100.30 % | B | Hanna–Francis–Petersburg 345 | | |
| | | | | 111 % | B | Hanna–Stout 345 / Hanna 345-138 | | |
| | | | | 99 % | B | Hortonville–Whitestown 345 | | |
| | | | | 101.10 % | B | Hanna–Stout 345 | | |
| | | | | 109 % | B | Hanna 345-138 | | |
| | | | | 106 % | B | Airco–Southeast 138 | | |
| | | | | 107.60 % | B | Airco–Stouts 138 | | |
| | | | | 104.10 % | B | Prospect–Center 138 | | |
| | | | | 104.60 % | B | Stouts–Center 138 | | |
| | | | | 109.20 % | B | Hanna–Franklin Township 138 | | |
| | | | | 98.30 % | B | Gardner Lane–Sheffield 138 | | |
| | | | | 98.30 % | B | Guion–Tremont 138 | | |
| IPL | 2009 | Guion–Tremont 138 | 276 | 101.60 % | B | Gwynneville–Sunnyside 345 / Sunnyside 345-138 | | IPL manages internal 138 kV loads through internal area 216 switching |
| | | | | 98.90 % | B | Hanna–Stout South-Thompson 345 / Stout South 345-138 | | |
| | | | | 98.40 % | B | Hortonville–Noblesville 345 | | |
| | | | | 100.80 % | B | Hortonville–Whitestown 345 | | |
| | | | | 99.40 % | B | Stout–Thompson 345 | | |
| | | | | 101.70 % | B | Sunnyside 345-138 | | |
| | | | | 107.20 % | B | Castleton–River Road 138 | | |
| | | | | 102 % | B | Guion–Crestview 138 | | |
| | | | | 109.20 % | B | East–Parker 138 | | |
| | | | | 103.90 % | B | Geist–Sunnyside 138 | | |
| IPL | 2009 | Pritchard–Centerton 138 kV | | 100.80 % | A | Base Case | | This facility is overloaded due to a fictitious generation at Centerton. |
| | | | 245 / 286 | 116 % | C | Bloomington–Worthington 345 & Merom–Dresser 345 | | |
| IPL | 2009 | Petersburg–Thompson 345 | 956 | 106.20 % | C | Petersburg–Hanna 345 & Breed–Wheatland 345 | | MISO curtail system transactions to relieve overloads |
| IPL | 2009 | Petersburg 345-138 E | 150 | 99.80 % | C | Hanna–Francis–Petersburg 345 & Petersburg–Thompson 345 | | MISO curtail system transactions to relieve overloads |
| IPL | 2009 | Guion-Tremont 138 | 245 | 105.50 % | C | DCT of Hanna–Fransis–Petersburg 345 & Hanna–Stouts 345 | | IPL manages internal 138 kV loads through internal area 216 switching |
| | | | | 99.80 % | C | Fall Creek-Sunny side 345 & Gwynville–Sunnyside 345-Hanna 345 / Sunnyside 345-138 | | |

**Table 6.1-13 (cont.): IPL - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| IPL | 2009 | Guion–Tremont 138 | 245 | 98.20% | C | Hanna–Francis Creek–Petersburg 345 & Hanna 345-138 #E & #W | | IPL manages internal 138 kV loads through internal area 216 switching |
| | | | | 106% | C | Hanna–Francis–Petersburg 345 & Noblesville–Hortonville–Whitestown 345 | | |
| | | | | 110.80% | C | Hanna–Francis–Petersburg 345 & Hanna-Stout–Thompson 345, Hanna 345-138, Stout 345-138 | | |
| | | | | 109% | C | Hanna–Stout 345 & Noblesville–Hortonville–Whitestown 345 | | |
| IPL | 2009 | Hanna–SE 138 | 286 | 116.00% | C | Guion–Rock Ville–Thompson 345 & Hanna–Sunny Side 345 | | Solutions for this overload include breaker CT changes scheduled before 2010 depending on construction forecast and budgetary concerns. |
| IPL | 2009 | South–Stouts 138 | 276 | 121.00% | C | DCT of Hanna–Francis–Petersburg 345 & Hanna–Stouts 345 | | IPL manages internal 138 kV loads through internal area 216 switching |
| | | | | | | | | |
| | | | | 98.20% | C | Petersburg–Hanna 345 & Breed–Wheatland 345 | | |
| | | | | 98.00% | C | Bedford–Gibson 345 & Bedford–Lost River 345 | | |
| | | | | 101.00% | C | Hanna–Francis Creek–Petersburg 345 & Hanna 345-138 #E & #W | | |
| | | | | 107.30% | C | Hanna–Francis–Petersburg 345 & Noblesville–Hortonville–Whitestown 345 | | |
| | | | | 99.40% | C | Hanna–Francis–Petersburg 345 & RockVille–Thompson 345/Hanna 345-138 | | |
| | | | | 102.50% | C | Hanna–Francis–Petersburg 345 & Hanna-Stout–Thompson 345, Hanna 345-138, Stout 345-138 | | |
| | | | | 123.90% | C | Hanna–Stout 345 & Noblesville–Hortonville–whitestown 345 | | |

## IPL - Outstanding Issues

South–Stouts 138 kV line and Guion–Tremont 138 kV lines are frequently overloaded for NERC Category B and Category C events. The overloading is due to the fact IPL area has 18% load increase from 2004 summer to 2009 summer.

Petersburg–Thompson is overloaded to 106% for NERC Category C contingency Petersburg–Hanna 345 kV & Breed–Wheatland 345 kV. Operating procedure should be adopted to relieve the overloading. Hanna–Southeast 138 kV is overloaded to 116% for NERC Category C contingency Guion–RockVille–Thompson 345 kV & Hanna–Sunny Side 345 kV. Solutions for this overload include breaker CT ratio changes and is scheduled before the 2010 year depending on construction forecast timing and budgetary concerns.

## NIPSCO

The following table is a list of violations identified in Phase 1 of the 2009 summer study. Prior to the 2004 operating season NIPSCO reviewed circuits that were identified in the MTEP study to operate at a higher temperature. The new circuit ratings mitigate those thermal violations. The proposed project to re-conductor Leesburg to Northeast 138 kV still remains. Midwest ISO will be monitoring this circuit for resolution.

**Table 6.1-14: NIPSCO - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| NIPS | 2009 | Schahfer Tap–Starke 138 kV | 156 | 102 % | B | Flint Lake-Tower Road 138-kV | PR2 | Rating upgrade – reviewed circuit to operate at a higher temperature. |
| | | Liberty Park–St. John 138 kV | 156 | 105 % | B | Hartsdale–St. John 138 kV | PR2 | Rating upgrade – reviewed circuit to operate at a higher temperature. |
| | | | 156 | 103 % | B | Green Acres–St. John 138 kV | | |
| | | Northeast–Goshen Jct. 138 kV | 253 | 114 % | B | Hiple–Collinwood 345 kV & Hiple 345-138 kV XFR | PR2 | Rating upgrade – reviewed circuit to operate at a higher temperature. |
| | | Leesburg–Northeast 138 kV | 222 | 100 % | B | Hiple–Collinwood 345 kV & Hiple 345-138 kV XFR | PR2 | Proposed project to re-conductor in 2007 summer. |
| | | Northeast–Goshen Jct. 138 kV | 253 | 112 % | B | Hiple–Leesburg 345 kV & Hiple 345-138 kV XFR | PR2 | Rating upgrade – reviewed circuit to operate at a higher temperature |
| | | Leesburg–Northeast 138 kV | 222 | 101 % | B | Hiple–Leesburg 345 kV & Hiple 345-138 kV XFR | PR2 | Proposed project to re-conductor in 2007 |
| | | Reynolds 345-138 kV | 224 | 116 % | C | Olive–Dequine–Westwood 345 kV & Westwood 345-138 | PR | Westwood–Dequine 345 kV line and Westwood 345/138 TX 2 |

**NIPSCO - Phase 2 Results**

With the planned and proposed projects, there are no limiting facilities identified in NIPSCO system.

## METC

As indicated in Appendix A, planned and proposed projects in the METC system from 2004 to 2009 include:

- Three new 345/138 kV transformers and associated switching
- Over 200 miles of new, rebuilt or reconductored 138 kV lines
- Over 900 Mvar of capacitor additions
- Numerous circuit up-rates resulting from improving sag clearance and terminal upgrades.

In the Midwest ISO Baseline 2009 summer peak model, the 46 kV and 69 kV systems connected to the METC system were not modeled. This is typical for models prepared for regional transmission system assessments used to identify regional limitations and constraints. However, the looped sub-transmission system provides significant support to the transmission system. Therefore, this Baseline model did not contain sufficient detail in portions of the METC area to provide accurate results when modeling facility outages at the 138 kV transmission level. The consequence of this modeling assumption is that some post-contingency conditions show more voltage violations when studies on the Midwest ISO Baseline case than those indicated in the more detailed METC planning model. Therefore, the METC detailed powerflow model was used by Midwest ISO in Phase I to determine the system support provided by the sub-transmission system for certain contingencies.

Only NERC Category B contingencies were studied in Phase I.

**Table 6.1-15: METC - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| METC | 2009 | Amber 138 | | 0.92 pu | B | Pere Marquette–Amber 138 | PR2 | Gallagher Cap (36 MVAR) DV_ID: 1078 |
| | | Bagley 138 | | 0.866 pu | | Gaylord–Livingston 138 | | |
| | | Bard Road 138 | | 0.91 pu | | Gallagher–Bard Road 138 kV | | |
| | | Clare 138 | | 0.72 pu | | Bullock–Edenville-Warren 138 | | |
| | | Begole 138 | | 0.917 pu | | Begole–Tittabawassee 138 | | |
| | | Evart Products 138 | | 0.91 pu | | Cobb–Brickyard J.–Felch Road 138 | | |
| | | Evart Products 138 | | 0.9167 pu | | Croton–Nineteen Mile–Mecosta 138 kV | | |
| | | McGulpin 138, Straints 138 | | 0.916 pu | | Livingston–Riggsville 138 or Riggsville–McGulpin 138 | | |
| | | Iosco 138 | | 0.89 pu | | Karn–Iosco 138 | | |
| METC | 2009 | Battle Creek–Verona 138 #1 | 309.3 | 99 % | B | Battle Creek–Verona 138 #2 | PR2 | Battle Creek–Verona 138 kV #1 Line, Remove Sag Limit BR_ID: 1317 |
| METC | 2009 | Battle Creek–Verona 138 #2 | 309.3 | 106 % | B | Battle Creek–Verona 138 #1 | PR2 | Battle Creek–Verona 138 kV #2 Line, Remove Sag Limit BR_ID: 1317 |
| METC | 2009 | Piston Ring, Cedar Spring 138 | | 0.88 pu | B | Four Mile–Piston Ring 138 | PL | Four Mile–Algoma 138 ckt 1 BR_ID: 515 |
| METC | 2009 | Brickyard–Felch Road 138 | 139.3 | 101 % | B | Four Mile–Piston Ring 138 | PR2 | Brickyard–Felch Rd 138 kV reconductor to 795 ACSS and CT Tap change BR_ID: 1336 |
| METC | 2009 | Brickyard-Felch Road 138 | 139.3 | 101 % | B | Hull Street-Englishville-Piston Ring 138 | PR2 | Brickyard - Felch Rd 138 kV reconductor to 795 ACSS and CT Tap change BR_ID: 1336 |

| Table 6.1-15 (cont.): METC - Phase 1 Results | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
| METC | 2009 | Campbell–Hudsonville 138 | 309.3 | 117 % | B | Plaster Creek–Kentwood 138 | PR2 | Campbell–Hudsonville 138 kV line, Remove Sag limit BR_ID: 1342” |
| METC | 2009 | Cobb–Sternberg 138 | 189.5 | 114 % | B | Campbell–Black River 138 | | |
| METC | 2009 | Savidge–Sternberg 138 | 189.5 | 112 % | B | Campbell–Black River 138 | | |
| METC | 2009 | Croton–Felch Road 138 | 86.1 | 120 % | B | Four Mile–Piston Ring 138 | PL2 | Croton–Felch Rd. 138 kV line reconductor BR_ID: 1318 |
| METC | 2009 | Croton–Felch Road 138 | 86.1 | 125 % | B | Hull Street–Englishville–Piston Ring 138 | PL2 | Croton–Felch Rd. 138 kV line reconductor BR_ID: 1318 |
| METC | 2009 | Croton B–Croton W 138 | 86.1 | 102 % | B | Four Mile–Piston Ring 138 | PR2 | Croton 138 kV breaker |
| METC | 2009 | Tippy–Hodenpyl 138 kV | 219 | 114 % | B | Keystone–Ludington 345 kV line | PR | Tippy–Hodenpyl 138 ckt 1, reconductor 795 ACSS BR_ID: 535 |
| METC | 2009 | Hudsonville–Jamestown 138 | 309.3 | 101 % | B | Plaster Creek–Kentwood 138 | PR2 | Hundersonville–Jamestown 138 kV line |
| METC | 2009 | James 138 Substation (City of Holland) | | 0.88 pu | B | Campbell–Black River 138 | PR2 | Black River Cap addition DV_ID: 46 |
| METC | 2009 | Kenwood 138 | | 0.9155 pu | B | Plaster Creek–Kenwood 138 kV | PR2 | Add Distribution Capacitors Bank (at Bayberry or Kenwood or Buck Creek) |
| METC | 2009 | Lowell–Marquette 138 | 268.9 | 99 % | B | North Belding–Vergennes 138 | PR2 | Lowell–Marguette, Change open-leg ratings at Marquette |
| METC | 2009 | Michigan Ave 138 | | 0.91 pu | B | Coldwater–Project 138 | PR2 | Batavia Capacitor Additions DV_ID: 1077 |
| METC | 2009 | North Belding–Sanderson–Eureka 138 kV | 209.9 | 110 % | B | Tittabawassee 345-138 #1 or #2 | PR2 | North Belding–Sanderson–Eureka reconductor to 795 ACSS and N Beld CT Tap to 1200 A BR_ID: 1331 |
| METC | 2009 | North Belding–Vergennes 138 | 239 | 124 % | B | Vergennes–Lowell-Marquette 138 | PR2 | Vergennes–North Belding 138 kV terminal upgrade |
| METC | 2009 | Rifle River, Simmons, Ogemaw 138 | | 0.90 pu | B | Gallagher 345-138 #2 | PR2 | Gallagher Cap (36 MVAR) DV_ID: 1078 |
| METC | 2009 | Summerton 138, Bluegrass 138 | | 0.91 pu | B | Bullock–Summerton 138 | PR2 | Alma Capacitor Additions DV_ID: 1076 |
| METC | 2009 | Tallmadge–Wealthy Street #2 | 358.5 | 101 % | B | Tallmadge–Wealthy Street #1 | PR2 | Wealthy Street sub Replace CT's BR_ID: 1322 |
| METC | 2009 | Thetford–Delaney 138 | 286.7 | 108 % | B | Hemphill–Thetford 138 | PR2 | Thetford–Delaney line, change CT Tap at Delaney and Remove Sag Limit BR_ID: 1352 |
| METC | 2009 | Tittabawassee 345-138 #1 | 610 | 110 % | B | Tittabawassee 345-138 #2 | PR2 | Tittabawassee 5 Ohm Reactors (add) BR_ID: 1315 |
| METC | 2009 | Tittabawassee 345-138 #2 | 601 | 106 % | B | Tittabawassee 345-138 #1 | PR2 | Tittabawassee 5 Ohm Reactors (add) BR_ID: 1315 |
| METC | 2009 | Tittabawassee-Dow Corning 138 | 358.5 | 103.50 % | B | Bullock-Tittabawassee 138 | PR2 | Tittabawassee–Dow Corning–Change Open Leg Rating at Tittabawassee |

In Phase 2 study, both NERC category B and NERC category C contingencies were analyzed, including double contingencies which have terminal bus voltage 345 kV and double contingencies that share same buses at 138 kV level.

**Table 6.1-16: METC - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| METC | 2009 | Cobb–Sternberg 138 | 181 | 115.7 % | B | Campbell–Northern Fibre –Black River 138 | | 87.5 % loading in the new model |
| | | Savidge–Sternberg 138 | | 114.9 % | | | | |
| | | Plaster–Kent–Buck Creek | 360 | 106.2 % | B | Campbell–Hudsonville 138 | | 93.3 % loading in the new model |
| | | Cole Creek–Dort 138 | 192 | 121.2 % | B | Goss–Beveridge 138 | | |
| | | James 138 kV substation | | 0.9272 pu | B | Campbell–Northern Fiber 138 | | 0.9929 pu in the new model |

The above table summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into this Midwest ISO study Baseline model.

METC also tested (and Midwest ISO verified) these single contingencies on the newly developed regional model with the Consumers Energy and Wolverine 46 kV and 69 kV systems equivalized in the case. Including these equivalized models in the case eliminated the remaining loading concerns.

The major load centers in the METC system are: Kalamazoo/Battle Creek area, Grand Rapids area, Midland/Bay City/Saginaw area and Flint area. Its Northern area is predominately rural with sparsely distributed loads.

The following study results for METC Double Contingencies reported here were based on the Midwest ISO 2009 Baseline model which did not include the 46/69 kV system equivalent. The severity of the reported problems should be reduced with equivalent looped sub-transmission system modeled as was shown in the single contingency test. Time did not permit rerunning all double contingency studies on the revised case with the improved model.

**Table 6.1-17: METC- Double Contingencies Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| **Kalamazoo/Battle Creek Area** | | | | | | | | |
| METC | 2009 | Argenta 345/138 #3 | 549.8 | 137.90% | C | Argenta 345/138 #1 & #2 | PL2 | The Weeds Lake 345-138 kV Substation |
| | | Argenta 345/138 #2 | 602 | 126.70% | C | Argenta 345/138 #1 & #3 | PL2 | |
| | | Agenta 345/138 #1 | 602 | 126.50% | C | Argenta 345/138 #2 & #3 | PL2 | |
| | | Aubil Lake Jct–Gaines 138 kV | 195 | 107.10% | C | Argenta–Morrow 138 & Argenta–Riverview 138 | PL2 | |
| | | Morrow–ParkVille Jct 138 kV | 320.5 | 105.30% | C | DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138 | PL2 | |
| | | Upjohn 138 kV bus tie | 256.5 | 120.60% | C | DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138 | PL2 | |
| | | | 280.2 | 131.70% | | DCT Argenta–Drake Rd 138 & Argenta–Lindbergh 138 | | |
| | | Battle Creek–Verona 138 kV #1 | 361.4 | 106.80% | C | Verona–Argenta 138 & Verona–Battle Creek 138 #2 | | |
| | | Milham 138 kV bus tie | 115.2 | 100.30% | C | Up John–Milham 138 kV & Up John 138 kV bus tie | | |
| **Grand Rapids Area** | | | | | | | | |
| METC | 2009 | Alpine–Cannon 138 kV | 209.9 | 124.50% | C | Vergennes–Lowell–Marquette 138 & Vergennes–North Belding 138 | | Load tripping |
| | | Alpine–Four Mile 138 kV | 263 | 105.80% | | Vergennes–Lowell–Marquette 138 & Vergennes–North Belding 138 | | |
| | | Cannon–Cowan Lake 138 kV | 209.9 | 104.40% | | Vergennes–Lowell-Marquette 138 & Vergennes–North Belding 138 | | |
| | | Campbell 345/138 kV transformer Four Mile 138 kV bus tie | 629 | 130.50% | C | DCT of Campbell–Tallmadge 345 & Campbell–Roosevelt 345 (operating procedure) | | |
| | | | 329.9 | 112.30% | | Tallmadge–Wealth St. #1 & #2 | | |
| | | Four Mile–Tallmadge 138 kV | 468.4 | 104.20% | | Tallmadge–Wealth St. #1 & #2 | | |
| | | Gaines–Meadowbrook 138 kV | 521 | 100.70% | | Campbell–Hudsonville 138 & Campbell–Port Sheldon 138 | | |
| | | Gaines–Meadowbrook 138 kV Lowell–Marquette 138 kV | 521 | 106.50% | | Vergennes 345/138 kV #1 & #2 | | |
| | | | 312.1 | 104.80% | | North Belding–Vergennes 138 & North Belding–Cowan Lake 138 | | |
| | | Mullins–Wealthy St. 138 kV | 289.7 | 100.70% | C | Four Mile–Tallmadge 138 & Four Mile–White Road 138 | PR2 | Mullins–Wealthy 138 kV rebuild in 2007 BR_ID: 1330 |
| | | Tallmadge–Wealthy St. 138 kV #1 | 518.7 | 102.40% | C | Tallmadge–Wealthy St. #2 & Tallmadge–Four Mile 138 | | |
| | | Tallmadge–Wealthy St. 138 kV #2 | 518.7 | 101.90% | C | Tallmadge–Wealthy St. #1 & Tallmadge–Four Mile 138 | PR2 | BR_ID: 1322 |

**Table 6.1-17 (cont.): METC- Double Contingencies Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| **Grand Rapids Area (cont.)** | | | | | | | | |
| METC | 2009 | Croton–Nineteen Mile 138 kV | 111 | 121.90 % | C | DCT of Keystone–Ludington–Pere Marquette 345 & Pere Marquette 345-138 #2 | | |
| | | Alba–Stover 138 kV | 180.5 | 103.40 % | C | Keystone 345 / 138 #1 & #2 | PR2 | Stover–Livingston 138 kV reconductored |
| | | Alba–Livingston 138 kV | | 133.10 % | | | | |
| | | Clearwater–Keystone 138 kV | 180.5 | 101.90 % | C | Livingston 345 / 138 #1 & #2 | PR2 | Clearwater–Keystone 138 kV rebuild in 2009 BR_ID: 1347 |
| | | Livingston–OTSE 138 kV | 130 | 103.10 % | C | Livingston 345 / 138 #1 & #2 | | |
| | | Emmet county | | Oden 138 kV (0.8696) | C | Livingston–Emmet 138 & Livingston peak off | | Under-voltage relaying at Oden would be expected to trip the Oden load if the voltage got this low. |
| | | Iosco, E. Tawas, Cottage Grove | | Cottage Grove 138 kV (0.9014) | C | Karn–Cottage Grove 138 kV with another source | | |
| **Midland / Bay City / Saginaw area** | | | | | | | | |
| METC | 2009 | Bullock–Dow Corning 138 kV | 329.9 | 101.40 % | C | Breaker failure: Tittabawassee–Bullock 138 & Tittabawassee–Begole | | |
| | | Claremont–Manning 138 kV | 309.3 | 149.40 % | C | Tittabawassee 345 / 138 #1 &#2 | | |
| | | Hackett–Saginaw River 138 kV | 192.2 | 145.50 % | | | | |
| | | Hackett–Saginaw River 138 kV | 192.2 | 101.40 % | C | Tittabawasee-Bullock 138 & Tittabawassee-Dow Corning 138 | | |
| **Flint Area** | | | | | | | | |
| METC | 2009 | Garfield Ave.–Hemphill 138 | 216.8 | 145.20 % | C | DCT of Thetford–Delaney 138 & Thetford–Hemphill 138 | PL2 | Garfield–Hemphill 138 rebuild in 2008 BR_ID:_336 |
| | | Duffield–Goss 138 kV | 260.1 | 102.20 % | C | Dort bus tie & Dort–Thetford 138 | | |
| | | Cole Creek–Dort 138 kV | 192.1 | 128.30 % | C | Goss–Duffield–Stacey-Beveridge 138 kV | | |
| | | Cole Creek–Dort 138 kV | 192.1 | 129 % | C | Goss–Beveridge 138 & Goss–Cornell 138 | | |
| | | Cole Creek–Dort 138 kV | 192.1 | 128.40 % | C | Goss–Beveridge 138 & Goss 345 / 138 kV | | |
| | | Cole Creek–Dort 138 kV | 192.1 | 128.40 % | C | Breaker failure: Goss–Beveridge 138 & Goss–Pasadena-Dort 138 | | |
| | | Hemphill 138 kV bus tie | 192.2 | 101.50 % | C | Hemphill–Thetford 138 & Hemphill–Neff Rd 138 | PR2 | BR_ID:_1320 |
| | | Goss 345 / 138 #1 | 595 | 109 % | C | Thetford 345 / 138 #3 & #4 | | |

## Kalamazoo/Battle Creek Area

The load of this area is mainly supported by Argenta 345 kV substation and Battle Creek 345 kV substation while power comes through 345 kV circuits from power plants at west: Palisades, Covert, and Benton Harbor IPP. Loss of Argenta substation is the most severe fault in this area. Loss of either two Argenta 345/138 kV transformers causes the remaining Argenta 345/138 transformer to be severely overloaded. Loss of double circuit tower Argenta-Drake Rd 138 kV & Argenta–Lindbergh 138 kV leaves the loads in Lindbergh/Bronco/Milham area fully dependant on the only 138 kV source from Morrow–Pavilion–Upjohn and overloads Morrow–Pavilion section and Upjohn 138 kV bus ties. The new Weeds Lake 345/138 kV Substation and transformer should take care of the overloads showed here.

The Verona area is supported mainly by power from two 138 kV lines from Battle Creek substation and one 138 kV line from Argenta substation. Loss of Battle Creek–Verona #2 line and Verona–Argenta line leaves Battle Creek-Verona #1 line overloaded to 107%.

Loss of Verona–Battle Creek 138 kV #1 circuit and Verona 138 kV bus tie left Elm St./Hughes Rd loads solely dependant on the only 138 kV source from Blackstone to Marshall to Hughes Rd. Blackstone–Marshall 138 kV circuit severely overloads to 169%. Tripping Blackstone–Marshall 138 kV line isolates Hughes Rd and Elm St. loads. No overloading was observed after the tripping.

## Grand Rapids Area

The Grand Rapids metro area is surrounded by a ring of double circuit 345 kV lines. Major 345 switching stations and 345/138 kV substations in this area include Kenowa, Tallmadge, Roosevelt, Gaines and Vergennes.

Four Mile 138 kV bus tie and Four Mile–Tallmadge 138 kV were observed to be overloaded for Tallmadge–Wealthy St. #1 & #2. Tallmadge–Wealthy St. 138 kV could be overloaded by the outage of Tallmadge–Four Mile and the other Tallmadge–Wealthy St. 138 kV line.

Vergennes–Lowell–Marquette could be overloaded up to 111% due to outage of North Belding–Vergennes 138 kV and North Belding–Cowan Lake and be overloaded to 102% due to outage of North Belding–Vergennes 138 kV & Vergennes–Spaulding 138 kV.

Loss of Vergennes–Lowell–Marquette 138 kV line and the Vergennes–North Belding 138 kV line results in the load east from Vergennes substation being fed by Four Mile 138 kV substation. The line from Four Mile–Alpine J.–Cannon J. could be overloaded. Consumer Energy has proposed to build a new 138/46 kV substation (Five Mile), new Four Mile substation, and redistribute their load in year 2006-2007 time frame. This project along with other area plans will be evaluated as METC gets closer to year 2009 to determine the most economic way to relieve this overload.

DCT outage of Campbell–Roosevelt 345 kV and Campbell–Tallmadge 345 kV caused the Campbell 345/138 kV transformer to be overloaded to 130% of the LTE rating. An STE rating and operating procedure have been established to protect for this condition. For trip of the bus tie, no overload over 125% was observed.

## Northern Area

Keystone is the major 345/138 kV station in the northwest METC area. Loss of two Keystone 345/138 kV transformer banks will lose all power transformation from large generation source connected to the 345 kV transmission grid. Should the first contingency occur operators will prepare for the next contingency. Dispatch local generation, turn on distribution capacitors and drop some local load may be needed. Additional capacitors at specific site locations will be planned and installed as METC gets closer to year 2009 to relieve the local low voltage condition.

## Midland/Bay City/Saginaw area

Tittabawassee is the major 345/138 kV station in the METC northeast area. It is the major station to step down MCV's generation to the 138 kV system. Loss of two Tittabawassee 345/138 kV transformer banks are severe N-2 contingency. Should the first contingency occur, operators will prepare for the next contingency. Re-dispatch MCV generation and other local generation, turn on distribution and bulk capacitors, reduce exports and drop some local load may be needed. METC continues to identify and propose specific projects to address the issue.

## Flint Area

Cole Crek–Dort 138 kV was found to be overloaded for several N-2 contingencies. With the underlying 46 kV system modeled, the overloading could be reduced. Note that all substations tapped from the outaged lines would be effectively load shed with automatic breaker action which would normally occur for METC 138 kV line outages.

The double circuit tower outage of the Thetford–Delaney and Thetford–Hemphill 138 kV circuits left Garfield Ave.–Hemphill 138 kV circuit severely overloaded. Tripping Garfield Ave.–Hemphill 138 kV circuit will overload Neff Road-Hemphill 138 kV. If this line is again tripped, Goss–Cornell–Tihart-Latson path will be overloaded. Tripping this path will isolate loads in the Oakland/Halsey area; thus the load shedding is limited only to this area.

# ITC

The following tables summarizes system performance issues that remained after submitted Planned and Proposed projects were inserted into the study model. Possible mitigation steps are indicated, and will be monitored by Midwest ISO for resolution.

