PUBLIC SERVICE COMMISSION OF WISCONSIN

Response to 1997 Wisconsin Act 204

Report to the Wisconsin Legislature on the Regional Electric Transmission System

September 1, 1998

PUBLIC SERVICE COMMISSION OF WISCONSIN

Report to the Wisconsin Legislature on the Regional Electric Transmission System

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Acknowledgements

The Public Service Commission of Wisconsin (PSCW or Commission) wishes to acknowledge the broad and diverse participation in this transmission assessment. The PSCW utilized the services of an independent consultant to assist in the performance of its responsibilities. State regulatory agencies from Wisconsin, Minnesota, Iowa, and Illinois were active participants. Ten major utilities and two public power agencies within the upper Midwest region, including one Canadian utility, provided electric transmission system models and transmission planner expertise. Two electric reliability councils also provided valuable input.

Consultant
Power Technologies, Inc.

Public Power Agencies
Badger Power Marketing Authority
Municipal Electric Utilities of Wisconsin

Regulatory Agencies
Illinois Commerce Commission
Iowa Utilities Board
Minnesota Department of Public Service
Minnesota Public Utilities Commission
Public Service Commission of Wisconsin[1]

Reliability Councils
Mid-America Interconnected Network, Inc.
Mid-Continent Area Power Pool

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[1] Public Service Commission of Wisconsin contributors: Dave Barger, William Fannucchi, Gail Hanson, Steve Leovy, Jim Loock, and Kevin O'Donnell.

Utilities

Alliant Energy-Wisconsin Power and Light Company
Commonwealth Edison
Dairyland Power Cooperative
Madison Gas and Electric Company
Manitoba Hydro
Minnesota Power
Northern States Power Company
Wisconsin Electric Power Company
Wisconsin Public Power, Inc.
Wisconsin Public Service Corporation

In 1997, the utilities and public power agencies formed an *ad hoc* group to contend with the reliability problems that arose because of the outages of multiple nuclear power plants in Wisconsin and Illinois. The *ad hoc* group was reconstituted in 1998 as the Wisconsin Reliability Assessment Organization (WRAO) to address continuing concerns about reliability. Prior to the enactment of 1997 Wisconsin Act 204, WRAO formed a subcommittee to begin analysis of the transfer capability of the transmission system, called the Wisconsin Interface Reliability Enhancement study (WIREs) group.

The transmission study required by 1997 Wisconsin Act 204 was accomplished by a cooperative effort of Commission staff, the WIREs group, and independent consultant (Power Technologies, Inc.), and the staff of regulatory agencies in other states. This report is the fruit of that effort. In addition, the WIREs group produced a technical report for WRAO about the transmission system analysis. See Appendix J for the Executive Summary of the WIREs report.

Part B

Executive Summary

The analysis investigated 50 sets of transmission . . .improvements. . . then concentrated on 12 representative options.

This report to the Wisconsin Legislature on the adequacy of the region's electric transmission system fulfils the requirements under 1997 Wisconsin Act 204 (Act 204). The report represents the efforts of a large and diverse group of interested parties over a relatively short period of time and is intended to identify transmission constraints on the regional bulk power transmission system and to identify possible solutions to relieve those constraints. The analysis investigated 50 sets of transmission system improvements with new transmission lines ranging in voltage from 138 kV up to 765 kV, lengths up to 560 miles, and costs of more than $250 million. The analysis then concentrated on 12 representative options.

Infrastructure improvements will be necessary. . . .

The high-voltage bulk power transmission system in the Midwest was essentially designed and built in a period extending into the 1970s and has not experienced any significant additions or upgrades since that time. Events of the summers of 1997 and 1998 have demonstrated that the system is no longer capable of sustaining the power transfers necessary to maintain the reliability that consumers have experienced in the past and have grown to expect. Changes in the use of the system and growing uncertainty of nuclear unit availability have placed excessive strain on the transmission system. Infrastructure improvements will be necessary to restore and maintain acceptable reliability of the interconnected network.

This study presents a number of system enhancements that will mitigate identified constraints and provide a simultaneous power transfer capability into Wisconsin of 3,000 MW (megawatts); either 2,000 MW from the west and 1,000 MW from the south, or 1,000 MW from the west and 2,000 MW from the south. The focus of this study was to screen many possible options to determine those warranting further examination rather than to identify a single solution. The potential impacts of each option have not been fully evaluated in this first phase of study. More detailed examination of the impact of new transmission lines and the impact of additional generation expansion must be performed. All identified options may require additional facilities based on more detailed analysis. In addition, the sensitivity of this study's findings to factors such as load, generation patterns, and simultaneous transfers, may also indicate the need for additional facilities.

Benefits of Interconnected Systems

The development of electric transmission systems allowed power plants to be linked to serve cities, metropolitan areas, states, and, ultimately, large multi-state regions. The growth of interconnections within the power system enabled utilities to take advantage of the diversity of electricity demand and generation between different parts of the power system, thus enhancing reliability. By sharing generation resources with neighboring utilities experiencing particularly high demand or a power plant outage, utilities can reduce required generation reserve margins throughout the system. These interconnections also enabled ever-larger transfers of power between areas and allowed utilities to take advantage of distant low-cost generation. Through most of the history of the electric utility industry, increasing interconnections have increased reliability and decreased electricity prices.

Wisconsin's Reliability Situation

Increased transmission transfer capability into eastern Wisconsin is required to ensure that utilities can continue to meet customer demands in spite of power plant outages.

With all generating units in operation, eastern Wisconsin utilities have sufficient generating capability to meet their customers' electricity demands. As the events of the last two summers indicate, however, unexpected problems can force generators out of service, threatening reliability. Increased transmission transfer capability into eastern Wisconsin is required to ensure that utilities can continue to meet customer demands in spite of power plant outages. Accordingly, the required amount of transmission transfer capability depends on the degree of reliability desired. The reliability standard historically used in Wisconsin and in the region is such that the loss-of-load expectation (LOLE) is no more than 1 day in 10 years or 0.1 day per year. This reliability standard, combined with new generation uncertainty and uncertain existing nuclear plant availability, supports an increase in transfer capability into Wisconsin to 3,000 MW, an approximate doubling of today's transmission transfer capability.

Transmission Constraints Identified

Identify constraints

A computer model of the Midwest electric transmission system for the year 2002 was used to find problems and test potential solutions. The analysis simulated the outage of transmission facilities to determine which other facilities would overload. As power transfers are simulated from the west or south into Wisconsin, the transmission system is stressed more and problems were identified.

Wisconsin

One of the most important limitations to power transfer from the west . . . is . . . the need to limit east-west phase-angle differences.

Virtually all of the transmission options considered were found to be limited by line overloads in the Eau Claire area and elsewhere throughout Wisconsin. One of the most important limitations to power transfer from the west, however, is not due to facility overloads, but to the need to limit east-west phase-angle differences.[2]

Northern Illinois

Serious overload problems in the Commonwealth Edison (CE) northern Illinois transmission system appeared in the study base case and nearly all transmission option scenarios. Because transfers from western and southern generation sources flow, in part, through the CE system, these problems pose a significant transfer limitation.

Transmission Reinforcement Options Considered

Fifty transmission system reinforcement options were examined to determine their impact on transfer capability into eastern Wisconsin. The starting point for selection of these options was the list of transmission lines proposed in the Wisconsin utilities' 1997 report to the Governor on electric reliability.

The list of options was further broadened to ensure that no class of potential solutions was overlooked. Additions included other new high-voltage transmission lines, construction of several relatively short lower-voltage lines, direct-current (DC) lines under Lake Michigan, and an option consisting of a single new line less than 30 miles long in conjunction with multiple upgrades of existing equipment. Consideration was also given to addressing the western interface phase-angle problem by the use of power control technology.

Additional options were developed through minor modification and refinement. For each set of new transmission lines, some upgrades of existing lines and equipment were required to allow each option to reach the target transfer potential. In this manner, the "long list" of transmission reinforcement plans, each comprising both new transmission lines and a number of upgrades, was found. This long list is detailed in Appendix I. The long list of options was narrowed to a short list of 12 options.

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[2] Technical discussion of this problem is presented in Chapters 3 and 4.

Electrical analysis

To be on the short list, options needed to provide 3,000 MW of simultaneous transfer capability into eastern Wisconsin; either 2,000 MW from the west and 1,000 MW from the south, or 1,000 MW from the west and 2,000 MW from the south. A lower phase angle between eastern and western Wisconsin at the Arpin Substation when the Eau Claire-Arpin 345 kV line is out of service is also an important electrical factor. Lastly, the amount of electrical losses is a factor that affects the efficiency of the electrical system and the cost of electricity. Future analyses of the options may determine that one or more of these options may need to be implemented to achieve the desired transfer level.

The following map, Figure ES.1, illustrates the length and location of the short list of options. The Cook-Zion submerged cable shown on the map is an alternative to the Plano-Plano Tap 345 kV line (option 12).

Economic analysis

The engineering analysis in this study did not limit or reject options based on cost. For the purposes of option comparison and guiding future policy and study directions, preliminary capital cost estimates were developed for each short-list option after the technical performance was determined (see Table ES.1).

The cost of electrical losses of the options, relative to each other, could amount to millions of dollars. However, no attempt was made to calculate the cost of losses in this report. This is because project details, line loadings, and physical characteristics cannot be accurately determined until more detailed studies are completed. Also, the study considered a single time slice, dispatch pattern, and load level. More system conditions must be studied to better estimate line losses.

Environmental impacts

The environmental and social issues and impacts associated with any of the identified bulk transfer transmission lines are likely to be significant.

The environmental and social issues and impacts associated with any of the identified bulk transfer transmission lines are likely to be significant. All the proposed solutions for increasing transfer capability into eastern Wisconsin will require the participation of not only landowners, utilities, and regulators in Wisconsin, but also landowners, utilities, and regulators in surrounding states. History has shown that construction of any high-voltage transmission line will be controversial. Construction of new transmission lines associated with the options analyzed in this report may lead to significant environmental impacts.

The nature and severity of environmental impacts will vary depending on what part of the state is involved. Regardless of location, private land will be required for any transmission line. The use of private land may require the exercise of eminent domain.

Figure ES.1 Potential options—regional map

[B&W Map]

Landowners, by law, will receive an easement payment for transmission right-of-way (ROW) on their property that reflects the fair market value of the land at the time the easement is procured. Eminent domain comes into play only after the Commission approves a project and landowners and utilities are unable to reach agreement on terms.

Summary of Study Results

Electrical and cost characteristics of the short-list options are summarized in Table ES.1.

Table ES.1 Short list of options and their characteristics

		Transfer Capability					
#	Option Description[1]	Western Sources (MW)	Southern Sources (MW)	Construction Capital Cost (millions)[2]	Length (Miles)	Arpin Phase Angle[3]	Losses[4] (MW)
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap 345 kV	2,220	2,040	$123	145	92°	486
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap 345 kV	2,121	2,279	$138	210	78°	475
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	1,980	1,960	$94	95	95°	504
3e	Arrowhead-Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	2,160	2,020	$181	490	65°	452
3j	Arrowhead-Weston 345 kV Plano-Plano Tap 345 kV	2,100	2,050	$139	230	70°	444
3k	Arrowhead–Weston 230 kV Plano-Plano Tap 345 kV	2,160	2,000	$118	230	83°	470
5a	Chisago-Apple River-Weston 345 kV[5] Plano-Plano Tap 345 kV	2,276	2,136	$149	210	48°	449
6c	Chisago-Rocky Run 500 kV Rocky Run-South Fond du Lac 345 kV Plano-Plano Tap 345 kV	2,393	2,150	$212	320	38°	410
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap 345 kV	2,090	1,970	$143	245	80°	481
9a	Huron-Split Rock-Lakefield Jct-Adams 345 kV Adams-Genoa-Columbia 345 kV Plano-Plano Tap 345 kV	2,572	2,412	$263	530	72°	440
12	Plano-Plano Tap 345 kV	1,910	1,710	$59	25	99°	510
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap 345 kV	2,250	2,070	$165	320	77°	459

[1] All options contain additional facilities which are detailed in Appendix H Table H.2.

[2] Costs shown are estimated capital investment in 1998 dollars.

[3] Arpin Substation is located south of Marshfield, Wisconsin. A phase angle of less than 60 degrees is desirable because it eliminates the need for cumbersome operating procedures.

[4] Losses of options were calculated with a simultaneous transfer of 1,000 MW from the west and 1,000 MW from the south. The figures in the table are losses relative to base case conditions without transfers.

[5] This line replaces the Chisago-Apple River 230 kV line which is assumed in service in all other options.

For illustrative purposes only, each of the 12 options were rated as GOOD, FAIR, or POOR, relative to each other, for 4 criteria as shown in Table ES.2.

Table ES.2 Comparative overview of the short list of options

#	Option Description	Construction Capital Cost ($ millions)	Length (Miles)	Arpin Phase Angle [1]	Losses [2] (MW)
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap 345 kV	◍	●	○	○
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap 345 kV	◍	◍	◍	◍
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	●	●	○	○
3e	Arrowhead-Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	◍	○	◍	◍
3j	Arrowhead-Weston 345 kV Plano-Plano Tap 345 kV	◍	◍	◍	◍
3k	Arrowhead–Weston 230 kV Plano-Plano Tap 345 kV	◍	◍	○	◍
5a	Chisago-Apple River-Weston 345 kV Plano-Plano Tap 345 kV	◍	◍	●	◍
6c	Chisago-Rocky Run 500 kV Rocky Run-South Fond du Lac 345 kV Plano-Plano Tap 345 kV	○	◍	●	●
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap 345 kV	◍	◍	○	○
9a	Huron-Split Rock-Lakefield Jct-Adams 345 kV Adams-Genoa-Columbia 345 kV Plano-Plano Tap 345 kV	○	○	◍	●
12	Plano-Plano Tap 345 kV	●	●	○	○
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap 345 kV	◍	◍	◍	◍
		Construction Capital Cost ($ millions)	Length (Miles)	Arpin Phase Angle [1]	Losses [2] (MW)
●	Good	0-100	0-200	38-59°	410-442
◍	Fair	101-200	201-400	60-79°	443-476
○	Poor	201-300	401-600	80-99°	477-510

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[1] Arpin Substation is located south of Marshfield, Wisconsin. A phase angle of less than 60 degrees is desirable because it eliminates the need for cumbersome operating procedures.

[2] Losses of options were calculated with a simultaneous transfer of 1,000 MW from the west and 1,000 MW from the south. The figures in the table are losses relative to base case conditions without transfers.

A detailed discussion of generation is not included in this report. While the focus of this report is to increase transmission transfer capability, the PSCW also recognizes and regularly reviews the need for generation. In the fall of 1997, the Commission ordered three utilities to procure 500 MW of new generation. In addition, Act 204 lifted legal barriers to encourage merchant power plants to be built in Wisconsin. To date, these two actions have resulted in commitments for over 500 MW of power by 2000 in eastern Wisconsin. The PSCW recognizes that both new generation and new transmission will be needed to provide reliable service to electric customers in Wisconsin.

Findings

Despite the substantial uncertainties and further study that lie ahead, this analysis yielded significant results.

- With the addition of local load-serving transmission facilities expected to be in place by the summer of 2002 (listed in Appendix C), the simultaneous power transfer capability into eastern Wisconsin will be 1,800 to 2,000 MW, which is short of the 3,000 MW target.
- Significant increases into transfer capability above this 1,800 to 2,000 MW level will not be possible unless limits in Commonwealth Edison's northern Illinois transmission network are either fixed by construction of a new 345 kV line in Illinois (approximately $35 million), bypassed by construction of a cable under Lake Michigan ($178 million), or new generation capacity is ultimately sited in northern Illinois.
- Construction of a major new high-voltage transmission line extending into a neighboring state from Wisconsin can achieve the transfer capability goals of the study, increase operating flexibility, and reduce the magnitude of the western interface phase-angle problem. New high-voltage transmission construction identified in the study involves investment from $80 to $250 million for 100 to 500 miles of construction.
- In addition to new high-voltage lines, other transmission facility improvements are needed. These facilities include the local load serving improvements listed in Appendix C. These facilities also include improvements in Wisconsin and northern Illinois, an investment up to $20 million, to upgrade existing facilities to increase transfer capability to desired levels.
- The upgrades and construction described above will lower losses to varying degrees. Generally, the more investment made in new transmission the lower the losses at the same transfer level. However, losses will increase as power transfers increase to make use of the higher transfer capability provided by the transmission upgrades and construction.

- History has shown that the construction of any high-voltage transmission line will be controversial. Construction of any of the new lines in the options analyzed in this report may have significant environmental impacts.

Next Steps

This study should be regarded as the first step in the process of identifying the most appropriate transmission reinforcement approach to enhance electric reliability in Wisconsin.

The PSCW and other stakeholders will continue to study some or all of the 12 options in greater detail and to work with neighboring state regulators that have an interest in the reliability of the regional electric transmission system. These studies will lead to the selection of the optimal options and ultimately in utility applications to build those options.

Chapter 1

Introduction

Historical Overview of Electric Reliability in Wisconsin

Electrical reliability prior to 1997

Wisconsin has maintained a high level of electric reliability prior to 1997. This is in part due to Wisconsin's long-range planning process; a single statewide integrated resource planning process for both generation and transmission. This is also in part due to the utilities following the reliability requirements and guidelines, established and adopted by the North American Electric Reliability Council (NERC), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP).

Events of 1997 and 1998, current unit outage situation and future prospects

The unplanned outages of the Kewaunee Nuclear Power Plant and the Point Beach Nuclear Power Plant (Point Beach) were key contributors to Wisconsin's summer 1997 reliability problems. In addition to plant outages in Wisconsin, several nuclear units throughout the region were also out of service at the same time, particularly in the spring of 1997. There were periods in April and May 1997 when as many as 10 nuclear units totaling over 9,000 MW in capacity were out of service at the same time in Wisconsin, Illinois, Michigan, and Minnesota. The largest impact on Wisconsin was from the outages, throughout the summer period, of the units in Illinois at Zion, LaSalle, and Clinton (total of over 5,000 MW) and Point Beach (1,000 MW). The effect of the plant unavailability in Illinois essentially reduced to zero the ability to import additional firm power from the south through Commonwealth Edison (CE) for the entire summer of 1997. All Wisconsin nuclear units are now in service but the upper Midwest region still has 4 nuclear units totaling 4,000 MW out of service. In addition, the two-unit Zion nuclear plant has been permanently retired (2,000 MW).

. . . in April and May 1997 . . . as many as 10 nuclear units totaling over 9,000 MW in capacity were out of service at the same time in Wisconsin, Illinois, Michigan, and Minnesota.

All Wisconsin nuclear units are now in service . . . .