**Table 6.1-18: ITC - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| ITC | 2009 | Placid, Proud, Prizm 120 | | 0.82 pu | B | Placid 345/120 | PL | PL: Placid 120 kV capacitor DV_ID: 88 |
| ITC | 2009 | Proud–Tamarack | 312 | 0.997 | B | Pontiac–Placid–Wixom 345 kV | CP2 | CP2: Placid–Walton 120 kV line 9.0 mile (new) (conceptual) BR_ID: 756 |
| | | Coventry–Tamarack | 343 | 0.988 | B | Pontiac–Placid–Wixom 345 kV | | |
| | | Proud end of Coventry–Proud-Wixom 120 kV | 343 | 100 % | C | Pontiac–Wixom 345 kV, Pontiac–Placid–Wixom 345 kV & Placid 345-120 kV | | |
| ITC | 2009 | Quaker 345-120 kV | 700 | 104 % | B | Wixom 345-120 kV | PL2 | Quaker project BR_ID: 757, 758, 759 |
| | | Wixom 345-120 kV | 624 | 109 % | B | Quaker 345-120 kV | | |
| | | Hines 230-120 kV | 405 | 102 % | A | Base Case | | |
| ITC | 2009 | Hancock–Southfield 120 kV, Hancock–Quaker 120 kV, Hancock–Wixom 120 kV | 222, 223, 445 | 118.90 % | C | Akron–Wixom & Quaker Tap to Quaker, Wixom and Wayne 345 kV | | |
| ITC | 2009 | Hancock–Southfield 120 kV, Hancock–Quaker 120 kV, Hancock–Wixom 120 kV | 222, 223, 445 | 114.00 % | C | Akron–Sunset& Quaker Tap to Quaker, Wixom and Wayne 345 kV | | |
| ITC | 2009 | Evergreen–Northwest 120 kV | 250 | 100.90 % | C | Wixom–Wayne & Quaker Tap to Quaker, Wixom and Wayne 345 kV | | |
| ITC | 2009 | Stephens 345-120 kV #301 | 624 | 111 % | B | Stephens 345-120 kV #303 | PL | Bismark–Golf 120 kV line. Project_ID: 518 Lenox Station. Project_ID: 509 |
| | | Stephens 345-120 kV #303 | 678 | 103 % | B | Stephens 345-120 kV #301 | | |
| | | Grayling, Malta, Victor, Augusta 120 kV | | 0.79 pu | B | Victor–Foundry–Jacob 120 | | |
| | | St. Clair–Jacob 120 kV | 249 | 125 % | C | St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV | | |
| | | Stephens–Benson–Macomb 120 kV | 312 | 149 % | C | St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV | | |
| | | St. Clair–Macomb 120 kV | 229 | 116 % | C | Beck–Stephens & Stephens–Benson-Macomb 120 kV | | |
| | | Golf/Boyne 120 kV | | 0.87 pu | C | St. Clair–Macomb 120 kV & St. Clair–Boyne 120 kV | | |
| | | Golf, Macomb, Boyne, Houston 120 kV buses | | 0.81 pu | C | Beck–Stephens & Stephens–Benson-Macomb 120 kV | | |
| ITC | 2009 | Macomb 120 area (Golf, Macomb, Boyne, Houston) | | 0.81 pu | B | Stephens–Macomb 120 | PL | Macomb 120 kV capacitor DV_ID: 87 |
| ITC | 2009 | Latson–Genoa 138 kV METC-ITC | 129 | 101 % | B | Madrid–Majestic 345 kV & Madrid 345-120 kV | PL | ITC–METC Interface Upgrade: BR_ID: 701 |
| ITC | 2009 | Lincoln–Northeast–Northwest 120 kV (Lincoln end) | 222.4 | 104 % | C | Bloomfield–Wheeler 120 kV & Bloomfield–Troy 120 kV | | |
| ITC | 2009 | Pontiac–Joslyn 120 kV | 416 | 106 % | C | Pontiac–Bloomfield 230 kV & Pontiac–Sunbird 120 kV | | |
| ITC | 2009 | Apache–Seneca 120 kV | 216 | 101 % | C | Troy–Wheeler 120 kV & Bloomfield-Troy 120 kV | | |
| | | | | 113 % | C | Bloomfield–Wheeler 120 kV & Bloomfield-Troy 120 kV | | |

**Table 6.1-18 (cont.): ITC - Phase 1 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| ITC | 2009 | Beck–Stephens 120 kV | 290 | 148 % | C | Erin–Stephens 120 kV #1 & #2 | CP2 | Stephens–Medina 120 kV new line 8.5 mile, Erie area in 2006 (conceptual) |
| | | Beck–Medina 120 kV | 244 | 154 % | | | | |
| ITC | 2009 | Spokane–Seneca 120 kV | 216 | 125 % | C | Troy–Wheeler 120 kV & Bloomfield–Troy 120 kV | PR2 | Spokane–Seneca - the limit on this circuit was a portion of underground cable. It was recently determined that the rating on this cable should be higher than the 216 MVA rating being used. |
| | | | | 138 % | C | Bloomfield–Wheeler 120 kV & Bloomfield–Troy 120 kV | | |

**ITC projects in Phase 2 include the following:**

- Placid–Walton: proposed project to create a 120 kV circuit from Placid to Walton.
- Quaker project is currently planned – it involves a 345/230 kV transformer at Wixom converting some 120 kV lines to 230 kV and creating Wixom–Quaker 230 kV and a 230/120 kV transformer at Quaker.
- Lenox (formerly called New Haven) project is planned. It involves building a new station west of the existing Victor site and creating a 120 kV bus group that ties together several 120 kV lines in the area. A 345/120 kV transformer will also be added.
- Bismarck–Golf project is planned. It involves creating a three ended Bismarck–Boyne–Macomb120 kV line by building a new 120 kV line from Bismarck to Golf. The proposal studied in this analysis involved building a switching station at Golf to avoid creating a three-ended line. The creation of the three-ended line is an interim step until the switching station can be constructed.
- ITC upgrades near it's METC interface include upgrading the Genoa 138-120 kV transformer, adding a reactor in Hunters Creek–Hemphill 138 kV, and upgrading the Atlanta 138-120 kV transformer.
- Add 54 MVAR capacitors at Placid 120 kV and Macomb 120 kV buses.
- Erin area: proposal to add 8.5 mile 120 kV new line from Stephens–Medina.

**Table 6.1-19: ITC - Phase 2 Results**

| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| ITC | 2009 | Madrid 345-120 #1 | 313 | 100.40 % | B | Cody-Nolan 120 kV | CP2 | Majestic 345-120 kV transformer and Majestic-Madrid, Majestic-Lark and Majestic-Phoenix 120 kV circuits BR_ID: 1377, 1378 |
| ITC | 2009 | Sterling 120 kV | | 0.89 pu | B | Jewell-Sterling 230 kV | CP2 | Add capacitors |
| | | | | 0.896 pu | B | Jewell 345-230 #3 | | |
| ITC | 2009 | Apache-Seneca 120 kV | 216 | 100.70 % | C | DCT Bloomfield-Troy 120 kV & Wheeler-Troy 120 kV | | |
| | | | | 113.10 % | C | DCT Bloomfield-Wheeler 120 kV & Bloomfield-Troy 120 kV | | |
| ITC | 2009 | Spokane-Seneca 120 kV | 290 | 102.80 % | C | DCT Bloomfield-Wheeler 120 kV & Bloomfield-Troy 120 kV | | |
| ITC | 2009 | Lincoln end of Lincoln-Northeast-Northwest 120 kV | 222 | 104.70 % | C | DCT Bloomfield-Wheeler 120 kV & Bloomfiled-Troy 120 kV | | |
| ITC | 2009 | Lincoln-Troy 120 kV | 196 | 102.40 % | C | DCT Bloomfield-Wheeler 120 kV & Bloomfiled-Troy 120 kV | | |
| ITC | 2009 | Bloomfield-Walton 120 kV | 312 | 101.50 % | C | DCT Bloomfield-Pontiac 230 kV & Pontiac-Sunbird-Colorado-Tienken 120 kV | | |

| Table 6.1-19 (cont.): ITC - Phase 2 Results | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Area | Model Year | Limiter Element | Rating | Contingent Level (%, PU) | Con. Type | Contingency | Plan Status | Project to Address Limiter |
| ITC | 2009 | Caniff–Northeast 120 kV | 250 | 106.10 % | C | Double: Northeast–Stephens 230 kV & Jewel–Sterling 230 kV | | |
| | | | | 115.90 % | C | Double: Northeast–Stephens 230 kV & Bismark 345-230 #3 | | |
| ITC | 2009 | Northeast–Red Run 120 kV | 313 | 100.40 % | C | Double: Jewel 345-230 #1 & Bismark–Red Run 230 kV | | |
| | | | | 102.70 % | C | Double: Bismark–Red Run 230 kV & Jewel–Sterling 230 kV | | |
| ITC | 2009 | Monroe–Bayshore 345 kV | 1536 | 100.40 % | C | Double: Monroe–Wayne 345 kV & Monroe–Brownstown 345 kV | | |
| ITC | 2009 | Monroe 345-120 #4 | 323 | 100.20 % | C | Double: Lulu–Monroe 345 kV & Monroe–Coventry 345 kV | | |
| | | | | 114.70 % | C | Double: Lulu–Monroe 345 kV & Monroe–Brownstown 345 kV | | |
| ITC | 2009 | Warren 230-120 #1 | 636 | 100.10 % | C | Double: DigTp–Navarre–Waterman 230 kV & Wayne–Hines 230 kV | | |
| ITC | 2009 | Wixom 345-120 #1 | 624 | 103.40 % | C | Double: Wayne–Wixom–Quaker 345 kV (with Quaker 345-120 kV transformer) & Wixom–Quaker 230 kV | | |
| ITC | 2009 | Newburgh–Peru 120 kV | 222 | 104.80 % | C | DCT Brownstown–Elm-Rotunda 230 kV & Elm–Taylor 130 kV | | |
| | | | | 100.20 % | C | Double: Baxter–Warren 230 kV & Brownstown–Elm Tap 230 kV | | |
| ITC | 2009 | Brownstown–Rotunda 230 kV | 850 | 101 % | C | Double: Fermi–Brownstown 345 kV & Wayne–Brownstown 345 kV | | |
| ITC | 2009 | Adams 120 kV | | 0.88 pu | C | DCT Jewell–Sterling 230 kV & Jewell–Spokane–Carbnet–St. Clair 120 | | |
| ITC | 2009 | Jewell / Sterling | | 0.87 pu | C | Double: Jewell 345-230 #3 & Bismark 345-230 #3 | | |
| ITC | 2009 | Sterling | | 0.87 pu | C | Double: Jewell 345-230 #3 & Bismark–Red Run 230 kV | | |
| | | | | 0.8665 pu | C | Double: Jewell–Sterling 230 kV & Bismark 345-230 #3 | | |
| | | | | 0.8661pu | C | Double: Bismark–Red Run 230 kV & Jewell–Sterling 230 kV | | |
| ITC | 2009 | Malta 120 kV | | 0.8988 pu | C | DCT Bismark–Red Run 230 kV & Northeast–Red Run 120 kV | | |
| ITC | 2009 | Red Run 230 kV | | 0.8866 pu | C | DCT Bismark–Red Run 230 kV & Northeast–Red Run 120 kV | | |

Midwest ISO 2004 Coordinated Summer Assessment identified ITC's Thumb areas as reactive reserve deficit areas. Macomb area does not have sufficient reactive reserve when subjected to loss of one line Stephens–Macomb 120 kV and one generator unit at St. Clair 120 kV bus. 54 MVAR capacitor is planned to be installed at Macomb 120 kV substation before 2009 summer. Meanwhile, Macomb area is planned to have another power source from Bismarck besides Stephens 345 kV substation and St. Clair generators. Bismarck–Golf project will create a three-ended Bismarck–Boyne–Macomb 120 kV line by building a new 120 kV line from Bismarck. Loss of Arrowhead–Tuscola 120 kV leads to voltage collapse at Bad Axe with Harbor Beach generation offline. Loss of Belle River–Greenwood–Pontiac 345 kV & Greenwood units forced outage leads to low voltage at Lee 120 kV bus with Harbor Beach generation offline. 30 MVAR dynamic VAR devices will be installed at Bad Axe 120 kV substation and Lee 120 kV substation. Placid 120 kV voltage drops down to 87% post contingency (Pontiac–Placid–Wayne 345 kV line). 54 MVAR capacitors will be installed at Placid 120 kV substation before 2005 summer. In addition to the capacitor, a 120 kV line from Pontiac–Walton is proposed to be built to increase the source to Pontiac.

DTE complained to the Michigan PUC in 2004 summer that there was insufficient AFC into DTE to allow them to import what they needed to meet their required reserve levels (15% firm reserve). METC and ITC have agreed to certain upgrades that will improve West-East transfers in Michigan. ITC upgrades near its METC interface include the following projects:

- Replace the Genoa transformer and upgrade the relays and current transformers to meet or exceed the limit of the transformer. The Madrid 345-120 kV transformer outage has a significant impact on the loading on the Genoa 138-120 kV transformer.

- Replace the Atlanta transformer and upgrade the relays and current transformer to meet or exceed the limit of the transformer. Also upgrade a relay, trainer, and current transformers in the Atlanta–Tuscola 120 kV circuit to meet or exceed the limit of the conductor. The Atlanta 130-120 kV limit can be reached for the outage of Belle River–Greenwood–Pontiac 345 kV (which includes outage of the Greenwood 345-120 kV and all Greenwood generation) for transfers from METC to ITC.

- Add a new bus and breaker along with the appropriate disconnects at the Hunters Creek substation to accommodate the reactor which will be placed in series with the Hemphill–Hunters Creek 120 kV circuit. The Hemphill–Hunters Creek 120 kV limits for the outage of Greenwood unit #1 could be significantly impacted by west-east flows.

The upgrades could improve transfer capability up to 1000 MW considering single contingencies. The project is planned to be completed before 2005 summer. Without the upgrades, Genoa 138/120 kV transformer was identified in baseline reliability Phase 1 study as limiting facility under single contingency. With the upgrades, it is no longer shown as a limiting facility.

As currently configured, the ITC system has approximately 1000 MW of generation at the Greenwood site that cannot operate unless the approximate 73-mile three-ended Belle River-Greenwood-Pontiac 345 kV circuit is in-service. A generation rejection scheme is in place that will reject the entire output from the Greenwood generating site for the contingent loss of the Belle River-Greenwood-Pontiac 345 kV circuit.

Subsequent to this analysis, ITC has identified three additional project concepts –

1) Bismarck-Troy 345 kV cable with a 345-120 kV transformer at Troy – this project mitigates overloads in the Northeast, Red Run, Troy, Bloomfield, Lincoln, Walton and Pontiac areas and reduces losses. ITC is in the process of studying other potential projects in this area that may be implemented in place of this cable.

2) Majestic 345-120 kV transformer and Majestic-Madrid, Majestic-Lark and Majestic–Phoenix 120 kV circuits – addresses thermal loading of the Madrid 345-120 kV and Coventry 345-120 kV and low voltages in the Genoa area and reduces losses.

3) Saratoga North–Additional 345 kV circuitry in Greenwood area and 345-120 kV transformer. Allows Greenwood generation to operate under all single transmission contingency/shutdown events. Supports voltage at Adams and throughout the “Thumb” area and reduces losses. Had these three conceptual projects been included, many of the limitations identified above would have been mitigated.

Outage of multiple system elements may result in potential local area cascading and loss of load. Additional information is provided in the ECAR Region study details appendix.

The thermal constraints due to NERC category C contingencies mainly are located at the Lincoln/Northeast area, Atlanta area, Madrid area, Wixom/Quaker area, Monroe/Elm area.

## 6.1.3 Operational Issues (AFC/TLR) TLR Issues

One NIPSCO flowgate and three LGEE flowgates are among Midwest ISO's top 25 called for TLR. They are:

- Dune Acres–Michigan City 138 1&2 (flo) Wilton Center–Dumont 765-kV
- Blue Lick–Bullitt County 161 kV/Clifty–Trimble 345 kV
- Blue Lick 345/161 kV transformer/Baker–Broadford 765 kV
- Paddy–Summershade 161 kV

Large west to east power transfers caused loading problem on the two Dune Acres to Michigan City 138 kV circuits. These two circuits as well as Wilton Center-Dumont 765 kV circuit are both west to east power transfer path. With the 765 kV outage, these two 138 kV circuits could overload. Because in the 2009 summer peak model, Wilton Center–Dumont 765 kV only carries about 200 MW power, the outage of the 765 kV circuit will not cause Dune Acres–Michigan City 138 1 & 2 overloading.

The Blue Lick–Bullit County 161 kV (LGEE/EKPC) and Paddy–Summershade 161 kV (LGEE/TVA) circuits are historically common north-south transfer limitations and highly correlated in response to similar conditions. Hence, they are treated with a common operating guide. These facilities are subject to high loadings during heavy North-South transfers and/or following the loss of AEP's Baker–Broadford 765 kV circuit.

The new Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project, provides an alternative north-south path. Hence in 2009 summer, the loading at Blue Lick–Bullitt County 161 kV, Blue Lick 345/161 kV transformer, Paddy–Summershade kV is expected to be reduced.MECS-IMO interface is also among the top 20 TLR calling list. The Michigan–Ontario interface was a significant limitation to transfers, particularly transfers involving Ontario. ITC is developing some conceptual plan, e.g., HVDC, to address this issue.

## 6.1.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. If you would like to see the technical details of the Phase 1 analysis and Phase 2 analysis for the Midwest ISO system in the ECAR study region, please see Appendix D1.

# 6.2 Midwest ISO - MAIN Region

## 6.2.1 System Description

The MAIN region of Midwest ISO includes investor-owned utilities, cooperative systems, municipal power agencies, independent power producers, power marketers, and municipal systems. This region provides electricity to 21 million people living in the 145,000 square miles the Region encompasses. This study region includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. The 8 million customers in this region represent a cross section of Mid-America: commerce, industry, agriculture, education, research, recreation, and residences in cities, suburbs, small towns, and rural areas.

The MAIN region is served by a grid of transmission lines consisting of 90 miles of 765 kV, 5,879 miles of 345 kV, and 226 miles of 230 kV transmission lines. Another 374 miles of 345 kV transmission is planned to be in service over the next five years.

In 2009 there was 64,611 MW of generation modeled in the MAIN region; 38,920 MW is owned by Midwest ISO members. The generation figures in table 6.2-1 are not indicative of available capacity to meet MAIN load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. The projected peak load for 2009 was 62,272 MW (Midwest ISO load only) representing a little more than 1.5% per year load growth across the MAIN study region from the present time. Table 6.2-1 shows the breakdown of load and generation across the MAIN area.

Note that Alliant West is not included in the MAIN area even though the company is officially part of the MAIN area. It is included with the MAPP area appraisal for purposes of clarity because operationally they align with the MAPP utilities more closely than with the MAIN utilities. It was their wish to have the study results of their area included with the MAPP appraisal.

**Table 6.2-1: MAIN Load, Generation, and Interchange in the Summer 2009 Peak Model**

| System | Modeled Load (MW) | Modeled Generation (MW) | Modeled Area Interchange (MW) |
|---|---|---|---|
| Duke Energy: Lee County | | 322 | 320 |
| ENRON/Lincoln Center | 1 | 665 | 664 |
| Columbia (Missouri) Water & Light | 331 | 198 | -135 |
| Ameren | 12,523 | 11,869 | -876 |
| AmerenIP | 4,338 | 4,080 | -354 |
| AmerenCILCO . | 1,287 | 1,299 | 0 |
| City Water, Light and Power | 515 | 518 | 0 |
| Southern Illinois Power Co-operative | 285 | 403 | 111 |
| Electric Energy, Inc | 90 | 1,331 | 1,235 |
| Northern Illinois (ComEd) | 24,196 | 25,689 | 962 |
| Alliant Energy East | 2,835 | 3,624 | 712 |
| Wisconsin Electric Power Company | 7,578 | 6,934 | -791 |
| Wisconsin Public Service Corporation | 2,762 | 2,657 | -175 |
| Madison Gas & Electric Company | 862 | 514 | -361 |
| Upper Peninsula Power Co | 170 | 146 | -30 |
| **TOTAL** | **57,773** | **60,249** | **1,282** |

**The following are the members of MAIN regional reliability organization:**

- Allegheny Energy Supply Co., LLC
- Alliant Energy Corporate Services
- Ameren
  *(including the operating companies of)*
  - AmerenUE
  - AmerenCIPS
  - AmerenCILCO
  - AmerenIP
- American Transmission Company, LLC
- Central Iowa Power Cooperative
- City Water, Light and Power
- Columbia (Missouri) Water & Light
- Commonwealth Edison Company
- Constellation Energy Commodities Group, Inc.
- Coral Power, LLC
- Duke Energy
- North America, LLC
- Edison Mission Marketing and Trading
- Electric Energy, Inc.
- GridAmerica LLC
- Illinois Municipal Electric Agency
- Madison Gas & Electric Company
- Midwest ISO
- Northern Indiana Public Service Co.
- NRG Energy, Inc.
- PJM Interconnection, L.L.C.
- PPL EnergyPlus, LLC
- Southern Illinois Power Co-operative
- Soyland Power Cooperative, Inc.
- Tenaska Power Services
- Wisconsin Electric Power Company
- Wisconsin Public Power Inc.
- Wisconsin Public Service Corporation.

## 6.2.2 Summary of Baseline Study Results for MAIN Region Systems in Midwest ISO

Table 6.2-2 shows the results from the phase 1 studies together with projects that would address the limiting conditions. The plan status, as shown, is the current status of the plan that would address the limiting condition.

**Table 6.2-2: Phase 1 Study Results and Projects That Address Limiting Conditions**

| Control Area | Year | Limiter / System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Ameren | 2009 | PT.PRAIR 161 kV | 0.899 pu | | B | 31542 PT.PRAIR 161 96059 5BIG CK 161 1 | PR2 | Point Prairie 28.8 MVAR cap at the 161 / 34 kV sub |
| ATCLLC | 2009 | CORNEL 1-FEBRNT5 138 kV | 1.015 pu | 225 | B | 39255 ARCADN5 138 39356 MORLND4 138 1 | n.a. | Existing Operating guide and / or generation redispatch |
| Ameren | 2009 | 31723 SELMA 138-31782 STFT 138 1 | 1.275 % | 253 | C | 31669 RUSH 345 31858 TYSON 1 345 1<br>31669 RUSH 345 31859 TYSON 2 345 1 | PL | Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim.-App A ID 401 |
| Ameren | 2009 | 31392 ORGD 2 138-31860 TYSON 138 1 | 1.003 % | 270 | C | 30079 WILDWD 345 30886 LABADIE 345 1<br>30079 WILDWD 345 31051 MASON 13 345 1<br>30886 LABADIE 345 31051 MASON 13 345 1 | PL<br>PR | Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401<br>Wildwood 345 kV PCBs App A ID 1412 |
| Ameren | 2009 | 31391 ORGD 1 138-31860 TYSON 138 1 | 1.022 % | 270 | C | 30079 WILDWD 345 30886 LABADIE 345 1<br>30079 WILDWD 345 31051 MASON 13 345 1<br>30886 LABADIE 345 31051 MASON 13 345 1 | PL<br>PR | Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401<br>Wildwood 345 kV PCBs App A ID 1412 |
| Ameren | 2009 | 30648 GRAYSUM1 345-30650 GRAY SUM 138 1 | 1.133 % | 560 | C | 30079 WILDWD 345 30886 LABADIE 345 1<br>30079 WILDWD 345 31051 MASON 13 345 1<br>30886 LABADIE 345 31051 MASON 13 345 1 | PL<br>PR | Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401<br>Wildwood 345 kV PCBs App A ID 1412 |
| Ameren | 2009 | 30421 CONWAY 1 138-31392 ORGD 2 138 1 | 1.177 % | 205 | C | 30079 WILDWD 345 30886 LABADIE 345 1<br>30079 WILDWD 345 31051 MASON 13 345 1<br>30886 LABADIE 345 31051 MASON 13 345 1 | PL<br>PR | Joachim 345 / 138-345 / 138 ckt 1, Sum rate 560-App A ID 401<br>Wildwood 345 kV PCBs App A ID 1412 |
| Ameren | 2009 | 30197 BUCKNOB 138-31870 VALMTAP 138 1 | 1.001 % | 253 | C | 31669 RUSH 345 31858 TYSON 1 345 1<br>31669 RUSH 345 31859 TYSON 2 345 1 | PL | Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim. |
| Ameren | 2009 | 30197 BUCKNOB 138-31723 SELMA 138 1 | 1.014 % | 253 | C | 31669 RUSH 345 31858 TYSON 1 345 1<br>31669 RUSH 345 31859 TYSON 2 345 1 | PL | Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim. |
| Ameren | 2009 | 30090 BAILEY 2 138-31774 ST FRANC 138 1 | 1.151 % | 210 | C | 31669 RUSH 345 31858 TYSON 1 345 1<br>31669 RUSH 345 31859 TYSON 2 345 1 | PL | Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim. |
| AMRN | 2009 | 30089 BAILEY 1 138-31774 ST FRANC 138 1 | 1.107 % | 229 | C | 31669 RUSH 345 31858 TYSON 1 345 1<br>31669 RUSH 345 31859 TYSON 2 345 1 | PLn.a. | Operating guide until 2007, and then, installation of a new 345 / 138 kV sub at Joachim. |

**Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions**

| Control Area | Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Ameren | 2009 | 30422 CONWAY 3 138-31391 ORGD 1 138 1 | 1.20 8 | 205 | C | 30079 WILDWD 345 30886 LABADIE 345 1<br>30079 WILDWD 345 31051 MASON 13 345 1<br>30886 LABADIE 345 31051 MASON 13 345 1 | PL<br>PR | Joachim 345/138-345/138 ckt 1, Sum rate 560-App A ID 401<br>Wildwood 345 kV PCBs App A ID 1412 |
| Ameren IP | 2009 | N DEC W 138 kV | 0.8976 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines:<br>CLINTON 345-MAROA W 345 1<br>MAROA W 345-OREANA E 345 1<br>MAROA W 345-LATHAM 345 1<br>CLINTON 345-MAROA E 345 1<br>MAROA E 345-OREANA E 345 1<br>MAROA E 345-GOS_CK_W 345 1<br>GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage |
| Ameren IP | 2009 | CATERPIL 138 kV | 0.8746 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines:<br>CLINTON 345-MAROA W 345 1<br>MAROA W 345-OREANA E 345 1<br>MAROA W 345-LATHAM 345 1<br>CLINTON 345-MAROA E 345 1<br>MAROA E 345-OREANA E 345 1<br>MAROA E 345-GOS_CK_W 345 1<br>GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage |
| Ameren IP | 2009 | RT 51 138 kV | 0.8922 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines:<br>CLINTON 345-MAROA W 345 1<br>MAROA W 345-OREANA E 345 1<br>MAROA W 345-LATHAM 345 1<br>CLINTON 345-MAROA E 345 1<br>MAROA E 345-OREANA E 345 1<br>MAROA E 345-GOS_CK_W 345 1<br>GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |

**Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions**

| Control Area | Year | Limiter / System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Ameren IP | 2009 | MT ZION 138 kV | 0.8789 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |
| Ameren IP | 2009 | ADM N AM 138 kV | 0.8703 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |
| Ameren IP | 2009 | ADM F AM 138 kV | 0.8703 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 1 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |

| Table 6.2-2 (cont.): Phase 1 Study Results and Projects That Address Limiting Conditions | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Control Area | Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
| Ameren IP | 2009 | BLMGTN E 138 kV | 0.8884 PU | | C | Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1 | n.a. | Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and/or generation re-dispatch |
| Ameren IP | 2009 | 32348 BROKAW 138-32378 NORMAL E 138 1 | 1.208 % | 165 | C | Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1 | n.a. | Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and/or generation re-dispatch. |
| Ameren IP | 2009 | PPG 138 kV | 0.8829 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines: CLINTON 345-MAROA W 345 1 MAROA W 345-OREANA E 345 1 MAROA W 345-LATHAM 345 1 CLINTON 345-MAROA E 345 1 MAROA E 345-OREANA E 345 1 MAROA E 345-GOS_CK_W 345 1 GOOS_CRK 345-GOS_CK_W 345 | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |
| Ameren IP | 2009 | RAAB RD 138 kV | 0.8922 PU | | C | Dbl. Cont. 1562 and 1596 opens 5 lines: 32348 BROKAW 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32392 ST FARM2 138 1 32268 BLMGTN 7 138 32389 BLMGTN W 138 1 32348 BROKAW 138 32391 ST FARM1 138 1 32374 BLMGTN E 138 32391 ST FARM1 138 1 | n.a. | Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and/or generation re-dispatch |

Table 6.2-3 shows the results from the phase 2 studies together with projects that would address the limiting conditions. The plan status, as shown, is the current status of the plan that would address the limiting condition.

**Table 6.2-3: Phase 2 Study Results and Projects That Address Limiting Conditions**

| Control Area | Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Ameren | 2009 | BAILEY ST FRANC 138 1 | 104.70% | 229 | C | RUSH ISLAND-TYSON-1&2 345 | PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 |
| Ameren | 2009 | BAILEY ST FRANC 138 2 | 108.40% | 210 | C | RUSH ISLAND-TYSON-1&2 345 | PL | Operating guide until 2007, and then, installation of a new 345/138 kV sub at Joachim. |
| Ameren | 2009 | SELMA St. Francois Tap 138 1 | 123.60% | 253 | C | RUSH ISLAND-TYSON-1&2 345 | PL | Operating guide until 2007, and then, installation of a new 345/138 kV sub at Joachim. |
| Ameren | 2009 | GRAY SUMMIT GRAY SUM 138 1 | 115.10% | 560 | C | LABADIE-MASON-3&4 345 | PL<br>PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009 |
| Ameren | 2009 | ORGD TYSON 138 1 | 102.10% | 270 | C | LABADIE-MASON-3&4 345 | PL<br>PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009 |
| Ameren | 2009 | ORGD TYSON 138 2 | 100.30% | 270 | C | LABADIE-MASON-3&4 345 | PL<br>PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009 |
| Ameren | 2009 | TYSON TYSON 138 1 | 102% | 560 | C | LABADIE-MASON-3&4 345 | PL<br>PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009 |
| Ameren | 2009 | TYSON TYSON 138 2 | 101.6 PU | 560 | C | LABADIE-MASON-3&4 345 | PL<br>PR | Operating guide until 2007, and then, instalation of a new 345/138 kV sub at Joachim. - App A ID 401 Also 345 kV PCBs proposed at Wildwood in 2009 |
| Ameren | 2009 | PARIS AM | 0.8933 PU | | C | KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138 | na | Operating Guide |
| Ameren | 2009 | PARIS AM | 0.8933 PU | | C | KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138 | na | Operating Guide |
| Ameren | 2009 | PARIS AM | 0.891 PU | | C | KANSAS SIDNEY 345, KANSAS CASEY 345, KANSAS 345 KANSAS 138 AND SIDNEY 345 SIDNEY 138 | PL | A breaker installation is planned for June of 2005 at the Sidney bus that will remove the multi-terminal outage. |

Table 6.2-3 (cont.): Phase 2 Study Results and Projects That Address Limiting Conditions

| Control Area | Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Cont. Type | Contingency | Plan Status | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|
| Ameren IP | 2009 | BROKAW NORMAL E 138 1 | 119.90% | 165 | C | Dbl. Cont. 1562 and 1596 opens 5 lines: BLOOMINGTON-ST FARM1-BROKAW and ST FARM 1-ST FARM 2, and BLOOMINGTON-BLOOMINGTON W. OR BROKAW-ST. FARM-BLOOMINGTON E. and ST FARM 1-ST FARM 2 | na | Further study needed to ensure adequate distribution voltages are being maintained in the Bloomington area and to evaluate possible system upgrades and/or generation re-dispatch |
| Ameren IP | 2009 | RAAB RD | 0.898 PU | | | | | |
| Ameren IP | 2009 | BLOOMINGTON EAST | 0.8931 PU | | | | | |
| Ameren IP | 2009 | ADM F AM | 0.8713 PU | | C | Dbl. Cont. 4571 and 4545 opens 6 lines: MOROA 345 TO CLINTON, OREANA E., AND LATHAM OR MOROA 345 TO CLINTON, ORANA E., AND GOOSE CREEK WEST | n.a. | Low voltages to be re-evaluated with detailed modeling of the large customer generating facilities in the Decatur area, along with evaluation of system changes to ensure adequate voltage. |
| Ameren IP | 2009 | ADM N AM | 0.8713 PU | | | | | |
| Ameren IP | 2009 | N DEC W | 0.8981 PU | | | | | |
| Ameren IP | 2009 | RT 51 | 0.8925 PU | | | | | |
| Ameren IP | 2009 | CATERPIL | 0.8757 PU | | | | | |
| Ameren IP | 2009 | MT ZION | 0.8796 PU | | | | | |
| Ameren IP | 2009 | PPG | 0.8835 PU | | | | | |

### Illinois Missouri Area

This area is located in the southern part of the MAIN region and is bounded by the service territories of the Ameren (including the operating companies of AmerenUE, AmerenCIPS, AmerenCILCO, and AmerenIP), City Water, Light and Power, Columbia (Missouri) Water & Light, and Southern Illinois Power Co-operative. There are several areas where there are known loading problems and low voltage issues. There are planned projects to mitigate those constraints. In Phase 2 analysis, Midwest ISO added known planned and proposed projects to the 2009 summer peak model to test the performance of those projects. All NERC category B loading violations were resolved. However, there are some NERC category C issues that remain. Because NERC planning standards allow significant operator adjustments for category C events, load shedding is allowed, and because of the many possible avenues that can be taken to deal with those issues, Midwest ISO will continue to work with the Transmission Owners to determine the best way to address the Category C issues. Some overload levels observed in 2009 are significant enough to warrant review by 2005 the Summer Assessment team to see if they are also issues in the near term. As was done in the northern part of MAIN, transfer levels were tested to ensure that load-serving reserves could be maintained at satisfactory levels, and Midwest ISO continues to work to ensure the ability of the region's transmission system to perform its function in a cost effective way.

### Wisconsin Minnesota Iowa Area of MAIN

The area is situated between the large load and generation centers in MAPP and Southern MAIN and includes the service territories of American Transmission Company, LLC; Central Iowa Power Cooperative, Madison Gas & Electric Company, Wisconsin Electric Power Company, Wisconsin Public Power Inc., and Wisconsin Public Service Corporation. Because of it's geographic and electrical location it is subject to through flows of electrical energy. The transmission system is in the process of being upgraded to handle local load serving issues, as well as, long term transmission needs. Several transmission projects are being built and/or considered for the future to improve voltage and the ability to move power across the region.

In Phase 2 of the Baseline Reliability Study, Midwest ISO added the Planned and Proposed projects to the 2009 summer peak model and determined the ability of those expansions plans to provide adequate system reliability. Phase 2 contingency analyses resulted in no planning criteria violations, indicating that the implementation of these expansion plans in the MAIN study region will provide adequate system performance. Transfer levels were tested to ensure that load-serving reserves could be maintained at satisfactory levels. Midwest ISO continues to work to ensure the ability of the region's transmission system to perform its function in a cost effective way.

Again, timely implementation of the planned and proposed facilities which comprise the expansion plan for the MAIN region of Midwest ISO, will result is a system that will meet planning reliability standards.

### 6.2.3 Operational Issues (AFC/TLR)

Of the top 23 flow gates in Midwest ISO; MAIN has 18 of them based on historical data. Five of the 18 are in the ALTW system and are addressed in the MAPP section of this report. Thirteen are left, and all thirteen are addressed by system additions that are included in Appendix A. Some system improvements will be completed by the time this report is published. Others are scheduled for completion as noted in Appendix A. Please see Section 6.4.1 addition discussion on operational issues.

### 6.2.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. If you would like to see the technical details of the Phase 1 analysis and Phase 2 analysis for the Midwest ISO system in the MAIN study region, please see Appendix D2.

# 6.3 Midwest ISO-MAPP Region

## 6.3.1 System Description

Midwest ISO System-MAPP Region membership now totals 6 transmission-owning members, including the newest member, Great River Energy (GRE). The MAPP region covers all or portions of Iowa, Illinois, Minnesota, Nebraska area, North and South Dakota, Wisconsin and the Canadian province of Manitoba and Saskatchewan.

The MAPP study region has several large load centers served by both local and remote generation. Thermal and hydro resources in the Dakotas, Wyoming, western Nebraska, and Canada deliver power across long EHV transmission lines to load centers in Minnesota, Nebraska, and Iowa. Because of the location of load and generation, several important flow patterns can be used to evaluate the MAPP transmission system. The assessment of transmission system was done on a MAPP sub-region area basis, which comprised of Canada, Dakotas, Iowa, Minnesota, and Nebraska. Key interfaces between Canada and the United States, the Dakotas and Minnesota, Minnesota and Wisconsin, and West-East Nebraska is studied.


**Figure 6.3-1: The Midwest ISO-MAPP Region**

The Canadian area of MAPP study region consists of the Manitoba Hydro (MH) and Saskatchewan Power (SPC) system. The area is synchronously interconnected to Saskatchewan Power (SPC) system to the west via three 230 kV and two 115 kV lines and to the Ontario Hydro Networks Company (OHNC) system to the east with two phase-shifted 230 kV lines. Saskatchewan system has a back-to-back HVDC link with the province of Alberta to the west. To the south, the Canadian area system is tied with the US part of the MAPP region system through a 500 kV line and three 230 kV lines in MH system, a phase-shifted 230 kV line in SPC system, and a phase-shifted 115 kV line from the northwest OHNC system. The MAPP RSG study participant from Canada is Manitoba Hydro (MH).

The Minnesota area covers the state of Minnesota and the portion of western Wisconsin that is within the MAPP region. The traditional powerflow pattern in Minnesota is from the northwest to the southeast and central areas of the state. A major portion of the electric load in Minnesota is concentrated around the Twin Cities metropolitan area of Minneapolis-St. Paul, the principal load center of the Xcel Energy North Control Area. The MAPP RSG study participants from Minnesota and Wisconsin are Alliant Energy–IPL (ALTW), Minnesota Power (MP), Otter Tail Power Company (OTP), and Xcel Energy North (XEL).

The Iowa area generally covers the transmission facilities located within the State of Iowa. The MAPP RSG participants from Iowa are Alliant Energy–IPL (ALTW), MidAmerican Energy Company (MEC), and Muscatine Power and Water (MPW). Besides facilities in Iowa, Alliant Energy has some transmission facilities in Illinois and Minnesota. MidAmerican Energy Company also has some facilities in Illinois and South Dakota. A relatively small portion of the Western Area Power Administration facilities are located in Iowa, with the majority of WAPA's facilities located in areas northwest of Iowa. The Iowa electric system consists mainly of 345, 161, and 115 kV transmission facilities.

The Dakotas area generally covers the transmission facilities in portions of Eastern Montana / Western North Dakota, Central North Dakota, Eastern North Dakota, Western South Dakota and Eastern South Dakota. The MAPP RSG participants from the Dakotas are Montana-Dakota Utilities (MDU), Otter Tail Power Company (OTP), Western Area Power Administration (WAPA), and Xcel Energy North (XEL). Nebraska generally covers the transmission facilities located within the State of Nebraska, portion of western Wyoming and South Dakota. The MAPP RSG participant from Nebraska is Lincoln Electric System (LES).

Table 6.3-1 shows the system intact base case model for 2009 summer peak case with area load and generation levels.

The generation figures in the table are not indicative of available capacity to meet MAPP load, but rather the dispatch levels anticipated at peak load for generation in the control areas, as consistent with the interchange levels projected by the Transmission Owners in 2003 when the 2009 model for this study was developed. Note that positive area interchange means the system is exporting power; negative area interchange is importing power.

The load growth in the 2009 summer case for the MAPP (including Alliant Energy-IPL) region is approximately 8%.

**Table 6.3-1: Base Case Area Load and Generation Levels**

| System | Modeled Load (MW) | Modeled Generation (MW) | Modeled Area Interchange (MW) |
|---|---|---|---|
| Alliant Energy–IPL | 4522.6 | 4388.2 | -206.2 |
| Xcel Energy North | 10334.5 | 8506.3 | -2156.0 |
| Minnesota Power | 1700.1 | 1380.2 | -7.7 |
| Southern MN Municipal Power Association | 325.4 | 181.1 | -145.0 |
| Great River Energy | 1611.7 | 2487.9 | 791.0 |
| Otter Tail Power Company | 1662.9 | 1204.6 | -504.5 |
| Muscatine Power and Light | 175.9 | 175.7 | -1.0 |
| MidAmerican Energy | 5154.5 | 5146.2 | -105.0 |
| Nebraska Public Power District | 2994.0 | 2778.1 | -327.0 |
| Omaha Public Power District | 2676.8 | 2603.1 | -104.0 |
| Lincoln Electric System | 814.5 | 139.8 | -687.0 |
| Western Area Power Administration | 3278.1 | 4758.9 | 1274.0 |
| Manitoba Hydro | 2784.2 | 4560.0 | 1494.0 |
| Saskatchewan Power Company | 3025.9 | 3118.9 | 0.0 |
| Dairyland Power Cooperative | 952.1 | 1198.3 | 164.0 |
| **Total** | **42013.2** | **42653.0** | **-520.4** |

## 6.3.2 Summary of Baseline Study Results for MAPP Region Systems in Midwest ISO

This section provides a long-term assessment of the reliability of the Midwest ISO System in the MAPP Study Region. The study was conducted in a joint collaborative effort between Midwest ISO Reliability Study Group (RSG) and the MAPP Transmission Reliability Assessment Working Group (TRAWG) members. In an effort to identify a reliability plan, this assessment discusses the facility upgrades needed as a result of the thermal, voltage and dynamic stability analysis performed. Depending on the results of the assessment study, further studies on more specific alternatives to improve system performance may follow.

Planned projects are the preferred solution to an identified issue and Proposed projects are a tentative solution to an identified issue. Additional facilities address system issues identified in Phase 2 of this study, which were not addressed by the Planned and Proposed facilities in Appendix A. Additional facilities are those in addition to the expansion facilities listed as Planned or Proposed in Midwest ISO Appendix A.

In general, the MAPP Region of the Midwest ISO transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the Appendix A, in addition to what the Midwest ISO have identified below, are implemented.

### Phase 1 Steady-State Analysis

Table 6.3-2 summarizes the Phase 1 reliability issues the Midwest ISO has identified in the 2009 summer peak study cases. It discusses the results; planned solutions to the reliability issues summarized at the MAPP sub-regional level. Phase 1 analysis consists of only planned (PL) facilities.

In the Phase 1 analysis, the Midwest ISO has identified several new reliability issues in the 2009 summer peak case. These reliability issues do not have a corresponding Appendix A planned (PL) or proposed (PR) projects identified (see branch ID column–N.A). It is also important to note that some planned projects were not listed in Appendix A during the Phase 1 analysis or had a proposed plan status that later changed to a planned status in Phase 2 analysis. This is noted in the plan status column. Projects that have the planned (PL) status will be monitored closely by Midwest ISO for development and construction of these facilities. Projects with a proposed (PR) plan status are expected to become planned status facilities in Appendix A and closely monitored in next MTEP 06 analysis. The detail of Phase 2 analysis is discussed in the next paragraph.

**Table 6.3-2: Phase 1 Steady-State Analysis Summary Table**

| Area | Model Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Con. Type | Contingency | Plan Status | Branch or Device ID | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|---|
| Dakotas | 2009 | Bismarck Downtown–East Bismarck 115 kV | 171% | 67.7 | B | Heskett–Mandan 115 kV | PR2 | N.A | Bismarck Downtown–East Bismarck 115 kV upgrade to at least 160 MVA |
| Dakotas | 2009 | Jamestown 115 kV buses | < 1.12 p.u | | B | Buffalo–Maple River 345 kV | PR2 | N.A | Jamestown 115 kV 25 MVAR capacitor |
| Dakotas | 2009 | Maple River–Red River 115 kV | 112% | 79.1 | C | Sheyenne–Cass County–Moderow 115 kV loop & Sheyenne 230/115 Transformer | PL | 1354 | Maple River–Red River115 kV upgrade to 310 MVA in 6/1/05 |
| Iowa | 2009 | Hazelton 345/161 kV Transformer # 1 | 112% | 223 | C | Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers | PR2 | N.A | Upgrade Salem transformer to 550 MVA and replace Hazelton transformer with old Salem Tr. 336 MVA |
| Iowa | 2009 | Salem 345/161 kV Transformer | 101% | 335 | C | Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV–Beaver Channel Generator | LT or PR2 | 1266 or N.A | Salem-Spring Green–West Middleton 345 kV line. Total project $310 million in 1/1/14 or Upgrade Salem transformer to 550 MVA |
| Minnesota | 2009 | Prairie Island–Red Rock 345 kV # 2 | 116% | 625 | C | Prairie Island–Blue Lake 345 kV and Prairie Island–Red Rock 345 kV | PR changed to PL | 1137 | Prairie Island–Red Rock 345 kV # 2 line upgrade to 1198 MVA in 6/1/06 |
| Minnesota | 2009 | Cromwell and McGregor 115 kV | 0.88 p.u | | B | Mahtowa–Wrenshall 115 kV | N.A | N.A | MP is currently looking into building a new 115 kV source into the Cromwell area |
| Minnesota | 2009 | Mahtowa, Cromwell and McGregor 115 kV | 0.87 p.u | | B | Wrenshall–Thompson 115 kV | N.A | N.A | MP is currently looking into building a new 115 kV source into the Cromwell area |
| Minnesota | 2009 | Alexandria 115 kV | 0.89 p.u | | B | Alexandria Switching St.–Alexandria SW 115 kV | PR | 1032 | Alexandria 115, 2 x 25 MVAR Capacitors in 3/1/07 |
| Minnesota | 2009 | Hibbard–Winter St. 115 kV | 102% | 200 | B | Arrowhead–Gary 115 kV | N.A changed to PL | 1242 | Stone Lake 345/161 tap of Arrowhead–Gardner Park 345 kV line |
| Minnesota | 2009 | Wheaton–Presto 161 kV | 102% | 300 | B | Elk Mound–Barron 161 kV | PR2 | N.A | Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV |
| Minnesota | 2009 | River Wood–Johnny Cake–Inver Grove-Black Dog 115 kV | 106% | 210 & 263 | B | River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV | PR changed to PL | 277 | Air Lake–Vermillion River 115 ckt 1, Sum rate 200 in 6/1/07 |
| Minnesota | 2009 | Eau Claire–Presto tap 161 kV | 102% | 300 | B | Elk Mound–Barron 161 kV | PR2 | N.A | Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV |
| Minnesota | 2009 | Barron–Washco 161 kV overload | 108% | 132 | B | Stinson MN–Stinson WI 115 kV Phase Shifter | N.A changed to PL | 1242 | Stone Lake 345/161 tap of Arrowhead–Gardner Park 345 kV line in 6/1/06 |
| Minnesota | 2009 | Monticello–Salida 115 kV | 118% | 154 | C | Blue Lake–Inver Hills–Red Rock 345 kV | PR changed to PL | 571 572 573 | Monticello–Sherco-Salida 115 kV , Sum rate 310, Sherco 345/115 ckt 1, Sum rate 448 in 6/1/06 |

| Table 6.3-2 (cont.): Phase 1 Steady-State Analysis Summary Table | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Area | Model Year | Limiter / System Need | Contingent Level (%, PU) | Rating | Con. Type | Contingency | Plan Status | Branch or Device ID | Project to Address Limiter |
| Minnesota | 2009 | River Wood–Johnny Cake–Inver Grove-Black Dog 115 kV | 106% | 210 & 263 | C | Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills-Red Rock 345 kV outage or Blue Lake–Inver Hills–Red Rock 345 kV | PR changed to PL | 277 | Air Lake–Vermillion River 115 ckt 1, Sum rate 200 in 6/1/07 |
| Minnesota | 2009 | Monticello–Salida 115 kV | 117% | 154 | C | Blue Lake-Inver Hills–Red Rock 345 kV | PR changed to PL | 571 572 573 | Monticello–Sherco–Salida 115 kV , Sum rate 310, Sherco 345/115 ckt 1, Sum rate 448 in 6/1/06 |
| Minnesota | 2009 | Aldrich–St. Louis Park 115 kV | 111% | 156 | C | Parkers–Basst Creek 115 kV and Parkers–St. Louis Park 115 kV | PR changed to PL | 249 | Aldrich–St. Louis Park 115 kV line upgrade to 310 in 6/1/06 |
| Minnesota | 2009 | Champlin–Champlin Tap 115 kV | 108% | 154 | C | Sherco-Maple Grove-Coon Creek 345 kV and Coon Creek 345/115/34.5 kV transformers | PR | 1138 | Champlin–Champlin Tap 115 kV line upgrade to 310 in 6/1/06 |
| Minnesota | 2009 | St. Cloud Tap–Salida 115 kV | 117% | 152 | C | Blue Lake–Inver Hills–Red Rock 345 kV | PR changed to PL | 569 574 | St. Cloud Tap–I94 Industrial-Salida 115 kV , Sum rate 310 in 6/1/06 |

PL–Planned Projects

PR–Proposed Projects

PR2–New Proposed Project not in Appendix A

N.A–Not Available

LT–Long Term Projects

## Phase 2 Steady-State Analysis

Table 6.3-3 summarizes the Phase 2 reliability issues the Midwest ISO has identified in the 2009 summer peak study case. It discusses the results; planned solutions to the reliability issues summarized at the MAPP sub-regional level. Phase 2 analysis consists of planned (PL) facilities from Phase 1, proposed (PR) facilities listed in Appendix A and new proposed (PR2) facilities not listed in Appendix A.

In the Phase 2 analysis, the new proposed (PR2) facilities not listed in Appendix A have shown to eliminate all of the reliability issues found in Phase 1 analysis. In this analysis, the Midwest ISO also has identified two new additional reliability issues in the 2009 summer peak case, which was not found in Phase 1 analysis. The following summarizes the new two limiting elements.

### Stone Lake 345 kV Bus

Loss of the planned Arrowhead 345/230 kV Transformer (ATCLLC) or Arrowhead 230 kV Phase Shifter (ATCLLC) has been shown to cause high voltage on the planned Stone Lake 345 kV bus (ATCLLC). The Stone Lake 345 kV bus facility was not modeled in the Phase 1 analysis. For these contingencies, the Arrowhead-Stone Lake Tap 345 kV line and cap banks at the Stone Lake Tap 345 kV substation will be cross-tripped. This new proposed remedial action would eliminate the high voltage issue on this bus. ATCLLC will study this facility in depth and propose a remedial action or operating guide that would cross trip the planned capacitor banks at the Stone Lake 345/230 kV substation. The facility is expected to be in service in 2006.

### Johnny Cake–Apple Valley West–Williams Pipeline–Fischer 115 kV Lines

The Johnny Cake–Apple Valley West–Williams Pipeline–Fischer 115 kV lines is overloaded approximately 106 percent for loss of single contingency; River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV branch and for the double contingency; Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills–Red Rock 345 kV outage or Blue Lake–Inver Hills–Red Rock 345 kV. This new limit is due to the addition of the planned Air Lake–Vermillion, Koch Refinery–Inver Hills 115 kV lines and the proposed Dakota County generations. A separate Dakota County generation interconnection study is underway between GRE and Midwest ISO that would increase the line rating of these lines as part of the generation outlet upgrade.

For projects that have new proposed (PR2) status will be monitored closely by Midwest ISO in next MTEP 2006 analysis. These facilities are expected to be included in the next Appendix A development or update for MTEP 2006 with a Planned or Proposed status. It is the expectation of the Midwest ISO that these facilities will be addressed with a project cost, in-service date and analysis performed of these facilities. The following describes the new proposed (PR2) facilities summarized at the MAPP sub-regional level.

## Dakotas

The Bismarck Downtown–East Bismarck 115 kV line (MDU) was overloaded at approximately 71 percent above its emergency line rating for the loss of Heskett–Mandan West 115 kV line (MDU). The Midwest ISO's proposal to upgrade the Bismarck Downtown–East Bismarck 115 kV line to at least 160 MVA has shown significant improvement for this contingency. The Bismarck area 115 kV transmission loop is being studied to determine the solution to implement.

The loss of Buffalo–Maple River 345 kV line may result in high voltages in the Jamestown area (OTP) of the Eastern North Dakota sub-region. These high voltage problems are due to charging current from the lightly loaded 345 kV line. The proposal to install a 25 MVAR shunt at Jamestown substation has shown significant voltage improvement for the loss of Buffalo–Maple River 345 kV line. An analysis to determine the appropriate shunt size will be performed.

## Iowa

The outage of Rock Creek 345/161 kV transformer and Beaver Channel 161 kV –Beaver Channel Generator (ALTW) results in overload of the Salem 345/161 kV transformer (ALTW). The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that a 550 MVA Salem 345/161 kV transformer may be recommended.

The loss of Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers (ALTW) may result in overload of the Hazelton 345/161 kV transformer #1 (ALTW) of approximately 12 percent above its emergency rating. The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that moving the Salem 336 MVA transformer from Salem to Hazelton maybe be recommended to eliminate the thermal overload on the existing transformer.

## Minnesota

Loss of Elk Mound–Barron 161 kV line (DPC) has shown to overload the Eau Claire–Presto tap 161 kV and Wheaton–Presto tap 161 kV lines to approximately 106 percent of its emergency rating. The proposed Elk Mound 161 Tap on Red Cedar–Hydro Lane 161 kV would relieve the flow on these lines. The Elk Mound unit generates approximately 72 MW of generation for loads in Northwest Wisconsin via the Elk Mound–Barron 161 kV line. This new proposed line would serve as an outlet to the Elk Mound generations for this contingency. XEL and DPC will perform a joint analysis.

The possibility of a breaker failure at Mahtowa–Wrenshall 115 kV (MP) or Wrenshall–Thompson 115 kV (MP), could result in low voltage occurring in the area immediately south of the Duluth/Cloquet load center. These limitations are confined to local area. To improve the reliability in this area, Midwest ISO and Minnesota Power is currently looking into building a new 115 kV source into the Cromwell area.

In the Phase 2 analysis, the construction of the ATCLLC Arrowhead–Stone Lake–Weston 345 kV line and Stone Lake 345/161 substation has shown to improve the overall performance and operational flexibility of the Northwestern Wisconsin transmission system.

## Nebraska

No significant branch overloads or voltage limitations occur on the LES system.

**Table 6.3-3: Phase 2 Steady-State Analysis Summary Table**

| Area | Model Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Con. Type | Contingency | Plan Status | Branch or Device ID | Project to Address Limiter |
|---|---|---|---|---|---|---|---|---|---|
| Dakotas | 2009 | Bismarck Downtown–East Bismarck 115 kV | 171% | 67.7 | B | Heskett–Mandan 115 kV | PR2 | N.A | Bismarck Downtown–East Bismarck 115 kV upgrade to at least 160 MVA |
| | | Jamestown 115 kV buses | < 1.12 p.u | | B | Buffalo–Maple River 345 kV | | | Jamestown 115 kV 25 MVAR capacitor |
| Iowa | | Hazelton 345/161 kV Transformer # 1 | 112% | 223 | C | Salem 345/161 kV and Hazelton 345/161 kV # 2 Transformers | | | Upgrade Salem transformer to 550 MVA and replace Hazelton transformer with old Salem Tr. 336 MVA |
| | | Salem 345/161 kV Transformer | 101% | 335 | C | Rock Creek 345/161 kV Transformer and Beaver Channel 161 kV –Beaver Channel Generator | | | Upgrade Salem transformer to 550 MVA |
| Minnesota | | Wheaton–Presto tap 161 kV | 102% | 300 | B | Elk Mound–Barron 161 kV | | | Elk Mound 161 kV Tap on Red Cedar–Hydro Lane 161 kV |
| | | Eau Claire–Presto tap 161 kV | 102% | 300 | B | Elk Mound–Barron 161 kV | | | |
| | | Stone Lake 345 kV | 1.16 p.u | | B | Arrowhead 345/230 kV Transformer or Arrowhead 230 kV Phase shifter | PR2 | N.A | The Arrowhead–Stone Lake Tap 345 kV and cap banks at Stone Lake Tap s/s will be cross-tripped. |
| | | Johnny Cake-Apple Valley West-Williams Pipeline–Fischer 115 kV | > 106% | 211 | B | River Wood–Black Dog 115 kV or River Wood–Burnsville 115 kV | | | Equipment upgrades to 310 MVA on William Pipeline–Fischer 115 kV , William Pipeline–Apple Valley West 115 kV , Johnny Cake–Apple Valley West 115 kV lines |
| | | | | | C | Prairie Island–Blue Lake 345 kV and Blue Lake–Inver Hills-Red Rock 345 kV outage or Blue Lake–Inver Hills-Red Rock 345 kV | | | |

New Limiter in Phase 2 Analysis

PL–Planned Projects PR–Proposed Projects PR2–New Proposed Project not in Appendix A

N.A–Not Available LT–Long Term Project

## Outstanding Issues

Table 6.3-4 summarizes the outstanding reliability issues the Midwest ISO has identified in the 2009 summer peak study case. In the Phase 2 analysis, no new proposed facilities were provided to eliminate the outstanding limiting elements. The following summarizes the limiting elements.

### Mahtowa, Cromwell and McGregor 115 kV Bus

The possibility of a breaker failure at Mahtowa–Wrenshall 115 kV (MP) or Wrenshall–Thompson 115 kV (MP), could result in low voltage occurring in the area immediately south of the Duluth/Cloquet load center. These limitations are confined to local area and not wide spread. To improve the reliability in this area, Midwest ISO and Minnesota Power is currently looking into building a new 115 kV source into the Cromwell area

The Midwest ISO will monitor the reliability issue shown above closely for a proposed facility and to be addressed with a project cost, in-service date and analysis performed on these facilities.

## Dynamic Stability Analysis

During the Phase 1 analysis, the dynamic stability analysis was also performed in parallel in an effort to identify any reliability issues. For dynamic stability analysis, post-disturbance thermal overloads are based on the component's *emergency rating*. The report discusses the facility upgrades needed as a result of the dynamic stability analysis. Post disturbance power flow analysis was performed on the 2009 power flow case using the disturbances shown in Appendix D3 (see section 6.3.4). Approximately sixty-two disturbances from NERC Category A, B and C were applied.

The analysis showed there was no significant branch, voltage or transient voltage limitations occurred in the 2009 summer peak case of the Midwest ISO System in the MAPP Study Region.

**Table 6.3-4: Outstanding Issue Summary Table**

| Area | Model Year | Limiter/System Need | Contingent Level (%, PU) | Rating | Con. Type | Contingency | Plan Status | Branch or Device ID | Resolution Status |
|---|---|---|---|---|---|---|---|---|---|
| Minnesota | 2009 | Cromwell and McGregor 115 kV | 0.88 p.u |  | B | Mahtowa-Wrenshall 115 kV | N.A | N.A | MP will perform a separate study to determine a new 115 kV source into the Cromwell area |
| Minnesota | 2009 | Mahtowa, Cromwell and McGregor 115 kV | 0.87 p.u |  | B | Wrenshall-Thompson 115 kV | N.A | N.A | MP will perform a separate study to determine a new 115 kV source into the Cromwell area |

*N.A – Not Available*

## 6.3.3 Operational Issues (AFC/TLR)

Midwest ISO Reliability Authority continues to monitor approximately 32 constrained flowgates within the MAPP region. These constraints can limit MAPP imports and exports under various conditions, and require continuous monitoring. Reliability problems are not expected as long as limits are identified in real time and respected.

The Salem 345/161 kV transformer (ALTW), an existing Midwest ISO flowgate is sensitive to south-to-north and east-to-west transfers. The base case flow on this transformer has increased since the 2003 summer. This is primarily due to an increased south-to-north bias. Updates to local line impedances and an increased ALTW load since the 2003 summer also contributed to the increase. A Salem Transformer Emergency Operating Guide (ALTW) applicable for post-contingency has been developed that calls for opening the Salem 161 kV bus tie (ALTW); however, its implementation would overload the Asbury-Lore 161 kV line (ALTW) under certain system conditions. ALTW plans to re-conductor the Asbury-Lore 161 kV line prior to the 2005 summer season. The reconductoring of this line allows the implementation of the Salem Transformer Emergency Operating Guide. The Midwest ISO and the Eastern Iowa study group will review this contingency and recommend a solution. It is possible that a 550 MVA Salem 345/161 kV transformer may be recommended.

Alliant Energy–IPL and Dairyland Power Cooperative presently is upgrading its 161 kV system, which includes the Asbury–Lore 161 kV , Salem–Maquoketa 161 kV , and Galena 161/69 transformer in the Dubuque, IA area for increased capacity for issues caused by loss of the Wempletown–Paddock 345 kV line connecting Illinois and Wisconsin. ATCLLC and ComEd are constructing the second Wempletown-Paddock 345 kV circuit; it is expected to be in-service by 6/1/2005 and long term proposal to construct an additional 345 kV circuit from south-central Wisconsin to either north-central Illinois or northeast Iowa in the 2012-2014 timeframe would strengthen the south-to-north and east-to-west flows and mitigate AFC/TLR issues on the Iowa system. Alliant Energy is also rebuilding the Poweshiek–Reasnor 161 kV line to mitigate overloading due to loss of the Montezuma–Bondurant 345 kV line. A joint effort by ALTW and XEL to build a second Lakefield–Fox Lake 161 kV line prior to the 2006 summer season would also mitigate the AFC/TLR issue for loss of Lakefield–Wilmarth 345 kV line. In addition, the Midwest ISO and ALTW will perform a comprehensive planning study of eastern Iowa that will include evaluating options to relieve loading on the Hills_IE 345/161 kV transformer for loss of Tiffin–D. Arnold 345 kV line, Wisdom–Triboji 161 kV line for loss of Raun–Lakefield 345 kV line and Arnold–Vinton 161 kV line (ALTW) for loss of Duane Arnold–Hazelton 345 kV line (ALTW). The Eastern Iowa study is currently under way and expected to be completed by early this year.

The MAPP Montezuma West flowgate ATC components were changed in 2004 because the Montezuma West (or Montezuma–Bondurant 345 kV line) flowgate is no longer a proxy OTDF flowgate for the Midwest ISO Poweshiek–Reasnor 161 kV line/flowgate. The MAPP Montezuma West flowgate ATC components are now defined to limit flows on the Montezuma–Bondurant 345 kV line so that the circuit breaker closing phase angle limits are not exceeded to protect nearby MidAmerican peaking and combined cycle plants from potential shaft torque damage. MEC will continue to have two MAPP 345 kV constrained interfaces (Quad Cities West and Montezuma West). Standing operating guides are in place for both interfaces to mitigate any AFC/TLR issues on these lines.

No significant operational issues are expected for northern MAPP sub-region. The existing standing operating guides, and temporary operating guides that are developed as needed, have proven to effectively deal with the system conditions throughout the year. The Manitoba–United States configuration was enhanced so that the scheduling limits were increased by 200 MW system-intact prior to last winter. Increased southward transfer flows from Manitoba may be experienced this summer, but they have not occurred yet.