The Wisconsin power supply situation is greatly improved from the summer of 1997. However, increased scrutiny by the Nuclear Regulatory Commission (NRC) has placed uncertainty about nuclear unit availability in the region. This uncertainty is greater due to the large number of nuclear units to the south. Unplanned lengthy outages of nuclear units have demonstrated their ability to greatly affect the regional generation and transmission system reliability.

In Wisconsin for the summer of 1998, all major fossil generating units were available, all Wisconsin nuclear units were operating, and the new Whitewater cogeneration facility was up and running. Reserve levels in eastern Wisconsin were expected to be 19 percent. The unavailability of several large nuclear units in Illinois, Michigan, and Ontario, Canada will strain the regional electrical system.

1997 reports to the Governor on electric reliability and legislative action

In the fall of 1997, the PSCW submitted a report to the Governor on electric reliability. This report detailed specific actions the Commission has taken to address the reliability of the state's electric system and specific measures the Commission will consider taking in the near future. The report also identified and recommended specific statutory changes. Similar reports were submitted by the Joint Utility Group,[3] the Customer Task Force on Electric Reliability,[4] and the Wisconsin Paper Council.

Restructuring is not likely to improve reliability in the near term.

The electric reliability report described steps that the PSCW, the utilities, and the Legislature could and should take to improve the reliability of Wisconsin's electric utility system. Many of those steps, however, will not improve the circumstances in 1998 and 1999 if nuclear plants in the region continue to experience the kinds of problems observed last summer. In addition, many who look for a solution to the reliability situation will point to a complete restructuring of the industry or to retail wheeling as a solution to the problem. Restructuring is not likely to improve reliability in the near term. If restructuring is hastily implemented as a solution, Wisconsin is more likely to experience a reduction in reliability, especially if retail wheeling is implemented without a functioning independent transmission system operator or if obligation to serve and consumer protection rules are not in place.

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[3] The Joint Utility Group consisted of the following entities: Dairyland Power Cooperative; LS Power, LLC; Madison Gas and Electric Company; Northern States Power Company; Municipal Electric Utilities of Wisconsin; Superior Water, Light, and Power Company; Wisconsin Electric Power Company; Wisconsin Federation of Cooperatives; Wisconsin Power and Light Company; Wisconsin Public Power, Inc.; and Wisconsin Public Service Corporation.

[4] The Customer Task Forces consisted of the following entities: Wisconsin Industrial Energy Group, the National Federation of Independent Business-Wisconsin, Citizens' Utility Board, and the American Association of Retired Persons.

1997 Wisconsin Act 204

. . . Act 204 opened the door to merchant power plants to build capacity in Wisconsin.

Act 204 details the statutory changes made to the existing legislation in an effort to strengthen the reliability of Wisconsin's electric power system. These changes are intended to streamline the current regulatory processes for review of transmission lines and electric power generation facilities. In addition, Act 204 opened the door to merchant power plants to build capacity in Wisconsin.

PSCW requirement to conduct study and prepare report

The PSCW was required by Act 204 to conduct a transmission study and prepare a report to the Legislature. The study goal was to identify interstate and intrastate transmission constraints and to identify reinforcement options to relieve these constraints.

> *s. 196.494(2), Wis. Stats. The commission shall conduct a study on identifying and relieving any constraint on an intrastate or interstate electric transmission system that adversely affects the reliability of transmission service provided to electric customers in this state and shall, no later than September 1, 1998, submit a report on the results of the study to the legislature in the manner provided under s. 13.172(2).*

It must be emphasized that this report presents the results of a screen study to identify one class of constraints and to perform an initial evaluation of transmission options, for the purpose of enhancing reliability of the regional transmission system—based upon assumptions, like future generation construction in the eastern Wisconsin area whose location is still to be determined. The report considers an array of options, some of which may not realistically be buildable because of the excessive cost, environmental impact, public opposition, or the fact that they are out of this state's jurisdiction.

The report is not a definitive or complete engineering study, nor, by itself, an adequate basis for a construction decision. The main impetus for this report is to identify and propose transmission options that can provide a satisfactory level of reliability at the least cost to utilities and consumers.

PSCW authority to order facility construction

The PSCW has been granted the authority to order facilities based on the provisions of Act 204.

> *s. 196.494(3), Wis. Stats. No later than December 31, 2004, the commission may, under this subsection, issue an order requiring an electric utility to construct or procure, on a competitive basis, the construction of transmission facilities specified by the commission in its order if the commission determines that, based on the results of the study under sub. (2), such construction is necessary to relieve a constraint on a transmission system and the construction will materially benefit the customers of the electric utility or other electric utilities or of an independent system operator, as defined in s. 196.485(1)(d), or independent transmission owner, as defined in s. 196.485(1)(dm).*

Transmission Study Scope and Execution

Study scope

This study identifies . . . solutions that would increase the simultaneous transfer capability into Wisconsin from adjoining regions to 3,000 MW . . . .

This study identifies transmission constraints and possible solutions that would increase the simultaneous transfer capability into Wisconsin from adjoining regions to 3,000 MW; either 2,000 MW from the west and 1,000 MW from the south, or 1,000 MW from the west and 2,000 MW from the south.

Study methodology

The base period for this study is 2002.

The base period for this study is 2002. This year was chosen due to the time needed to complete a full engineering study. Many years are needed to construct large transmission lines. It would be unrealistic to construct lines of these magnitudes in a shorter time frame.

The modeling approach for the study consisted of developing a base case model of the electric transmission system. This base case modeled the present day system updated with all facility additions expected to be in-service in 2002. The base case was then utilized to develop options to attain the study goal. Selected options that satisfied the study goals were then modeled further. This additional modeling included calculation of losses for the entire electrical system, and phase-angle impacts at one interface to examine how these options solve existing constraints. The ability to relieve constraints and provide increased transfer capability into Wisconsin was the main focus of the study.

Significance and Limitations of Study

Preliminary identification of constraints, screening of reinforcement options

The technical focus of this study is to identify transmission constraints and reinforcement options to alleviate these constraints. Identification of constraints was based on thermal limits. Voltage and dynamic limits of the system might be reached before thermal limits are exceeded. The screening of reinforcement options needs more study to determine the optimal solutions. This study screened many options that, with further study, may become more robust solutions.

The significance of this study is that, in general, many of the transmission limitations are now known. The study also produced a cornucopia of options that meet the intended goal of relieving transmission constraints to reach the transfer goal in the study. These options will need further study including stability analysis and may be mixed and matched to achieve the import goal.

Limitations of this study and necessary follow-up steps

The main focus of this study was to screen many possible options to examine further. In order to achieve the September 1, 1998, completion date, many issues were not addressed in this study.

The potential impact on electric reliability, cost, and environmental impacts with intrastate and interstate options will not be completely known after this first phase of study. More detailed examination of the impact of new lines must be studied. Effects of additional generation must also be examined.

All of the options on the short list may require additional facilities based on more detailed and precise alternating-current (AC) and dynamic stability analyses. In addition, sensitivities to load, generation patterns, simultaneous transfers, etc. may also indicate the need for additional facilities. Lower voltage (less than 100 kV) problems were not completely addressed in this study. These problems may require additional system reinforcement on the underlying transmission system to attain the objective.

Other limitations of the study are that the starting point included a large number of projected facility additions and equipment upgrades. The significance of certain options that might not be constructed could greatly affect the transfer capability stated in the study. Also, some of these options cross into or are entirely within other state boundaries.

Overview of Report Contents

The remainder of this report describes the study, presents results and provides background on technical topics. Chapter 2 discusses the reliability benefits of transmission, describes the configuration of Wisconsin’s transmission system, and explains how the need for transmission system improvements is calculated. Chapter 3 provides a technical introduction to the operation of the transmission system, including constraints to power transfer between areas and approaches to alleviating such constraints. The methodology of the engineering study and the selection of transmission reinforcement options are described in Chapter 4, as are the results of this study, which include identification of transmission constraints and the performance of the reinforcement options examined. Chapter 5 examines costs associated with transmission reinforcement, both direct construction costs and the impact on electrical losses in the transmission system. Environmental impacts of transmission lines are considered in Chapter 6. Study conclusions are reported in Chapter 7. A glossary of terms and other supplemental information can be found in the appendices.

Chapter 2

Reliability of Existing System

Brief History of Power System Development and Interconnection

Overview

Thomas Edison's first power plants served only a few city blocks.

From the origin of the electric utility industry more than a century ago, the growth in electricity demand has been matched by ever-increasing interconnection of the electric power system. Thomas Edison's first power plants served only a few city blocks. The development of electric transmission systems, however, allowed power plants to be linked to serve entire cities, states and, ultimately, large multi-state regions. The most substantial steps in the increasing interconnection of North American electric systems took place between about 1950 and 1970. Many miles of high-voltage transmission lines were constructed within and between regions, ultimately encompassing virtually all electrical loads in the contiguous United States and Canada within one of four interconnected systems. Wisconsin is within the Eastern Interconnection, extending from Saskatchewan to Florida and Oklahoma to Nova Scotia.

Reliability benefits of interconnection

The growth of interconnection within the power system allowed ever-larger transfers of power between areas and enabled utilities to take advantage of distant low-cost generation. More importantly, it allowed utilities to take advantage of the diversity of electricity demand and generation between different parts of the power system, enhancing reliability.

. . . utilities must generally maintain some generation capacity in excess of their peak customer demand.

To ensure reliability, utilities must generally maintain some generation capacity in excess of their peak customer demand. This surplus is commonly expressed as the reserve margin, which is the capacity excess as a percentage of peak demand. By sharing their generation resources with neighboring utilities experiencing particularly high demand or a power plant outage, utilities can reduce the required reserve margin throughout the system. Thus, increasing interconnection has contributed, through most of the history of the electric utility industry, to increased reliability and decreased prices.

Origin of reliability councils

This march toward ever-increasing reliability through interconnection, however, was not without missteps. Particularly significant was the November 1965 blackout which affected millions of customers throughout the Northeast. This blackout ultimately covered a large area because of a lack of coordination within the extensively interconnected electric transmission network. Largely in response to this event, NERC—a system of 10 regional reliability councils—was formed, encompassing all of the interconnected North American power system. These reliability councils, composed of the utilities within each region, established coordination in planning and operation to reduce the risk of widespread power outages.

Open transmission access and utility deregulation

. . . Order 888 . . . required most transmission-owning utilities to offer the use of their transmission systems, under fair and open conditions and rates, to all interested parties.

A more recent challenge to the integrity of the interconnected electric system is Order 888, issued by the Federal Energy Regulatory Commission (FERC) in 1996. This order requires most transmission-owning utilities to offer the use of their transmission systems, under fair and open conditions and rates, to all interested parties. The ensuing two years have seen ever increasing use of the transmission system to serve transactions between often-distant buyers and sellers. Utilities retain the authority to curtail some such transactions as required to ensure that the system will allow them to meet demand in their own service areas. Nonetheless, the recent proliferation of long-distance power transactions represents a substantial change from the past, when utilities were focused on using the transmission network, in a cooperative manner, to ensure reliability of the interconnected system.

FERC Order 888 is part of a broader movement to deregulate parts of the electric utility industry. At a minimum, this deregulation holds potential for reduced information flow and cooperation between utilities.

It is in the context of this history and ongoing developments that Wisconsin's current reliability situation must be understood. It is also important, however, to understand the nature of the Wisconsin electric power system—generation, load, and the transmission system in and surrounding Wisconsin.

Existing Wisconsin Power System

Wisconsin's divided power system

. . . Wisconsin utilities are members of two different regional reliability councils.

Electrically, Wisconsin is divided between eastern and western areas, with strong transmission connections within each area, but relatively weak connections between them. This is evident in the map of the existing electric transmission system, Figure 2.1. This division, a result of the historical development of the power system, is reflected in the fact that Wisconsin utilities are members of two different regional

Figure 2.1 Wisconsin's existing electric transmission system

reliability councils. Utilities in the western part of the state, roughly that area north and west of the Wisconsin River, belong to the MAPP reliability council. The eastern Wisconsin utilities, which serve the bulk of the state's electrical demand, are members of the MAIN reliability council.

. . . the most significant reliability-threatening transmission constraints experienced in the state are those associated with moving power into eastern Wisconsin.

By and large, the connections between western Wisconsin and Minnesota are strong enough to ensure reliability. In contrast, relatively weak links connect the eastern and western parts of the state. Combined with the large electricity demand in eastern Wisconsin, the weakness of this connection sometimes make it difficult to transfer needed power into eastern Wisconsin. In essence, the most significant reliability-threatening transmission constraints experienced in the state are those associated with moving power into eastern Wisconsin. Accordingly, this study focused on the problem of power transfer into eastern Wisconsin, along with that part of upper Michigan which is both part of MAIN and closely integrated into the eastern Wisconsin system. This subsystem of the electrical network is known as the Wisconsin-Upper Michigan System (WUMS).

Connections to neighboring transmission systems

Bounded by one great lake to the north and another to the east, the significant WUMS transmission connections can be characterized as either part of the western interface (across western Wisconsin to Minnesota and Iowa) or the southern interface (the Wisconsin-Illinois border).

The relatively weak western interface comprises one major transmission line—a 345 kV line. . . . Three 345 kV lines cross the southern interface.

The relatively weak western interface comprises one major transmission line—a 345 kV line—and a small number of lower-voltage lines. Three 345 kV lines cross the southern interface. Beyond the western interface, an extensive transmission system surrounds the Minnesota twin cities area and extends from Iowa to Duluth and beyond. If connections to this system were improved, the transfer of power into eastern Wisconsin could be increased, particularly from areas to the west and Canada.

Across the southern interface, northern Illinois has a very extensive transmission system as well, particularly surrounding Chicago. This system is heavily used, however, and is somewhat constrained in its ability to transfer power into Wisconsin. Power transfer is particularly limited now that the Zion nuclear plant, just south of Kenosha County, has been permanently shut down. Nonetheless, reinforcement of the southern interface, combined with selected improvements within the northern Illinois transmission system, could yield improved transmission access to the south, east, and west.

Transmission Transfer Capability and Reliability in Wisconsin

Overview

With all generating units in operation, eastern Wisconsin has sufficient generating capability to meet electricity demand including a reserve margin. As the events of the last two summers indicate, however, unexpected problems can force generators out of service, threatening reliability. Transmission transfer capability into eastern Wisconsin is required to ensure that utilities can continue to meet their demand, in spite of power plant outages. Accordingly, the amount of transmission transfer capability which is required depends on the degree of reliability desired.

Loss-of-load expectation (LOLE)

. . . LOLE is a measure of the adequacy of the generation system . . . .

Reliability is a probabilistic concept and must be described in terms of probabilities. The most commonly used measurement of power system reliability is LOLE. LOLE is defined as the fraction of time during which electricity demand would be expected to exceed available electric capacity, based on the probabilities associated with electricity demand and generation outages. As generally used, LOLE is a measure of the adequacy of the generation system, and thus does not consider outages due to transmission and distribution system damage, such as that caused by windstorms.

In Wisconsin and elsewhere in the U.S., power system planners have generally set a reliability standard in which the LOLE is to be no more than 0.1 day per year (or 1 day in 10 years). This is the standard that the PSCW has used in determining the amount of generation in excess of peak load (known as the reserve margin) that the utilities must maintain.

LOLE analysis for eastern Wisconsin was conducted in conjunction with this report; details are provided in Appendix F. This LOLE analysis began by assuming eastern Wisconsin to be an electrical island, i.e., without transmission connections to its neighbors, and proceeded to determine the amount of capacity that had to be added to existing eastern Wisconsin generation in order to reduce the LOLE to 0.1 day per year. This required additional capacity represents the total transmission transfer capability necessary to maintain eastern Wisconsin's electric reliability at the accepted level.

Transfer capability required to maintain reliability

The LOLE analysis detailed in Appendix F found that approximately 1,100 MW of transfer capability into eastern Wisconsin will be required by 2002 to maintain reliability. As indicated in Table F.1, this is about 10 percent of eastern Wisconsin's predicted peak demand in that year.

This analysis was based on a variety of assumptions regarding electricity demand and generation. To the extent that these assumptions do not accurately reflect conditions in 2002, the modeled year, the results of the analysis will be skewed. These assumptions include the number, capacity rating, and reliability of power plants. Electricity demand—which is affected by weather, the economy, electricity pricing, energy conservation, and interruptible demand programs—is also a key assumption. Three such assumptions deserve particular mention.

New generation uncertainty

The LOLE analysis assumed that nearly 1,500 MW of new generation capacity—enough to maintain an 18 percent reserve margin—will be in operation within eastern Wisconsin by 2002. This is more generation capacity than utilities currently have plans for. On the other hand, non-utility power plant developers have expressed considerable interest in building "merchant plants," which would produce power to sell on the open market, in Wisconsin. This interest has been boosted by provisions in Act 204 which reduce the regulatory burden associated with developing such plants. Depending on the amount of generation that is built in eastern Wisconsin, the need for transmission transfer capability could increase or decrease.

. . . power plant developers have expressed considerable interest in building "merchant plants," . . . in Wisconsin.

Uncertain nuclear plant availability

A second significant source of uncertainty in the LOLE calculation is the assumption that Wisconsin's nuclear power plants will be as reliable in future years as they were prior to 1997. The significant forced-outage problems experienced at all three Wisconsin nuclear units over the last two years, and the stepped-up vigilance of the NRC, increases the chance that these plants may again sustain lengthy outages. This suggests the need for increased transfer capability.

Target transfer capability level

Finally, the LOLE analysis assumed both a perfectly reliable transmission system and the availability of excess power outside of eastern Wisconsin. In fact, a variety of problems sometimes prevent the transmission system from being fully utilized and during the summer of 1998 there were a few days when very little power was available for sale. To compensate for this weakness and the likelihood that nuclear units will again experience unplanned outages at a higher rate than in the pre-1997 era, this study sought to identify transmission improvements which could yield 2,000 MW of transfer capability from both western sources and, not simultaneously, southern and eastern sources. Along with this non-simultaneous transfer target, a simultaneous transfer criterion of 3,000 MW from both directions was established. This choice of targets will ensure that this study reaches beyond minimum expected transfer requirements.

. . . this study reaches beyond minimum expected transfer requirements.

Chapter

3

Introduction to Transmission, Constraints, and System Reinforcement

Introduction to Power Flow

. . . electric power travelling between two points will actually spread out over many different lines in the network.

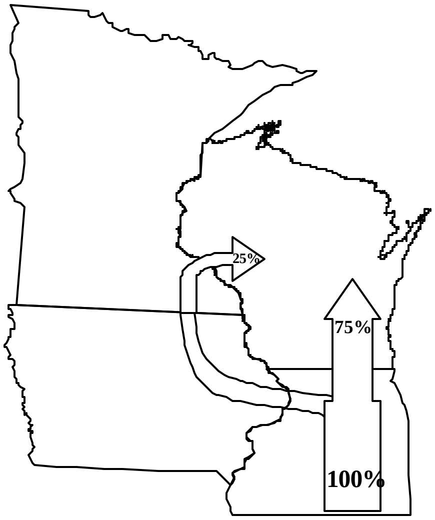
Virtually all of the eastern United States and most of Canada are connected into a single AC electrical network, called the Eastern Interconnection. Like water flowing through a system of pipes, electrical power follows the path of least resistance (technically, the path of least *impedance*, the proper term for resistance to AC power flow). This means that electric power travelling between two points will actually spread out over many different lines in the network. In fact, by seeking out low-impedance transmission paths, power can take rather surprising and seemingly circuitous routes. As a consequence, making a change in one part of the power system can have significant effects in a distant part of the network.