No significant operational issues are expected in Nebraska during 2005. Lincoln Electric System (LES) experienced a bulk transmission transformer failure on January 27, 2004. This 345/115 kV transformer is a critical interconnection to the bulk transmission system. The transformer repair or replacement is estimated to take 12-18 months. LES and NPPD are developing operating procedures necessary to maintain system reliability in the Lincoln area. Currently undergoing diagnostic testing, however, ongoing test issues make it less than certain that the transformer will be in-service prior to midsummer 2005.

### 6.3.4 Analysis Details

The outstanding issues of the Baseline Reliability Study are summarized above. Technical details of the Phase 1 and Phase 2 steady-state analysis and Dynamic stability analysis of the 2009 summer peak case for the Midwest ISO system in the MAPP study region are available in Appendix D3.

## 6.4 System-Wide Studies

### 6.4.1 Operational Issues Overview - AFC/TLR

Transmission system constraints that limit the availability of 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 is because mechanisms exist for the curtailment of scheduled transactions when system conditions are other than planned and are designed to prevent system security violations. These commercial limitations give rise, however, to congestion costs that may or may not exceed the costs of relieving the constraints. Much of the congestion realized simply reflects proper management of the system within reliable bounds, 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 an extreme majority of the time. Alternatively, when a transmission limit is reached and generation resources are fully utilized, the situation is very critical. The following discussion provides information about constraints that have been most frequently involved in limiting transactions and measures being taken to ensure reliability is maintained.

The primary value in summarizing this information is that the TLR history is pure historical data of one measure of system performance. This summary does not include tracking the individual impacts upon flowgates (FG's) of new FG's being introduced or the dynamics as the system itself changes over time. While no particular attempt has been made in MTEP to dissect specific historical data or merge commonly impacted FG's, this summary (particularly the individual FG charts in Appendix D9) provide 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 project needs or in addressing stakeholder questions about the transmission system. This MTEP report does correlate where planned expansions are expected to mitigate the need for future TLR. Similarly, expansions have been identified that may mitigate negative AFC. Therefore, this section attempts to report the overall congestion metrics, and known related expansion activity. More substantive congestion planning may be realized from post March 31, 2005 market data, and expansion studies that are base on simulating future market loadings of the system.

Historically the transmission reservation process has attempted to measure the available flowgate capacity (AFC) and used that as a basis on which to grant or refuse additional service requests. Subsequent to the granting of transmission service, transmission loading relief (TLR) is a procedure to control flows and prevent system security violations. Beginning March 31, 2005 the Midwest ISO intends to implement a centrally controlled security constrained dispatched as a part of the LMP based market, and this dispatch will become 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. MTEP reports after 2005 may contain a review of system limits based on central dispatch history. Such central dispatch history may provide information to better resolve if the cost of relieving constraints would warrant network expansion solutions. Meanwhile this report associates known expansions that will mitigate TLR at certain locations. It should be recognized that the historical TLR has often only been needed to serve as a security operating mechanism where expansion solutions were not necessary. Therefore, historically predominant TLR locations may or may not be associated with need for transmission facility expansion. The following is the historical information from a transmission service perspective and any subsequently required TLR.

To characterize this massive amount of history, the TLR summaries in the MTEP text focus heavily on average statistics over the past 48 months. This aggregated (or averaged) approach can be misleading in that it does 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 FG to have high average values but not represent an issue going forward. Therefore, the reader is urged to reflect upon the detailed monthly TLR patterns for the top 24 FG's as illustrated in Appendix D9. This MTEP does not expand on the multitude of individual factors for each FG over the 48-month period. It is intended that the charts in Appendix D9 will provide a basis for further insight. On occasions Midwest ISO and its members have provided more intensive analysis and explanations for specific FG's of interest, and will continue to contribute to such forums beyond an MTEP report

### 6.4.1.1 Transmission Service AFC Conditions

With the start of open access transmission service the Available Flowgate Capacity (AFC) process of the Midwest ISO or similar business processes of other OASIS providers was the first type of tool that evolved to manage the open access reservation and use of the transmission system. This approach was implemented out of necessity and has been the primary "before-the-fact" congestion management tool for most of the eastern interconnection. The term "before-the-fact" meaning the months, days, or hours ahead of actual schedules between control areas. While the business practices have been designed to be technical in the sense that the impacts upon flowgates are calculated with realistic network knowledge by applying power flow distribution factors, the result is subject to further distortion due to inaccuracies caused by coordination (or lack of coordination) with adjacent transmission providers and truncating or ignoring very small impacts. While diligent efforts have been made by transmission providers to be consistent and coordinated in evaluation of TSR's the end results are a mix of art and science due to the complexities inherent in providing fair and reliable access to available system capacity. For example, the cumulative effect of small impacts (typically less than 5%), the multitude of coordination policies, and the requirement to implement rules in non-discriminatory fashion results in a system that can either oversell or undersell transmission service.

Midwest ISO Expansion Planning Staff reviewed Available Flowgate Capacity values as of November 25, 2004. Midwest ISO TSR's are evaluated for impacts on 616 flowgates throughout the Midwest ISO tariff footprint[1]. About 40% or 251 of the 616 Midwest ISO TSR flowgates have a zero or negative monthly AFC for the period December, 2004 through October, 2007. This means that any request for service that would add flow above accepted cutoff values for distribution factors to any of these 251 would be refused. This presents a situation where many reservations cannot be approved, but it does not indicate that where there is negative AFC on a flowgate there is a reliability violation. Negative AFC's can occur when despite efforts, there is mis-coordination in selling, inaccurate data or assumptions, or when small impacts below cutoff levels for denying service requests accumulate to exceed flowgate capability. Often, more than one transmission path is reserved for use by a single source. Efforts are made by transmission providers to consider, when evaluating requests for service, that not all such reservations can be scheduled simultaneously. However, the AFC values reflect some measure of reservations that may exceed actual schedule potential at any one time. As a result of these factors, although there may be negative AFC on a flowgate that precludes the equitable sale of additional service impacting the flowgate, there are usually redispatch options that can maintain system reliability, as evidenced by the successful implementation of TLR for many of these flowgates. In rare situations the "redispatch" can manifest itself as dropping load and backing down generation rather than simply shifting generation among sources.

The universal back up, in non-market environments, to assure reliability in managing flowgate capacity is NERC's Transmission Loading Relief (TLR) procedure. Table 6.4-1 is a summary of Midwest ISO AFC versus TLR. The table illustrates that the 40% or 251 of 616 Midwest ISO TSR flowgates that have a zero or negative AFC, account for 84% of the TLR Hours on Midwest ISO TSR flowgates. Including all 616 Midwest ISO TSR flowgates with negative or positive AFC values, 131 have been associated with TLR over a 48-month period from 1/1/2001 to 12/31/2004. Section 6.4.1.2 covers a more detailed discussion of the 316 flowgates (Midwest ISO TSR flowgates plus other Midwest ISO RA responsibility flowgates) that have experienced TLR. For another perspective, Figure 6.4-1 is an illustration the AFC values sorted for all 616 Midwest ISO TSR flowgates and the TLR Hours associated with 131 of them. Of the 131 flowgates, 88 flowgates have a zero or negative AFC value and have been in TLR over the 48-month period from 1/1/2004 to 12/31/2004. Bottom line is that 84% of the historical TLR Hours on Midwest ISO TSR flowgates are associated with flowgates that have a forward-looking zero or negative AFC value. Of those zero or negative AFC values, 24 of the 88 Midwest ISO flowgates accounted for 67% of flowgate hours in TLR and the remaining 64 Midwest ISO flowgates accounted for 17% of the flowgate hours in TLR.

| Table 6.4-1 Transmission Service Flowgates<br>Positive and Negative AFC and Associated TLR Activity | | | |
|---|---|---|---|
| | Positive AFC/FG's | Zero or Negative AFC/FG's | Total |
| Number with TLR | 43 | 88 | **131** |
| Number without TLR | 208 | 277 | **485** |
| Total AFC FG's | 251 | 365 | **616** |
| TLR Hours | 4,640 | 24,700 | **29,340** |
| % TLR Hours | 16% | 84% | **100%** |

*(future AFC's from December 2004 through October 2007)*
*(historical TLR from January 2001 through December 2004)*

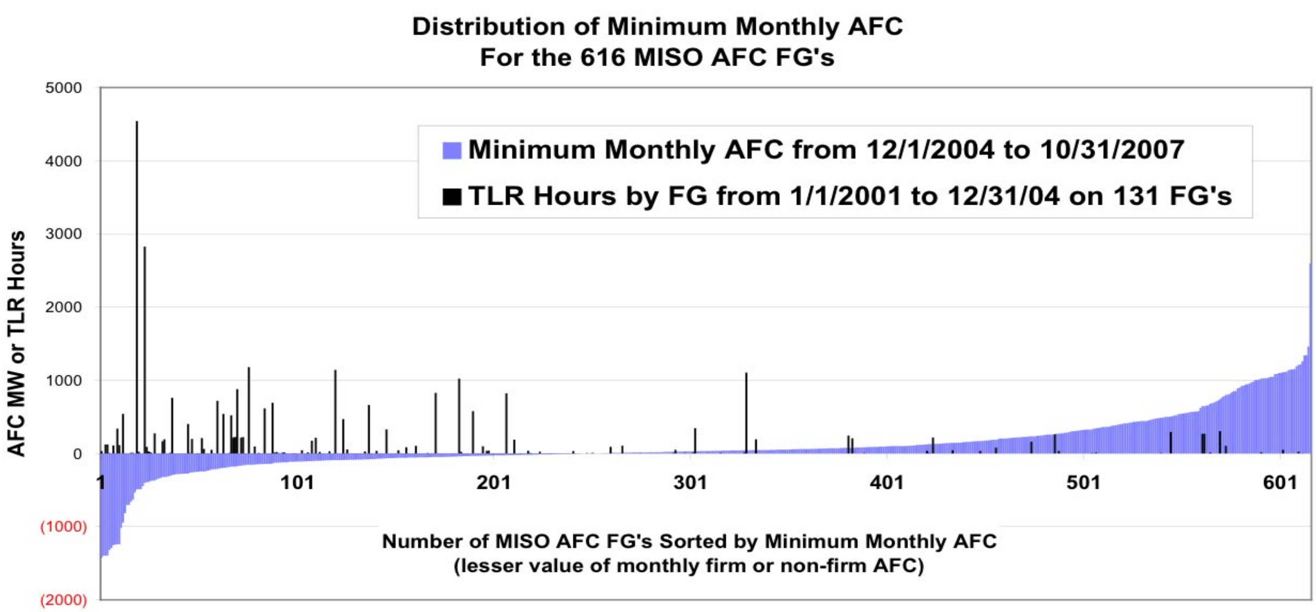



**Figure 6.4-1 Minimum Monthly AFC Flowgate Distribution And Correlation to TLR Activity**

### 6.4.1.2 Resolution of Negative AFC Flowgates

While it is clear from the correlation with TLR events that flowgates with negative AFC do not require mitigation in order to ensure reliability, these flowgates, as with others in frequent TLR do result in congestion costs and need to be reviewed to see whether their resolution is economically justified. The Midwest ISO will be in a better position to be able to make these determinations when we begin monitoring actual congestion costs associated with binding constraints under market operations. Until that time, Midwest ISO has reviewed both flowgates with negative AFC values and those with positive AFC but that have significant TLR hours associated with them and whether or not plans are in place to address these issues. The FG with negative AFC are discussed here and any others that are associated with significant TLR hours are addressed in the TLR discussion in section 6.4.1.4 below.

Of the 251 FG with negative AFC, reviews of plans contained in MTEP 05 indicate that 84 of these will be addressed by these plans . Of the remaining 167 FG with no specific plans in place in MTEP that will likely relieve the loading levels on these FG, 118 are not associated with a TLR call. That leaves 49 of greater interest that were negative, had a TLR, and have no related expansion solution.

Looking forward, a 2009 review was done by running a security constrained dispatch (SCD) model that is indicative of the market dispatch that may be expected for 2009 with planned and proposed projects from MTEP 05 included. The SCD model indicates that of the 251 flowgates that now show negative AFC, 15 of these appear to be significant drivers of congestion costs under the market dispatch, as indicated by the high shadow prices and large number of binding hours associated with these Flowgates. Consequently, a majority of the flowgates with negative AFC do not have a significant impact on Day 2 market operations.

Three of the 15 flowgates in Midwest ISO with higher constraint costs and hours have projects identified to mitigate them. That leaves 12 of the 251 FG that currently show negative AFC values and that therefore limit commercial transactions, for which there are no planned solutions in place and that continue to show the potential under the market dispatch to cause congestion. These flowgates are tabulated in Table 6.4-2 along with the market model congestion parameters: Sum of Flowgate Price at Max (annual value), Average Price at Max (shadow price), Hours at Max (binding hours).

**Table 6.4-2**
**Flowgates with Negative AFC and Congestion in 2009 SCD Model**

| Flowgate Name | Min. AFC | TLR Hours by FG from 1/1/2001 to 12/31/04 | Hours at Max | Sum of Flowgate Price at Max $ | Average Price at Max $ | Project from Appendix A |
|---|---|---|---|---|---|---|
| Moberly–Overton 161 (flo)<br>Thomas Hill–McCredie–Kingdom City 345 | -158 | | 4360 | $257,240 | $59 | |
| Genoa–Coulee 161 (flo)<br>Genoa–LaCrosse 161 | -179 | 219 | 1907 | $150,920 | $79 | Proposed Genoa–Coulee 161 kV line upgrade to 304 MVA - 12/31/08 (Branch 313) |
| Cassville–Nelson Dewey 161 (flo)<br>Wempletown–Paddock 345 | -73 | 36 | 6465 | $129,710 | $20 | Wempletown–Paddock 345 kV line #2 project in 2005 (Branch 344) |
| Renshaw–Livingston 161 (flo)<br>E. W. Frankfort-Shawnee 345 | -58 | 86 | 2461 | $112,870 | $46 | |
| Northside–Jeffersonville Jct. 138 (flo)<br>Northside–Beargrass 138 | -49 | | 112 | $74,700 | $667 | |
| MH_SPC_W | -110 | 45 | 4509 | $61,070 | $14 | |
| Rivermines–Fredricktown 138 (flo)<br>St. Francis–Lutesville 345 | -114 | | 467 | $31,320 | $67 | |
| N. Coulterville–Cahokia 230 (flo)<br>Pinckneyville–St. John 230 | -98 | | 134 | $13,170 | $98 | Upgrade planned for 2007 to increase rating to 400/475 SN/SE. |
| MH_IMO_E | -28 | | 4671 | $11,180 | $2 | |
| Columbia–Portage 138 #1 (flo)<br>Columbia–Portage 138 #2 | (84) | | 56 | $7,940 | $142 | Uprate Portage–Columbia double ckt 138 kV line terminal equipment in 2005 (BR 422, 423) |
| Kenton–Wedonia 138 (flo)<br>Spurlock–Maysville Junction 138 | (14) | | 56 | $5,940 | $106 | |
| Hills 345/161 Xfm (flo)<br>Duane Arnold Unit | (119) | | 46 | $4,010 | $87 | |
| Hills 345/161 Xfm (flo)<br>Tiffin–Arnold 345 | (88) | 55 | 46 | $4,010 | $87 | |
| Murdock–Sidney 138 (flo)<br>Sidney 345/138 Xfm | (54) | | 15 | $1,360 | $91 | |
| Kansas–Murdock 138 (flo)<br>Sidney 345/138 Xfm | (19) | | 2 | $220 | $109 | |

### 6.4.1.3 History of TLR Curtailments

This historical review is based on including a flowgate (FG) 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 TO's, and includes flowgates of non-member systems in the MAPP region that have their RA functions contracted to Midwest ISO. On this basis, there are 841 Midwest ISO flowgates listed in the September, 2004, NERC book of flowgates. TLR was called on 316 of these flowgates during the 48-month period from January 1, 2001, through December 31, 2004. Over this period, 24 Midwest ISO flowgates accounted for 67% of flowgate hours in TLR (each of these 24 flowgates were in TLR for 1% of the time or more). The January 1, 2001 start was selected because at that time curtailment practices became uniform over the entire Eastern Interconnection. NERC began saving data directly from TLR events and placed it in a database. The following review is based on hourly information from the NERC database.

Figure 6.4-2 is a time of day illustration of the total hours that flowgates were required to be under TLR in the Eastern Interconnection, and the portion of TLRs called by the Midwest ISO RA. TLR is more predominant during the active hours of the day. The late PM and early AM hours experience about half the TLR hours as during the mid day hours.

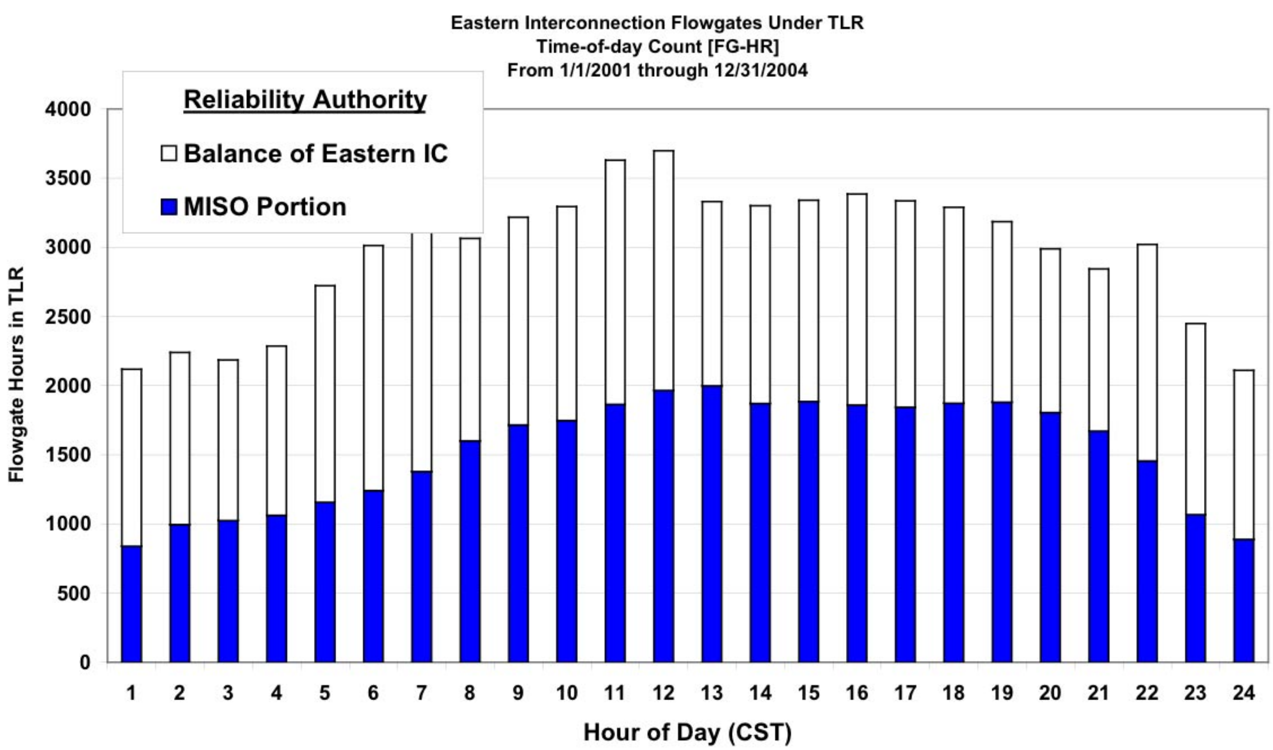



**Figure 6.4-2. Midwest ISO Flowgate TLR Hours by Time of Day Relative Eastern Interconnection**

Nine levels of TLR are listed below. Figure 6.4-2 and other summaries in this report are inclusive of the TLR levels ranging from curtailing transactions (Level 3a) to taking Emergency action (Level 6).

**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

**Level 3b:** Curtail transactions using Non-firm Point-to-Point transmission service to mitigate 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)

**Level 5b**: Curtail transactions using Firm Point-to-Point transmission service to mitigate operating security limit violations

**Level 6**: Emergency action.

Figure 6.4-3 illustrates grouping Midwest ISO curtailments by time of day and TLR Level. The totals are the same as the Midwest ISO portion in Figure 6.4-2, but in addition Figure 6.4-3 shows how the contribution from each priority level varies throughout the day. Levels 3 and 4 are the most significant contributors to causing the daily pattern. Figure 6.4-4 illustrates grouping Midwest ISO curtailments by month and TLR Level. This reflects a general increasing trend, but can experience both high and low periods of activity. The lowest periods are during late winter and early spring.

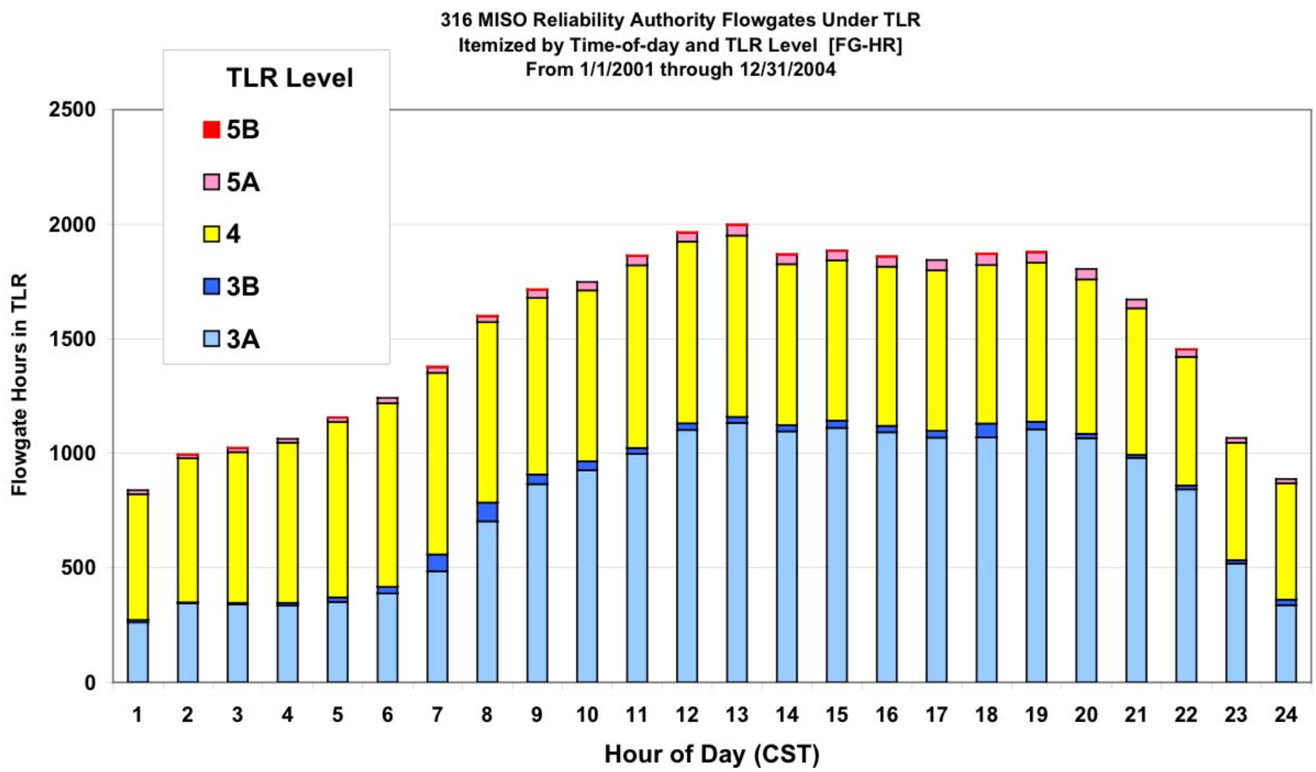



Figure 6.4-3. Midwest ISO Flowgate Hours by Time of Day

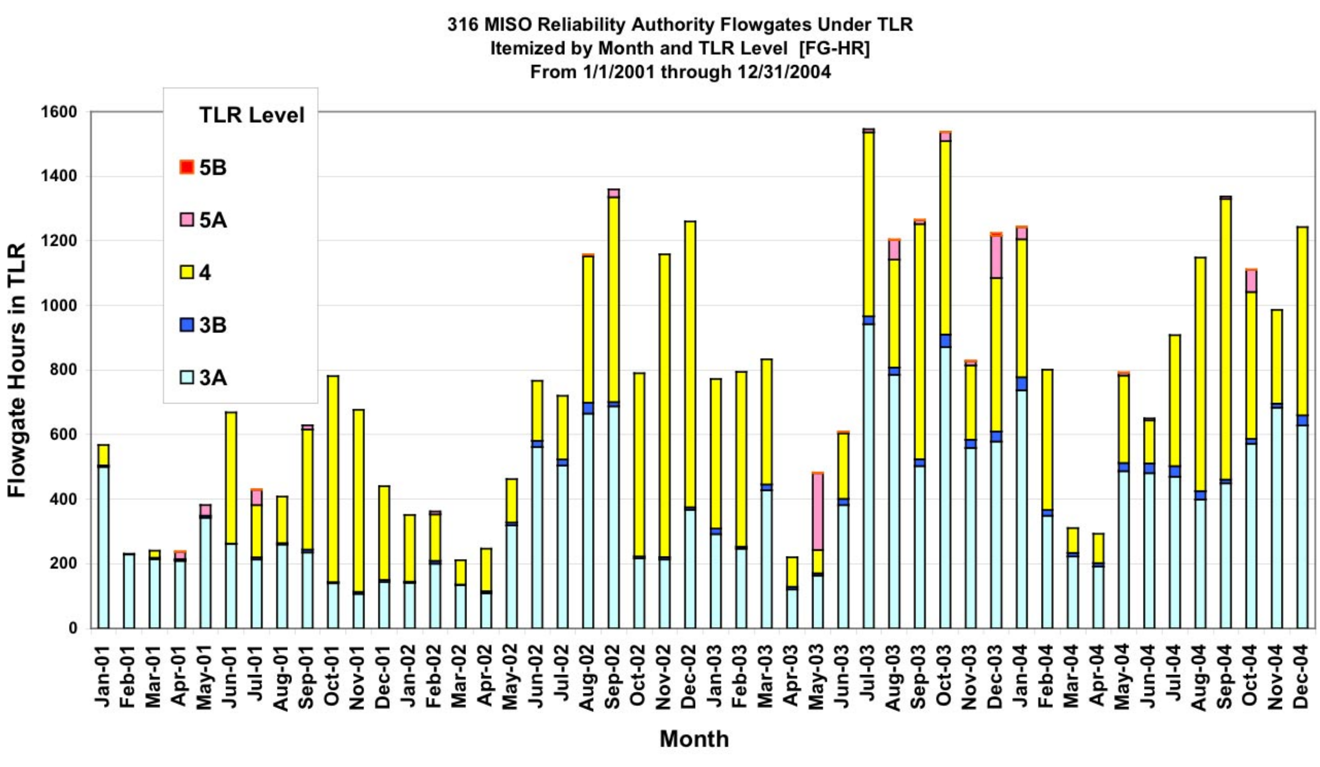



Figure 6.4-4 Midwest ISO Flowgate Hours by Month

Figure 6.4-5 shows the TLR hours distributed over the predominant 24 Midwest ISO flowgates involved during the same 48-month period. The 24 FG shown in Figure 6.3-5 accounted for two thirds or 67% of all Midwest ISO TLR hours. Similarly, the top eleven flowgates included in Figure 6.3-4 accounted for half of all Midwest ISO TLR hours.

There has been a flattening effect compared to the analysis in MTEP 03. In MTEP 03 just 19 FG's accounted for 80% of the TLR hours where as currently it would take the aggregate history of 44 FG's to account for 80% of the Midwest ISO TLR hours. This flattening effect is in part due to the previous 24 months of history having involved TLR on only 110 FG's versus the present 48-month history base where TLR was called on 316 FG's. The increased time frame increases the likelihood of TLR having been called on a larger diverse collection of FG's across the system.

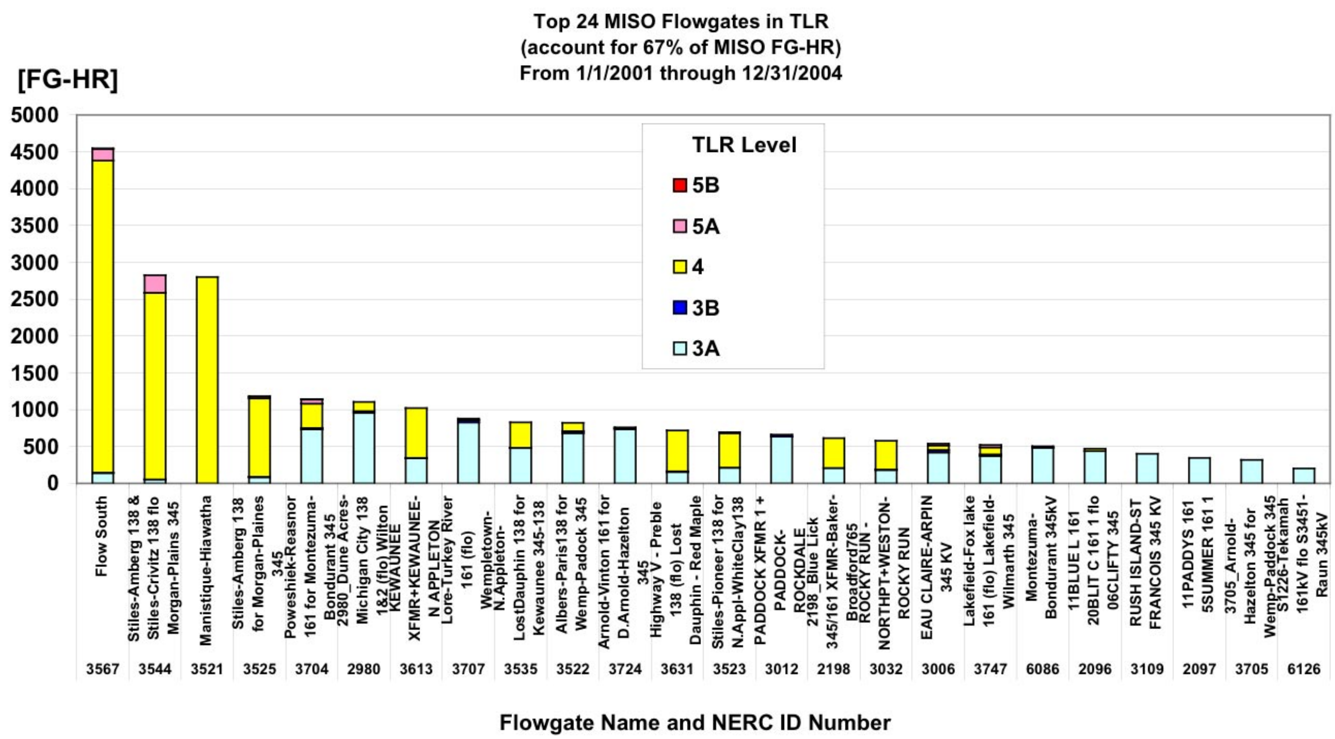



**Figure 6.4-5 Top 24 Midwest ISO Flowgates in TLR Accounting for 67% of Midwest ISO FG-HR from 1/1/2001 through 12/31/2004 Midwest ISO TLR**

The flattening effect is most clear when the TLR activity is itemized by FG and by month. Figure 6.4-6 shows the monthly TLR hours for the leading ten Midwest ISO flowgates individually and the balance of 306 FG combined, over the 48-month period. This demonstrates how curtailments on specific flowgates vary over time since they are dependent upon load levels, generation outage patterns, and transmission outage schedules. Clearly some FG's were active early in the 48-month period and different FG's contribute more heavily later on. Such variables affect the type and location of the competing generation that comprises the market at any moment. The detailed monthly TLR patterns for the top 24 FG's are illustrated in Appendix D9.

The transmission system imposes constraints on the market by being the reason for refusing transmission service, need for TLR calls, or (in the near future) driving LMP prices higher. Absent any constraints or loss effects, only the generation or market prices determine the cost of energy. In the past generation costs plus a margin defined a sell or buy price across the system. After April 1, 2005 the part within the MISO Market is the market cleared price in DA or RT, which is the same in the whole market. After April 1, 2005 the reason why we have different LMP's at different CPNodes is we have different congestion (sometimes zero) and loss cost at different CPNodes

Most of the time the transmission system has adequate capability to maintain reliability while not constraining the generation dispatch. The most frequently curtailed Midwest ISO flowgate in Figure 6.4-5 represents a constraint to generation dispatch or market preferences about 12.9% of the time. In the 48-month period, curtailments affected Firm transmission service (those at TLR Level 5a or 5b) totaled 806 Flowgate Hours. This represents 2.3% of the time in the 48-month period. Of the 806 Flowgate Hours at Level 5 one incident in the northern WI and Upper MI area alone, accounted for 240 Flowgate Hours.

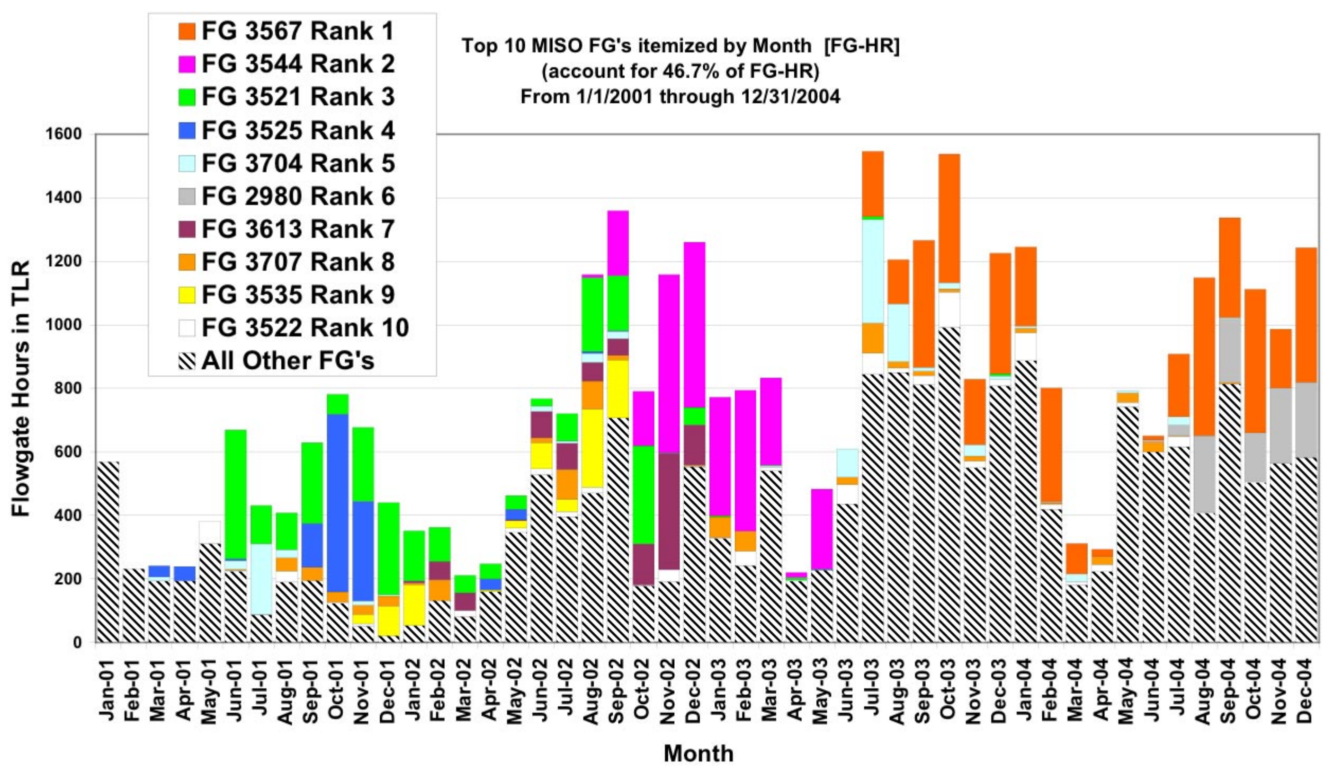



**Figure 6.4-6. Monthly TLR Itemized for 10 Predominant Midwest ISO Flowgates (See Figure 6.4-5 X-Axis Labels for FG Name Associated with NERC FG Number)**

Figure 6.4-7 displays the relative contribution of all 316 FG's. The 80% of TLR accumulation from the top most 44 FG is noted, along with the 350-hour mark which represents one percent of the time in the 48 month period.

The 80% of TLR accumulation from the topmost 44 FG is noted, along with the 350-hour mark which represents one percent of the time in the 48 month period. The 350-hour mark is the cutoff level that defines the top 24 Midwest ISO flowgates.

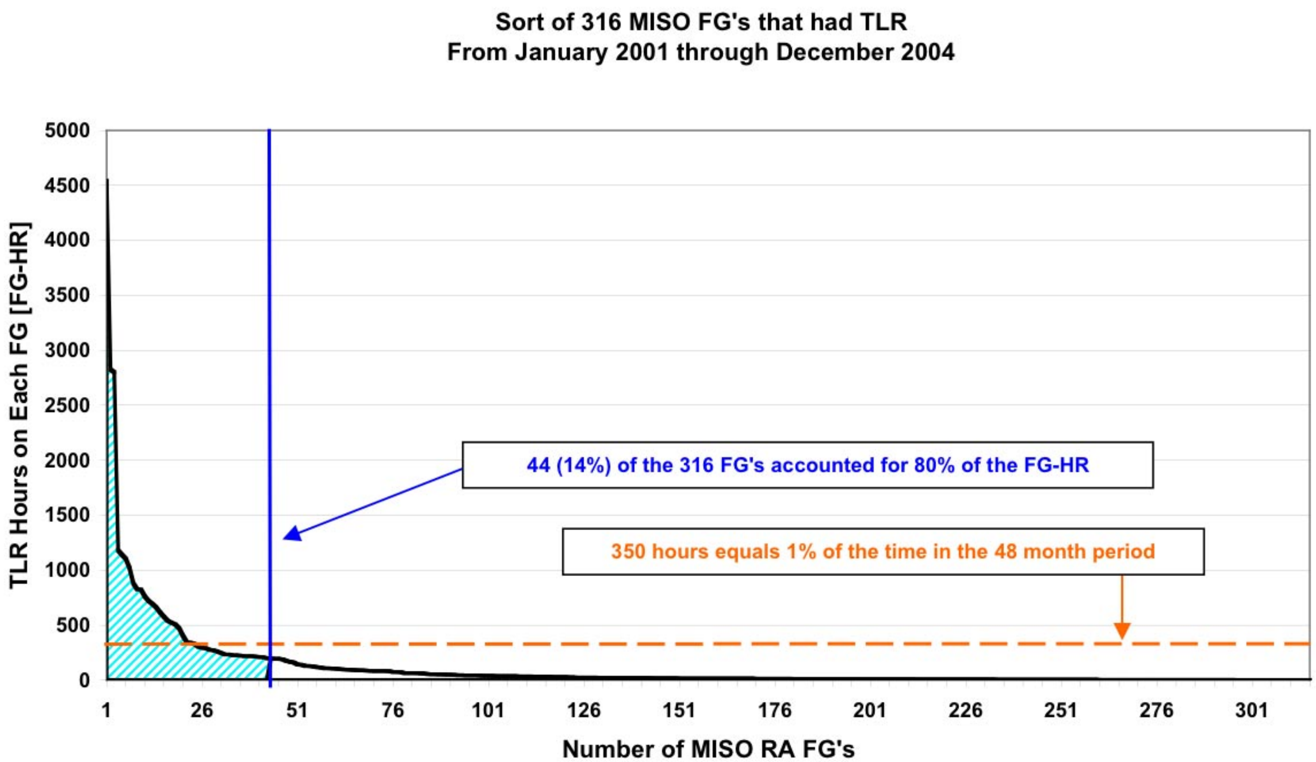



**Figure 6.4-7 Sort of 316 Midwest ISO Reliability Authority Flowgates that had TLR From Jan 2001 through December 2004**

### 6.4.1.4 Resolution of Flowgates that are Constraints to Commercial Operation

Plans identified in this Midwest ISO Transmission Expansion Plan address many of these constraints that fall within the Midwest ISO footprint. The following chart in Figure 6.4-8 shows the specific flowgates that have most frequently involved TLR and that are addressed by projects in this plan, highlighted in white circles.

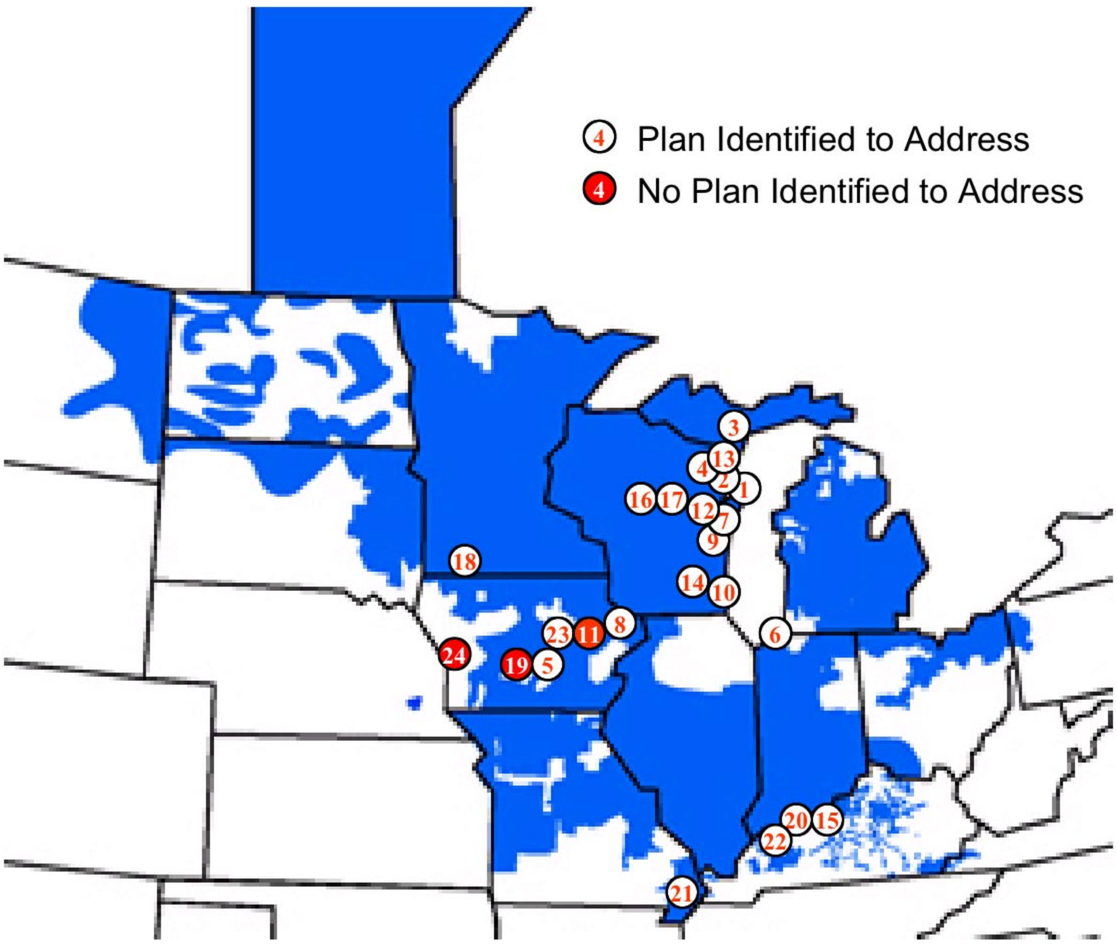



**Figure 6.4-8. Specific Flowgates That Have Most Frequently Involved TLR**

The following Table 6.4-3 lists the member improvements that will contribute to mitigating TLR on 21 of the 24 top Midwest ISO flowgates.

**Table 6.4-3: Top 24 Active Flowgates, 21 With Pending or Completed Improvements**

| MTEP 05 TLR Rank | Flowgate (NERC ID Number) | Pending Improvement or Completed Project (As of MTEP 05) | Year |
|---|---|---|---|
| 1 | Flow South<br>(NERC 3567) | 1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line.<br>2) Uprate Morgan–White Clay 138 kV.<br>3) Rebuild Morgan–Stiles 138 kV.<br>4) Uprate North Appleton–White Clay 138 kV.<br>5) Considering adding a series reactor to the Highway V–Preble 138 kV line.<br>6) Construct a 345 kV line from a new Werner West SS to Morgan. | 1) 2005<br>2) 2005<br>3) 2005<br>4) 2005<br>5) 2005<br>6) 2009 |
| 2 | Stiles–Amberg 138 & Stiles–Crivitz 138 flo Morgan–Plains 345<br>(NERC ID 3544) | 1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line.<br>2) Rebuild the Stiles–Amberg double circuit 138 kV line | 1) 2005<br>2) 2006 |
| 3 | Manistique–Hiawatha 69 kV Circuit<br>(NERC ID 3521) | 1) Rebuilding single circuit 69 kV line to double circuit 138 kV<br>2) Operate rebuilt line at 69 kV until Morgan–Werner West 345 kV line is in-service | 1) 2005<br>2) 2009 |
| 4 | Stiles–Amberg 138 kV Circuit flo Morgan–Plains 345 kV Circuit<br>(NERC ID 3525) | 1) Rebuilding double circuit Plains–Amberg 138 kV line, construct, rebuild and convert the 69 kV & 138 kV line from West Marinett to Amberg as a 138 kV line with portions double circuited with a 69 kV line.<br>2) Rebuild the Stiles–Amberg double circuit 138 kV line | 1) 2005<br>2) 2006 |
| 5 | Poweshiek–Reasnor 161 for Montezuma–Bondurant 345 (NERC 3704) | Reconductor of Poweshiek–Reasnor 161 kV line to 326 MVA | 2005 |
| 6 | Dune Acres–Michigan City 138 1&2 (flo) Wilton Center–Dumont 765<br>(NERC 2980) | Both 138 kV circuits from Dune Acres to Michigan City are planned for reconductor to 186 MVA capacity. | 2005 |
| 7 | KEWAUNEE XFMR+KEWAUNEE–N APPLETON<br>(NERC 3613) | Should be resolved with the installation of the Forest Junction transformer in 2003. In addition, Kewaunee redispatch is still an option | 2003 |
| 8 | Lore–Turkey River 161 (flo) Wempletown–Paddock 34<br>(NERC 3707) | 1) ATCLLC's Wempleton–Paddock 345 kV circuit #2<br>2) Long term proposal of a new 345 kV line to north-central Illinois or northeast Iowa | 1) 2006<br>2) 2014 |
| 9 | N.Appleton–LostDauphin 138 flo Kewaunee 345-138 TR (NERC ID 3535) | Relief is provided by the Forest Jct. Project which loops the Point Beach–Arcadian 345 line into a new 138 kV substation with 345-138 kV TX's | 2003 |
| 10 | Albers–Paris138 for Wemp–Padock 345<br>(NERC 3522) | Construct Wempletown–Paddock 345 kV circuit #2. | 2005 |
| 11 | Arnold–Vinton 161 for loss of D. Arnold–Hazelton 345 (NERC 3724) | None. (Not significantly constrained in 2009 SCD model.) | |
| 12 | Highway V - Preble 138 (flo) Lost Dauphin - Red Maple 138<br>(NERC 3631) | Install a series reactor on the Highway V - Preble 138 kV line | 2005 |

**Table 6.4-3 Twelve of Top 24 Flowgates With Pending or Completed Improvements (cont.)**

| MTEP 05 TLR Rank | Flowgate (NERC ID Number) | Pending Improvement or Completed Project (As of MTEP 05) | Year |
|---|---|---|---|
| 13 | Stiles–Pioneer 138 flo N.Appl–WhiteClay138 (NERC ID 3523) | Rebuild the Morgan–Falls–Pioneer-Stiles 138 kV line to double circuit 138 kV and operate as a single circuit initially | 2006 |
| 14 | Paddock XFMR 1 + Paddock Rockdale (NERC 3012) | Construct Wempleton–Paddock 345 kV circuit #2 | 2005 |
| 15 | Blue Lick 345/161 XFMR–Baker–Broadford765 (NERC 2198) | Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project | 2009 |
| 16 | Rocky Run–NorthPT+ Weston–Rocky Run (NERC 3032) | Rocky Run-Northpoint has had switches replaced. Northpoint–Weston will be rebuilt in 2006. Weston–Rocky Run will see relief with the new Gardner Park ss planned for 2006. | 2006 |
| 17 | Eau Claire–Arpin 345 kV Circuit (NERC ID 3006) | Arrowhead-Weston 345 kV line | 2008 |
| 18 | Lakefield–Fox lake 161 (flo) Lakefield-Wilmarth 345 (NERC 3747) | Circuit # 2 from Lakefield-Fox Lake 161 kV | 2006 |
| 19 | Montezuma–Bondurant 345 kV (NERC 6086) | None (Not constrained in 2009 SCD model) | |
| 20 | 11BLUE L 161 20BLIT C 161 1 flo 06CLIFTY 345 11TRIMBL 345 (NERC 2096) | Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project | 2009 |
| 21 | Rush Island–St. Francois 345 kV (NERC 3109) | A second Rush Island–St. Francois 345 kV line was completed in 2003, eliminating this line as a limit to system transfers. | 2003 |
| 22 | 11PADDYS 161 5SUMMER 161 1 (NERC 2097) | Proposed Mill Creek–Hardin County 345 kV line, a part of Trimble County Outlet #2 project | 2009 |
| 23 | Arnold–Hazelton 345 for loss of Wempleton–Paddock 345 (NERC 3705) | 1) ATCLLC's Wempleton–Paddock 345 kV circuit #2<br>2) Long term proposal of a new 345 kV line to north-central Illinois or northeast Iowa | 1) 2006<br>2) 2014 |
| 24 | S1226–Tekamah 161 kV flo S3451–Raun 345 kV (NERC 6126) | None (Not significantly constrained in 2009 SCD model.) | |

*Legend: flo means "for loss of"*

As can be seen, there are three Flowgates with substantial TLR hours for which there is no specific plan in place to resolve these constraints. As with the AFC analyses above, a review was made of a 2009 security constrained dispatch model that is indicative of the market dispatch that may be expected for 2009 with planned and proposed projects from MTEP 05 included. The SCD model indicates that of these three high TLR flowgates without an associated expansion plan solution, none of these are expected, based on the SCD model to be significant drivers of congestion costs under the market dispatch, as indicated by the low shadow prices and binding hours associated with these Flowgates.

### 6.4.1.5 Financial Transmission Rights Allocations with Binding Constraints

With the start of the Midwest ISO Midwest Energy Market in March of 2005, addressing Financial Transmission Rights (FTR) will now become part of the MTEP transmission expansion planning process. The first FTR allocation was completed by Midwest ISO in January 2005, which produced a list of binding transmission constraints. This list of binding constraints was reviewed in light of the expansion plan developed in MTEP 05(see table 6.4-4 below).

**Table 6.4-4: FTR Allocation Binding Constraints with System Upgrade Project**

| Binding Constraint Name | Contingency | System Upgrade or Comment | App A Branch |
|---|---|---|---|
| Richland–Ridgeville 138 | Midway–Naomi–Wauseon 138, Naomi–Richland 138 | Proposed upgrade to 193MVA - 6/1/2005 (FE) | |
| Power JctB–Power; 138 | Duck Creek–Tazewell 345 | None | |
| Bluemnd6–Butler 138 | Arcadian–Granville 345 | Lannon Jct. Substation in 2007. | 103 |
| Genoa–Coulee 161 | Genoa–LaCrosse 161 | Proposed line upgrade to 304 MVA - 12/31/2008 (DPC) | 313 |
| Mason Cy–1346A TP 138 | Duck Creek–Tazewell 345 | None | |
| Newton–Effinghm 138 | Newton–Casey 345 | Planned line reconductor to 382 MVA - 6/2006 | 390 |
| Fawkes Tap–Fawkes 138 | Fawkes EKPC–Fawkes 138 | Proposed line upgrade to 277 MVA - 11/30/2007 | 485 |
| Farr RDJ–Tippy 138 | Ludington–Keystone 345 | Planned line upgrade to 286.8/329.9 MVA - 5/1/2005 and Tippy–Hodenpy 138 rebuild - 6/1/2006 | 534, 535 |
| Gibson C–GibsonCP 138 | Base Case | Gibson City Plant generation can be designated for a maximum of 174 MW unless Gibson City S–Brokaw and Gibson City S–Paxton 138 kV lines are upgraded. | |
| Green River Steel–Cloverport 138 | Smith–Hardin County 345 | None | |
| Havana–Ipava 138 | Havana–Monmouth 138 | Planned line reconductor to 243 MVA - 6/2006 | 393 |
| Clinton RT54– SClinton 138 | Brokaw–Statefarm–SBloom 138 | None | |
| Clinton Tap–SBloomington 138 | Brokaw–Statefarm - SBloom 138 | None | |
| Lakefield Jct–Fox Lake 161 | Lakefield –Wilmarth 345 | Lakefield–Fox Lake 161 kV line #2 434MVA - 4/1/2006 | 266 |
| Lyon Co–Marshall 115 | Base Case | Upgrades for wind outlet or Marshall area load serving. | 537 |
| Lyon Co–Marshall 115 | Big Stone gen #1 | Upgrades for wind outlet or Marshall area load serving. | 537 |
| Monroe–Wayne 345 | Monroe–Brownstown S 345 | None | |
| Moranvl4 230/115 transformer | Base Case | None | |

**Table 6.4-4: FTR Allocation Binding Constraints with System Upgrade Project (cont.)**

| Binding Constraint Name | Contingency | System Upgrade or Comment | App A Branch |
|---|---|---|---|
| Maries 138 / 161 transformer | Bland–Franks 345, Maries-Lakeside 138 | Planned Callaway–Franks 345 kV line -12 / 2006. The Maries 138 / 161 kV Xfmr should not be the limit after implementation of the Maries operating guide. | 46 |
| Palmyra 345 / 161 Xfm | Palmyra Tap-Sub T 345 | None.<br>Emergency rating of Palmyra 345 / 161 kV Xfmr is 370 MVA for the outage of the Louisa–Sub T-Hills 345 kV line in Iowa. (Palmyra Tap–Sub T outage is used as a proxy to model this contingency). | |
| Pruntytown–Mt. Storm 500 | Black Oak–Bedington 500 | PJM constraint | |
| Reasnor–Des Moines 161 | Montezuma–Bondurant 345 | Planned line upgrade to 326 MVA - 6 / 1 / 2007 | 1020 |
| Richer–Roseau 230 | Dorsey–Roseau 500 | SPS implemented after Tier 1. No constraint with Special Protection Scheme. | n.a. |
| Spokane–Tinken 120 | Base Case | A radial line. | |
| Weston 345 / 115 tx | Weston gen | Gardner Park substation in 6 / 2006 | 136, 137 |
| Weston–Rocky Run 345 | Weston gen | Gardner Park substation in 6 / 2006 | 136, 137 |

Twenty five binding constraints were identified. Fourteen of the constraints have solutions identified from the existing transmission expansion plan developed in MTEP 05. The remaining constraints don't have a solution identified at this time. As the constraints were just identified in January of 2005, when the MTEP 05 report was being written, additional analysis and plan development will be performed in future MTEP studies to address the long-term binding constraints from the FTR allocation process.

*(Footnotes)*

[1] *Because the Midwest ISO is the Reliability Authority (RA) for an area larger than its Transmission Provider footprint,*
*Midwest ISO calls TLR on up to 841 NERC flowgates.*

## 6.4.2 Deliverability to Load

The Midwest ISO Reliability Authority (RA) area was subdivided into 14 LOLE zones for testing the ability of a load zone to meet its reliability requirements through internal generation plus the use of transmission system for import of external resources. Each of these zones were either consistent with an existing Control Area (CA) or were an aggregate of more than one CA.

In 2009, for 5 of the 14 zones the internal generation mix alone was sufficient to meet the reliability criteria of 1 day in 10 years or an Loss of Load Probability (LOLP) value of 0.1, without depending on support from transmission ties. For the remaining 9 zones, the amount of transmission support needed to sustain reliability criteria was within the import transfer capability of the transmission. Tables 6.4-5 and 6.4-6 list the findings for each zone, with the following discussion providing some background on the table content. In 2004, for 6 of the 14 zones the internal generation was sufficient to meet the criteria.

Two stages of calculations were done. First the Loss Of Load Probability was calculated on the basis that the only resource was the generation internal to a zone. This first stage interim value is referred to as the LOLP without transmission support. Without support meaning without support of transmission tie lines that could be considered as a resource to complement the internal generation supply.

Where an area's stand-alone or without tie line support LOLE value was below the 1 day in 10 year criteria, the amount of additional proxy generation that would achieve the 1 day in 10 year level was calculated.

The amount of the proxy generation was equated to a level of transmission capacity into the area that would be needed to sustain the 1-day in 10-year level. In the last step the ability of the transmission system to provide import capacity was determined, and this import transfer capability was compared to the amount needed to sustain the reliability criteria for each area.

The ability of the transmission system to provide import capacity was quantified by calculating the First Contingency Total Transfer Capability (FCTTC) in to each Sink Zone. The FCTTC was accomplished by using a MUST run of each area to calculate the First Contingency Incremental Transfer Capability (FCITC) and adding the base case import. Tables 6.4-5 and 6.4-6 summarize the generation and transmission capability findings for each of the 14 LOLE areas or Sink Zones.

| Table 6.4-5: Imports needed for meeting Reliability criteria in 2004 | | | | | |
|---|---|---|---|---|---|
| LOLE Zone | | FCTTC (MW) | Imports Needed (MW) | Import Capability Margin (MW) | Comments |
| MAPP1 | (1) | 6947 | 2432 | 4515 | |
| MAPP2 | (2) | -761 | 0 | n/a | Self Sufficient, Normally Exporting in Summer and Importing in Winter |
| MAPP3 | (3) | 2919 | 0 | 2919 | Self Sufficient, LOLP = 0.00169 without support |
| ATC | (4) | 2546 | 1000 | 1546 | |
| SMAIN | (5) | 6973 | 0 | 6973 | Self Sufficient, LOLP = 0.00038 without support |
| METC | (6) | 2325 | 0 | 2325 | Self Sufficient, LOLP = 0.0027 without support |
| ITC | (7) | 3318 | 2862 | 456 | |
| FE | (8) | 4504 | 0 | 4504 | Self Sufficient, LOLP = 0.005 without support |
| CIN | (9) | 5682[2] | 1275 | 4407 | |
| HE | (10) | 1279 | 525 | 754 | |
| IPL | (11) | 1243 | 625 | 618 | |
| LGEE | (12) | 1037 | 0 | 1034 | Self Sufficient, LOLP = 0.002 without support |
| NIPS | (13) | 2508 | 850 | 1658 | |
| SIGE | (14) | 393 | 130 | 263 | |

| Table 6.4-6: Imports needed for meeting Reliability criteria in 2009 | | | | | |
|---|---|---|---|---|---|
| LOLE Zone | | FCTTC (MW) | Imports Needed (MW) | Import Capability Margin (MW) | Comments |
| MAPP1 | (1) | 8082 | 1200 | 6882 | |
| MAPP2 | (2) | -602 | 0 | 1050[3] | Self Sufficient, Normally Exporting in Summer and Importing in Winter |
| MAPP3 | (3) | 2191 | 0 | 2191 | Self Sufficient, LOLP = 0.0004 without support |
| ATC | (4) | 2408 | 700 | 1708 | |
| SMAIN | (5) | 6802 | 0 | 6802 | Self Sufficient, LOLP = 0 without support |
| METC | (6) | 4900 | 0 | 4900 | Self Sufficient, LOLP = 0.03 without support |
| ITC | (7) | 4520 | 4910 | -390 | ITC needs additional 390 MW to meet the criteria |
| FE | (8) | 3773 | 300 | 3473 | |
| CIN | (9) | 11649 | 7000 | 4649 | |
| HE | (10) | 1054 | 650 | 404 | |
| IPL | (11) | 977 | 900 | 77 | |
| LGEE | (12) | 1425 | 0 | 1425 | Self Sufficient, LOLP = 0.0004 without support |
| NIPS | (13) | 2874 | 1555 | 1319 | |
| SIGE | (14) | 281 | 341 | -60 | SIGE needs an additonal 60 MW to meet criteria. |

In 2004, all 14 LOLE zones meet the reliability criteria of 1 day in 10 year. This translates into all zones having sufficient import capability to meet the load obligations in 2004. When load was increased by 5% in all 14 LOLE zones within Midwest ISO footprint, all zones meet the criteria also. (Table 6.4-7)

In 2009, generators from the interconnection queue were added to the 2004 case. Adding generators of Interconnection Agreement Executed (IAE) and Filed (IAF) status from the queue, International Transmission Company (ITC) and Southern Indiana Gas and Electric (SIGE) do not have enough import capability to satisfy the criteria. ITC had an LOLP of 0.262 and SIGE had 0.221 LOLP. (Table 6.4-8) Adding additional generators from the queue of Interconnection Agreement Pending (IAP) status and other "active" status generators didn't help ITC and SIGE since those generators were from LGEE, NSP (MAPP1 LOLE zone), WPS (ATC zone), and SIPC (South MAIN zone) areas. From imports needed in 2009 Table 6.4-6, ITC needs 390 MW of additional imports or new generation in the zone to meet the reliability criteria. Efforts are underway for more detailed analysis to determine imports needed for ITC using PROMOD software. This study will focus on import and export capabilities of companies in Michigan area. Similarly SIGE needs 60 MW of additional import capability or new internal generation to meet reliability criteria in 2009.