The pattern of power flow is determined by the physical characteristics of the power lines that form the network and the geographical distribution of electrical generation and demand. With few exceptions, power system operators cannot directly control the way power flows through particular lines, but can only modify flow patterns through the cumbersome process of adjusting generator outputs, or the generally undesirable process of taking power lines out of service. Since the pattern of power flow depends on patterns of generation and demand, it changes considerably over time as consumers alter their demand and power plants adjust their generation levels.

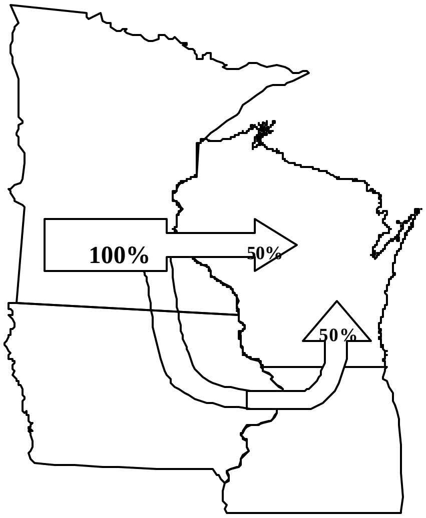
The electric system in eastern Wisconsin is connected to Illinois and western Wisconsin by only a few high-voltage transmission lines. The lines to Illinois that make up the southern interface consist of three 345 kV lines and one 138 kV line. The lines to western Wisconsin that make up the western interface consist of one 345 kV line and one 115 kV line. The high-voltage transmission network in the Midwest includes 345 kV lines in Illinois, Iowa, Minnesota, and Wisconsin.

The analysis simulated power transfers into Wisconsin from the south and from the west. Figure 3.1 depicts how such power transfers would generally flow into eastern Wisconsin. Only 75 percent of the power from the south would actually flow across the southern interface while roughly 25 percent generally flows across Iowa, Minnesota, and the western interface. In a similar way, power from the west would partially flow across the western interface, but roughly 50 percent generally flows across Iowa, Illinois, and the southern interface. These patterns of power flow happen because electricity follows the path of least resistance, which may not be the most direct path. This is why transmission problems, and their solutions, involve the entire Midwest region.

Figure 3.1 Typical power flow pattern



Typical Power Flow Pattern from the South



Typical Power Flow Pattern from the West

Problems That Limit Power Transfer

Overview

While the existing electric power system is capable of moving large amounts of power hundreds of miles, there are limits to the movement of power that is possible between regions. These include thermal, voltage, and stability limits, which are described below.

Contingencies

Power system operators must constantly monitor the system to ensure that limits are not exceeded. Moreover, they must operate the system such that these limits will not be violated even if the pattern of power flow changes suddenly as the result of a contingency, i.e., the unexpected failure of a generator or part of the transmission system.

Some contingencies, such as equipment failure, may take days or weeks to repair. In contrast, automatic circuit breakers can trip (disconnect) short-circuited power lines and reconnect them in a matter of seconds. As long as the event that caused the short circuit is no longer present, as is true of lightning, for example, the line can be promptly returned to service.

Thermal overloads

All transmission lines have some electrical resistance. This resistance, analogous to friction, means that power lines experience losses, i.e., some power flowing through the network causes heating of the wires which is then lost to the air. If the transmission system is overloaded, power lines and equipment can overheat, leading to stretching and sagging of lines and possible permanent damage to lines and equipment. An overheated line can be taken out of service—and automatic protective devices do so to prevent damage—but this generally will shift power flow onto remaining lines. Consequently, operators must be alert to the possibility of cascading outages, in which removal of one line causes a chain reaction of overloads and line outages, possibly resulting in widespread blackouts.

The need to keep flows low enough to prevent such overheating poses what is known as a thermal limit on power transfer. The transformer or line that would overheat if the limit were not observed is called a limiting element.

Voltage stability

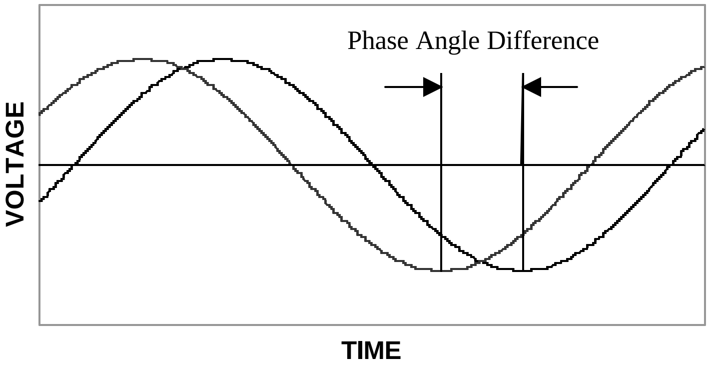
Voltage problems also can limit power transfer. Under some circumstances, the pattern of power flow in the network can make it difficult to maintain voltages at acceptable levels. Generally, voltage control is most difficult when electricity demand and power transfer are high.

Voltage stability is a distinct and very important power system problem. Under certain conditions, usually associated with high power transfer, portions of the power system can suddenly experience “voltage collapse,” in which voltage plummets without warning, leading to power failure. Large areas may be affected. The threat of such a serious calamity forces system operators to limit transfers below the level at which voltage collapse is a concern.

Transient stability and phase-angle problems

Power system generators are large rotating machines. All generators in the Eastern Interconnection rotate at the same rate, their synchronism maintained by the exchange of electrical energy through the connecting transmission network. Although they rotate at the same rate, some generators are slightly ahead of others in their rotational position. This results in the AC voltage at some generators being slightly out of phase with that at other generators—referred to as a difference in phase angle between generators—even though a common AC frequency of 60 hertz prevails throughout the system. (See Figure 3.2.)

Figure 3.2 Phase-angle difference



Plot of voltage versus time for two different points in the transmission system which are out of phase with each other. The degree to which they are out of phase is the phase-angle difference.

In fact, all parts of the power system, not just generators, can be characterized as having a certain voltage phase angle relative to other parts of the power system. These phase-angle differences are closely related to patterns of power flow.

Another way to visualize the phase-angle phenomenon is to think of an automobile with a flexible drive shaft. As more power is applied by the engine to move heavier and heavier loads, the drive shaft will tend to twist as the amount of power transfer to the rear wheels increases. The amount of twist in this drive shaft represents the electrical phase angle across the transmission system.

A problem occurs if a line outage or other contingency reduces the amount of power transfer between two areas to a level below that required to maintain synchronism. Generators in one area can then speed up while those in the other area slow down. This can lead to forced disconnection of the areas, frequencies that deviate from 60 hertz, and other problems. In this respect, the power system is similar to a car with a manual transmission. As long as the clutch can transfer sufficient power, the engine and drivetrain remain synchronized. However, if the clutch becomes worn and loses its ability to transfer power, it can slip, causing the engine to speed up and the car to slow down. The need to prevent the possibility of such a loss of synchronism in the power system imposes limits on the allowable power transfer between areas.

Even if the two areas do not lose synchronism, a line outage can cause the two areas to "swing" relative to each other, increasing the phase angle between them. Since large phase-angle differences are associated with significant potential to transfer power, re-establishing a broken connection across a large phase-angle difference can produce a sudden power surge. This may be a significant shock to the system, possibly resulting in equipment damage. Consequently, system operators must restrict power transfers as required to limit the phase-angle difference which could develop across a line that is out of service. In fact, this problem poses an important limit to power transfer across the western interface into eastern Wisconsin, a problem considered in detail in the next chapter.

Limits considered in this study

The problem of loss of synchronism, known as transient stability, must be considered before any significant proposed change to the transmission system is implemented. The same is true of voltage stability. The timeframe of this study, however, did not allow these complicated and computationally involved investigations to be undertaken. Rather, the focus of this study was identifying and relieving transmission constraints which are due to thermal limits in the transmission system. Also considered were limits on the flow of power across the western interface, which have been found necessary to counter the serious phase-angle-difference problem experienced in that area.

Possible Transmission Solutions

Upgrade of existing lines

A variety of approaches to avoiding transmission transfer constraints are possible. In some cases thermal limits can be overcome by reconductoring—replacing a transmission line's current-carrying conductors with new conductors which are larger or which have a higher temperature rating. Sometimes a thermal limit is not due to a transmission line rating, but to ratings of associated equipment in substations. In this case thermal limits can be overcome by replacing substation equipment.

. . . power-carrying capacity of lines can be increased not only by reconductoring lines to increase allowable current, but also by rebuilding a line to operate at a higher voltage.

Electrical power is equal to the product of current and voltage. Accordingly, power-carrying capacity of lines can be increased not only by reconductoring lines to increase allowable current, but also by rebuilding a line to operate at a higher voltage. This typically requires using larger insulators and may also require that taller poles or towers be used. It also may require new transformers to connect a line—with its newly increased voltage—to existing substations.

New transmission lines

A new transmission line between two areas provides a new path for electric power to flow between the areas. This tends to reduce the flow on some nearby lines (although it may increase the flow on others). A well-chosen line can not only directly increase power transfer between two areas, it can reduce flows on lines which are near thermal limits, indirectly allowing increased power transfer. Building a new transmission line generally also reduces electrical losses and problems associated with phase-angle differences, transient stability, and voltage stability.

. . . the higher the transmission voltage, the more power a line can carry and the lower the losses are.

Each transmission line is designed to operate at a particular voltage level. A variety of transmission voltage levels are in use in North America. Wisconsin's transmission system is composed primarily of a 345 kV "backbone," a system of 115, 138, and 161 kV lines—each of which is used in a different area of the state—and an extensive network of 69 kV lines. Transmission systems in adjacent states include 500 and 765 kV lines. In general, the higher the transmission voltage, the more power a line can carry and the lower the losses are. Higher-voltage lines, however, require the use of taller structures and wider rights-of-way (although they can carry more power per foot of ROW width than can lower-voltage lines). Typical transmission tower and right-of-way dimensions are shown in Appendix G.

Direct-current (DC) transmission

The power system is designed to transmit and distribute AC power. Although it has certain disadvantages, DC transmission is also possible, and a small number of DC transmission lines operate in North America, including two lines connecting North Dakota and Minnesota. DC lines must have a converter station at each end, to allow interconnection with the AC power system. These converter stations are very expensive. Moreover, it is generally not practical to make a new connection in the middle of a DC transmission line (and would require an additional converter station in any case). This is in contrast to AC transmission lines, which can be readily connected to other parts of the system at any point.

Despite these disadvantages, DC transmission makes sense in certain circumstances. For point-to-point transmission of electricity over long distances, for example between a large population center and a remote power plant, both losses and cost of the transmission line (excluding converter stations) may be lower for a DC line than for an AC line with the same power-handling capacity.

Other advantages of DC transmission include the ability to transmit electricity much further through underwater cables than is possible using AC transmission, and the fact that the converter stations make possible the precise control of power through the DC line.

Other control devices

While DC transmission converter stations allow control of the power flow over DC lines, other devices, though not widely used, are available to allow control of power over existing AC lines. Two such devices, which are representative of available technology and which have potential application in the Wisconsin transmission system, area are described below.

A phase shifting transformer . . . is capable of altering the effective phase-angle difference between the two ends of the line.

A phase shifting transformer is a device which, when connected to a transmission line, is capable of altering the effective phase-angle difference between the two ends of the line. Since power flow over a transmission line is closely related to the phase-angle difference between the line ends, phase shifting transformers allow the flow of power across a line to be adjusted. Phase-shifting capability also can allow system operators to overcome the phase-angle problem described earlier—reducing the phase-angle difference across an out-of-service line enough to allow the line to be reconnected.

In contrast to conventional phase shifting transformers, which are a mature technology, the unified power flow controller (UPFC) is a new device which is just beginning to be used on transmission systems. The UPFC uses semiconductor switching technology to alter the flow of power through a line on which it is installed. Among other capabilities, this versatile device can act like a phase shifting transformer and can modify power flows to alleviate voltage problems, including voltage collapse. In addition, semiconductor technology allows very rapid switching and precise control; this, in turn, makes possible quick response to, and mitigation of, a variety of fast-developing power system problems.

In principle, the ability of devices such as phase shifting transformers and UPFCs to control power flow through individual lines allows operators to better utilize the existing transmission system. On the other hand, using phase shifting transformers to alter patterns of power flow can simply move transmission problems into other areas. Other drawbacks of these devices include their expense and the fact that their use can complicate system operation, particularly when interactions between multiple control devices must be considered.

Chapter 4

Engineering Analysis

Study Methodology

The heart of this study is a computer model of a large portion of the North American power system. By simulating power transfers into eastern Wisconsin, it is possible to identify transmission constraints and to quantify the performance of a range of transmission reinforcement options. The power system model and simulation are laid out in detail in Appendix B. The main elements of the analysis, however, are described below.

A large computer model of the entire Eastern Interconnection was developed . . . .

A large computer model of the entire Eastern Interconnection was developed, reflecting generation, demand, inter-area transactions, and transmission system modifications expected to be in place in 2002. This model represents an electric system on a hot summer weekday, when electrical demand reaches its highest level. This model included several transmission facilities in and around Wisconsin, listed in Appendix C, which have not yet been installed. It is not certain that all of these options will receive regulatory approval or that they will be built. Nonetheless, these facility additions were included in an effort to maximize the realism of the modeled system, since they—or similar alternative options—are believed to be required to ensure that local loads can be reliably served in 2002.

. . . transfer . . . limits were . . . calculated with thousands of possible line outage contingencies . . . .

Once the base-case system was defined, additional sources of electricity were identified in states to the west, south, and east. The simulation then modeled increasing levels of power transfer from these sources into eastern Wisconsin, up to the point that power flow through some element of the transmission system reached its thermal rating, posing a transfer limit. Two different transfer scenarios were examined: one with most generation sources to the west, and one with most generation sources to the south and east. Not only were transfer limits calculated with all transmission lines in service, but limits were also calculated with thousands of possible line outage contingencies—a considerably more demanding condition.

These "first-contingency" transfer capability limits were found, in many cases, to be avoidable through relatively inexpensive equipment modifications or line reconductoring. Simulated power transfers continued to be increased until a "hard" limit—one surmountable only by expensive or otherwise difficult means—was reached. This fact accounts for the large number of individual construction items included in each option listed in Appendix I Table I.1. Several smaller transmission system fixes are required to allow a large fix, such as a new high-voltage transmission line, to achieve its transfer potential. If simulated power transfer reached the target level of 2,000 MW from one set of sources and 3,000 MW total, the transmission option under study was deemed successful and no further transfer was modeled.

The computer model simulated the operation of a power system consisting of thousands of generators and tens of thousands of interconnecting transmission lines.

The computer model simulated the operation of a power system consisting of thousands of generators and tens of thousands of interconnecting transmission lines. Computer simulation of so large a power system is an enormously demanding computational undertaking, particularly when the outage of each of thousands of lines is considered in turn.

Fortunately, approximation techniques are available for this sort of power system analysis which greatly simplify the computation. These techniques were used to calculate the transfer capability of each option, shown in Table 4.2. Based on these results, a subset of options (the "short list") was then selected, including options which both fared well on the initial screening and formed a representative sample of diverse approaches to transmission system reinforcement. Additional analysis using more exact techniques was then performed on this subset of options to gather more detailed information on the performance of these options, including the phase angle and electrical loss data in Table 4.2.

Transmission Constraints Identified

Northern Illinois constraints

. . . transfers from western generation sources flow, in part, through the CE system . . . .

Through the analysis procedure described above, transmission constraints which limit transfer capability in the modeled system were identified. Serious overload problems in the CE's northern Illinois transmission system appeared in the base case and in nearly all transmission option scenarios, typically at power transfer levels well below the target level. Because transfers from western generation sources flow, in part, through the CE system, these problems pose a significant transfer limitation.

A new transmission line connecting Plano to a new Plano Tap Substation . . . was found to eliminate the most serious problems . . . .

These constraints can be seen in Table 4.1, which identifies limiting elements encountered in the analysis. Some, but not all, of these northern Illinois problems could be fixed with relatively inexpensive equipment modifications. Most prominent among the remaining problems are constraints associated with the flow of power between CE's Plano Substation and areas closer to Chicago, to the east. A new transmission line connecting Plano to a new Plano Tap Substation, approximately

20 miles to the east, was found to eliminate the most serious overload problems, and allowed a substantial increase in power transfer into eastern Wisconsin.

Table 4.1 Partial list of constraints in the analysis

Constraints	State
Eau Claire-Wheaton 161 kV line	Wisconsin
Arpin Interface operating flow limit	Wisconsin
Electric Junction-Plano 345 kV line	Illinois
Wheaton-Wheaton Tap 161 kV line	Wisconsin
Wheaton-Elk Mound 161 kV line	Wisconsin
Wien-T Corners 115 kV line	Wisconsin
Arcadian 345/230 kV transformer	Wisconsin
Itasca-Lombard breaker	Illinois
Seneca-Genoa 161 kV line	Wisconsin
Columbia-South Fond Du Lac 345 kV line	Wisconsin
Blackhawk-Colley Road 138 kV line	Wisconsin
Rock River-Liberty 138 kV line	Wisconsin
Paddock 345/138 kV transformer	Wisconsin
Sand Lake-Port Edwards 138 kV line	Wisconsin
Pulliam 138/115 kV transformer	Wisconsin
Rocky Run-Whiting 115 kV line	Wisconsin
Turkey River-Cassville 161 kV line	Iowa / Wisconsin
Paddock-Wempletown 345 kV line	Wisconsin / Illinois
Lore-Turkey River 161 kV line	Iowa
Kelly-Whitcomb 115 kV line	Wisconsin
Weston 345/115 kV transformer	Wisconsin
Sigel-Arpin 138 kV line	Wisconsin
Forest Junction-Highway V 138 kV line	Wisconsin
Arpin 345/138 kV transformer	Wisconsin
Goodings Grove-Lockport 345 kV line	Illinois
Itasca-Tonne transformer	Illinois
Plains 345/138 kV transformer	Michigan

With this discovery, the Plano-Plano Tap transmission line was then made a part of nearly all options, and allowed several of them to reach the target transfer capability level. It is important to note, however, that this line, while short, will require entirely new ROW through a rapidly developing area west of Chicago. Accordingly, it may not be realistic to assume that this line can be built in the near future.