Detailed report is given in the appendix.

*(Footnotes)*

[1] *Imports Needed represents the firm capacity a zone needs, to meet the 1 day in 10 reliability criteria. This value was found from "Annual Remaining Load Curve" in MARELI. Each zone's LOLP was based on that zone's peak load hour for that year instead of the system peak. This note applies to both 2004 and 2009.*

[2] *Cinergy's FCITC value in 2004 is less than what Cinergy found in its internal analysis.*

[3] *Considering sufficient capacitors turning ON in northern MAPP and minimal load growth and network changes, the import capability margin is expected to remain near 1050 MW in 2009.*

**Table 6.4-7: 2004 LOLP Results - Base Case and Load Sensitivity Case**

| Target LOLP (Loss of Load Probability) = 0.1 day per year (1 day in 10 year) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 01MAPP1 | 02MAPP2 | 03MAPP3 | 04ATCLLC | 05MAINS | 06METC | 07ITC |
| Base Case | – | – | – | – | – | – | – |
| Load Sensitivity | – | – | | – | – | – | – |
| | 08FEE | 09CIN | 10HEREC | 11IPL | 12LGEE | 13NIPSCO | 14SIGEE |
| Base Case | – | – | – | – | – | – | – |
| Load Sensitivity | – | – | | – | – | – | – |

**Note:** Load Sensitivity Increased load by 5% in all 14 areas.

**Table 6.4-8: 2009 LOLP Results - Base Case and Sensitivity Cases**

| Target LOLP (Loss of Load Probability) = 0.1 day per year (1 day in 10 year) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 01MAPP1 | 02MAPP2 | 03MAPP3 | 04ATCLLC | 05MAINS | 06METC | 07ITC |
| With IAs E&F | - | - | - | - | - | - | 0.262 |
| With IAP | - | - | - | - | - | - | 0.262 |
| With IAs E&F - Coal | - | 0.310 | - | - | - | - | 0.423 |
| With IAs E&F - FOR | - | 0.460 | - | - | - | - | 0.567 |
| | 08FEE | 09CIN | 10HEREC | 11IPL | 12LGEE | 13NIPSCO | 14SIGEE |
| With IAs E&F | - | - | - | - | - | - | 0.221 |
| With IAP | - | - | - | - | - | - | 0.221 |
| With IAs E&F - Coal | - | - | - | 0.261 | - | - | 0.455 |
| With IAs E&F - FOR | - | - | - | 0.191 | - | - | 0.504 |

**Note:**

| | |
|---|---|
| IAs E&F | Agreements Executed (Signed) and Filed |
| IAP | Agreements Pending |
| IAs E&F - Coal | Coal Units less than 75 MW are retired in all 14 Midwest ISO Areas |
| IAs E&F - FOR | Forced Outage Rates were increased by 25% in all 14 Midwest ISO Areas |

### 6.4.3 Small Signal Stability Analysis

As part of the MTEP 05 Baseline Reliability Study, Midwest ISO performed a Small Signal Study Analysis (SSSA) study for the whole Midwest ISO footprint and non-Midwest ISO MAPP members.

The full-size Eastern Interconnection light load model was selected to run the study. The case was studied and reported in this report.

The study work consist of:

- Developed SSAT model
- Power transfers and inter-area modes: three critical modes were identified
- Impacts of Forbes SVC on inter-area mode
- Impacts of loads model

There are multiple inter-area modes existing in the system. Increasing the power transfer from MAPP region to southeast regions causes the damping of one critical inter-area mode decreasing. The power transfers can move both frequency and damping of the related inter-area modes. Three critical inter-area modes were identified.

A few conclusions can been drawn from the study:

i. The electrical distance (impedance) between the generation center and the load center is the fundamental factor to cause inter-area oscillations

ii. The longer distance could cause lower damping of the inter-area modes

iii. The heavier power transfer could cause lower damping of the inter-area modes

The studies showed that the inter-area modes were well damped in the summer peak conditions (e.g. baseline 04 & 09 cases).

The low damping or undamping oscillation could happen under certain heavy long distance power transfer conditions. In the future power market circumstance, more and more power will be long-distance transferred from low price generation area to the high price load centers. We need pay more attention to the inter-area modes. More dynamic / small signal studies are necessary for the various operation conditions.

Possible solutions to improve the damping of the inter-area modes (idea only):

1) Identify several critical inter-area stability interfaces through further small signal / dynamic stability studies under various conditions – generations, loads and power transfers

2) Set up the stability interface limits, which are normally less than the thermal limits. The inter-area modes damping can be maintained to a safe level by limiting the power flows on these interfaces

3) Transmission line expansion plans can directly increase damping of some inter-area modes by decreasing the electrical distance (impedance) between the generators and the loads

4) Set up the supplementary controllers through existed PSS, SVC or HVDC is an efficient way to improve the damping of one (one group of) inter-area mode

# Section 7: Exploratory Projects

## 7.1 General Objectives of Exploratory Studies

In the first Midwest ISO Transmission Expansion Plan, MTEP 03, the Midwest ISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal and wind generation, as well as gas generation based the interconnection queues at the time. This study is available on the Midwest ISO web site. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

Among the dozen potentially regionally beneficial expansion concepts reviewed in MTEP 03, two have been addressed further in this MTEP 05, because of the potential benefits that the preliminary analyses showed, and because of significant stakeholder interest in these two concepts. These two expansion concepts are referred to as 1) the Northwest Exploratory Project, and 2) the Iowa–Southern Minnesota Exploratory Project. Both projects would provide enhanced access by coal and wind resources to load centers in the Midwest ISO.

It is the intention of the Midwest ISO to continue the development of these regional expansion projects through further evaluation of the nature, value, and beneficiaries of these plans. The Midwest ISO intends to recommend such plans as these to the Midwest ISO Board of Directors at such time as the Midwest ISO in collaboration with interested stakeholders can complete these evaluations, and a determination of cost responsibility and recovery can be made, consistent with the Midwest ISO tariff and the Transmission Owners Agreement. Additional regional projects of this type may be evaluated by the Midwest ISO in subsequent MTEP based on stakeholder expressed interest and staff resources.

The Northwest Exploratory study involves generation in the Dakotas and transmission upgrades from the Dakotas to Minnesota. The Iowa–Southern Minnesota Exploratory study involves generation in northern Iowa, southern Minnesota, and South Dakota and transmission upgrades from generation to major load centers in Minnesota, Iowa, and Wisconsin. Both studies are in progress and results to date and future work efforts are described in this section.

## 7.2 Northwest Exploratory Study

### Purpose and Introduction

Midwest ISO identified in MTEP 03 a plan to study the expansion of transmission in the Dakotas and into Minnesota with the goal to eliminate existing market constraints in northwestern MAPP. In addition there is a coalition of generation developers, government entities and utilities interested in expanding generation in the Dakota's that will require similar transmission expansion.

The goal of this study is to continue the study effort in the region begun in MTEP 03 for increasing the power delivery capability of the transmission system from the Dakota's and coordinate with the best information available on potential generation expansion to develop a reliability based technical analysis of transmission developments that can enhance the market and meet the regional reliability needs in northwest MAPP region. This study will be the next step in the Midwest ISO evaluation for the MTEP 05 plan. It will provide the transmission information needed for the interested advocacy groups such as the Upper Great Plains Transmission Coalition (UGPTC) and the local utilities in this region to provide the foundation for the final detailed studies required for commitment and regulatory approval for transmission expansion.

To date, only preliminary results have been developed.

### Scope

The purpose of this study is to evaluate the incremental delivery capability from potential generation development regions in North Dakota and southeast South Dakota that might be achieved with various transmission development scenarios. This evaluation is to determine the transmission capability added to the system with single 345 and 500 kV transmission additions along with various multiple combinations of these transmission additions. Each transmission option will be evaluated for it's increase in transmission delivery from the potential generation expansion regions to the Twin Cities, it's impact on recognized constrained interfaces, and it's flexibility to accommodate various generation development scenarios.

## Issues Under Investigation

- Determine most efficient method of collecting generation from five different geographic sites.
- Determine most beneficial way to deliver power from new potential wind and coal generation locations to load centers.
- Use this information to piece together a full transmission plan that will enable flexibility in implementation.

This evaluation will be based on the increase of transmission capability above the presently recognized limits of the North Dakota Export (NDEX), Manitoba Hydro Export (MHEX) and the Minnesota-Wisconsin Stability Interface (MWSI). The evaluation will be made to encompass a minimum of 2000 MW's of new generation.

The final product is to be a series of projects evaluated for providing the best capability from each site plus for the overall region. It will identify what is accomplished with the best single 345 kV plan, the best single 500 kV plan and the best two, three or any multiple circuit plan required to increase the export capability to the Twin Cities up to a 2000 MW minimum.

The results of this evaluation will provide the necessary information required by Midwest ISO and the utilities to base decisions on the best transmission development concepts for expanding generation in North Dakota and south east South Dakota. This can also provide important information for initiating a Certificate of Need study of any development chosen for further consideration.

## Model Development

The Northwest Exploratory Study used the 2009 summer peak model from the MAPP Regional Study Group (RSG). This model was used in performing the Midwest ISO Baseline Reliability Study as part of MTEP 05. All known generation and transmission projects that are expected to be completed and in-service by 2009 were added to the models. This includes the bulk transmission facilities in the Buffalo Ridge area, the Xcel Energy SW Minnesota 825 MW transmission upgrades. Members of the MAPP RSG have reviewed all of these models and have submitted numerous corrections. Alliant West (ALTW), who is a participant on the MAPP RSG, is a MAIN member and has submitted extensive modeling changes after reviewing these cases.

Summer off-peak models will also be available from the latest stability package developed by the Northern MAPP Operating Review Working Group (NMORWG). These cases will include stressed conditions with maximum simultaneous exports over the three previously mentioned constrained interfaces of NDEX, MHEX, and MWSI. Since the presently allowed power flow limit across the NDEX interface results from stability violations at high simultaneous transfer limits, the need for accurate summer off-peak cases will be critical.

The following interface limits were used for the stressed models.

- NDEX = 2080 MW
- MHEX = 2175 MW
- MWSI = 1480 MW

The 2009 summer off peak is a MAPP 2003 series model and the interface limits were changed in the model using the idevs from the UIP package.

## Generation Options Examined

The following generation options are used in the study for the transfer study analysis:

### Option 1 - Coal Site

500 MW of base load generation level at Belfield, ND connected at Belfield 345 kV bus.

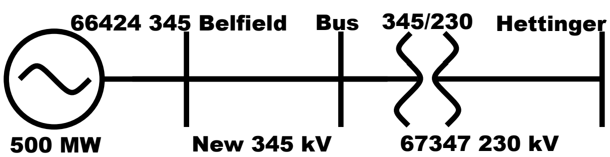



Figure 7.2-1

In order to connect the new generator at Belfield, a new 345 kV line was modeled from Belfield to Hettinger with a new 345/230 kV transformer installed at Hettinger. In addition, a new 345 kV line was also modeled from Hettinger to Oahe and to Watertown to bypass some of the known system constraints on the 230 kV system south of Hettinger towards New Underwood and Rapid City.

### Option 2 - Wind Site 1

250 MW of base load generation southwest of Minot, ND, connected to a tap between Leland Olds and Logan.

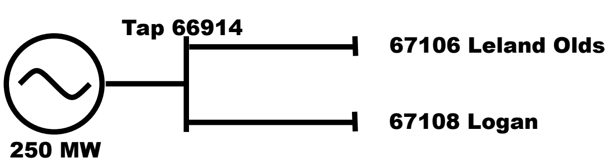



Figure 7.2-2

### Option 3 - Wind Site 2

500 MW of base load generation northwest of Ellendale, ND, connected at intersection of Ellendale – Wishek 230 kV line and Leland Olds-Groton 345 kV line.

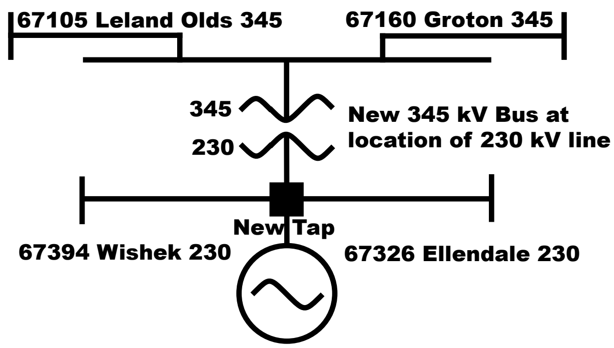



Figure 7.2-3

### Option 4 - Wind Site 3

250 MW of base load generation northeast of Fort Thompson, SD connected at the Fort Thompson 230 kV bus.

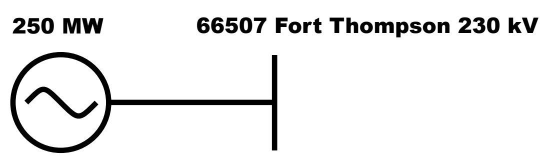



Figure 7.2-4

### Option 5 - Wind Site 4

500 MW base load generation in the Buffalo Ridge area connected at Watertown 230 kV bus.

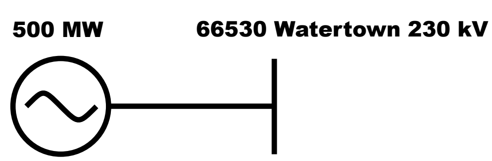



Figure 7.2-5

## Transmission Options in The NW Exploratory Study

Seven initial transmission projects were studied as part of NW Exploratory Study. These are explained below. All of the below options are new construction options.

**Table 7.2-1: Transmission Option 1**

| From | To | kV |
|---|---|---|
| Antelope Valley | Jamestown | 345 |
| Jamestown | Maple River | 345 |
| Maple River | Audubon | 345 |
| Audubon | Badoura | 345 |
| Badoura | Riverton | 345 |
| Riverton | Benton County | 345 |

**Table 7.2-2: Transmission Option 2**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Hettinger | Ellendale | 345 |
| Ellendale | Watertown | 345 |
| Watertown | MN Valley | 345 |
| MN Valley | Blue Lake | 345 |

**Table 7.2-3: Transmission Option 3**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Antelope Valley | Huron | 500 |

**Table 7.2-4: Transmission Option 4**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Watertown | MN Valley | 345 |
| MN Valley | Blue Lake | 345 |

**Table 7.2-5: Transmission Option 5**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Ellendale | Alex Switch Station | 345 |
| Alex Switch Station | Benton County | 345 |

**Table 7.2-6: Transmission Option 6**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Maple River | Alex Switch Station | 345 |
| Alex Switch Station | Benton County | 345 |

**Table 7.2-7: Transmission Option 7**

| From | To | kV |
|---|---|---|
| Belfield | Hettinger | 345 |
| Antelope Valley | Center | 345 |
| Center | Jamestown | 345 |
| Jamestown | Maple River | 345 |
| Maple River | Audubon | 345 |
| Audubon | Badoura | 345 |
| Badoura | Riverton | 345 |
| Riverton | Benton County | 345 |

## Methodology

Transfer analysis was performed on the 2009 summer peak model by evaluating each generation site individually up to two times its base generation level. The primary steady state screening tool will be the PTI MUST program with verification of key results via full AC powerflow. For each generation site, MUST will be used to perform a transfer analysis by delivering generation from each site to the Twin Cities while simulating contingencies in the northern MAPP region. Each transmission option will be tested individually for each of the generation sites. Once all of the generation sites are individually tested, a comprehensive investigation will be performed on all generation sites together with the transmission options tested separately up to a total generation level of 3000 MW's.

Contingencies of 230 kV and above from the MAPP RSG contingency file were performed during this analysis. During the transfer analysis elements with a voltage of 115 kV and higher in North Dakota, South Dakota and Minnesota will be monitored.

Twin Cities area generation was selected for sinking the new generation with an attempt to avoid, to the extent possible, reducing the Sherco, Monticello, Prairie Island and King units since these are the primary base load units and will cause the highest load impacts in the 345 kV.

After the first benchmark run, the team evaluated the initial proposed interconnections to address local issues and possibly identify better interconnections, if needed. These potential new interconnections would then be re-run to establish the base benchmarks. In addition, each transmission project will be reviewed and modified for better performance, if so indicated based on the results of the first run, to take advantage of the information learned from the first run. Those options that are revised will be re-run with the modifications.

The study team used the results of the steady state evaluation to select the alternatives to evaluate for system stability. The same analysis was done on summer off-peak models to understand how the new transmission options behaved under summer off-peak stressed system conditions. The final transmission options would be selected on the results of both summer peak and summer off-peak transfer study results.

## Discussion Of Results with Initial Transmission Options

FCITC analysis was performed with each generation site as the source and Xcel Energy generation acting as the sink. The results are explained below. Summer Peak models were used for the screening transfer studies. Each generation option was dispatched up to twice its output for the transfer study. All the above seven transmission options were tested to determine the transfer capability each option provided for each of the five-generation options.

## Generator Option 1

The following results were observed for a transfer of 1000 MW from Generator 1 into the Twin Cities.

- Constraints around Maple River (OTP).
- Constraints around the generator location.
- Constraints around Leland Olds.
- Constraints in WAPA's 230 kV and 115 kV systems in the southern direction.
- Constraints around Bison, Maurine, and New Underwood.

The transfer capability provided by the transmission options for Generator Option 1 is as follows:

**Transmission Option 1**
The 1st valid limit is 621 MW with BELFELDT 345 66424 BELFELD3 345 limiter for the outage of BELFELD3 345 67183 CHAR.CK3 345 line.

**Transmission Option 2**
The 1st valid limit is 283 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 464 MW.

**Transmission Option 3**
The 1st valid limit is 231 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 306 MW.

**Transmission Option 4**
The 1st valid limit is 279 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

**Transmission Option 5**
The 1st valid limit is 242 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

**Transmission Option 6**
The 1st valid limit is 219 MW with STANLEY7 115 67385 TIOGA4 7 115 limiter for the outage of LOGAN 4 230 67208 LOGAN TY 230 line.

**Transmission Option 7**
The 1st valid limit is 601 MW(DC) with BISON 4 230 66497 MAURINE4 230 limiter for the outage of STEGALL3 345 67207 STEGALTY 345 line.

## Generator Option 2

The following results were observed for a transfer of 500 MW from Generator 2 into the Twin Cities.

- Local 115 kV and 230 kV system violations.
- Overloads in Maple River OTP system.

The transfer capability provided by the transmission options for Generator Option 2 is as follows:

**Transmission Option 1**
The 1st valid limit is 480 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line.

**Transmission Option 2**
The 1st valid limit is 278 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 608 MW.

**Transmission Option 3**
The 1st valid limit is 74 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 452 MW.

**Transmission Option 4**
The 1st valid limit is 203 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 537 MW.

**Transmission Option 5**
The 1st valid limit is 568 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 6**
The 1st valid limit is 416 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 7**
The 1st valid limit is 507 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line

## Generator Option 3

The following results were observed for a transfer of 1000 MW from Generator 3 into the Twin Cities.

- Overloads in OTP Maple River System.
- Violations in OTP and WAPA systems in the southeast and northeast of the generator.
- OTP 230 kV system constraints.
- The 230 kV systems out of Ellendale does not have sufficient capacity.

The transfer capability provided by the transmission options for Generator Option 3 is as follows:

**Transmission option 1**
The 1st valid limit is 458 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency Dak001B 4707.

**Transmission option 2**
The 1st valid limit is 430 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

**Transmission option 3**
The 1st valid limit is 259 MW with HOOT LK7 115 63231 FERGSFL7 115 limiter for the outage of HENNING4 230 63331 FERGSFL4 230 line.

**Transmission option 4**
The 1st valid limit is 439 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

**Transmission Option 5**
The 1st valid limit is 438 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

**Transmission Option 6**
The 1st valid limit is 430 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

**Transmission Option 7**
The 1st valid limit is 480 MW with GARRISN7 115 67308 BEULAH 7 115 limiter for the contingency of GARRISN4 230 66442 GARRISN7 115 Transformer.

## Generator Option 4

The following results were observed for a transfer of 1000 MW from Generator 4 into the Twin Cities.

- Flows into northwest Area towards Leland Olds constraint.
- Constraints around Fort Thompson 230 kV system.

The transfer capability provided by the transmission options for Generator 4 is as follows:

**Transmission Option 1**
There are no valid limiters found for the transfer of 500 MW from Generator option 4.

**Transmission Option 2**
There are no valid limiters found for the transfer of 500 MW from Generator option 4.

**Transmission Option 3**
The transfer capability was negative which means this option cannot provide any transfer capability for Generator Option 4.

**Transmission Option 4**
There are no valid limiters found for the Transfer of 500 MW from the Generator Option 4.

**Transmission Option 5**
The 1st valid limit is 297 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 6**
The 1st valid limit is 352 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 7**
The 1st valid limit is 394 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

## Generator Option 5

The following results were observed for a transfer of 1000 MW from Generator 5 into the Twin Cities.

- Constraints around Leland Olds.
- Local 230 kV systems around Watertown (WAPA).

The transfer capability provided by the transmission options is as follows:

**Transmission Option 1**
The 1st valid limit is 562(DC) MW with JOHNJCT7 115 63216 ORTONVL7 115 limiter for the contingency Dak002B 4708.

**Transmission Option 2**
The 1st valid limit is 38 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 586 MW.

**Transmission Option 3**
The 1st valid limit is -34 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. Therefore, this option cannot provide any transfer capability for Generator Option 5. If we upgrade the Grant County - Morris 115 kV line, the next valid limiter is 270 MW.

**Transmission Option 4**
The 1st valid limit is 86 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 526 MW.

**Transmission Option 5**
The 1st valid limit is 421 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 6**
The 1st valid limit is 403 MW with COULEE 5 161 69523 GENOA 5 161 limiter for the contingency of GENOA 5 161 69535 LAC TAP5 161 line.

**Transmission Option 7**
The 1st valid limit is 254 MW with GRANTCO7 115 66555 MORRIS 7 115 limiter for the contingency of WAHPETN4 230 63331 FERGSFL4 230 line. If we upgrade this line, the next valid limiter is 416 MW.

## Conclusions

Based on the results above, the group decided to concentrate on the Transmission Option 1, 2 and 7 for further study. These three transmission options were selected because the incremental transfer capability provided by each of them was acceptable, as per the study requirements, for each of the five generation options and they do not have negative impacts on the transmission system.

Also, the group decided to make the following modifications to generation options 1 and 3:

- For Generation Option 1 the group decided to add a 345 kV line going from Hettinger to Oahe to Watertown to bypass some of the system constraints on the 230 kV system south of Hettinger towards New Underwood and Rapid City.
- For Generation Option 3 the group decided to add a 345 kV line going from Ellendale to Maple River to bypass some of the system constraints identified on the 230 kV system east of Ellendale towards Hankinson.

With these modifications, another set of the FCITC runs were made for both summer peak and summer off-peak cases and based on those results the following combinations of three lines were agreed upon for further studies.

## Final Three Transmission Options

- Transmission Option 1: Antelope Valley–Jamestown–Maple River 345 kV line with a Maple River–Alexandria–Benton County 345 kV line.
- Transmission Option 2: Hettinger–Ellendale–Watertown–Granite Falls–Blue Lake 345 kV line.
- Transmission Option 2K: Hettinger–Ellendale–Watertown–Granite Falls with a Maple Rive–Alexandria–Benton County 345 kV line.

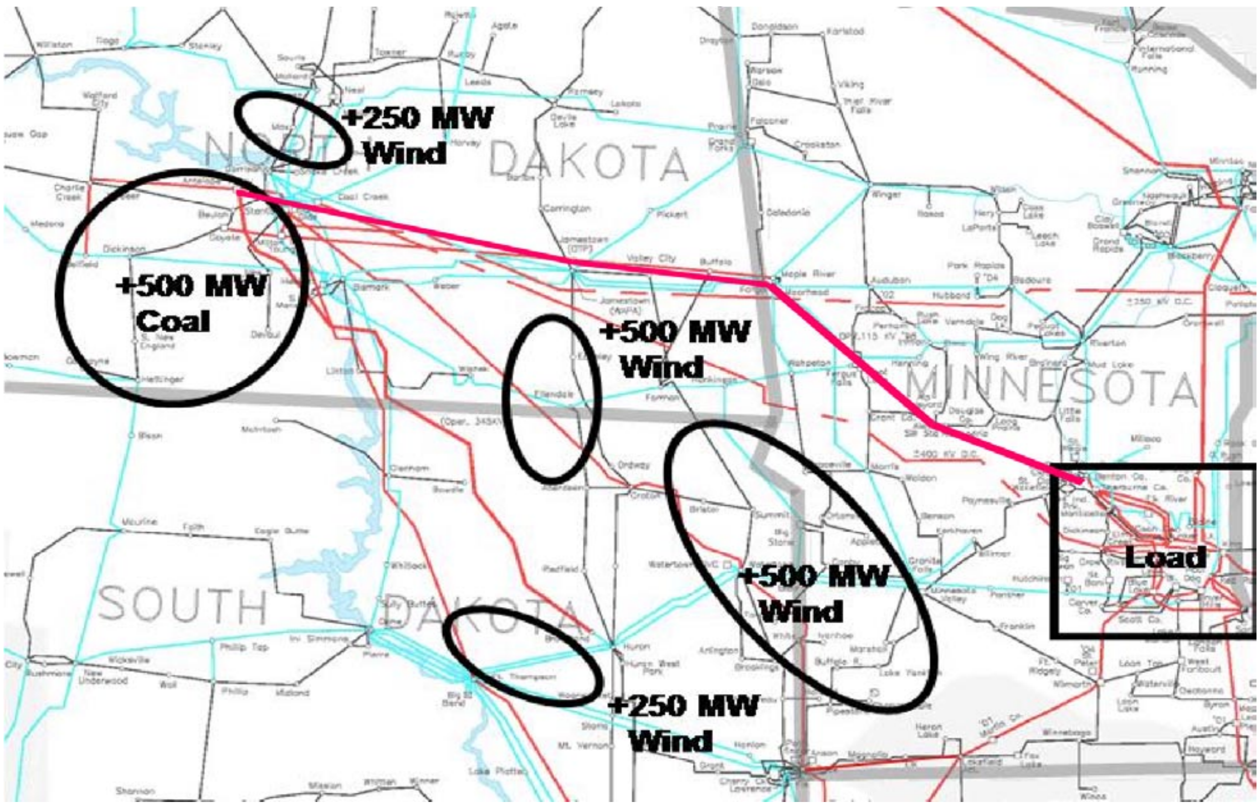



**Figure 7.2-6: NW Transmission Option**

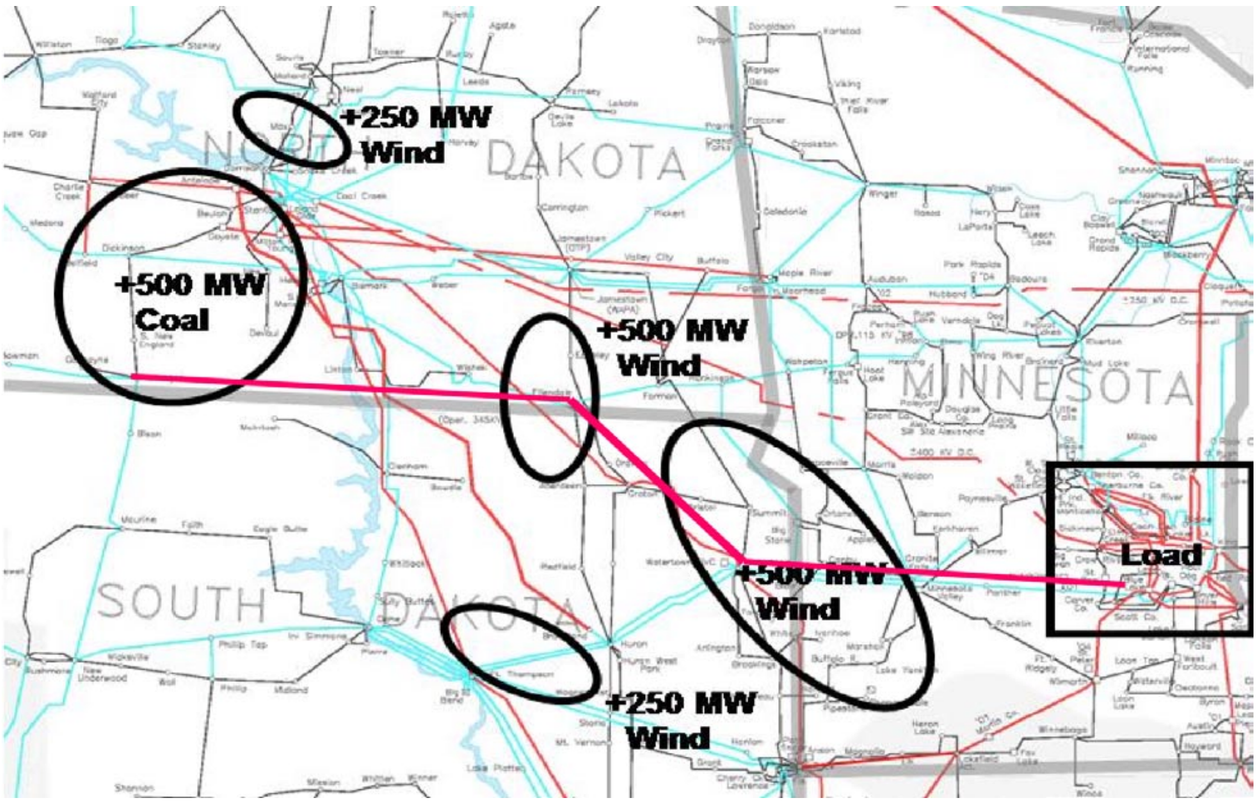



**Figure 7.2-7: NW Transmission Option 2**

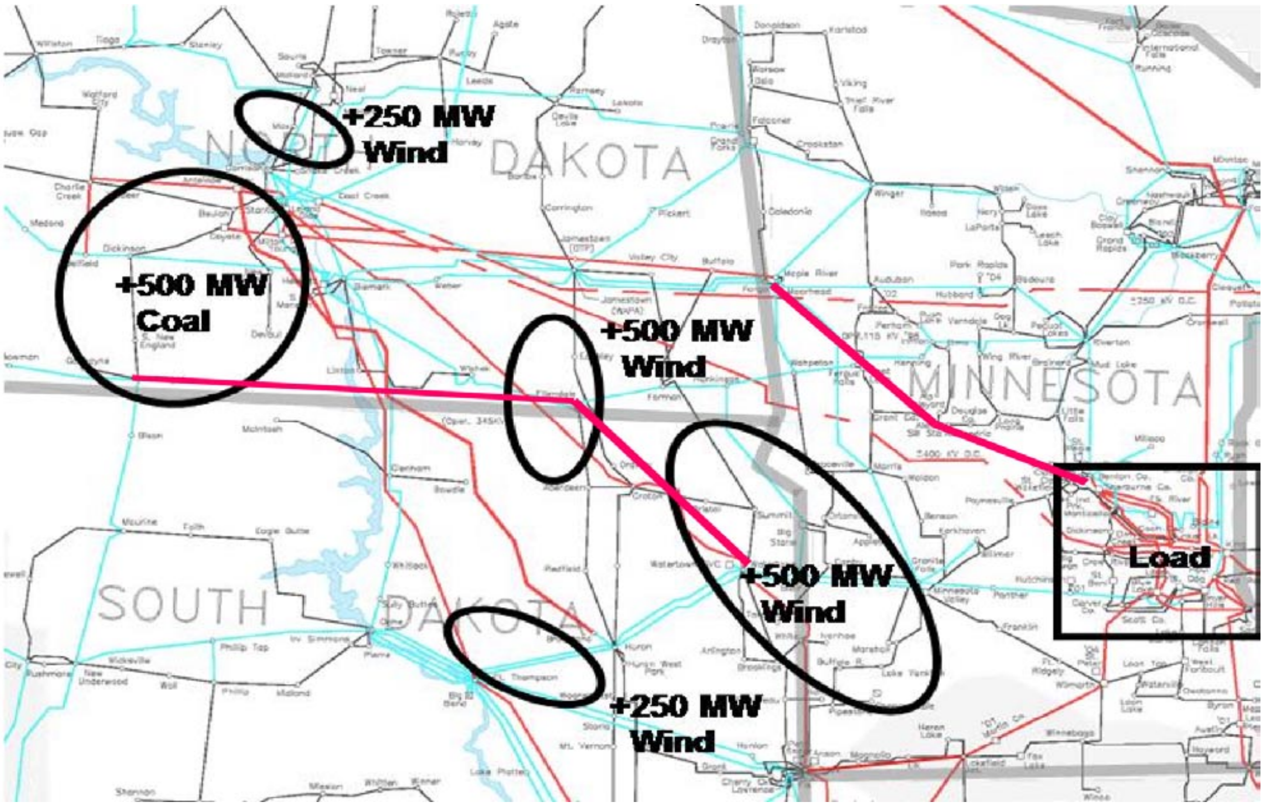



**Figure 7.2-8: NW Transmission Option 2K**

## Tabulation Of FCITC Results

**Table 7.2-8: MUST FCITC Table for 2009 Summer Off-Peak Case**

| | Site 1 (Belfield) generation + Hettinger-Oahe-Watertown 345 kV capability / MW | | Site 2 (Leland Olds-Logan 230 kV line) generation capability / MW | | Site 3 (Ellendale 345) generation + Ellendale-Maple River 345 kV capability / MW | |
|---|---|---|---|---|---|---|
| **Option existing system** | first limiter | second limiter | first limiter | second limiter | first limiter | second limiter |
| | 253 | 356 | 293 | 562 | -1511 | 244 |
| **limiter** | Bemidji–Nary 115 | Bison–Hettinger 230 | Brainerd–Riverton 115 | Hubbard–Palmer Lake 115 | Kerkhoven–Kerkhoven Tap 115 | Brainerd–Riverton 115 |
| **outage** | Hubbard–Audubon 230 & Hubbard 230 / 115 | Hettinger–Oahe 345 | Riverton–Mud Lake 230 | Hubbard–Badoura 230 | Granite Falls–Morris 230 | Riverton–Mud Lake 230 |
| **1** | 505 | No Limit | No Limit | No Limit | 191 | 1272 |
| **limiter** | Bison–Hettinger 230 | none | none | none | Ellendale–Gen3 230 | Brainerd–Riverton 115 |
| **outage** | Hettinger–Oahe 345 | none | none | none | Groton–Gen3 345 | Riverton–Mud Lake 230 |
| **2** | 551 | 710 | 692 | 718 | 64 | 740 |
| **limiter** | Brainerd–Riverton 115 | Bison–Hettinger 230 | Brainerd–Riverton 115 | Huron-Broadland 230 | Ellendale–Gen3 230 | Brainerd–Riverton 115 |
| **outage** | Riverton–Mud Lake 230 | Hettinger–Oahe 345 | Riverton–Mud Lake 230 | Leland Olds–Ft Thompson 345 | Groton–Gen3 345 | Riverton–Mud Lake 230 |
| **2k** | 769 | 841 | No Limit | No Limit | 65 | 1146 |
| **limiter** | Bison–Hettinger 230 | Granite Falls–Minn Valley Tap 230 | none | none | Ellendale–Gen3 230 | Granite Falls–Minn Valley Tap 230 |
| **outage** | Hettinger–Oahe 345 | Brookings–Watertown 115 & Watertown-White 345 | none | none | Groton–Gen3 345 | Brookings–Watertown 115 & Watertown–White 345 |
| | **Site 4 (Ft Thompson) generation capability / MW** | | **Site 5 (Watertown) generation capability / MW** | | **All Sites generation capability / MW** | |
| **Option existing system** | first limiter | second limiter | first limiter | second limiter | first limiter | second limiter |
| | 399 | 527 | 368 | 516 | 262 | 338 |
| **limiter** | Brainerd–Riverton 115 | Mt Vernon–Storla 115 | Brainerd–Riverton 115 | Granite Falls–Minn Valley Tap 230 | Nary–LaPorte 115 | Brainerd–Riverton 115 |
| **outage** | Riverton–Mud Lake 230 | Ft Thomp–Ft Randall 230 & Ft Thomp-Lakplat 230 | Riverton–Mud Lake 230 | Willmar–Granite Falls 230 & Willmar 230 / 69 | Hubbard–Audubon 230 & Hubbard 230 / 115 | Riverton–Mud Lake 230 |
| **1** | No Limit | No Limit | 891 | 976 | 960 | 970 |
| **limiter** | none | none | Johnson Jct–Ortonville 115 | Johnson Jct–Morris 115 | Bison–Hettinger 230 | Ellendale–Gen3 230 |
| **outage** | none | none | Watertown–Granite Falls 230 & Blair–Granite Falls 230 | Watertown–Granite Falls 230 & Blair–Granite Falls 230 | Leland Olds–Ft Thompson 345 | Groton–Gen3 345 |
| **2** | No Limit | No Limit | 689 | 760 | -1 | 244 |
| **limiter** | none | none | Brainerd–Riverton 115 | Granite Falls–Minn Valley Tap 230 | Ellendale–Gen3 230 | Huron–Broadland 230 |
| **outage** | none | none | Riverton–Mud Lake 230 | Granite Falls–Blue Lake 345 | Gen3–Groton 345 | Antelope Valley–Leland Olds 345 1 & 2 |
| **2k** | No Limit | No Limit | 757 | 983 | 273 | 946 |
| **limiter** | none | none | Granite Falls–Minn Valley Tap 229 | Panther–Minn Valley Tap 230 | Ellendale–Gen3 230 | Granite Falls–Minn Valley Tap 230 |
| **outage** | none | none | Brookings–Watertown 115 & Watertown–White 345 | Split Rock–White 345 & Split Rock–Sioux City 345 | Gen3–Groton 345 | none |

**Table 7.2-9: MUST FCITC Table for 2009 Summer Peak Case**

| | Site 1 (Belfield) generation + Hettinger-Oahe-Watertown 345 kV capability / MW | | Site 2 (Leland Olds-Logan 230 kV line) generation capability / MW | | Site 3 (Ellendale 345) generation + Ellendale-Maple River 345 kV capability / MW | |
|---|---|---|---|---|---|---|
| **Option** | first limiter | second limiter | first limiter | second limiter | first limiter | second limiter |
| **existing system** | 302 | 659 | -113 | 340 | 102 | 154 |
| **limiter** | BELFELDT 345 66424 BELFELD3 345 | BENTON 7 115 60146 GRANCTY7 115 | HOOT LK7 115 63231 FERGSFL7 115 | LELANDO4 230 66914 OPT_2 230 | JOHNJCT7 115 63216 ORTONVL7 | OAKES 4 230 67326 ELLENDL4 |
| **outage** | BELFELD3 345 67175 N_HETTI 345 | BENTON 7 115 60348 BENCTP7 115 | HENNING4 230 63331 FERGSFL4 230 | LOGAN 4 230 66914 OPT_2 230 | Dak002B 4704 | GROTON 3 345 67172 TAP_345 |
| **1** | 438 | 662 | 338 | none found | 376 | 669 |
| **limiter** | BELFELDT 345 66424 BELFELD3 345 | BUFFALO3 345 66792 MAPLE R3 345 | LELANDO4 230 66914 OPT_2 230 | | SHEYNNE4 230 66754 MAPLE R4 230 | GOOSELK7 115 62091 VADNSTP7 115 |
| **outage** | BELFELD3 345 67175 N_HETT 345 | JAMESTN3 345 66792 MAPLE R3 345 | LOGAN 4 230 66914 OPT_2 230 | | MAPLE R3 345 61742 N_ALEXA 345 | |
| **2** | 325 | 493 | 338 | none found | 684 | 754 |
| **limiter** | BELFELDT 345 66424 BELFELD3 345 | BENTON 7 115 60146 GRANCTY7 115 | LELANDO4 230 66914 OPT_2 230 | | GOOSELK7 115 62091 VADNSTP7 115 | OAKES 4 230 67326 ELLENDL4 |
| **outage** | BELFELD3 345 67175 N_HETT 345 | BENTON 7 115 60348 BENCTP7 115 | LOGAN 4 230 66914 OPT_2 230 | | | GROTON 3 345 67172 TAP_345 |
| **2k** | 296 | 683 | 338 | none found | 690 | 1146 |
| **limiter** | BELFELDT 345 66424 BELFELD3 345 | GOOSELK7 115 62091 VADNSTP7 115 | LELANDO4 230 66914 OPT_2 230 | | GOOSELK7 115 62091 VADNSTP7 115 | |
| **outage** | BELFELD3 345 67175 N_HETT 345 | KOLMNLK3 345 60251 TERMINL3 345 | LOGAN 4 230 66914 OPT_2 230 | | | |
| | **Site 4 (Ft Thompson) generation capability / MW** | | **Site 5 (Watertown) generation capability / MW** | | **All Sites generation capability / MW** | |
| **Option** | first limiter | second limiter | first limiter | second limiter | first limiter | second limiter |
| **existing system** | -174 | 149 | -157 | 69 | -237 | 112 |
| **limiter** | HOOT LK7 115 63231 FERGSFL7 115 | JOHNJCT7 115 63216 ORTONVL7 115 | HOOT LK7 115 63231 FERGSFL7 115 | JOHNJCT7 115 63216 ORTONVL7 115 | HOOT LK7 115 63231 FERGSFL7 115 | JOHNJCT7 115 63216 ORTONVL7 115 |
| **outage** | HENNING4 230 63331 FERGSFL4 230 | Dak002B | HENNING4 230 63331 FERGSFL4 230 | Dak002B | HENNING4 230 63331 FERGSFL4 230 | Dak002B |
| **1** | none found | none found | 593 | 710 | 530 | 1054 |
| **limiter** | | | BIGSTONY 230 63314 BIGSTON4 230 | JOHNJCT7 115 63216 ORTONVL7 115 | SHEYNNE4 230 66754 MAPLE R4 230 | LXNGTON7 115 62091 VADNSTP7 115 |
| **outage** | | | Dak002B | Dak002B | 3982STK | 022 5 |
| **2** | 480 | none found | 420 | 896 | 615 | 1013 |
| **limiter** | SIOUXF1T 230 66523 SIOUXFL4 230 | | WATERT1T 345 66529 WATERTN3 345 | MNVLTAP4 230 66550 GRANITF4 230 | COULEE 5 161 69523 GENOA 5 161 | HIBRDGE7 115 60239 ROGRSLK7 115 |
| **outage** | SPLT RK4 230 66523 SIOUXFL4 230 | | Dak002B | BLUE LK3 345 61743 N_GRANI 345 | GENOA 5 161 69535 LAC TAP5 161 | 022 5 |
| **2k** | none found | | 533 | 596 | 566 | 1076 |
| **limiter** | | | WATERT1T 345 66529 WATERTN3 345 | MNVLTAP4 230 66550 GRANITF4 230 | COULEE 5 161 69523 GENOA 5 161 | HIBRDGE7 115 60239 ROGRSLK7 115 |
| **outage** | | | Dak002B | WILLMAR4 230 66550 GRANITF4 230 | GENOA 5 161 69535 LAC TAP5 161 | 022 5 |

## Stability Studies

Initial stability analysis was done using the NMORWG Study Package. All present operating guides and special protection systems will continue for the duration of this study. This evaluation is not investigating improving plant operation of the existing generation. The main goal of the stability study is to get a bare minimum plan where each generation addition and transmission addition still maintain system's stability.

Dynamic study work was done using faults in the UIP package and the faults on the new lines. Dynamic simulations were run on 15 models. These 15 cases were developed from the base case and adding the five generators and three transmission options of the study.

## Findings

Stability studies showed that Generation Option 3 and Generation Option 5 have dynamic voltage violations around the point of interconnection.

Stability analysis did not show any potential problems with the addition of new transmission options.

## Next Steps

The Northwest Exploratory Study Group has decided that it would be better to determine if any conversion options perform similar to the new construction options. The group came up with 13 new conversion and new construction options for further study along with the finalized three new construction options. Further transfer studies were done on the 16 total transmission options and the results are being evaluated among the study group and will be presented to the Steering Committee of the Northwest Exploratory Study. The next steps of the study will be decided upon after the Steering Committee evaluates the results. These are the 16 new transmission options.

**Transmission Option A**
This is a conversion option with the Maple River-Sheyenne-Audubon-Hubbard-Badoura-Riverton-Mud Lake-Benton County 230 kV transmission lines being converted to 345 kV.

**Transmission Option B**
This is a conversion option with the Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV transmission lines being converted to 345 kV.

**Transmission Option C**
This is a new 345 kV construction option. It is a single line option from Maple River to the Alexandria Switching Station to Benton County.

**Transmission Option D**
This is a single line conversion option. This option includes converting 230 kV lines from Maple River-Sheyenne-Fargo-Moorhead-Morris-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake to 345 kV.

**Transmission Option E**
This is new single line 345 kV options. This option includes building a Watertown to Blue Lake 345 kV lines.

**Transmission Option F**
This is a new single line 345 kV option. This option includes building a new Antelope Valley-Jamestown-Maple River-Alexandria-Benton County 345 kV line. This is Transmission Option 1 from the initial study group's recommendation.

**Transmission Option G**
This is a combination of both new construction and a conversion of existing line options. This option includes building a new Antelope Valley-Jamestown-Maple River 345 kV line and converting Maple River-Sheyenne-Audubon-Hubbard-Badoura-Riverton-Mud Lake-Benton County 230 kV line to 345 kV.

**Transmission Option H**
This is a combination of both new construction and a conversion of existing line options. This option includes building a new Hettinger-Ellendale-Watertown 345 kV line and converting the existing Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV line to 345 kV.

**Transmission Option I**
This is new single line 345 kV build option. This option includes building a new Hettinger-Ellendale-Watertown-Granite Falls-Blue Lake 345 kV line. This is the Transmission Option 2 from the study group's initial recommendations.

**Transmission Option J**
This is a new double line 345 kV option. This option includes building a Hettinger-Ellendale-Watertown-Granite Falls 345 kV line and building a new Maple River-Alexandria-Benton County 345 kV line. This is the Transmission Option 2k from the study group's initial recommendations.

**Transmission Option K**
This is a new single line 500 kV option. This option includes building a new Antelope Valley-Maple River-Benton County 500 kV line.

**Transmission Option L**
This is a new single line 500 kV option. This option includes building a new Hettinger-Ellendale-Watertown-Blue Lake 500 kV line.

**Transmission Option M**
This is a conversion option, which converts two segments of the transmission system to 500 kV. This option includes converting the Antelope Valley—Huron 345 kV line to 500 kV and converting the Huron-Watertown-Granite Falls-Minnesota Valley-Panther-McLeod-Blue Lake 230 kV line to 500 kV.

**Transmission Option N**
This is a new double line 345 kV option. This option includes building a new Antelope Valley-Maple River-Alex-Benton County 345 kV line and building a new Hettinger-Ellendale-Blue Lake 345 kV line.

**Transmission Option O**
This is a new double line 500 kV option. This option builds a new Antelope Valley-Maple River-Benton County 500 kV line segment and a new Hettinger-Ellendale-Blue Lake 500 kV line.

**Transmission Option P**
This is a combination of both new construction and conversion of the existing line options. This option includes building a new Antelope Valley-Maple River-Benton County 500 kV line and converting the existing Antelope Valley-Huron 345 kV line to 500 kV and building a new Watertown-Blue Lake to 500 kV line.

## 7.3 Iowa-Southern Minnesota Exploratory Study

### Objectives

The objective of the Iowa-Southern Minnesota Exploratory Study (ISMNEX) is to develop a high-level exploratory transmission plan which provides increased transmission capability to facilitate the development and integration of wind generation resources in this area and addresses regional reliability issues. The study results will provide direction to Midwest ISO and transmission providers in the region on how to best develop the transmission system in this region. This exploratory study will not attempt to resolve underlying system issues, but develop an understanding of what bulk transmission improvements would be required to delivery significant amounts of generation. This study is a continuation of the MTEP 03 exploratory study. This study is an open and collaborative planning process with Midwest ISO staff, wind developers, wind advocates, utility planners, and state regulatory staff members in the stakeholder/study group.

### System Issues

The following system issues are drivers for this study. The transmission system in this area has limited capacity to allow for significant development of additional wind generation projects. Because the northern Iowa and southern Minnesota area is a very good wind resource, there are a large number of generator interconnection requests in this area — literally thousands of megawatts of requests. This study will determine how to get 2,700 to 3,500 MW of wind generation to market in addition to existing and committed generation projects. The Rochester, Minnesota area; La Crosse, Wisconsin area; Worthington, Minnesota area and eastern Iowa area all have future load serving reliability concerns. The Minnesota-Wisconsin Stability Interface is a system constraint which can impact the ability of new generation to be sited in Minnesota and Wisconsin. The State of Minnesota also has a Renewable Energy Objective in which utilities in the state should have 10% of energy come from renewables by 2015. This exploratory study will develop a transmission plan which addresses these concerns at a high-level.

### Scope and Methodology

The scope and methodology for Iowa - Southern Minnesota Exploratory Study is described in this section. First, generation scenarios were developed with Midwest ISO Generation Interconnection Queue and stakeholder input to capture realistic wind development in the area. Considering the proposed generation scenarios and regional reliability needs, exploratory transmission options were developed. Next the generation and transmission scenario combinations were screened for thermal limitations using ShawPTI's MUST program. MUST performs linear (DC) First Contingency Incremental Transfer Capability (FCITC) analysis. The MUST screening results were then reviewed and the transmission options were modified, if necessary. When the transmission scenarios are reasonable from a thermal performance standpoint, the study will proceed with the AC powerflow analysis to determine the voltage and thermal performance of the generation and transmission scenarios. The transmission options may be modified at this stage in the study. The final transmission scenarios will be analyzed in using PROMOD to determine the market benefits of the transmission upgrades.

All thermal issues and the associated generation output level when the thermal issues occur will be documented. It is the desire of the stakeholders to develop a transmission plan which delivers a specified amount of generation, instead of developing a transmission plan and determining how much generation the plan could deliver. However, because of the exploratory nature of the transmission, issues on the underlying system will only be documented, but not be addressed by the plan. For example, a 161 kV line may overload at a generation output of 1800 MW. This limitation will be noted. Investment costs to achieve a given level of generation output will be calculated, assuming underlying system overloads can be addressed by rebuilding the transmission line or upgrading transformers.

## Generation Scenarios

The following two generation scenarios (G1 and G2) were developed with stakeholder input at the 8/24/04 study group meeting. A majority of these locations reflect generation interconnection queue projects. However, some generation locations were requested by wind developers. Note that a majority of the generation is located on 345 kV buses for this study, because of the high-level nature and focus of this study.

**Table 7.3-1: ISMNEX Generation Scenarios**

| State Substation kV | | | G1 MW | G2 MW |
|---|---|---|---|---|
| IA | Spencer | 161 | 200 | 200 |
| IA | Webster | 345 | | 300 |
| IA | Eagle | 230 | 120 | |
| IA | Winnebago | 345 | 190 | 300 |
| IA | Top of Iowa | 161 | 200 | 200 |
| MN | Lakefield Jct. | 345 | 200 | 200 |
| MN | Yankee | 115 | 200 | 300 |
| MN | Lakefield | 345 | 300 | 300 |
| MN | Adams | 345 | 500 | 500 |
| MN | Chanarambie | 345 | 200 | 200 |
| MN | Nobles | 345 | 200 | 400 |
| MN | Fenton | 115 | | 200 |
| MN | Byron | 345 | 200 | 200 |
| MN | Rochester–LaCrosse | 345 | | 200 |
| SD | White | 345 | 200 | |
| SD | Big Stone | 345 | | 600 |
| | Total Generation | | 2710 | 4100 |

Two delivery scenarios (D1 and D2) were developed with stakeholder input at the 8/24/2004 study group meeting. Delivery Scenario D2 was later modified. We assumed delivery of the study generation to utility load in the MUST screening, because this would reflect future deliveries to meet the Minnesota renewable energy objective. Note that approximately 2,200 MW of Delivery Scenario D1 is delivered to Minnesota utilities to meet the renewable energy objective requirements. A similar amount is delivered to Minnesota utilities in Delivery Scenario D2 for this purpose. Delivery Scenario D1 goes with Generation Scenario G1 and Delivery Scenario D2 goes with Generation Scenario G2. The Delivery Scenarios used for MUST Screening are described below, with the utilities' MW share of the delivery specified.

**Table 7.3-2: ISMNEX MUST Delivery Scenarios**

| Utility Load to Scale | Scenario D1 MW | Scenario D2 MW |
|---|---|---|
| Minnesota Deliveries | | |
| ALTW (MN) | 30 | 30 |
| MP | 335 | 335 |
| OTP | 68 | 68 |
| XEL | 1110 | 1310 |
| DPC (MN) | 21 | 21 |
| GRE | 325 | 425 |
| MPC | 54 | 54 |
| SMP | 99 | 99 |
| Municipals | | |
| XEL-municipal | 103 | 103 |
| RPU municipal | 69 | 69 |
| DPC municipal | 10 | 10 |
| GRE-municipal | 33 | 33 |
| Iowa Deliveries | | |
| ALTW | 226.5 | 250 |
| MEC | 226.5 | 250 |
| Wisconsin Deliveries | | |
| ALTE | | 1 |
| WPL | | 232 |
| WEC | | 551 |
| WEC | | 4 |
| WPS | | 175 |
| MGE | | 72 |
| UPPCo | | 14 |
| Total MW | 2710 | 4107 |

## Transmission Scenarios

The following two transmission scenarios (T1 and T2) were developed with stakeholder input at the 8/24/2004 study group meeting. Note the scenarios have many lines in common. The differences between them are in how the lines are brought into the Twin Cities and southeastern Wisconsin. Transmission Scenario T1 has 1190 miles of 345 kV transmission lines and Transmission Scenario T2 has 1300 miles of 345 kV lines. Note the Big Stone-Benton County 345 kV line is only modeled with Generation Scenario G2 and is not included in the previous mileage totals for T1 and T2. The table also shows the reduced options (T1b and T2b) which resulted from the first round of MUST screening analysis.

**Table 7.3-3: ISMNEX Transmission Scenarios**

| Line Section Description | Miles | Conductor | Voltage | T1 | T2 | T1b | T2b | State |
|---|---|---|---|---|---|---|---|---|
| Salem-Wempleton | 60 | T2-556 | 345 kV | T1 | n.a. | T1b | n.a. | IL |
| Wilmarth-Blue Lake #2 | 65 | 2-1192A | 345 kV | T1 | n.a. | T1b | n.a. | MN |
| Lakefield-Winnebago | 52 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | MN |
| Winnebago-Hayward | 50 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | MN |
| Hayward-Adams | 30 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | MN |
| Winnebago-Burt | 40 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | IA |
| Burt-Webster | 50 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | IA |
| Burt-Emery | 50 | T2-556 | 345 kV | T1 | T2 | n.a. | n.a. | IA |
| Emery-New Hampton | 50 | T2-556 | 345 kV | T1 | T2 | n.a. | n.a. | IA |
| Hazelton-Salem | 70 | T2-556 | 345 kV | T1 | T2 | T1b | T2b | IA |
| White-Chanarambie | 55 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Chanarambie-Franklin | 95 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Nobles Co-Chanarambie | 41 | 2-1192A | 345 kV | T1 | T2 | n.a. | n.a. | MN |
| Franklin-Blue Lake | 88 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Nobles Co-Wilmarth | 120 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Prairie Island-Rochester | 56 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Rochester-Fremont | 32 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| Fremont-N La Crosse | 44 | 2-1192A | 345 kV | T1 | T2 | T1b | T2b | MN |
| N La Crosse-Spring Green | 116 | 2156A | 345 kV | T1 | T2 | T1b | T2b | WI |
| Spring Green-W Middleton | 29 | 2156A | 345 kV | T1 | T2 | T1b | T2b | WI |
| Salem-Nelson Dewey | 41 | 2156A | 345 kV | n.a. | T2 | n.a. | T2b | IA |
| Nelson Dewey-Spring Green | 60 | 2156A | 345 kV | n.a. | T2 | n.a. | T2b | IA |
| Spring Green-W Middleton | 29 | 2156A | 345 kV | n.a. | T2 | n.a. | T2b | WI |
| Wilmarth-Byron | 80 | 2-1192A | 345 kV | n.a. | T2 | n.a. | T2b | MN |
| Byron-Rochester | 20 | 2-1192A | 345 kV | n.a. | T2 | n.a. | T2b | MN |
| Big Stone-Benton Co | 159 | 2-1192A | 345 kV | G2 | G2 | G2 | G2 | MN |

n.a. = not applicable to the transmission scenario

**Figure 7.3-1: ISMNEX Transmission Scenario T1 Diagram**

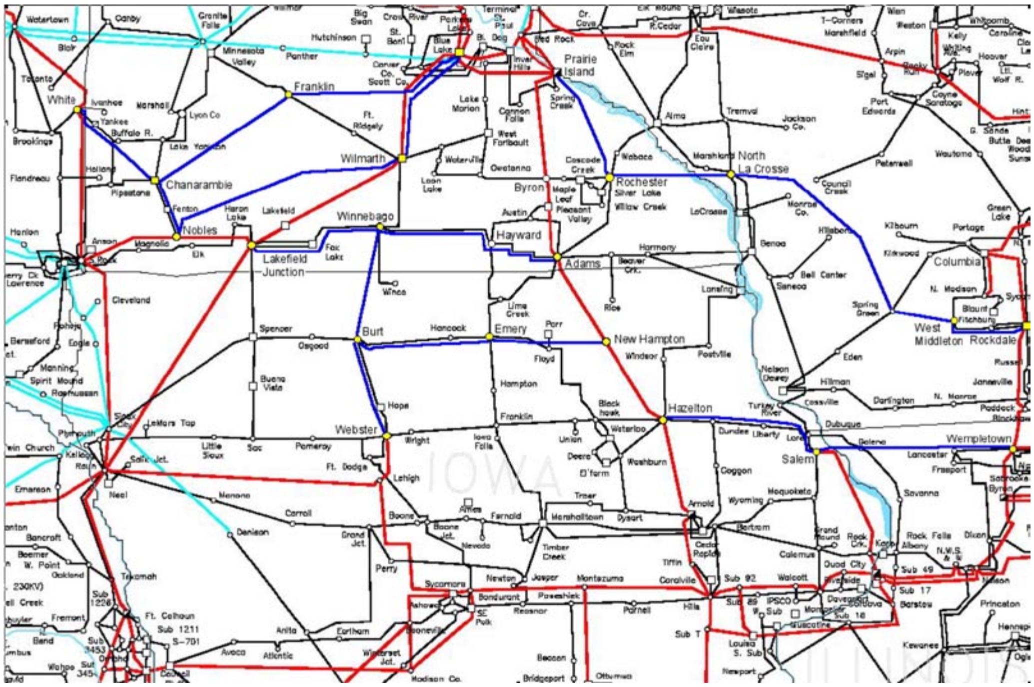
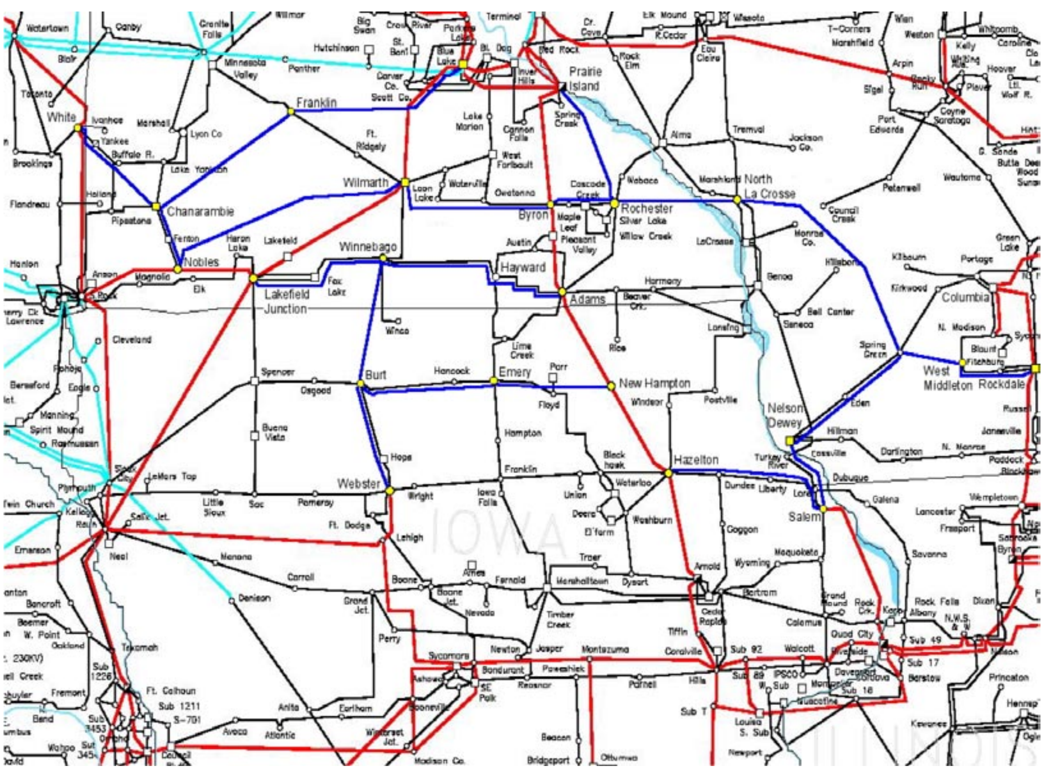



**Figure 7.3-2: ISMNEX Transmission Scenario T2 Diagram**



The transmission scenarios also have transformers at the following locations.