Options to the Plano-Plano Tap line (or a similar Chicago-area line) do exist. One particularly interesting option involves bypassing the congested northern Illinois transmission system entirely by means of a new line beneath Lake Michigan. The best under-lake candidate for relieving northern Illinois overloads appears to be a line between the Donald C. Cook nuclear power plant in far southwestern Michigan and the now-closed Zion nuclear plant in the northeastern corner of Illinois. This line is quite effective in circumventing the problems in northern Illinois and facilitating power transfer into eastern Wisconsin. The length of this underwater line, however, requires that DC transmission technology be used. Consequently, this is a far more expensive solution than an above-ground AC line such as Plano-Plano Tap.

. . . transmission system limitations on the scale considered in this study must be regarded as a regional problem and regional solutions must be fostered.

Consideration of transmission constraints in northern Illinois points to an important lesson: significant improvement in transmission transfer capability into eastern Wisconsin will require the construction of new facilities in other states. Ultimately, transmission system limitations on the scale considered in this study must be regarded as a regional problem and regional solutions must be fostered.

. . . significant improvements in transmission transfer capability into eastern Wisconsin will require the construction of new facilities in other states.

Wisconsin constraints

In addition to transmission constraints in northern Illinois, this study identified numerous constraints within Wisconsin. Virtually all of the transmission options considered, for example, were found to be limited by line overloads in the Eau Claire area. These limits, and many others, could be overcome relatively inexpensively through transmission system upgrades.

While these constraints did limit transfer in the modeled system, it is important to recognize that many of the limiting elements in Table 4.1 do not limit transfer in the present system. Typically, these limits are not significant today because power transfer is prevented from ever reaching the level at which they would be constraining by the existence of other, lower, limits. Similarly, if actual generation and transmission in 2002 does not correspond to the system modeled in this study, a different set of limits may appear. Consequently, it does not necessarily make sense to act quickly to fix the problems identified in Table 4.1, even though they may be quite inexpensive.

Limits due to western interface phase-angle problem

The most important limitation to power transfer across the western interface, however, is not due to facility thermal overloads, but to the need to limit phase-angle differences across the western interface. As described earlier, power system operators limit flows on the 345 kV line between Eau Claire and Arpin to ensure that, should the line trip out of service, the subsequent phase-angle difference between the two ends of the line can be restored to a level within established limits. Specifically, is must be possible to reduce this phase-angle difference to 60 degrees, in order to allow the line to be returned to service. Reconnecting the power line at larger phase-angle differences results in a power surge that could damage generators at the Weston Power Plant near Wausau.

To enable the line to return to service, phase angles can be reduced by increasing generation in eastern Wisconsin and decreasing generation to the west. This is necessarily a slow process, however, leaving the system vulnerable to overloads of other lines or additional disturbances, such as lightning strikes and equipment failures. To ensure that this angle can be reduced to 60 degrees within a reasonable period of time, a transfer limit for this line of 775 MW has been established. This is well below the thermal limit of the line.

Ideally, any transmission reinforcements selected to increase transfer capability would also yield a post-contingency phase-angle difference (i.e., that which results from an outage of the line) of less than 60 degrees. This would allow the immediate return to service of the Eau Claire-Arpin line, without the need to adjust generation levels.

On June 25, 1998, western Wisconsin lost synchronism with both Minnesota and eastern Wisconsin, becoming an electrical "island."

Events in two previous years highlight the key role of this transmission line and the potential for severe consequences when large phase-angle differences delay the return to service of this line. Outages of the Eau Claire-Arpin line, and extended delays in returning the line to service, brought the power system close to the point at which blackouts could have occurred on both June 11, 1997, and June 25, 1998. In both cases, the unexpected disconnection of other parts of the transmission system (by automatic protective devices) led to an excessive phase-angle difference across the western interface when the Eau Claire-Arpin line was disconnected (also by an automatic protective device). On June 25, 1998, western Wisconsin lost synchronism with both Minnesota and eastern Wisconsin, becoming an electrical "island." All of the MAPP region nearly became an island on June 11, 1997. Subsequent studies indicated that, had flows on a key Nebraska line been only slightly higher, that line would have been forced out of service and cascading outages would then have disconnected all remaining ties from MAPP to the south and west.

Such an event, called a system separation, causes problems not only in the area with more demand than generation but also on the other side, which has more generation than demand. This is because generators accelerate suddenly when demand is lost, and may then have to be disconnected to prevent damage. This can ultimately lead to inadequate generation on both sides, forcing blackouts. Consequently, the western interface phase-angle problem is a concern to utilities on both sides of the interface.

While steps such as reconductoring to increase a line's allowable power carrying capacity may overcome thermal limits to power transfer, they do nothing to alter the pattern of power flow and, thus, have no effect on this phase-angle problem. Rather, new lines or other means of altering the flow of power must be implemented. In general, new transmission interconnections should improve voltage stability problems as well as phase-angle problems. This is significant because voltage stability problems are believed to limit transfers across the western interface to levels only slightly more than the 775 MW phase-angle limit. The precise nature of this voltage stability limit, and the effect of transmission reinforcement on this limit, must await further study.

Transmission Reinforcement Options Considered

Several transmission system reinforcement options were examined to determine their impact on transfer capability into eastern Wisconsin. The starting point for selection of these options was the list of transmission lines proposed in the Wisconsin utilities' 1997 report to the Governor on electric reliability. Additional options were generated through minor modification of these original proposals.

The list of options was further broadened to ensure that no class of potential solutions was neglected. Additions included additional high-voltage transmission line routes, construction of several relatively short lower-voltage lines, DC lines under Lake Michigan, and an option consisting of a single new line less than 30 miles long in conjunction with multiple upgrades of existing lines and equipment.

Consideration was also given to addressing the western interface phase-angle problem by adding equipment rather than new lines. The benefits of this approach, however, are only described qualitatively in this report. Quantitative analysis, which would allow detailed comparison with other options, can be realistically conducted only in the context of more detailed follow-up studies.

Performance of Transmission Options

Initial Analysis of Transmission Options

Each of 50 transmission reinforcement options, some of which differed only slightly from each other, were assessed to determine the transfer capability they could provide for eastern Wisconsin. Two different scenarios, one with most of the power coming from sources to the west and the other with most of the power coming from southern Illinois and states to the east, were examined.

The results of this preliminary analysis appear in Appendix I. Several points are apparent from examination of these results. First, it is clear that some means of overcoming problems in northern Illinois will be required to achieve transfer levels close to the target levels in this study. Without the Plano-Plano Tap line—or, in one case, a line from Plano to Paddock—no option is close to providing 2,000 MW of transfer from either southern or western sources.

Those options which did not yield power transfers approaching the target transfer level were not analyzed further. Among those options which did reach the target transfer level, or nearly did so, a subset of 12 was selected for further analysis. The transmission lines associated with the 12 options are illustrated in Figure 4.1. This

Figure 4.1 Regional map of potential options

[color map]

subset was selected so as to include those options which appeared the most promising, and to ensure that as wide a range of options as possible received further examination. Typically, only one of several similar options which yielded the desired transfer were carried on to the next phase of the analysis.

Analysis of short-list options

In this second phase more precise calculation of power flow patterns resulting from each option was carried out. This allowed estimation of the phase angle which would result from the outage of the Eau Claire-Arpin line and a calculation of the impact of the new line (or lines) on electrical losses.

All options exhibited transfer capabilities very close to the target level of 2,000 MW from each direction.

Table 4.2 and Figures 4.2 and 4.3 show the performance of these 12 options. All options exhibited transfer capabilities very close to the target level of 2,000 MW from each direction. Some options could probably have shown higher transfer levels if limits avoidable through relatively inexpensive means were pursued. Once an option reached a transfer level in excess of 2,000 MW, however, no attempt was made to do so. In any case, transfer capabilities much higher than 2,000 MW generally could not be accurately modeled because of limitations in modeling assumptions and approximation methods used in the calculation. Consequently, differences in transfer capability associated with the options shown in Table 4.2 should not be accorded great significance. The important point is that all options appear to be good candidates for providing levels of transfer sufficient to ensure reliability.

As noted above, the post-contingency phase angle across the western interface is significant for reliability of system operation. Nonetheless, the transfer capability analysis did not explicitly consider this limit. This is because the limit itself is a function of the structure of the transmission system, and adding a new line to the system should be expected, in general, to increase the transfer level at which the threshold phase-angle difference occurs. Accordingly, rather than enforcing the western interface transfer limit in the simulation, the post-contingency phase-angle difference for each option on the short list was calculated under maximum power transfer conditions.

The smaller the resulting phase-angle difference, the better the performance of these options. In particular, a phase-angle difference less than 60 degrees indicates that the option will eliminate the need for generation readjustment to reduce the phase-angle difference to 60 degrees following a trip of the Eau Claire-Arpin line. Conversely, post-contingency phase angles that exceed 60 degrees will require continued reliance on these operating procedures and thus, leave the power system more vulnerable to disruption.

Table 4.2 Short list of options

#	Option Description[1]	Transfer Capability Western Sources (MW)	Southern Sources (MW)	Arpin Phase Angle[2]	Losses[3] (MW)
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap 345 kV	2,220	2,040	92°	486
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap 345 kV	2,121	2,279	78°	475
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	1,980	1,960	95°	504
3e	Arrowhead-Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	2,160	2,020	65°	452
3j	Arrowhead-Weston 345 kV Plano-Plano Tap 345 kV	2,100	2,050	70°	444
3k	Arrowhead–Weston 230 kV Plano-Plano Tap 345 kV	2,160	2,000	83°	470
5a	Chisago-Apple River-Weston 345 kV[4] Plano-Plano Tap 345 kV	2,276	2,136	48°	449
6c	Chisago-Rocky Run 500 kV Rocky Run-South Fond du Lac 345 kV Plano-Plano Tap 345 kV	2,393	2,150	38°	410
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap 345 kV	2,090	1,970	80°	481
9a	Huron-Split Rock-Lakefield Jct-Adams 345 kV Adams-Genoa-Columbia 345 kV Plano-Plano Tap 345 kV	2,572	2,412	72°	440
12	Plano-Plano Tap 345 kV	1,910	1,710	99°	510
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap 345 kV	2,250	2,070	77°	459

[1] All options contain additional facilities which are detailed in Appendix H Table H.2.

[2] Arpin Substation is located south of Marshfield, Wisconsin. A phase angle of less than 60 degrees is desirable because it eliminates the need for cumbersome operating procedures.

[3] Losses of options were calculated with a simultaneous transfer of 1,000 MW from the west and 1,000 MW from the south. The figures in the table are losses relative to base case conditions without transfers.

[4] This line replaces the Chisago-Apple River 230 kV line which is assumed in service in all other options.

Figure 4.2 Arpin phase angle

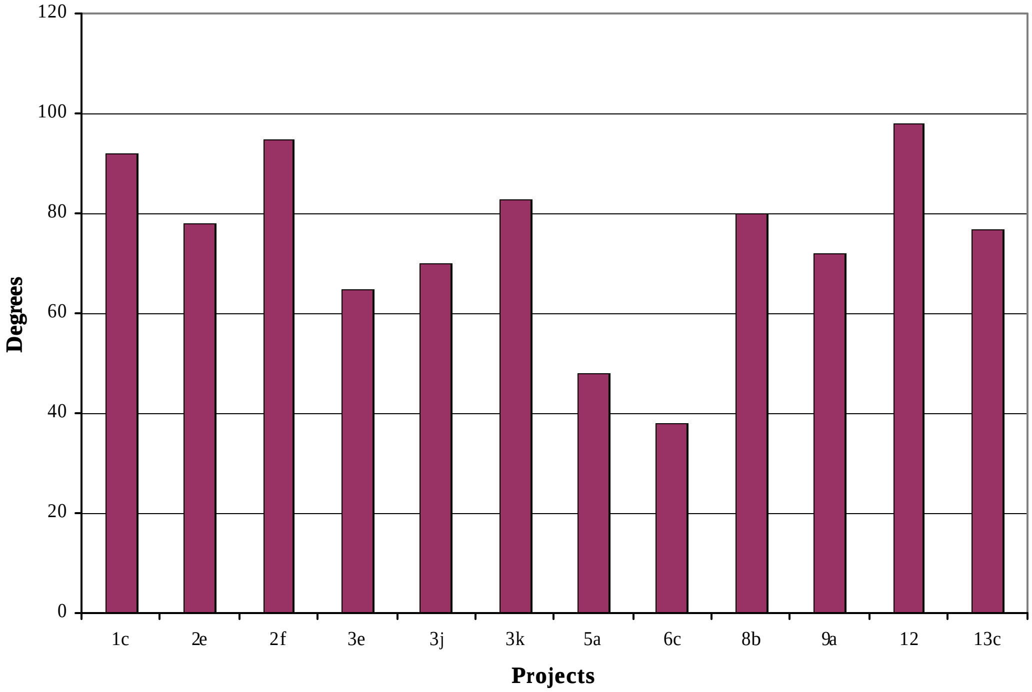
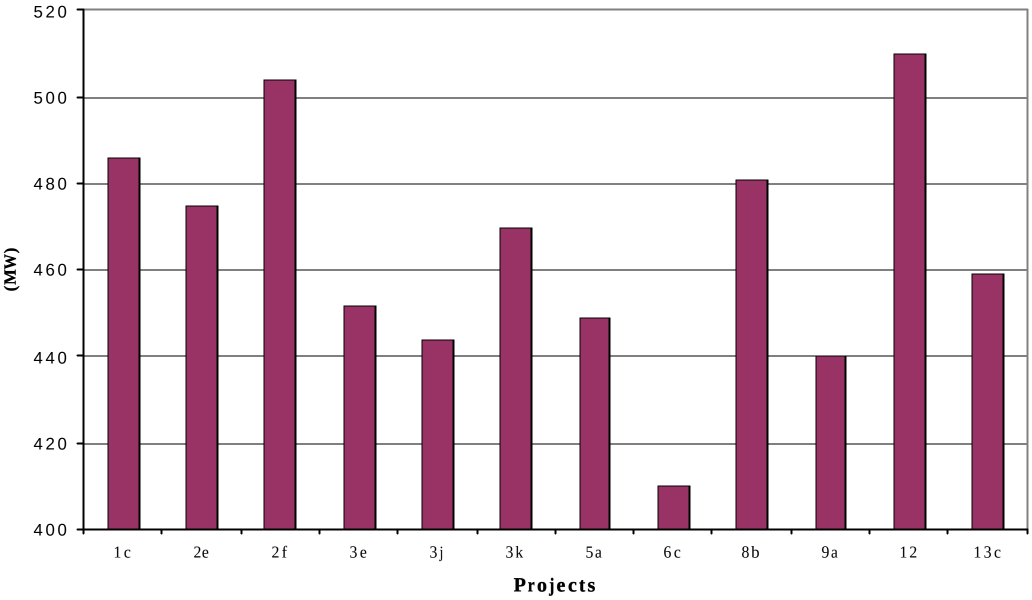


Figure 4.3 Losses



. . . the reinforcement options which most closely parallel the existing Eau Claire-Arpin line are the most successful in reducing the post-contingency phase angle.

As Table 4.2 shows, the reinforcement options which most closely parallel the existing Eau Claire–Arpin line are the most successful in reducing the post-contingency phase angle. Lines which originate at Chisago, Arrowhead, and Prairie Island perform relatively well, as do lines which terminate at Weston or Rocky Run. Lines that provide a less satisfactory alternative path to Eau Claire–Arpin, such as Wilmarth-Byron-Columbia or the lines originating in Salem, perform less well. Option 12, which includes less than 30 miles of new transmission line, performs remarkably well in terms of transfer capability, but does not come close to reducing the Arpin phase angle to within acceptable limits.

Table 4.2 also summarizes the loss performance of the options. Adding a new line to the transmission system generally reduces losses and higher-voltage lines reduce losses more than lower-voltage lines. However, system losses increase in proportion to increases in power transfers. Losses were calculated system-wide; not just in Wisconsin. These losses correspond to peak demand conditions and high transfer levels.

Performance of DC line under Lake Michigan

All transmission reinforcement options in Table 4.2 include a new transmission line from CE's Plano Substation. Analysis demonstrated that such a line was required to overcome important limits to power transfer. The new Plano-Plano Tap line (included in 11 of 12 transmission reinforcement options) is not exceedingly expensive but prospects for quick construction of this line are uncertain because this line will require a new ROW in the fast-developing western Chicago suburbs. If this line (or a similar line) cannot be built, other upgrades or new construction in Wisconsin will not provide the desired transfer capability into Wisconsin.

An alternative to improvements in the CE northern Illinois network is to bypass the region with a transmission line cable under Lake Michigan. The length of this line necessitates the use of DC transmission technology. Several line terminations are possible on the western and eastern sides of the lake. A line between the Cook Substation on the eastern shore and the Zion Substation on the western shore appears the best choice for relieving constraints in the northern Illinois transmission system. Moreover, the strength of the transmission system at each of these locations minimizes problems in delivering power to or from these substations. A more northerly line, between Michigan's Campbell Substation and the Oak Creek Substation south of Milwaukee, was also modeled, but is not depicted on the maps (Figures ES.1 and 4.1).

To test whether a DC line under Lake Michigan will relieve the transmission problems in northern Illinois, two new transmission options were developed, in which option 12 was modified by inserting each of these DC lines in place of the Plano-Plano Tap line.

Each DC line was assumed to have a capacity of 1,000 MW. The results of this simulation are presented in Table 4.3.

Table 4.3 Effect of a DC line under Lake Michigan on transfer capability

Western Import Total Transfer Capability with a 1,000 MW Southern Bias (MW)			Southern Import Total Transfer Capability with a 1,000 MW Western Bias (MW)		
No DC Line	With Cook-Zion DC Line at 1,000 MW	With Campbell-Oak Creek DC Line at 1,000 MW	No DC Line	With Cook-Zion DC Line at 1,000 MW	With Campbell-Oak Creek DC Line at 1,000 MW
1,319	1,805	1,755	1,041	1,820	1,880
(Stated transfer capabilities do not include the DC line MW flow)					

As these results show, the modeled under-lake lines effectively relieve the transmission limits in northern Illinois and, including the power transferred over the DC line, allow power transfer that meets the target established for this study. In fact, analysis indicates that this target could be reached with only 500 MW of DC transmission, and that additional DC transmission provides little additional increase in transfer capability over other lines.

While this analysis shows that a single under-lake line, in combination with line and equipment upgrades, can significantly enhance power transfer into Wisconsin, it is important to keep in mind two important drawbacks of this approach. First, such a line should be expected to do little to alleviate the western interface phase-angle problem. Consequently, the phase-angle limit will continue to constrain transfer in the absence of other actions to address this problem. Secondly, DC transmission technology is quite expensive. At approximately $250/kW, the DC converter stations alone are more than half the cost of a new natural gas-fired combustion turbine power plant.