**Table 7.3-4 Transmission Scenarios**

| Transformer Description | Rating | HV-LV | T1 | T2 | T1b | T2b | State |
|---|---|---|---|---|---|---|---|
| White 345/115 TX | 448MVA | 345/115 | T1 | T2 | T1b | T2b | SD |
| Chanarambie 345/115 TX | 448MVA | 345/115 | T1 | T2 | T1b | T2b | MN |
| Franklin 345/115 TX | 448MVA | 345/115 | T1 | T2 | T1b | T2b | MN |
| Winnebago 345/161 TX | 560MVA | 345/161 | T1 | T2 | T1b | T2b | MN |
| Burt 345/161 TX | 560MVA | 345/161 | T1 | T2 | T1b | T2b | IA |
| Emery 345/161 TX | 560MVA | 345/161 | T1 | T2 | n.a. | n.a. | IA |
| Rochester 345/161 TX | 560MVA | 345/161 | T1 | T2 | T1b | T2b | MN |
| North La Crosse 345/161 TX | 560MVA | 345/161 | T1 | T2 | T1b | T2b | WI |
| Spring Green 345/138 TX | 500 MVA | 345/138 | T1 | T2 | T1b | T2b | WI |
| Nelson Dewey 345/138 TX | 500 MVA | 345/138 | n.a. | T2 | n.a. | T2b | WI |
| Big Stone 345/230 TX | 500 MVA | 345/230 | G2 | G2 | G2 | G2 | SD |

## Model Development for MUST Analysis

The MTEP Baseline summer 2009 peak case (Base09S_Jun0104_v03.sav) was used to develop the cases for MUST FCITC screening. Existing wind generation and other significant new generation projects in the study area were turned on at maximum output. Planned transmission upgrades from Appendix A were modeled. The generators in the generation scenarios were modeled on-line with output of 0 MW and no load was scaled, because the MUST program will increase generation and loads to simulate the delivery of the generation to the specified loads. The MUST powerflow models contained transmission scenario facilities. The following powerflow base cases were developed for MUST FCITC screening.

Transmission Scenario T1 and Generation Scenario G1
sp09_t1_g1_must.sav

Transmission Scenario T1 and Generation Scenario G2
sp09_t1_g2_must.sav

Transmission Scenario T2 and Generation Scenario G1
sp09_t2_g1_must.sav

Transmission Scenario T2 and Generation Scenario G2
sp09_t2_g2_must.sav

Note that no Northwest Exploratory transmission option facilities were included in the Iowa–Southern Minnesota Exploratory study base cases. Integration of the exploratory plans may occur in future studies.

## MUST Analysis

The MUST FCITC analysis used the following inputs and assumptions. Analyze all single contingencies for facilities, including tie lines, greater than 100 kV in MAPP and MAIN regions. Monitor all facilities greater than 100 kV , including ties lines, in the MAPP and MAIN regions. Contingent overloads were flagged at 100% of normal rating (rate A). This is more stringent than standard planning criteria, but the study group wanted to capture all elements which may limit delivery of the generation to load. MUST output was filtered with a distribution factor cutoff of 1% and contingency case flow change cutoff of 1 MW.

## Results of MUST FCITC Analysis

All the transmission and generation scenario combinations have thermal limitations on the underlying transmission system. The only exploratory facility which is thermally limited is the Chanarambie 345/115 transformer at 1300 MW of new generation being transferred. Thermal limits were flagged at 100% of normal facility rating, therefore, not all the limiters identified at this level will need to be addressed to enable the transfers to occur. Some limiters are common to all plans. Many limiters appear to be related to increasing Xcel Energy load 1100 MW on 115 kV which is mostly in Twin Cities, and is a result of the generation-to-load delivery assumption.

MUST screening result summaries can be found in Appendix D8.

## Exploratory Facility Loading

There are 35 exploratory lines and transformers between the two transmission scenarios. Each facility was monitored with MUST and maximum flows during system intact and contingent conditions were estimated. Nine of exploratory facilities are over 400 MW (the approximate Surge Impedance Loading (SIL) of a 345 kV line) during system intact, post-transfer condition. Twenty one are over 400 MW during contingencies. A few facilities don't load significantly. However, they would likely be beneficial for load serving during low wind periods.

Estimated exploratory facility flows can be found in Appendix D8.

## Reduced Transmission Scenarios

Midwest ISO staff identified several facilities which were not loading significantly and proposed to the study group that a sensitivity should be performed. The ISMNEX study group agreed to remove the Burt–Emery–New Hampton 345 kV line and Chanarambie–Nobles 345 kV line from the transmission scenarios. The Burt 345/161 kV transformer was going to be removed, but the Burt transformer would likely have reliability benefits for the Webster 345/161 transformer outage. Therefore, the Burt transformer was left in the reduced transmission scenario cases. The Emery transformer was removed as the associated 345 kV was removed.

The powerflow models were created for the reduced transmission scenarios and MUST FCITC analysis was performed. Overall, the reduced scenarios performed similar to the original transmission scenarios, with 140 miles of transmission removed from the scenarios. There were a few new 161 kV overloads in the area where the transmission was removed, but the overloads did not occur until generation transfer levels were around 3400 MW.

## Market Screening

In order to determine the ability of the generation to be delivered to a specific market, MUST FCITIC analysis was performed on the transmission and generation scenarios. A separate transfer of 2500 MW to each of the MN, IA, and WI markets was assumed. Generation-to-Generation dispatch was assumed. Large, low cost base load plants were excluded from the market delivery areas to make the generation dispatch more realistic. That is, the generation being delivered to market should be used to displace high cost generation.

This analysis showed that most limiters were market specific. Only limiters near the generation were common to multiple markets. The Iowa market had a noticeably lower number of limiters at the 2500 MW transfer level.

MUST result summaries for the market analysis can be found in Appendix D8.

## Next Steps

The Iowa–Southern Minnesota Exploratory Study is still in progress. There are several work items remaining before the study will be completed. The parts of the study to be performed are an AC powerflow analysis and a PROMOD economic analysis.

## 7.4 CapX 2020: Identifying Minnesota's Electric Transmission Infrastructure Needs

Minnesota's electric transmission infrastructure—a network of high voltage transmission

Lines of 230 kilovolts and higher—requires major upgrades and expansion over the next 15 years to support customers' growing demand for electricity. To ensure the backbone transmission system is developed and available to serve these growing needs, the six largest Minnesota transmission-owning utilities initiated the CapX 2020 project. CapX 2020 is short for Capital Expenditures by the year 2020.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region; and
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

Great River Energy, Minnesota Power, Otter Tail Power Company and Xcel Energy jointly formed CapX 2020 in the summer of 2004; Missouri River Energy Services and Southern Minnesota Municipal Power Agency subsequently joined this effort, and other investor-owned utilities, cooperatives, and municipal utilities have been following the initiative.

This Interim Report presents our work to date. Its purpose is to create awareness of the significant need for new transmission investment, to inform stakeholders of our study efforts underway, and to begin a public dialogue on transmission issues. We present this report in the following sections:

- *Our future needs,* presenting forecasts of customer demand over the next 15 years.
- *Our current system,* outlining the characteristics and capacity of our current backbone transmission system.
- *A changed market*, describing how management of the transmission network operates under federal reforms.
- *The CapX 2020 planning effort,* providing an overview of our CapX 2020 study.
- *Our preliminary results,* presenting our findings to date.
- *Next steps,* discussing the continued planning effort and inviting stakeholder dialogue.

A final CapX 2020 report is scheduled to be completed in the second quarter 2005.

## 7.5 Other Exploratory Expansion Plans

This section provides an overview of exploratory plans from previous studies and other reliability regions. After tariff additions to address sharing of large interstate projects has been implemented and necessary technical analysis have been performed, some of these exploratory projects may become part of future MTEP recommended expansion plans.

MTEP 03 report[1] outlined transmission plans for Western Nebraska-Western Kansas (SPP 345 kV ) and from Indiana to Kentucky (Rockport-Paradise) that would provide transmission to allow coal derived electric energy to flow toward areas of higher concentrations of gas derived electric energy. This exploratory plan had economic merit in MTEP 03 analysis. Transmission reliability studies would need to be performed to determine how this exploratory plan integrates with the transmission system.

SPP has an exploratory plan, called Plan A that addresses the Western Nebraska-SPP potential transmission expansion.

Peabody Energy Corporation has pursued interconnection studies for the Thoroughbred coal fired plant in Kentucky requiring a TVA to AEP interconnection. The Rockport to Paradise line identified in MTEP 03 proposed a similar interconnection.

The Michigan 765 kV Exploratory Expansion study included a 765 kV line traversing Michigan and connecting to Ontario and the Cleveland area. This exploratory proposal produced little economic benefit for the Midwest ISO footprint in MTEP 03 and was not pursued.

As the energy markets mature, costly transmission constraints will be identified. New exploratory transmission studies will be performed to determine if transmission system upgrades can be made in a cost effective manner to improve market performance.

*Footnotes*

*1 - The MTEP 0 3 report is available on the Midwest ISO web site under Planning and Interconnections and Expansion Planning.*

# Section 8: Summary Transmission Investment Needs

The present Midwest ISO Transmission System consists of 112,000 miles of existing transmission lines. This section provides an overview of the expansion plans identified in the regional expansion planning process. The MTEP documents planned facilities above 100 kV . Of the reported 6,940 mile total for expansion facilities as far out as the year 2017, about 2,852 miles are Planned lines in the 2004 through 2009 timeframe. Together with some planned lower voltage facilities of Midwest SO Transmission Owners, these future expansion facilities become a predictor of additional revenue requirements that must be provided for via the Midwest ISO Tariff.

Most of the plans in development by the Transmission Owners are reliability-driven plans. Projects in the MTEP are designated as either Planned, or Proposed. Planned plans are those for which a system condition has been found to violate applicable planning standards, and the Planned plan has been determined to be the recommended plan from among alternatives. Planned plans are in various stages of corporate internal and external approval processes. Proposed plans are those for which a system condition has been found to violate applicable planning standards, and the proposed plan is the best-known alternative at this time. Proposed projects will continue to be evaluated and, unless system conditions change from projected, the Proposed plan will either become a Planned plan, or will be replaced by a preferred alternative Planned plan in subsequent issues of the MTEP.

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 MISO Reliability Authority (RA). The most significant of these adjacent facilities are included on the MISO Expansion Planning map (Form 3 in Appendix A). Appendix A contains a detailed list of the locally planned facilities. Appendix A includes the following forms:

| | |
|---|---|
| Form 1 | A transmission line list |
| Form 2 | A device list, which are mostly capacitor banks |
| Form 3 | An expansion planning map |

For the purposes of organizing system upgrade information in Appendix A, MISO has grouped the transmission expansion facilities into four planning areas as described below.

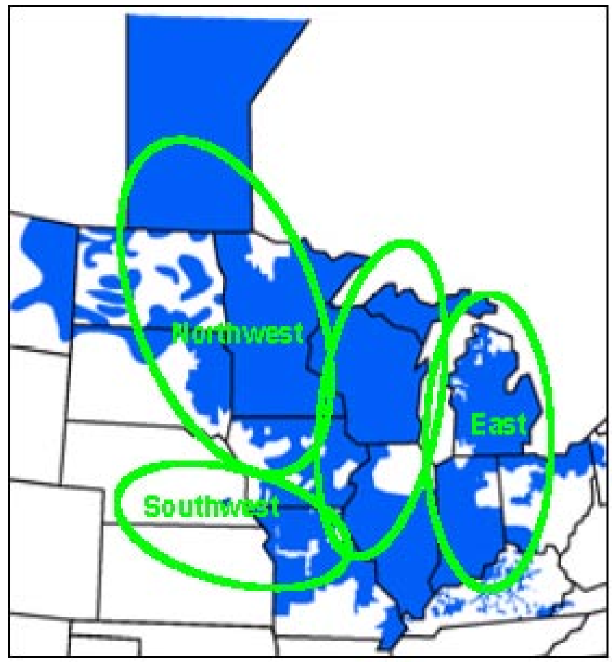



**Figure 8.1-1: Planning Regions in MISO**

**Table 8.1-1: Planning Regions and Sub-Regions**

Tree Structure "Bottom Up" Planning Activity

| | Planning Regions | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Central | | | East | | Northwest | | | | Southwest |
| Existing and Potential Sub Regional Planning Groups | Central and Southern Illinois (C-CSILL) | Northern Illinois (C-NILL) | Wisconsin, Upper Michigan (C-WUM) | S. Indiana, S. Ohio, Kentucky (E-IOK) | Michigan, N. Indiana, N. Ohio (E-MIO0 | Iowa Transmission Working Group (N-ITWG) | Missouri Basin (N-MB) | Nebraska (N-Nebraska) | Northern MAPP** (N-NM) | Southwest (SW) |
| Midwest ISO Member, Pending, and MOU Systems | CWLP Grid Am (AMRN & CILCO) SIPC | * | ATCo | LGEE VECTREN | CIN ITC Grid Am (FE & NIPS) HE IPL METC | ALT | * | LES | OTP MDU MH*** MP XEL GRE | Aquila**** |

* Seams Coordination Only
** Subsequent to MTEP 03 the N-RRV and N-UMV have been combined into the "Northern MAPP" Subregional Planning Group (N-NM)
*** MH is not a Midwest ISO member but coordinates via a Memorandum of Understanding
**** Aquila has a practice of reporting their facilities and coordinating plans through the Nebraska SPG (N-Nebraska)

The total estimated direct cost of the Planned and Proposed facilities plus the facilities that went into service since 2003 is **$2.91 billion** for the six-year period 2004-2009 periods. This is substantially above the **$1.96 billion** that was estimated for the six-year period 2002-2007 in MTEP 03. Of these projects, $204 million were In Service by 2004, $1,565 million are considered Planned, and $1,144 million are considered Proposed and will continue to be reviewed.

The cumulative expected spend over the 2004-2009 period is shown in Figure 8.1-2 below.

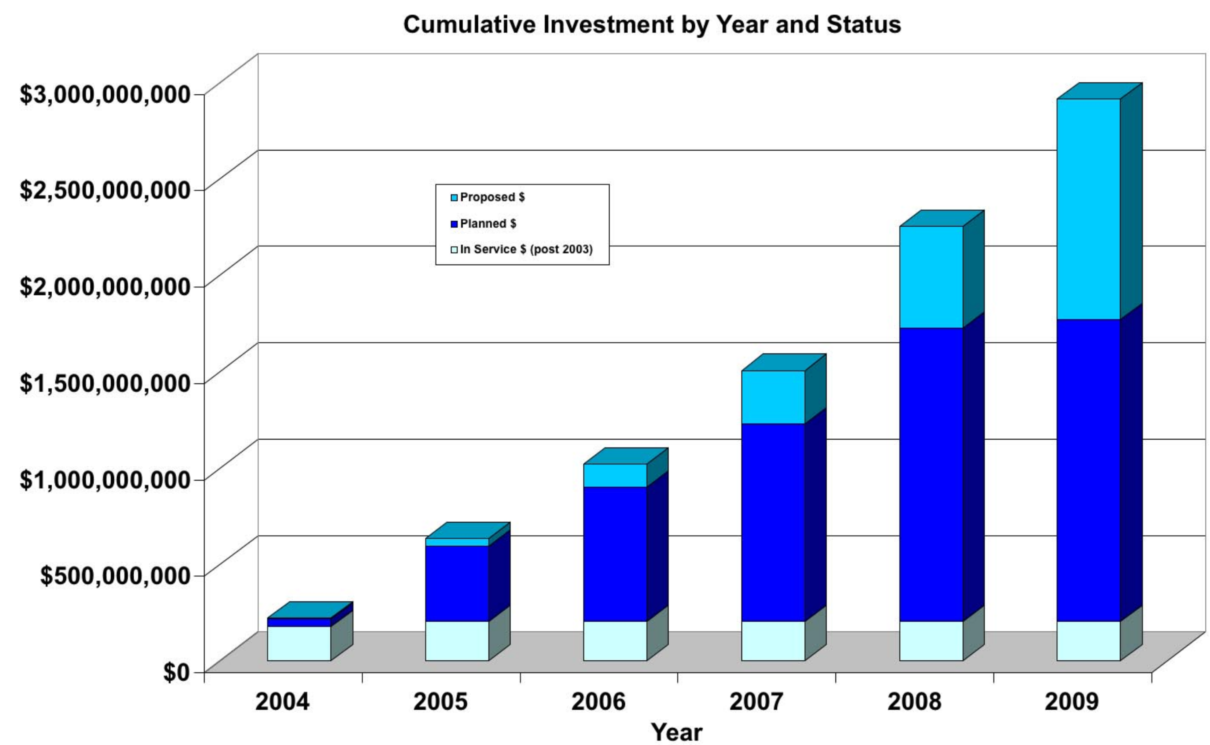



**Figure 8.1-2: Cumulative Projected Spending All Projects**

When totaled, the TO reported transmission lines planned for new construction and enhancement amount to 5,123 miles by 2009. This includes lines that went in service in 2004, as well as lines Planned or Proposed through 2009. In contrast to the approximate 112,000 miles of line existing throughout the MISO area, only about 1,836 miles of the 5,123 miles by 2009 represent an increase as new corridor usage over the six-year period 2004-2009. The cumulative miles of line by voltage class are shown in Figure 8.1-3. The cumulative line additions by planning status (In service in 2004, Planned, or Proposed) are shown in Figure 8.1-4 as cumulative miles, and the impact by corridor types is shown in Figure 8.1-5.

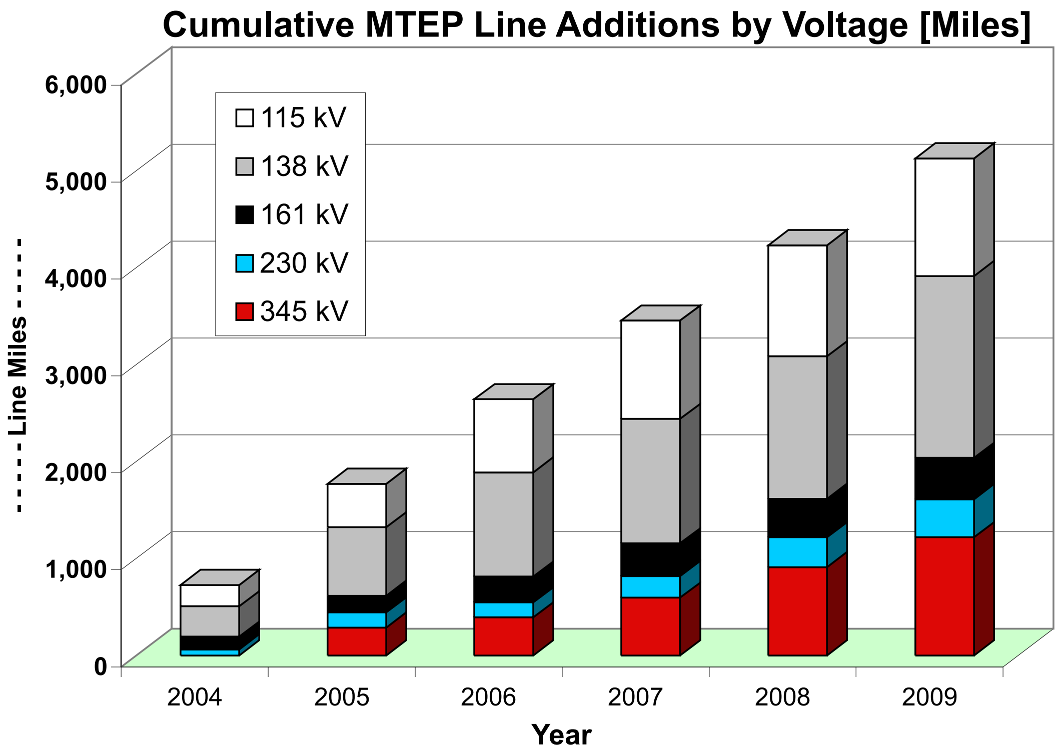



**Figure 8.1-3: Cumulative Line Additions/Enhancements by Voltage Class / Miles**

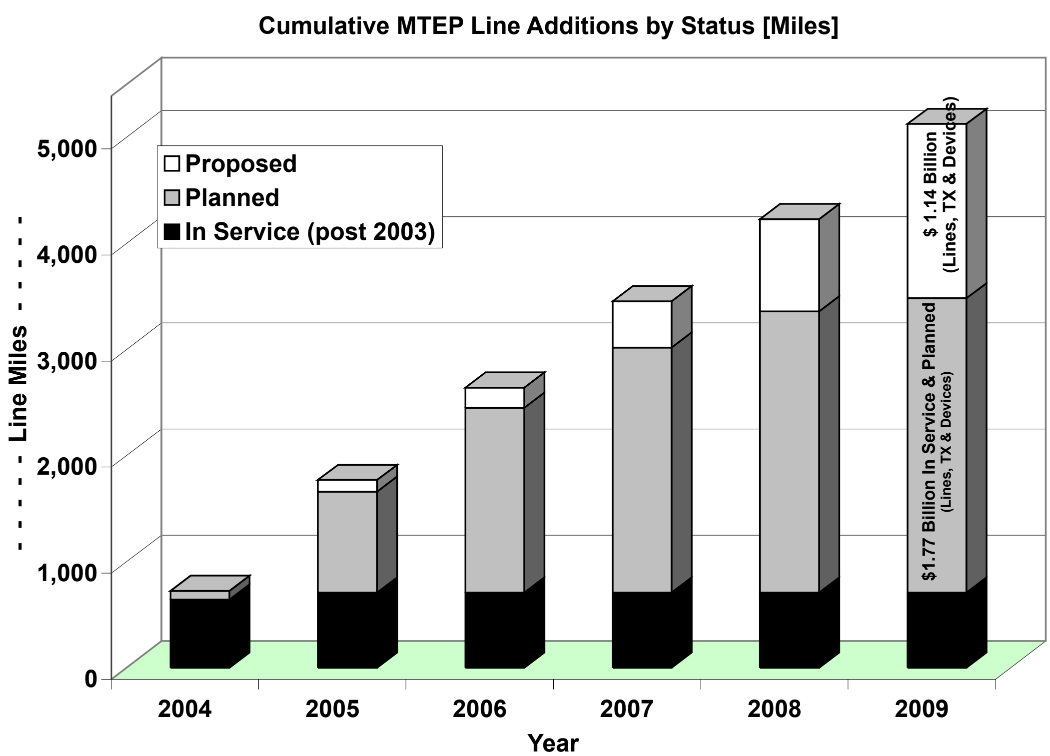



**Figure 8.1-4: Cumulative Line Additions/Enhancements by Planning Status (Miles)**

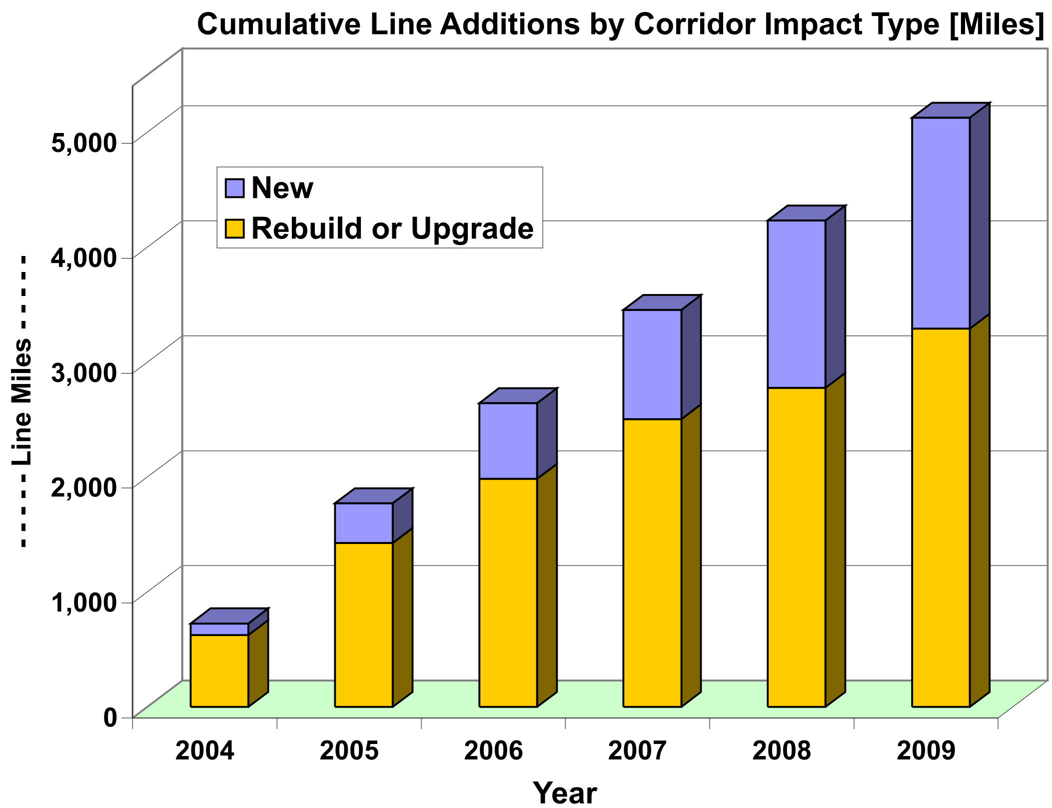



**Figure 8.1-5: Cumulative Line Additions/Enhancements by Corridor Impact Type (Miles)**

The anticipated 5,123 miles of new or enhanced line and the associated termination facilities at substations are estimated to cost about $2.91 billion. The allocation to specific planning regions is shown in Table 8.1-2.

**Table 8.1-2: Cost Allocations to Functional Use Categories**

| Planning Region | Lines and Terminals | Devices | Total | Percent of Total |
|---|---|---|---|---|
| Northwest | $1,108,667,079 | $47,672,083 | $1,156,339,161 | 39.7% |
| Central | $1,025,590,492 | $30,749,009 | $1,056,339,501 | 36.3% |
| East | $630,538,612 | $48,354,380 | $678,892,992 | 23.3% |
| Southwest | $19,615,975 | $2,011,235 | $21,627,210 | 0.7% |
| **TOTAL** | **$2,784,412,158** | **$1,287,786,706** | **$2,913,198,864** | **100.0%** |

Local system plans have been driven by a number of factors including Native Network Load, Generation Interconnection, Transmission Service, etc. Table 8.1-3 is an estimate of the transmission investment by functional use categories. This includes $128,787 for devices (capacitor banks, reactors and reactive power compensators) that has been prorated on a percentage basis across the Functional Use Categories.

**Table 8.1-3: Cost Allocations to Functional Use Categories**

| Native Network Load | Gen Interconnection | Transmission Service | Misc. Other | Total |
|---|---|---|---|---|
| $1,573,883,432 | $544,600,376 | $319,957,031 | $474,758,025 | $2,913,198,864 |
| 54.0% | 18.7% | 11.0% | 16.3% | 100.0% |

Larger projects, with estimated costs of $5,000,000 and higher have been summarized below in Figure 8.1-6. This figure shows a comparison of expected spend grouped by NERC region within the Midwest ISO for the out years of 2007 through 2009. For the purpose of this summary, companies having projects that exceed $ 5,000,000 are in groupings as follows:

| MAPP | MAIN | ECAR |
|---|---|---|
| XEL | ATC | CIN |
| OTP | AMRN | ITC |
| MDU | CILCO | METC |
| MP | IP | LGEE |
| MH | SIPC | HE |
| GRE | CWLP | IPL |
| LES | CWLD | VECTREN |
| AQN | | |
| ALTW | | |

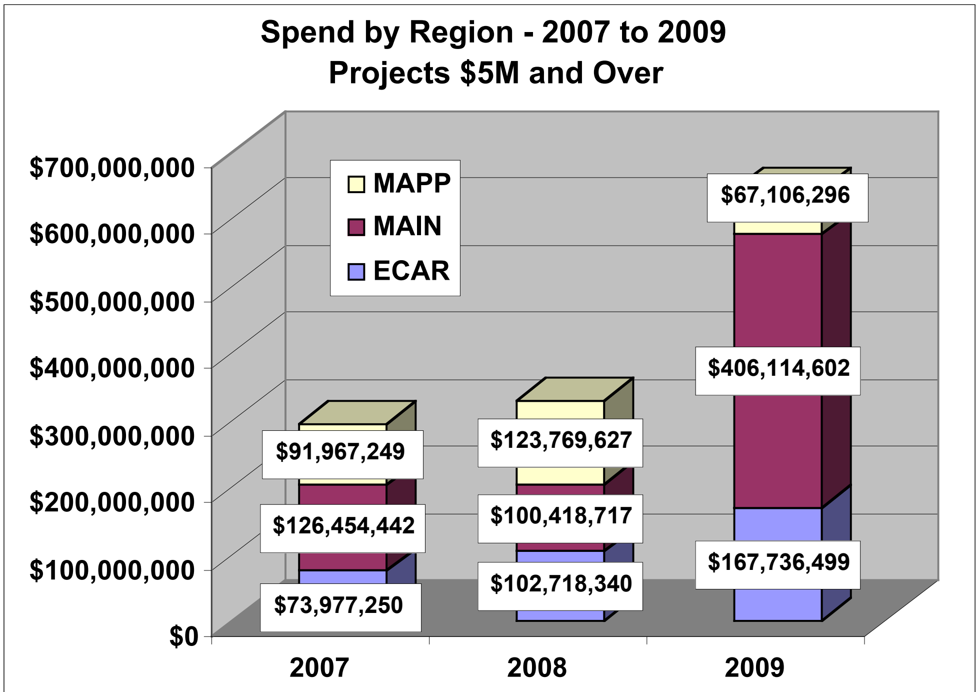



Figure 8.1-6 Spend by Year by Region ($)

This summary shows that of the $1,260,263,022 expected to be spent over the three-year period about 51% is projected for the year 2009. In addition, projected spending is relatively balanced between the three areas for 2007 and 2008, while in 2009 the MAIN areas entities project spending of about 63% of the 2009 total with ECAR 26% and MAPP 11%. This summary has excluded two significant projects with a combined cost of $552,000,000 the Arrowhead–Weston Project of ATC LLC and the Buffalo Ridge Area Generation Outlet Project of XEL. The jurisdictional regulatory authorities already have approved these projects.