Control Options for Western Interface Phase-Angle Problem

In order to increase transfer capability into eastern Wisconsin to the levels assumed in this study it will be necessary to find a solution to the phase-angle problem on the western interface. The most robust solution to this problem is probably construction of a new high-voltage transmission line, roughly in parallel to the existing 345 kV line across the western interface. Construction of a new transmission line is a significant undertaking, however, and one which is sure to raise concern about cost and environmental impacts and to face opposition from those who live along the proposed route. For this reason, it is appropriate to consider alternative approaches to addressing the phase-angle problem.

By modifying existing devices connected to the transmission lines or by installing new devices, it may be possible to reduce the phase-angle problems on the western interface, thereby increasing allowable power transfer. Three such approaches are described below. Since voltage stability considerations are likely to pose limits to transfer only modestly higher than the phase-angle transfer limit, further study will be required to allow the effectiveness of these approaches to be fully assessed and to allow comparison with a new transmission line.

Single-pole reclosing

The principal problem with reconnecting the Eau Claire-Arpin line at large phase angles is that the resulting power surge affects nearby generating stations, possibly causing mechanical damage to the generator and the plant auxiliary equipment. The shock can be reduced somewhat by spreading the change over a longer time span. This can be done by employing single-pole reclosing—connecting the three transmission line conductors one at a time, perhaps a few tenths of a second apart, rather than reconnecting all three simultaneously.

Single-pole reclosing is used sparingly around the world because the network unbalance caused by the scheme causes other network problems. This technique is very inexpensive and easy to implement, however, and should increase the transfer limit posed by concern for phase angle. Further investigation of this approach should be considered.

Phase shifting transformer

Phase shifting transformers (described briefly in Chapter 3) are commonly used to control the power flow through a transmission line. They are particularly effective in rearranging and leveling flows in surrounding AC systems, thereby increasing transfer capability. The phase-angle problem on the western interface, however, suggests a different application for this device: reducing the phase-angle difference across an out-of-service line to a level that would allow the line to be reconnected.

This scheme uses a phase shifting transformer in a very unusual way. The stress on the transformer and transformer maintenance problems caused by this application are unknown. The requirements for time responsiveness of the phase shifting transformer and the effectiveness of this scheme in reducing stress on the nearby generators are unknown.

Despite these uncertainties this scheme may be a very cost-effective means to increase the limit to power transfer across the western interface. To be sure, such a scheme complicates the present operating procedures. Nevertheless, further and more detailed investigation of this scheme should be considered.

Unified Power Flow Controller (UPFC)

This is a new device that uses electronics to quickly control power flows, phase angles, and voltages on a transmission line. Such a capability would seem to be ideal for this circumstance where all these parameters are in need of quick and effective control.

However, conceptual application of a UPFC raised a concern that present-day devices could not handle conditions as severe as that seen on the Arpin-Eau Claire line. Without a new transmission line, the post-contingency phase angle associated with 2,000 MW of power transfer is in excess of 120 degrees. The UPFC controls angle by injecting a compensating voltage into the line. It is unclear whether existing UPFC designs can create sufficient offset voltages for angles of this magnitude.

UPFC cost is another concern. Preliminary cost estimates for a UPFC is $225/kVA, yielding a total cost of about $337 million to handle the maximum loading of 1,500 MVA of this line. Like the phase shifting transformer, a UPFC could complicate system operation.

. . . control schemes may be available to increase the transfer capability of the Arpin-Eau Claire 345 kV line.

In summary, various control schemes may be available to increase the transfer capability of the Arpin-Eau Claire 345 kV line. In general, more detailed investigations will be required to determine if these approaches are effective in reducing the existing phase-angle problem. Even if some option proves effective in mitigating the phase-angle problem, they may do nothing to solve voltage stability or other problems, which may impose a new transfer limit only slightly higher than the existing limit. Nonetheless, the fact that these options may reduce the need for new transmission line construction suggests that further study to resolve these questions is appropriate.

Chapter 5

Economic Analysis of Transmission Options

The engineering analysis in this study did not limit or reject options based on cost. For the purposes of option comparison and guiding future policy and study directions, capital costs were estimated for each short-list option after its technical performance was determined (see Table 5.1 and Figure 5.1). Actual cost could deviate substantially from these preliminary estimates.

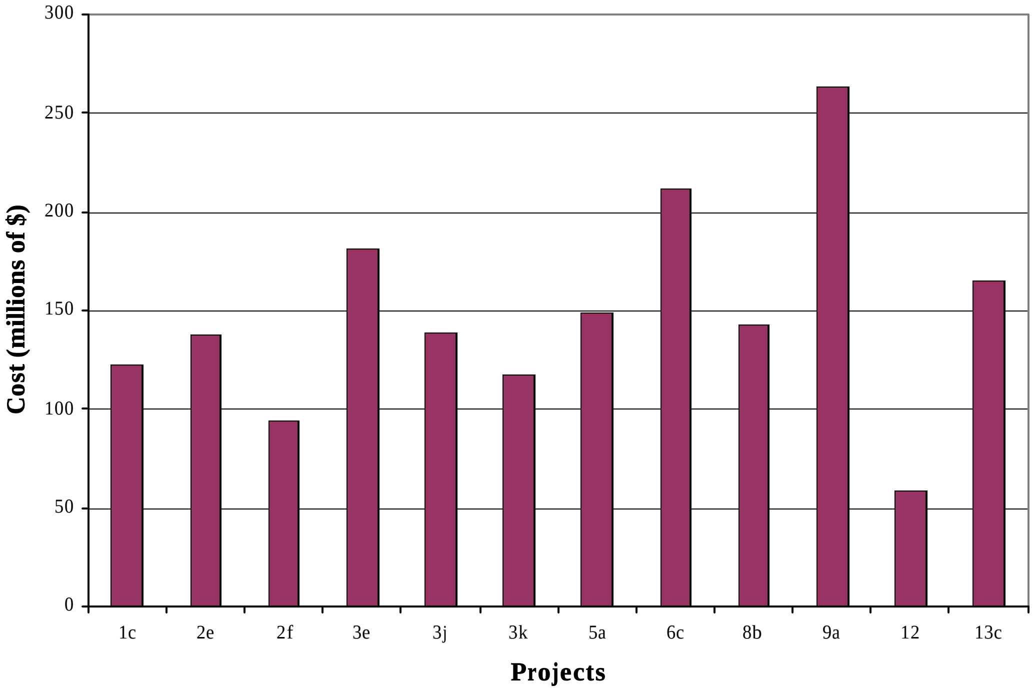
Table 5.1 Short list of options

#	Option Description [1]	Construction Capital Cost (millions) [2]
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap 345 kV	$123
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap 345 kV	$138
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	$94
3e	Arrowhead-Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	$181
3j	Arrowhead-Weston 345 kV Plano-Plano Tap 345 kV	$139
3k	Arrowhead–Weston 230 kV Plano-Plano Tap 345 kV	$118
5a	Chisago-Apple River-Weston 345 kV Plano-Plano Tap 345 kV	$149
6c	Chisago-Rocky Run 500 kV Rocky Run-South Fond du Lac 345 kV Plano-Plano Tap 345 kV	$212
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap 345 kV	$143
9a	Huron-Split Rock-Lakefield Jct-Adams 345 kV Adams-Genoa-Columbia 345 kV Plano-Plano Tap 345 kV	$263
12	Plano-Plano Tap 345 kV	$59
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap 345 kV	$165

[1] All options contain additional facilities which are detailed in Appendix H Table H.2.

[2] Costs shown are estimated capital investment in 1998 dollars and include facilities detailed in Appendix H Table H.2.

Figure 5.1 Option cost



Construction Cost

The short-list options involved three types of investment items:

- Upgrades to terminal equipment and transformers;
- Transmission line reconductoring or voltage upgrading; and
- New construction on new ROW.

Termination upgrades, reconductoring, and voltage upgrading costs tend to be very specific to the existing physical facility details. Many of the option items of this type have been studied previously and costs have been estimated by the relevant utility. Therefore, the cost of these items was provided by these companies.

Estimating new construction cost in detail requires more time than was available and appropriate for this screening study. Power Technologies, Inc. estimated these costs on the same basis for all new construction based on typical industry cost data and simple estimates of line distances and equipment requirements.

Cost of new construction proceeded with these steps:

- Distances were estimated by map measurement following existing ROWs where possible. These estimates were refined by the transmission providers.
- A mileage estimate was subdivided into rural and suburban portions. H-frame construction was assumed in rural areas and steel-pole construction in suburban areas.
- The number of major river and overhead line crossings was estimated for each new line. Structure height and strength must be increased for river and line crossings. Additional costs are included for river crossings and transmission line crossings. Costs for underground construction for river crossings were not included in these estimates but could involve millions of dollars for each crossing.
- The number of line terminations (switchyard extensions, switchgear, breakers, relaying, communications, etc.) and transformers was determined for each new line.
- Typical costs (in 1998 dollars) were used to calculate the cost of each new transmission facility. These are shown in Appendix H.

Impact on Losses

The technical studies demonstrate that all the options reduced transmission losses at the test transfer levels compared to the unexpanded transmission system. Estimated losses for the short-list options are shown in Figure 5.2 and Table 4.2. No attempt was made to calculate the economic value of losses because:

- Option details, line loadings, and physical characteristics cannot be accurately determined until more detailed studies are completed.
- The study considered a single time slice, dispatch pattern, and load level. More system conditions must be studied to better estimate line losses.

Other Costs

Estimates of other line costs such as operation and maintenance or ancillary service cost differences (e.g., voltage support, reserve costs) for each plan was not attempted.

Lake Michigan DC Cable Option

All of the short list options required construction of a high-voltage transmission line in Illinois to achieve the transfer capability objectives. The new 345 kV Plano-Plano Tap line is not exceedingly expensive (estimated to be less than $30 million) but prospects for quick construction of this line are uncertain because this line will require a new ROW in the fast-developing western Chicago suburbs. An alternative to improvements in the CE northern Illinois network is to bypass the region with a cable connection under Lake Michigan.

An estimate of the cost of a DC cable connection under Lake Michigan is about $178 million based on these assumptions:

- Termination cost (both ends combined) $250/kVA;
- DC line rating 500 MW;
- Cable cost $125 per foot installed; and
- 80 mile length.

This $178 million cost is to be contrasted with the $35 million cost of the 345 kV Plano-Plano Tap line included in most options.

Chapter 6

Environmental Impact Analysis of Transmission Options

Overview

A detailed quantitative environmental assessment for the transmission lines identified in this study cannot be performed in the short time allotted for the preparation of this report. Some qualitative judgments, however, can be made. The environmental and social issues and impacts associated with any of the identified high-voltage transmission lines are likely to be significant. All the proposed solutions for increasing transfer capability to eastern Wisconsin will require the participation of not only landowners, utilities, and regulators in Wisconsin, but also landowners, utilities, and regulators in surrounding states. History has shown that the construction of any high-voltage transmission line will be controversial. Construction of new transmission lines associated with the options analyzed in this report may lead to significant environmental impacts.

Environmental Impacts

Figure 4.1 shows the approximate location of new bulk power transmission lines identified in the study. Line locations are largely straight-line connections between endpoints. A line's eventual route may shift to avoid sensitive areas or to connect additional substations. However, changes in alignment will increase a line's length and cost.

Transmission lines require that a ROW be cleared on either side of the line to allow access to the line and to protect the line from falling trees or structures. The width of the ROW depends generally on the line's voltage and physical design. Generally, the most significant environmental issues and impacts associated with electric transmission lines include: loss of forest land and associated wildlife habitat, damage to wetland soils during construction and repair activities, incremental resource losses associated with forest fragmentation and the resulting conversion of wildlife habitat, interference with farming operations, and concerns about the potential health effects related to exposure to electromagnetic fields (EMF).

Table 6.1 lists the estimated length of each line proposed in this study and the estimated acres potentially affected within the ROW of each line.[5] The nature and severity of environmental impacts will vary depending on what part of the state is involved. Lines constructed in the northern third of the state will affect primarily forests and wetlands. Northern areas of the state also have a higher proportion of state- and federally-owned land. Transmission lines built in the southwestern and western part of the state will affect a larger proportion of farmland than in the north, however, a significant amount of woodlands on forested bluffs could be affected. Transmission lines built in the central, southern, and southeastern portions of the state will cause impacts to farmland, scattered woodlands, and wetlands. Impacts to urban, suburban, and ex-urban areas are most likely in the east central and southeastern parts of the state. Impacts from forest fragmentation will be most severe in western and northern Wisconsin.

Social Impacts

Regardless of location, the use of private land will be required for any transmission line. The use of private land will likely require the exercise of eminent domain. Wisconsin landowners, by law, will receive an easement payment for transmission ROW on their property that reflects the fair market value of the land at the time the easement is procured. One-time payments for loss of marketable timber, in Wisconsin, may also be made. Eminent domain, in Wisconsin, comes into play only after the Commission approves a project.

Landowners are largely concerned over the loss of use of their property, aesthetics, and decreases in property value. The easement payment theoretically compensates landowners for any loss of use. Aesthetic impacts are difficult to quantify. In general, lines of the type proposed in this report would be located in rural landscapes. Transmission facilities, from an aesthetic perspective, are not compatible with a rural landscape and would significantly affect aesthetic values in the immediate vicinity of the line. Changes in property value are also difficult to quantify. While there is no hard evidence to support the claim that the construction of a new transmission line reduces property value, some reduction in value may occur, especially in rural settings. Compensation for real or perceived aesthetic impacts or for potential reductions in property values are problematic and unlikely to be satisfactory for many landowners in projects of this scale.

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[5] Calculations assume that a 110-foot wide ROW will be used for lines rated at 345 kV and above.

Table 6.1 Land impact characteristics

#	New Transmission Line	Estimated Total Miles	Estimated Miles in Wisconsin	Number of Acres Potentially Affected in Wisconsin
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap 345 kV	135	125	1,667
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap 345 kV	200	200	2,667
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	85	80	1,067
3e	Arrowhead-Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	270	205	2,733
3j	Arrowhead-Weston 345 kV Plano-Plano Tap 345 kV	220	175	2,333
3k	Arrowhead–Weston 230 kV Plano-Plano Tap 345 kV	220	175	2,333
5a	Chisago-Apple River-Weston 345 kV Plano-Plano Tap 345 kV	200	152	2,027
6c	Chisago-Rocky Run 500 kV Rocky Run-South Fond du Lac 345 kV Plano-Plano Tap 345 kV	310	250	3,333
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap 345 kV	235	95	1,267
9a	Huron-Split Rock-Lakefield Jct-Adams 345 kV Adams-Genoa-Columbia 345 kV Plano-Plano Tap 345 kV	520	90	1,200
12*	Plano-Plano Tap 345 kV	25	0	0
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap 345 kV	302	267	3,560
**	Cook-Zion (submersed DC cable) (IL & MI)	80	0	0

* A component in all options except 3e.
** This line is an alternate to option 12.

Other Siting Issues

An important component of any transmission line environmental review is a determination of whether or not functionally equivalent alternatives or a combination of alternatives exist where environmental impacts are reduced or less severe. Environmental reviews search not only for different transmission line options, but for non-transmission options as well. Non-transmission options include, among other things, upgrading or rebuilding existing lines or adding larger transformers or capacitor banks to the system. All of the bulk transfer solutions suggested in this report include many non-transmission changes to the system in addition to new lines (see Appendices C and I). Achieving the target transfer capability to eastern Wisconsin cannot be accomplished simply by increasing the size and voltage of existing lines or by adding substation components such as transformers or capacitor banks. While facility additions for meeting the expected growth in electric demand have been considered in this report, methods for reducing the rate of growth of this demand have not been explored. A balanced environmental review needs to seriously consider energy conservation and management of demand in concert with building new facilities.

One type of non-transmission solution that was not explored in this report is the efficacy of meeting some or all of the demand in eastern Wisconsin with new generation sources located near the load centers. Generation in eastern Wisconsin could significantly affect the decision on what kind of lines might be needed and where they should be placed (see Chapter 2).

Siting and building any of the major new transmission lines identified in this report will require a great deal of cooperation between utilities and state regulatory agencies in the region. Each state's unique statutory requirements and regulatory processes must be accommodated if any regional transmission lines are to be built. A considerable amount of time and effort will be required for such a process.

Chapter
7

Conclusions

Overview

This study should be regarded as the first step in the process of identifying the most appropriate transmission reinforcement approach to enhance electric reliability in Wisconsin.

The substantial cost, effort, and environmental impact entailed by a new transmission line or other major transmission reinforcement dictate that the contribution of the new facility to power transfer, its impact on other elements of electric power system operation, and the performance of all available alternatives be well understood prior to making a decision to proceed. While present-day electric reliability concerns lead us to focus on the immediate future, consideration should be given not only to the needs of the next few years, but also to sensible and appropriate transmission system development over the long term.

Need for Further Study

The size and complexity of the interconnected power system into which Wisconsin is integrated require additional studies on several aspects of the engineering performance of the transmission lines identified in this report, as well as the potential of non-transmission-line approaches to overcoming the western interface phase-angle problem. Additional studies required of each proposed reinforcement option include:

- More detailed power flow studies to examine voltage implications and reactive power support requirements.
- Examination of the impact on voltage stability, along with improved understanding, in general, of voltage stability problems associated with high levels of power transfer from Minnesota to Wisconsin.
- Dynamic stability analyses.
- More precise determination of maximum acceptable post-contingency phase angle across the western interface.

- Thorough analysis of the sensitivity of calculated performance to assumptions such as demand levels, base-case transmission facilities, base-case interchange and choice of locations for additional generation (sources) and demand (sinks).
- Detailed economic analysis, indicating the incremental transfer capability benefits of each new line or upgrade.
- Examination of the ability of options to contribute to power system goals other than inter-regional transfer.
- A comparative analysis of the likely environmental impacts associated with proposed transmission solutions focusing on environmental cost and performance.

Perhaps the most important issue to resolve, however, is the need for transmission transfer capability to maintain electric reliability. As noted in Chapter 2, the transfer capability required to maintain electric reliability in eastern Wisconsin is a function of electricity demand and generation in eastern Wisconsin. Significant uncertainty is associated with these factors, particularly the development of new power plants within eastern Wisconsin in the next few years and the performance of Wisconsin's nuclear power plants.

Findings

Despite the substantial uncertainties and further study that lie ahead, this analysis yielded significant results.

- With the addition of local load-serving transmission facilities expected to be in place by the summer of 2002 (listed in Appendix C), the simultaneous power transfer capability into eastern Wisconsin will be 1,800 to 2,000 MW, which is short of the 3,000 MW target.
- Significant increases into transfer capability above this 1,800 to 2,000 MW level will not be possible unless limits in Commonwealth Edison's northern Illinois transmission network are either fixed by construction of a new 345 kV line in Illinois (approximately $35 million), bypassed by construction of a cable under Lake Michigan ($178 million), or new generation capacity is ultimately sited in northern Illinois.
- Construction of a major new high-voltage transmission line extending into a neighboring state from Wisconsin can achieve the transfer capability goals of the study, increase operating flexibility, and reduce the magnitude of the western interface phase-angle problem. New high-voltage transmission construction identified in the study involves investment from $80 to $250 million for 100 to 500 miles of construction.
- In addition to new high-voltage lines, other transmission facility improvements are needed. These facilities include the local load serving improvements listed in Appendix C. These facilities also include improvements in Wisconsin and

northern Illinois, an investment up to $20 million, to upgrade existing facilities to increase transfer capability to desired levels.

- The upgrades and construction described above will lower losses to varying degrees. Generally, the more investment made in new transmission the lower the losses at the same transfer level. However, losses will increase as power transfers increase to make use of the higher transfer capability provided by the transmission upgrades and construction.
- History has shown that the construction of any high-voltage transmission line will be controversial. Construction of any of the new lines in the options analyzed in this report may have significant environmental impacts.

Appendix A—Glossary

AC—Alternating current

Act 204—1997 Wisconsin Act 204

Adequacy—The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Availability—A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

Bulk Electric System—A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Capacity—The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Cascading—The uncontrolled successive loss of system elements triggered by an incident at any location.

CE—Commonwealth Edison

Contingency—The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are linked by situations leading to simultaneous component outages.

Continuous Rating—The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life.

Control Area—An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Curtailability—The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Curtailment—A reduction in the scheduled capacity or energy delivery.

DC—Direct current

Demand—The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. Demand should not be confused with Load.

Demand-Side Management—The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Disturbance—An unplanned event that produces an abnormal system condition.

ECAR—East Central Area Reliability Coordination Agreement, a regional reliability council of the North American Electric Reliability Council (NERC).

Electrical Energy—The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

Electric System Losses—Total electric energy losses in the electric system. Losses are primarily due to electrical resistance within transmission system lines and transformers.

Electric Utility—A corporation, person, agency, authority, or other legal entity that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated.

Element—Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Emergency—Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Emergency Rating—The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or element can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

EMF—Electromagnetic fields

ERCOT—Electric Reliability Council of Texas, a regional reliability council of the North American Electric Reliability Council (NERC).

FERC—Federal Energy Regulatory Commission

Firm Capacity—Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

Firm Energy—Electrical energy backed by capacity, interruptible only on conditions as agreed upon by contract, system reliability constraints, or emergency conditions and where the supporting reserve is supplied by the seller.

Forced Outage—The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate (FOR)—The probability that a generator will not be available, as a result of a forced outage, when it is desired. FOR is generally expressed as a percent.

Frequency—The rate at which the voltage of an AC power system varies, measured in Hertz (cycles/second).

Frequency Deviation—A departure from scheduled frequency.

Hertz—A unit of measure of AC frequency in cycles per second.

Impedance—Characteristic of an electrical network or device, resistance to AC power flow.

Independent Power Producer (IPP)—Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base.

Interchange—Electric power or energy that flows from one entity to another.

Interconnected System—A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection—When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Quebec, and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a control area or system.

Interface—The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

Interruptible Demand—The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.

Island—A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

kV—A kilovolt equals 1,000 volts.

kVA—A kilovolt-ampere equals 1,000 volt-amperes.

Limiting Element—The element that is either operating at its appropriate rating or would be following the limiting contingency and, as a result, establishes a system limit.

Load—An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.

Loss of Load Expectation (LOLE)—The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as hourly LOLE if hourly demands are used in the calculations instead of daily peak demands.

MAIN—Mid-America Interconnected Network, Inc.; a regional reliability council of the North American Electric Reliability Council (NERC).

Maintenance Outage—The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a maintenance outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

MAPP—Mid-Continent Area Power Pool, a regional reliability council of the North American Electric Reliability Council (NERC).

MVA—A megavolt-ampere equals 1,000 kVA.

MW—A megawatt equals 1,000 kilowatts or 1 million watts.

NERC—North American Electric Reliability Council

Nonfirm Energy—Electrical energy that may be interrupted by either the provider or the receiver of the energy by giving advance notice to the other party to the transaction.

Normal Rating—The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

NRC—Nuclear Regulatory Commission

Operating Procedures—A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric system.

Operating Reserve—That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Outage—The planned or unplanned removal of a system element from service.

Peak Demand—The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year).

Phase Angle—The measure of the progression of a periodic wave in time or space from a chosen instant or position. The degree to which different locations in the electric system are out of phase in relation to each other.

Planned Outage—Removing the equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

Planning Reserve—See Reserve Margin.

Power—The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Power Flow Program—A computerized algorithm that simulates the behavior of the electric system under a given set of conditions.

Power Pool—Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

PSCW—Public Service Commission of Wisconsin

PSS/E—Power System Simulator for Engineering, a power flow simulation package developed by Power Technologies, Inc.

Rating—The operational limits of an electric system, facility, or element under a set of specified conditions.

Reliability—The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system. See also Adequacy and Security.

Reserve—Extra system capacity available for use during unforeseen or unexpected events.

Reserve Margin—The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

ROW—Right-of-way

Scheduled Frequency—60.0 Hertz, except during a time correction.

Scheduled Interchange—Electric power scheduled to flow between entities, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time.

Security—The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Single Contingency—The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Southern Interface—A group of transmission facilities that connect Wisconsin to the south.

Stability Limit—The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

System—An interconnected combination of generation, transmission, and distribution components comprising an electric utility, an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

Thermal Rating—The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Tie Line—A circuit connecting two or more control areas or systems of an electric system.

TLTG—A linearized power flow analysis activity with PSS/E.

Transfer Capability—The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, subregion, or NERC region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."

Transient Stability—The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance.

Transmission—An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Constraints—Limitations on a transmission line or element that may be reached during normal or contingency system operations.

UPFC—Unified power flow controller.

Voltage Collapse—A sudden drop in voltage in some part of the power system, due to inadequate reactive support. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Stability—The ability of an electric system to avoid the risk of voltage collapse.

Western Interface—A group of transmission facilities that connect Wisconsin to the west. Connects MAIN and MAPP.

WUMS—Wisconsin-Upper Michigan System, a sub-area of MAIN which includes eastern Wisconsin and the western upper peninsula of Michigan.

Appendix
B

Appendix B—Study Methodology

Base Case Development

The starting point utilized for this study was the NERC 2002 base case. This base case was modified to reflect currently scheduled interchanges, and adding all planned facility additions expected to be in-service in 2002. Additional facilities had to be added to achieve convergence of the base case which are incorporated in Appendix C. Contingency analysis was then performed on the model to locate any modeling errors in the base case.

Source/Sink List

Base case imports into WUMS totaled approximately 375 MW from the west and 150 MW from the south respectively. In order to evaluate the reinforcement options using PSS/E activity TLTG and meet the study objective of 2,000 MW non-simultaneous transfer capability on each WUMS interface, additional sources west of WUMS had to total 1,625 MW and additional sources south of WUMS had to total 1,850 MW. Conversely, sinks within WUMS had to be identified to facilitate the imports.

Western MAPP sources

Due to the lack of available generation in MAPP region, the study used a combination of load reduction in western MAPP and the addition of new generating units in Nebraska and North Dakota to provide the 1,625 MW exported to WUMS. Load was reduced to 90 percent of peak in the following control areas:

- Nebraska Public Power District
- Omaha Public Power District
- Lincoln (NE) Electric System
- Western Area Power Administration
- Otter Tail Power Company

The load reduction method produced approximately 925 MW of available capacity. The remaining 700 MW was split between two 350 MW generators. One unit was added at the Gentleman facility located in Nebraska and another was added at Antelope Valley in North Dakota. The western MAPP source list is summarized in Appendix E.

The load reduction represents a shoulder peak condition in western MAPP in which cooler weather frees up generation for export to WUMS while that area experiences high temperatures and peak load conditions. This scenario has occurred several times in the past as weather systems move from west to east. The study did not consider load reduction in eastern MAPP (Minnesota, Iowa, and western Wisconsin) because of its proximity to WUMS.

Gentleman and Antelope Valley were selected as new generation sites for the following reasons:

- As confirmed in subsequent sensitivity analyses, the remote location (western MAPP) does not unduly favor or punish any options.
- Adequate transmission system outlet capacity—both sites have significant installed generation capacity and a transmission system built to meet the needs of the additional generation.

The generators were added only to provide capacity for transfers in this study. The utilities that own and manage these sites do not have plans to add this capacity by 2002.

Southern Illinois/ECAR Sources

The study utilized available generating capacity in Southern Illinois and ECAR to provide exports totaling 1,850 MW to WUMS. Southern Illinois generation participated in 10 percent of that total, with ECAR accounting for the remaining 90 percent. The southern Illinois/ECAR source list is summarized in Appendix E.

Northern Illinois did not participate in the transfers for the following reasons:

- additional generation capacity in Northern Illinois was not available in the base case.
- load reduction in Northern Illinois had the potential to mask transfer capability problems that would be otherwise identified in this study.

Power flows that result from the use of the Southern Illinois/ECAR source list stress the Chicago area transmission system and has the potential to identify system limitations between Northern and Southern Illinois. The 10 percent/90 percent split was deemed to be an adequate representation based on the available generation in each region.

WUMS sinks

The study used all on-line generating units within WUMS to sink imported power. The amount each unit participated in the specified transaction was directly proportional to its MW output in the base case. The WUMS sink list is summarized in Appendix E. Note that the WUMS sink lists are different for the western and southern import studies.

Initially, two options were identified to provide the necessary sink points within WUMS:

- Sink transfers into WUMS by consecutively turning off units based on a highest to lowest variable operating cost ranking of the WUMS units.
- Sink transfers into WUMS by considering turning off a select list of large base loaded WUMS units.

The first option has the advantage of evenly distributing the sink points throughout the region. This approach provides a realistic generation profile for the importing companies that takes into account optimal generation dispatch along with scheduled and unscheduled outages to smaller units. The second option has the advantage of highlighting problems associated with outages to the largest generating units on the WUMS system, a significant reliability concern.

The method ultimately chosen, utilizing all WUMS generation, touches upon the advantages of each option. The sink points are spread throughout the region, while the high concentration of generation in eastern Wisconsin participates enough in the specified transaction to act as a proxy for a large unit outage.

Description of Computational Model (PSS/E)

Computer simulation of the power system was carried out using the PSS/E power system simulation package developed by Power Technologies, Inc., a powerful and widely used electric power system modeling software. Modeled electric system configuration consisted of the entire eastern interconnection with 31,268 busses, 43,161 line and transformer elements, and 5,289 generators representing a total network load of 728,390,685 MW.

Selection of Contingencies and Monitored Elements

The monitored elements were selected to be all elements 100 kV and above within MAIN and the eastern half of MAPP. Emergency ratings, typically 110 percent of normal continuous ratings, were used for all monitored elements.

The contingency list considered all valid single contingencies 100 kV and above within the monitored area list. Certain double contingencies and operating guides were also implemented. Commonwealth Edison submitted a separate contingency list for all facilities located in its service territory. The CE list included many multi-segment contingencies and operating guides. Several utilities also submitted operating guides to implement during the following contingencies:

- King-Eau Claire-Arpin 345 kV
- King-Eau Claire 345 kV
- Eau Claire-Arpin 345 kV
- Arpin-Rocky Run 345 kV
- Paddock-Rockdale 345 kV
- Wempletown-Paddock 345 kV
- Granville 345 kV bus
- Granville 345/138 kV transformer
- Prairie Island-Byron 345 kV
- Adams-Byron 345 kV

Generally transmission facilities below 100 kV contribute little to regional transfer capability and primarily provide local load serving support. However, the study did monitor the following 69 kV lines in the event of a 345 kV contingency:

- Council Creek–Oakdale
- Council Creek-Tomah/Tunnel City
- Hilltop–Mauston
- Monroe County–Sparta

The study also defined and monitored three "interfaces:"

Arpin-Eau Claire (ARP-EAU) rated at 775 MW
Defined by the flow on the Arpin-Eau Claire 345 kV line.

Prairie Island-Byron (PRI-BYR) rated at 825 MW
Defined by the flow on the Prairie Island-Byron 345 kV line.

MNEX rated at 2,650 MW
King-Eau Claire 345 kV
Prairie Island-Byron 345 kV
Blue Lake-Wilmarth 345 kV
King-Willow River 115 kV
Red Rock-Glenmont 115 kV
Lake Marion-West Faribault 115 kV

The interface flow limits are applied to the intact system with ratings set to levels that protect the system from stability problems associated with critical contingencies.

Opposite Interface "Bias"

In an effort to simulate a 3,000 MW simultaneous transfer into WUMS, the transfer capability limits on each WUMS interface were tested using PSS/E activity TLTG with a 1,000 MW "bias" applied to the study case on the opposite interface. The TLTG runs testing the impact of Southern Illinois/ECAR -WUMS transactions used a biased study case in which WUMS western imports totaled 1,000 MW. Conversely, the TLTG runs testing the impact of western MAPP-WUMS transactions used a biased study case in which WUMS southern imports totaled 1,000 MW.

The additional WUMS imports that created the biases, replaced "unplanned generation" inserted into the original base case to balance loads, interchange and generation within the WUMS control areas. "Unplanned generation" totaled 808 MW in the base case. Table B.1 summarizes the WUMS generation changes made to the base case that created the "biased" study cases.

Table B.1 **WUMS generation adjustments for the biased study cases**

WUMS Import Study	Biased WUMS Interface	Base Case Transactions on the Biased Interface	Transactions Needed to Reach 1,000 MW Bias	Unplanned Generation Replaced by Transactions in the Biased Study Case	Unplanned Generation that Remained On-line in the Biased Study Case	Planned Generation Replaced by Transfers in the Biased Study Case
West	Southern	150 MW	850 MW	808 MW	0 MW	42 MW[1]
South	Western	375 MW	625 MW	625 MW	183 MW	0 MW

[1] South Fond du Lac Unit #4

In-service "unplanned generation" was spread evenly throughout central and eastern Wisconsin to minimize its impact on the transfer capability study. The units were included in sink lists, and therefore participated in the transfer studies simulated using TLTG. WUMS "unplanned generation" remained in-service at the following locations in the western biased study case:

Rock River	53 MW	(south central Wisconsin)
Burlington	35 MW	(southeast Wisconsin)
Kewaunee	55 MW	(northeast Wisconsin)
Biron	40 MW	(central Wisconsin)

Note that the southern biased study case had no "unplanned generation" on-line.

Generation resources were updated in the base case. All study participants reviewed the generation resources within their respective areas and confirmed each unit's availability in the 2002 time period.

Development and Analysis of Reinforcement Options

The initial list of potential reinforcement options utilized in the study were stated in the utilities' September 30, 1997, report to the Governor. This list was then expanded with new options and combinations of existing and new options over the course of the study. The "long list" is comprised of all the options (sets of new facilities) that were ever analyzed, some which do not provide adequate transfer capability. The "short list" of options is a representative subset of options of the "long list" that provide the desired amount of transfer capability. The "short list" is displayed in the executive summary. The "long list" is exhibited in Appendix I.

TLTG (Transfer Capability) Analysis

The TLTG activity within PSS/E was used to analyze the increase in transfer capability associated with each option. This software tool utilizes a linear approximation ("DC load flow") approach to calculating power flows within the power system, linearizing about the base-case operating point. DC load flow only identifies thermal limitations caused by increasing power transfers. AC load flows must be used to analyze voltage and dynamic stability issues for the proposed options.

Transfer limit analysis was performed on numerous options. Transfer limits were then evaluated and solutions devised to obtain the transfer objective. This involved the use of operating guides, equipment upgrades, line reconductors, and additional reinforcements.

Detailed Examination of Model Output

Facilities with a distribution factor of 2 percent or greater were reported but only facilities with a 3 percent or greater distribution factor were considered valid transfer limitations.

Transfer limitations avoidable via phase-shifter/DC transmission control were not considered valid limits. Operating guides were also implemented when necessary to obtain study objectives. Inexpensive upgrades to facilities were added to options to overcome limits experienced with various options.

Confirmation/Extension of TLTG (Transfer Capability Analysis) Results

Additional analysis was performed on the short list of options. Further analysis consisted of loss analysis, cost analysis, Arpin phase angle, and environmental analysis. The loss analysis was performed with 1,000 MW of simultaneous transfers from the West and the South. The Arpin phase angle was calculated during maximum 2,000 MW transfer from the West with a 1,000 MW Southern bias. These calculations were made using an AC load flow model.

Appendix
C

Appendix C—Base-Case Facility Additions

Table C.1 lists all facilities expected to be constructed at the 2002 starting point of the study.

Table C.1 Base-case facility additions

Company	Addition	Year
CE	Add Electric Junction # 4 345/138 kV transformer (300 MW)	1999
CE	Upgrade Goodings Grove 345 kV bus tie	1999
CE	Add Goodings Grove #2 345/138 kV transformer (300 MW)	2000
CE	Add East Frankfurt # 1 345/138 kV transformer (300 MW)	2001
CE	Add Prospect Heights # 3 345/138 kV transformer (300 MW)	2002
CE	Add Lockport-Lombard 345 kV line (two circuits)	2001
DPC	Genoa-Coulee reconductor (795 ACSR)	2000
DPC	Construct a 161-69 kV substation at the crossing of DPC's Seneca-Nelson Dewey 161 kV line and WPL's Hillside-Boscobel 69 kV line.	2000
DPC	Replace the Genoa 161/69 kV transformers with two 100 MVA units	2000
DPC	Replace the 30 MVA 161-69 kV transformer at Bell Center with a 60 MVA unit	2002
DPC	Replace the Hillsboro 60 MVA 161-69 kV transformer with a 100 MVA unit	2002
NSP	Add Chisago Co-Lawrence Ck-Apple River 230 kV line	2002
NSP	Add Chisago Co loop-in of Red Rock-Rush City 230 kV line	2002
NSP	Add Chisago Co 345/230 kV transformer (448 MVA)	2002
NSP	Add Lawrence Ck 230/115 kV transformer (187 MVA)	2002
NSP	Add Lawrence Ck 115/69 kV transformer (112 MVA)	2002
NSP	Add Chisago Co-Lawrence Ck 115 kV line	2002
NSP	Add Apple River 230/161 kV transformers (2 x 350 MVA)	2002
NSP	Add Elm Creek 345/115 kV transformer (448 MVA)	1999
NSP	Add Split Rk-WAPA Sioux Falls 230 kV line	1999
NSP	Add Split Rk 230/115 kV transformer (336 MVA)	1999
NSP	Add Split Rk-Cherry Ck 115 kV line	1999
NSP	Upgrade Lincoln Co-Cherry Ck 115 kV to 194 MVA	1998
NSP	Replace Split Rk 115/161 kV transformer (2 x 47-->1 x 187 MVA)	1998
NSP	Upgrade Split Rk capacitors to 2 x 120 MVAR	1999
NSP	Add Split Rk 2 x 50 MVAR reactors	1999

Company	Addition	Year
NSP	Upgrade Split Rk-Pathfinder 115 kV to 240 MVA	1998
NSP	Upgrade Pathfinder-Pipestone 115 kV to 172 MVA	1998
NSP	Upgrade Pipestone-Buffalo R-Lk Yankton 115 kV to 172 MVA	1998
NSP	Upgrade Lk Yankton-Marshall T-Minn Valley 115 kV to 172 MVA	1998
NSP	Add 2nd Pipestone 115/69 kV transformer	1998
NSP	Add Lk Yankton 40 MVAR 115 kV capacitor bank	1999
NSP	Add W Faribault 40 MVAR 115 kV capacitor bank	1999
NSP	Add Pipestone-Ruthton-Lk Yankton 115 kV line	2002
NSP	Add Wind gen-Buffalo Ridge & Ruthton (Chanarambie)	1998-2002
NSP	Add Stone Lk-Bay Front 161 kV line	2001
NSP	Add Stone Lk 2 x 20 MVAR 161 kV capacitor banks	2001
NSP	Add Bay Front 161/115 kV transformer (187 MVA)	2001
NSP	Add Hurley synchronous condensers (2 x 18 MVA)	1998
NSP	Gen uprates: Riverside, Inver Hills, Prairie Island, Monticello	1998
NSP	Pine Lk-Wissota 115 kV: reconductor	1999
NSP	Wissota (Hydro Ln)-T Corners 115 kV: rebuild	2000
NSP	Add Johnny Ck-Dodd-Air Lake-Lk Marion 115 kV line (CP)	1999
NSP	Reconductor Big Stone-Hwy 12-Ortonville (OTP)	1998
MGE	Reconnect WP&L Cross Country substation from the MGE 69 kV line to the MGE 138 kV line	1999
MGE	Construct a new 69 kV line from the MGE Fitchburg Substation to the WP&L Verona substation	2001
WEPCO	Spring Valley—Build a 138 kV line from Bain to the new Spring Valley 138/24.9 kV, 35 MVA substation.	1998
WEPCO	Swan—Tap the Granville-68th St 138 kV line (KK3441) for the new Swan Substation and install a 138/24.9 kV, 84 MVA transformer.	1998
WEPCO	Lyndon—Install a second 35 MVA transformer at Lyndon by tapping the Random Lake-Elkhart Lake (KK5711).	2001
WEPCO	Lyndon—Replace existing transformer with a 35 MVA transformer.	2001
WEPCO	Root River—Install a new 138/24.9 kV, 84 MVA transformer substation at Root River by tapping the Oak Creek-St. Martins 138 kV line (KK836).	1999
WEPCO	Fredonia—Install a second transformer at Fredonia by tapping the Saukville-Random Lake 138 kV line(KK8251).	1999
WEPCO	Clintonville—Construct a 115 kV line from Badger to Clintonville and install a 115/34.5 kV, 42 MVA transformer at Clintonville.	1999
WEPCO	Oak Creek—Rebuild the 138 kV bus, build a 345 kV bus, and install a 345/138 kV transformer.	1999
WEPCO	Oak Creek—Move Gen 5 from 230 kV bus to 138 kV bus.	1999
WEPCO	Morgan—Build a 345/138 kV substation at a point known as Morgan on the Plains-Falls-White Clay 138 kV line. The Morgan -Plains portion will be converted to and operated at 345 kV.	1999
WEPCO	Nabob—Install a 138/24.9 kV, 30 MVA transformer at the new Nabob substation by tapping the St. Lawrence-Barton 138 kV line (KK8032).	2001
WEPCO	Cedarsauk—Build a 345/138 kV substation at Cedarsauk.	2002
WEPCO	Forest Junction—Install a 345/138 kV transformer.	2002
WEPCO	Saukville-68th-Swan-Granville—Rebuild with 795 ACSR conductor.	2002
WEPCO	Saukville-Mequon-Parkland-Granville-Rebuild with 795 ACSR conductor.	2002

Company	Addition	Year
WEPCO	Unplanned Generators—Install 166 MW of generation at Burlington and 80 MW at Forest Junction.	2002
Alliant	Uprate the 6.2 mile Paddock-RCEC Newark 69 kV lines 3/0 ACSR conductor to a 220°F conductor operating temperature.	1998
Alliant	Replace the low impedance Brick Church 47 MVA 138-69 kV transformer with a standard impedance 47 MVA transformer.	1999
Alliant	Replace the 37 MVA 115-69 kV transformer at Whitcomb with a new 60 MVA 115-69 kV transformer.	2000
Alliant	Construct 161-69 kV substation at the crossing of DPC's Seneca-Nelson Dewey 161 kV line and WP&L's Hillside-Boscobel 69 kV line.	2000
Alliant	Construct a 69 kV switching station at Union Center and construct 16 miles of 69 kV from the Wonewoc substation to the Reedsburg substation.	2000
Alliant	Replace the Hazleton-Dundee-Liberty-Lore-Turkey River-Cassville 161 kV line terminal equipment to uprate line to 202 MVA	2000
Alliant	Replace the Kilbourn 12 MVA 69-34.5 kV transformer with a 20 MVA 69-34.5 kV transformer.	2001
Alliant	Construct the 6-mile Fitchburg-Verona 69 kV tie line.	2001
Alliant	Replace the existing Kegonsa 47 MVA 138/69 kV transformer with a 187 MVA transformer.	2001
Alliant	Install a second 93 MVA (or 100 MVA) 138-69 kV transformer at the Kirkwood substation, construct a second 69 kV square, move the Kirkwood-Spring Green 138 kV line to the spare 138 kV face at the Kirkwood substation, and replace Kirkwood 69 kV breaker's 30	2002
Alliant	Install a North Randolph 224 MVA 345-138 kV transformer, construct a 345 kV bay at the North Randolph substation, construct a 0.5 mile double circuit 345 kV line tapping the Columbia-South Fond du Lac 345 kV line, move the North Beaver Dam 47 MVA 138-69 kV.	2002
Alliant	Replace the existing North Lake Geneva 47 MVA 138-69 kV transformer with a 100 MVA 138-69 kV transformer.	2002
Alliant	Install a 10.8 MVAR 69 kV capacitor bank at the South Lake Geneva substation.	2002
Alliant	Replace the existing Petenwell 33 MVA 138-69 kV transformer with a 50 MVA 138-69 kV transformer.	2002
WPS	Lost Dauphin-Red Maple-DePere construction of a new 138 kV transmission line with the purpose of connecting a new generating station to the power grid.	1999
WPS	T-Corners-Wien-Cassel Rebuild (The WPSC portion of the Baldwin to Marathon City Interface Option)—reconstruction of an existing 115 kV transmission line to 161 kV specifications between Abbotsford, WI and Marathon City, WI. The line will be initially energized at 115 kV.	1999
WPS	Hilltop-Pine Rebuild—reconstruction of an existing 115 kV transmission line between Wausau, WI and Merrill, WI	1999
WPS	Pine-Eastom 46 kV Conversion—conversion of an existing 46 kV transmission line to 115 kV operation between Merrill, WI and Tomahawk, WI.	2000
WPS	Sunset Point 138/69 kV Transformer Upgrade adds a new 138/69 kV transformer at Sunset Point (in Oshkosh, WI).	2000
WPS	Rocky Run 345/115 kV Transformer Upgrade replaces an existing 150 MVA transformer at Rocky Run (near Stevens Point, WI) with a 300 MVA unit.	2000

Company	**Addition**	**Year**
WPS	M-117-Roosevelt Rd.-Wells St. involves the construction of a new 138 kV transmission line in Marinette, WI. The Roosevelt Rd. portion of the option will initially be energized at 69 kV.	2002
WPS	Weston 345/115 kV Transformer Upgrade replaces an existing 200 MVA transformer at Weston (located near Wausau, WI) with a 300 MVA unit.	2002

Appendix D—Base-Case Interchange

Table D.1 **Base case transaction table**

(all numbers in MW; positive numbers represent net transfers out of "FROM" areas and net transfers into "TO" areas)

TO	Name	WPL	WEP	WPS	MGE	UPP	WE-PI	CWP	MEUW	NI/CE	WAPA	MP	NSP	DPC	AEP	VP	DUKE	AMRN	MEC	IP	OTHER	FROM
FROM	Name																					TOTAL
	WPL		367	215	186	8				-140	-195	-117										324
	WEP	-367				46	-330			52		-62										-661
	WPS	-215			89			10	70													-46
	MGE	-186		-89						-60												-335
	UPP	-8	-46																			-54
	WE-PI		330																			330
	CWP			-10																		-10
	MEUW			-70																		-70
	NI/CE	140	-52		60										-518	-344	-344	-26	384	35		-665
	WAPA	195																				195
	MP	117	62																		-58	121
	NSP													-4								-4
	DPC												4								95	99
	AEP									518												518
	VP									344												344
	DUKE									344												344
	AMRN									26												26
	MEC									-384												-384
	IP									-35												-35
	OTHER											58		-95								-37
TO	TOTAL	-324	661	46	335	54	-330	10	70	665	-195	-121	4	-99	-518	-344	-344	-26	384	35	37	

AEP—American Electric Power Company
AMRN—Ameren
CWP—Consolidated Water Power Company
DPC—Dairyland Power Cooperative
DUKE—Duke Power
IP—Illinois Power Company
MEC—MidAmerican Energy Company
MEUW—Municipal Electric Utilities of Wisconsin
MGE—Madison Gas and Electric Company
MP—Minnesota Power Company
MPU—Manitowoc Public Utilities
NI/CE—Northern Illinois Commonwealth Edison Company
NSP—Northern States Power Company
UPP—Upper Peninsula Power Company
VP—Virginia Power
WAPA—Western Area Power Administration
WEPCO—Wisconsin Electric Power Company
WP&L—Alliant-Wisconsin Power and Light Company
WE-PI—Wisconsin Electric–Presque Isle Area
WPS—Wisconsin Public Service Corporation

Appendix E—Source and Sink Participation Points

WUMS Sinks

Sinks are made at all WUMS generators in each of the following control areas.

Western import with southern bias

Consolidated Water Power Company
Madison Gas and Electric Company
Manitowoc Public Utilities
Upper Peninsula Power Company
Wisconsin Electric Power Company
Wisconsin Electric Power Company–Presque Isle area
Wisconsin Power and Light Company
Wisconsin Public Service Corporation

Southern import with western bias

Same as above plus 183 MW of Unplanned Generation

WUMS "unplanned generation" remained in-service at the following locations:

• Rock River	53 MW	(south central Wisconsin)
• Burlington	35 MW	(southeast Wisconsin)
• Kewaunee	55 MW	(northeast Wisconsin)
• Biron	40 MW	(central Wisconsin)

MAPP Sources

Nebraska Public Power District
Omaha Public Power District
Lincoln Electric System
Western Area Power Administration
Otter Tail Power Company

ECAR Sources

Allegheny Power
Ohio Edison Company
Texaco Energy Services
Cleveland Electric Illuminating Company
American Electric Power Company
Ohio Valley Electric Corporation
Hoosier energy Rural Electric Cooperative, Inc.
Cinergy Corporation
Dayton Power and Light Company
Kentucky Utilities Company
Big Rivers Electric Corporation
Duquesne Light Company
Indianapolis Power and Light Company
Northern Indiana Public Service Company
Consumers Energy
Detroit Edison Company
East Kentucky Power Cooperative, Inc.
Indiana Municipal Power Agency

Southern and Central Illinois Sources

Central Illinois Light Company
Springfield City Water, Light, and Power
Eastern Missouri Subregion
Illinois Power Company
Constellation Power Source, Inc.

Appendix F—Loss-of-Load Expectation

Table F.1 documents the calculation of the reserve requirement to meet the 0.1 day per year Loss of Load Expectation (LOLE) for the Eastern Wisconsin Utilities' (EWU) generation system for the summer of 1998.

Study Area: Eastern Wisconsin Utilities
- Wisconsin Electric Power Company
- Wisconsin Public Service Corporation
- Wisconsin Power and Light Company
- Madison Gas and Electric Company

Study Periods
- Summer 1998 (weeks 16 to 39, mid-April through September)

Methodology
- Loss of Load Expectation Program used by MAIN to determine adequacy of generation system reliability

Assumptions
- Load
    - ? Peak loads MAIN Coordinated Bulk Power Supply and Demand Summary, April 1997 (8,898 MW adjusted for full responsibility purchases and sales)
    - ? Load forecast uncertainty due to weather only (5.4 percent equals one standard deviation)
    - ? Load profile based upon actual loads for period 1984 to 1996
- Generation
    - ? Installed capacity MAIN Coordinated Bulk Power Supply and Demand Summary, April 1997 (10,675 MW adjusted for capacity purchases and sales)
    - ? Planned maintenance schedule
    - ? Outage rates based upon NERC Generation Availability Database System (GADS) for MAIN units, 1992 to 1996

Table F.1 Eastern Wisconsin Capacity Requirements (all values in MW)

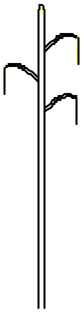
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Year	Non-coincident Utility Net Demand	Total Existing Capacity Resources	Non-coincident Utility Net Demand + 18%	New Generation Capacity Needed to Meet 18% Reserves	Non-coincident Utility Net Demand + 32%	New Generation Needed to Provide 32% Reserves	New Generation Capacity Needed to Increase Reserves From 18% to 32%	Transfer Capacity Needed to Increase Reserves From 18% to 32%
1998	9,464	11,381	11,168	(213)	12,492	1,111	1,111	1,004
1999	9,726	11,308	11,477	169	12,838	1,530	1,362	1,032
2000	10,046	11,405	11,854	449	13,261	1,856	1,406	1,065
2001	10,206	11,321	12,043	722	13,472	2,151	1,429	1,082
2002	10,481	11,264	12,368	1,104	13,835	2,571	1,467	1,112
2003	11,068	11,252	13,060	1,808	14,610	3,358	1,550	1,174
2004	11,343	11,246	13,385	2,139	14,973	3,727	1,588	1,203
2005	11,619	11,197	13,710	2,513	15,337	4,140	1,627	1,232
2006	11,880	11,197	14,018	2,821	15,682	4,485	1,663	1,260
2007	11,774	11,147	13,893	2,746	15,542	4,395	1,648	1,249

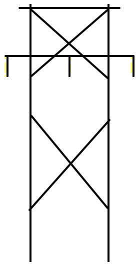
(B): From peak demand forecast for MGE, WEPCO, WP&L, WPPI-E, and WPS from Advance Plan 8 Figure D-14A-2; excludes all other utilities.

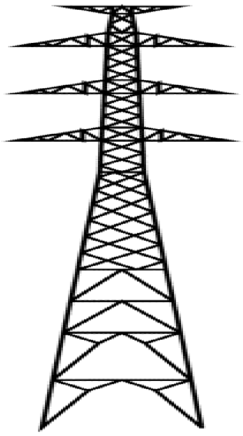
(C): Planned generation capacity for MGE, WEPCO, WP&L, WPPI-E, and WPS from Advance Plan 8 Figure D-14A-2; excludes all other utilities. Includes utility-owned existing capacity by resource type, adjusted to account for uprates/derates and retirements, plus (net) utility committed capacity transactions.

(D): (B) * 1.18
(E): (D) – (C)
(F): (B) * 1.32
(G): (F) – (C)
(H): Min(G,G-E)
(I): (B) – (D / 1.32)

Appendix G—Typical Dimensions of Transmission Line Structures and Rights-of-Way







	Single Pole	H-Frame	Steel Lattice Tower
ROW Width	60-80 feet	80-100 feet	100-150 feet
Structure Height	75-100 feet	60-80 feet	100-150 feet
Span Length	600-800 feet	750-1,000 feet	750-1,200 feet
Voltage Range	69-345 kV	138-345 kV	345-765 kV

Appendix
H

Appendix H—Costs for Transmission Improvements

Table H.1 shows cost estimates for new transmission facilities.

Table H.1 Cost estimates for new transmission facilities

Item	Unit	Cost ($1,000s)
Transmission lines		
Wood H-frame for 230 kV rural structures	Mile	230
Steel pole, horizontal-delta or vertical for 230 kV suburban	Mile	260
Wood H-frame for 345 kV rural structures	Mile	345
Lattice 345 kV for river crossing	Mile	390
Steel pole, horizontal-delta or vertical for 345 kV suburban	Mile	380
Steel H-frame for 500 kV rural structures	Mile	500
Lattice 500 kV for river crossing	Mile	550
Steel pole, horizontal-delta or vertical for 500 kV suburban	Mile	530
Underwater DC cable	Mile	660
Terminations		
500 kV	End	3,818
345 kV	End	2,223
230 kV	End	1,468
161 kV	End	539
Transformers		
500 kV (1,200 MVA)	Each	10,000
345 kV (448 MVA)	Each	3,936
230 kV (187 MVA)	Each	1,285
161 kV (187 MVA)	Each	1,018
DC Transmission		
Converter stations (1,000 MVA)	Pair	250,000

Table H.2 details the cost of each item included in the short list of options.

Table H.2 Transmission reinforcement requirements and costs

		Project												Cost
Item	Description	1c	2e	2f	3e	3j	3k	5a	6c	8b	9a	12	13c	($1,000)
1	Reconductor Eau Claire - Wheaton	■	■	■	■	■	■	■	■	■	■	■	■	$387
2	Upgrade Barron - Apple River terminal equipment	■	■	■	■	■	■	■		■	■	■	■	$10
3	Plano-Plano Tap 345 kV line	■	■	■		■	■	■	■	■	■	■	■	$35,000
4	Reconductor portion of Itasca - Lombard R (0.1 mi)	■	■	■		■	■	■	■	■	■	■	■	$10
5	Upgrade Itasca - Lombard B 345 kV breaker	■	■	■		■	■	■	■	■	■	■	■	$1,000
6	Upgrade Itasca - Lombard R 345 kV breaker	■	■	■		■	■	■	■	■	■	■	■	$1,000
7	Schaumburg Breaker's/Swap red & blue terminations	■	■	■		■	■	■	■	■	■	■	■	$1,000
8	Convert Oak Creek-Arcadian to 345 kV operation	■	■	■		■	■	■	■	■	■	■	■	$13,600
9	Reconductor Wheaton - Wheaton Tap	■	■	■			■	■			■	■	■	$198
10	Wheaton 161 kV busses tied together	■	■	■				■		■	■	■		$4,000
11	Relocate Des Plaines transformer on new bus					■	■	■			■		■	$50
12	Upgrade Weston - Rocky Run 345 kV terminal eq.				■	■	■	■						$300
13	Reconductor Wheaton - Elk Mound	■	■	■								■		$324
14	Upgrade Weston 345/115 to 500 MVA					■	■	■						$2,000
15	Rebuild Kelly-Whitcomb (24 mi) 115 kV line					■	■	■						$4,100
16	Uprate Elk Mound - Barron to 212 F operating temp.	■		■								■		$759
17	Reconductor Wien - T-Corners with SSAC	■		■								■		$1,200
18	Upgrade Blackhawk - Colley Rd terminal equipment		■	■										$200
19	North Madison-Fitchburg-Rockdale 345 kV line	■												#N/A
20	Salem-Fitchburg 345 kV line	■												$31,625
21	Reconductor Eau Claire - Wheaton	■		■						■		■		$387
22	Capacitor Additions 229 MVAR													
23	Columbia-Lacrosse-Prairie Island 345 kV line		■											#N/A
24	Inc Forest Junction-Highway V 138kV line to 275 deg		■	■						■		■		$215
25	Replace ss limiters on Columbia-S FDL 345 kV line		■											$300
26	Upgrade Baker - Saratoga terminal eq.		■											$100
27	Upgrade Rock River - Liberty terminal equipment			■								■		$15
28	Salem-Paddock 345 kV line			■										#N/A
29	Reconductor Janesville-Russell/Uprate term equipment			■										$1,000
30	Upgrade Paddock 345/138 kV terminal equipment			■										$100
31	Improve Goodings-Lockport Red/Blue line sag				■									$50
32	Plano-South Fond Du Lac 345 kV				■									#N/A
33	South Fond Du Lac - Weston 345 kV				■									$57,471
34	Weston - Arrowhead 345 kV				■	■								$42,579
35	Weston-Arrowhead 230 kV						■							$80,696
36	Chisago-Weston 345 kV							■						$59,836
37	Itasca -Tonne B 138 kV busses tied together													
38	Replace 4 Itasca - Tonne B 138 kV c/s with breakers													
39	Chisago-Rocky Run 500 kV								■					#N/A
40	Rocky Run-South Fond Du Lac 345 kV								■					$124,816
41	Byron (MN)-Columbia 345 kV line									■				$36,002
42	Byron (MN)-Wilmarth 345 kV line									■				$63,903
43	Huron, SD - Columbia 345 kV										■			$22,923
44	Upgrade Itasca - Lombard B 345 kV breaker													
45	Uprate Paddock-Wempletown line conductor											■		$150
46	Upgrade Plains 345/138 kV transformer to 500 MVA												■	$2,700
47	Arrowhead-Plains 345 kV												■	#N/A
48	Morgan-North Appleton 345 kV												■	$18,200
49	Upgrade Sand Lake-Port Edwards terminal eq.					■								$50
50	Upgrade Pulliam 138/115 kV terminal eq.					■								$10

Appendix I—Options—Long List

Table I.1 Components and transfer capability

Item	Option #	00b	1	1a	1b	1c	1d	1e	2	2a	2b	2c	2d
1	Plano-Plano Tap 345 kV line					■		■	■	■	■		
2	North Madison-Fitchburg-Rockdale 345 kV line		■	■	■	■	■	■					
3	Hazleton-Salem 345 kV line			■									
4	Prairie Island-Lacrosse kV line								■		■	■	
6	Adams-LaCrosse 345 kV line									■	■		
7	Lacrosse-N. Madison 345 kV line								■	■	■	■	
8	Salem-LaCrosse 345 kV line											■	
12	Salem-Fitchburg 345 kV line		■	■	■	■	■	■					
13	Salem-Paddock 345 kV line												■
14	Arcadian-Rockdale 345 kV line				■								
25	Plano-Paddock 345kV line						■						
34	Monroe Co.-Council Creek 161 kV line							■					
46	Reconductor Eau Claire - Wheaton circuit 1		■	■	■	■	■	■	■	■	■	■	■
47	Upgrade Barron - Apple River terminal equipment		■	■	■	■	■	■	■	■	■	■	■
48	Itasca Area fixes					■		■	■	■	■	■	
49	Convert Oak Creek-Arcadian to 345 kV operation					■		■	■	■	■	■	
50	Reconductor Wheaton - Wheaton Tap					■	■	■	■	■	■	■	
51	Upgrade Goodings Grove-Lockport B 345 kV breaker						■						
52	Wheaton 161 kV busses tied together					■	■	■					
53	Reconductor Wheaton - Elk Mound					■	■	■	■	■		■	
54	Uprate Elk Mound - Barron to 212 F operating temp.					■	■	■					
55	Reconductor Wien - T-Corners with SSAC					■	■						
56	Upgrade Blackhawk - Colley Rd terminal equipment						■						
57	Reconductor Eau Claire - Wheaton circuit 2					■	■						
58	Inc Forest Junction-Highway V 138kV line to 275 deg								■	■	■	■	
59	Upgrade Baker - Saratoga terminal eq.							■	■	■	■	■	
60	Improve Goodings-Lockport Red/Blue line sag						■						
61	Upgrade Plains 345/138 kV transformer to 500 MVA							■					
67	Reconductor Eau-Claire-Seven Mile							■		■	■		
	Transfer from West (MW, with 1000 MW Southern Bias)	1080	1280	1340	1320	2220	2200	2100	2040	1830	2100	2050	1250
	Transfer from South (MW, with 1000 MW Western Bias)	1000	1100	1120	1110	2040	2140	2020	2150	2150	2150	2150	1080

New Transmission Lines	Line/Equipment Upgrades

* Reconductor portion of Itasca-Lombard, Upgrade Itasca-Lombard 345 kV breakers, Upgrade Schaumburg breakers, swap red & blue terminations

Item	Option #	2e	2f	3	3a	3b	3c	3d	3e	3f	3g	3h	3i
1	Plano-Plano Tap 345 kV line	■	■							■	■	■	■
4	Prairie Island-Lacrosse kV line	■											
5	Columbia-Lacrosse 345 kV line	■											
9	Ironwood-Hwy. 8-Weston 345kV line			■									
10	Arrowhead-Arpin 230 kV line					■							■
11	Arrowhead-Arpin 345 kV line						■					■	
13	Salem-Paddock 345 kV line		■										
17	Plano-South Fond Du Lac 345 KV line								■				
18	South Fond Du Lac - Weston 345 KV line								■				
19	Weston - Arrowhead 345 KV line				■				■	■			
20	Weston-Arrowhead 230 kV line							■			■		
46	Reconductor Eau Claire - Wheaton circuit 1	■	■	■	■	■	■	■	■	■	■	■	■
47	Upgrade Barron - Apple River terminal equipment	■	■						■		■	■	■
48	Itasca Area fixes	■	■										
49	Convert Oak Creek-Arcadian to 345 kV operation	■	■							■	■	■	■
50	Reconductor Wheaton - Wheaton Tap	■	■								■		
52	Wheaton 161 kV busses tied together	■	■										
53	Reconductor Wheaton - Elk Mound	■	■										
54	Uprate Elk Mound - Barron to 212 F operating temp.		■										
55	Reconductor Wien - T-Corners with SSAC		■										
56	Upgrade Blackhawk - Colley Rd terminal equipment	■	■										
57	Reconductor Eau Claire - Wheaton circuit 2		■										
58	Inc Forest Junction-Highway V 138kV line to 275 deg	■	■										
59	Upgrade Baker - Saratoga terminal eq.	■											
60	Improve Goodings-Lockport Red/Blue line sag								■				
63	Upgrade Weston - Rocky Run 345 kV terminal eq.			■	■			■	■	■	■		
64	Upgrade Weston 345/115 to 500 MVA				■			■		■	■		
65	Rebuild Kelly-Whitcomb (24 mi) 115 kV line									■	■	■	■
66	Upgrade Arpin-Rocky Run terminal equipment, adjust relays											■	■
68	Replace ss limiters on Columbia-S FDL 345 kV line	■											
69	Upgrade Rock River - Liberty terminal equipment		■										
70	Reconductor Janesville-Russell/Uprate Term Equipment		■										
71	Upgrade Paddock 345/138 kV terminal equipment		■										
	Transfer from West (MW, with 1000 MW Southern Bias)	2121	1980	1340	1360	1240	1330	1260	2160	2260	2150	1830	1850
	Transfer from South (MW, with 1000 MW Western Bias)	2279	1960	1090	1090	1050	1080	1050	2020	1300	1260	1290	1250

New Transmission Lines	Line/Equipment Upgrades

* Reconductor portion of Itasca-Lombard, Upgrade Itasca-Lombard 345 kV breakers, Upgrade Schaumburg breakers, swap red & blue terminations

Item	Option #	3j	3k	3l	3m	5a	6	6a	6b	6c	8	8a	8b
1	Plano-Plano Tap 345 kV line	■	■	■	■	■		■	■	■			■
10	Arrowhead-Arpin 230 kV line				■								
11	Arrowhead-Arpin 345 kV line			■									
15	Rocky Run-South Fond du Lac 500 kV line						■	■					
16	South Fond du Lac-Plano 500 kV line						■						
19	Weston - Arrowhead 345 KV line	■											
20	Weston-Arrowhead 230 kV line		■										
21	Chisago-Apple River-Weston 345 kV line **					■							
22	Chisago-Rocky Run 500 kV line						■	■	■	■			
23	Rocky Run-South Fond Du Lac 345 kV line									■			
24	Byron (MN)-Columbia 345 kV line										■	■	■
26	Byron (MN)-Wilmarth 345 kV line											■	■
46	Reconductor Eau Claire - Wheaton circuit 1	■	■	■	■	■	■	■	■	■	■	■	■
47	Upgrade Barron - Apple River terminal equipment	■	■	■	■	■					■	■	■
48	Itasca Area fixes	■	■	■	■	■		■	■	■			■
49	Convert Oak Creek-Arcadian to 345 kV operation	■	■	■	■	■		■	■	■			■
50	Reconductor Wheaton - Wheaton Tap		■			■							
52	Wheaton 161 kV busses tied together					■							■
57	Reconductor Eau Claire - Wheaton circuit 2												■
58	Inc Forest Junction-Highway V 138kV line to 275 deg												■
60	Improve Goodings-Lockport Red/Blue line sag						■						
62	Relocate Des Plaines transformer on new bus	■	■	■	■	■							
63	Upgrade Weston - Rocky Run 345 kV terminal eq.	■	■			■							
64	Upgrade Weston 345/115 to 500 MVA	■	■			■							
65	Rebuild Kelly-Whitcomb (24 mi) 115 kV line	■	■	■	■	■							
66	Adjust relays, upgrade terminal equipment on Arpin-Rocky Run			■	■								
77	Upgrade Sand Lake-Port Edwards terminal eq.	■											
78	Upgrade Pulliam 138/115 kV terminal eq.	■											
	Transfer from West (MW, with 1000 MW Southern Bias)	2100	2160	1830	1850	2276	2320	2340	1806	2393	1280	1310	2090
	Transfer from South (MW, with 1000 MW Western Bias)	2050	2000	1950	1940	2136	2160	2150	2100	2150	1100	1110	1970

▨ New Transmission Lines	Line/Equipment Upgrades

* Reconductor portion of Itasca-Lombard, Upgrade Itasca-Lombard 345 kV breakers,
Upgrade Schaumburg breakers, swap red & blue terminations

** This line replaces the base-case Chisago-Apple River 230 kV line

Item	Option #	9a	10	10a	11a	12	12a	13a	13b	13c	13d	14	14a
1	Plano-Plano Tap 345 kV line	■				■	■			■	■		■
25	Plano-Paddock 345kV line		■	■									
27	Plano-Paddock 765 kV line				■								
28	Huron, SD - Columbia 345 kV line	■											
29	Paddock-Pleasant Prairie 345 kV line			■	■								
31	Arrowhead-Plains 345 kV line							■		■			
32	Arrowhead-Plains 230 kV line								■		■		
33	Morgan-North Appleton 345 kV line							■	■	■	■		
34	Monroe Co.-Council Creek 161 kV line						■					■	■
35	Spring Creek-Alma 161 kV line											■	■
36	Jackson Co.-Port Edwards 161 kV											■	■
38	Genoa-Hillsboro-Council Creek 161 kV line											■	■
39	Hillsboro-Reedsburg 161 kV line											■	■
40	Council Creek-Kilbourn-Reedsburg-Kirkwood 138 kV line											■	■
42	Bell Center-Spring Green 161 kV line											■	■
43	Lancaster (IL)-S. Monroe-N. Monroe-Verona-Fitchburg 138 kV line											■	■
44	Spring Green W. Middleton 138 kV line											■	■
45	Sauk Co.-N. Madison 138 kV line											■	■
46	Reconductor Eau Claire - Wheaton circuit 1	■	■	■	■	■	■	■		■	■	■	■
47	Upgrade Barron - Apple River terminal equipment	■	■	■	■	■	■	■	■	■	■		
48	Itasca Area fixes *	■				■	■			■	■		
49	Convert Oak Creek-Arcadian to 345 kV operation	■				■	■			■	■		
50	Reconductor Wheaton - Wheaton Tap	■	■	■	■	■	■			■	■		
52	Wheaton 161 kV busses tied together	■				■	■						
53	Reconductor Wheaton - Elk Mound					■	■						
54	Uprate Elk Mound - Barron to 212 F operating temp.					■	■						
55	Reconductor Wien - T-Corners with SSAC					■							
56	Upgrade Blackhawk - Colley Rd terminal equipment		■		■								
57	Reconductor Eau Claire - Wheaton circuit 2					■	■						
58	Inc Forest Junction-Highway V 138kV line to 275 deg					■							■
59	Upgrade Baker - Saratoga terminal eq.						■						
60	Improve Goodings-Lockport Red/Blue line sag		■		■								
61	Upgrade Plains 345/138 kV transformer to 500 MVA							■	■	■			
62	Relocate Des Plaines transformer on new bus	■								■	■		
67	Reconductor Eau-Claire-Seven Mile						■					■	■
69	Upgrade Rock River - Liberty terminal equipment		■		■	■							
70	Reconductor Janesville-Russell/Uprate Term Equipment				■								
74	Upgrade Itasca - Lombard B 345 kV breaker												■
75	Uprate Paddock-Wempletown line conductor					■							
76	Reconductor Saratoga-Petenwell, Upgrade terminal equipment						■						
79	Upgrade Paddock 345/138 kV terminal equipment		■										
80	Upgrade Goodings Grove-Lockport 345 kV breaker		■		■								
	Transfer from West (MW, with 1000 MW Southern Bias)	2572	1460	1480	1540	1910	1940	1400	1280	2250	1930	1220	2270
	Transfer from South (MW, with 1000 MW Western Bias)	2412	1710	1690	1930	1710	1780	1110	1060	2070	2000	1010	2150

New Transmission Lines	Line/Equipment Upgrades

* Reconductor portion of Itasca-Lombard, Upgrade Itasca-Lombard 345 kV breakers, Upgrade Schaumburg breakers, swap red & blue terminations

Appendix
J

Appendix J—Wisconsin Interface Reliability Enhancement Study (WIREs) [6]

Phase I Screening Report—A Report to the Wisconsin Reliability Assessment Organization (WRAO)—August 1998

Study participants

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Executive summary

General discussion

To address requirements in Wisconsin Act 204 (originating as Wisconsin Assembly Bill 940), the Wisconsin Interface Reliability Enhancement (WIRE) study was initiated in March 1998 by the Wisconsin Reliability Assessment Organization (WRAO) to identify possible regional transmission improvements that could substantially increase

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[6] This Executive Summary is from the WIREs Report to the WRAO and has been inserted without modification as Appendix J. It is not a document produced by the PSCW but is included for informational purposes.

the transfer capability between eastern Wisconsin -- also known as Wisconsin/Upper Michigan Systems (WUMS) – and adjoining regions. A study group was assembled representing utilities; state regulators in Illinois, Iowa, Minnesota and Wisconsin; the Mid-Continent Area Power Pool (MAPP); and Power Technologies Incorporated, a consultant to the Public Service Commission of Wisconsin Staff. The utility participants included:

- Alliant Utilities (ALT)
- Commonwealth Edison (ComEd)
- Dairyland Power Cooperative (DPC)
- Madison Gas and Electric (MGE)
- Manitoba Hydro (MH)
- Minnesota Power (MP)
- Municipal Electric Utilities of Wisconsin (MEUW)
- Northern States Power (NSP)
- Wisconsin Electric (WE)
- Wisconsin Public Power Incorporated (WPPI)
- Wisconsin Public Service Corporation (WPS)

The WIRE study provides the basis for a report on transmission constraints and mitigating transmission reinforcements being prepared by the Public Service Commission of Wisconsin for submittal to the Wisconsin State Legislature on September 1, 1998.

The WIRE study consists of a screening analysis to identify transmission constraints and possible reinforcements, leading up to identification of a set of transmission plans that would increase the simultaneous transfer capability into WUMS from adjoining regions to 3,000 MW; either 2,000 MW from the west and 1,000 MW from the south, or 1,000 MW from the west and 2000 MW from the south. The study is based on a 2002 power flow model which is discussed in more detail in Section 4 of this report.

This phase of the WIRE study is considered a screening analysis because it is focused primarily on removing thermal (facility overload) limitations to transfer capability. Further technical analysis of the plans, including voltage stability, dynamic stability, and detailed power flow analysis is necessary to confirm each plan's adequacy.

Of forty-seven plans evaluated, twelve representative plans that nominally reach the study's transfer capability goals were identified by the group for further analysis after September 1, 1998. Although distinct, these plans are characterized by many common elements. Eleven of the twelve plans contain a common set of improvements on the Commonwealth Edison (ComEd) system; the remaining plan illustrates an alternative to these improvements. All but one plan establishes a new EHV (230 kV or above) tie between MAPP and eastern Wisconsin; the remaining plan (Plan 12) illustrates the impact of an alternative which includes upgrades of existing facilities in Wisconsin in addition to the ComEd area improvements common to most plans.

Study results for the twelve plans are summarized in the following table. The plans are denoted by the new facilities involved, but it is important to recognize that their performance is dependent on the upgrade of numerous existing facilities also. Appendix D contains a full description of each plan.

Table 1a “Short List” Plans

#	Option Description	Western Import[1] (MW)	Southern Import[1] (MW)	Loss Saving[2] (MW)	Indicative Capital Cost[3] ($M)	Arpin Phase Angle[4]
1c	Salem–Fitchburg 345 kV No. Madison-Fitchburg-Rockdale 345 kV Plano-Plano Tap red & blue 345 kV	2,220	2,040	97	$122	92°
2e	Prairie Island-LaCrosse-Columbia 345 kV Plano-Plano Tap red & blue 345 kV	2,120	2,150	108	$138	78°
2f	Salem–Paddock 345 kV Plano-Plano Tap 345 kV	1,980	1,960	79	$93	95°
3e	Arrowhead-Weston-S. Fond du Lac 345 kV S. Fond du Lac-Plano 345 kV	2,160	2,020	131	$181	65°
3j	Arrowhead-Weston 345 kV Plano-Plano Tap red & blue 345 kV	2,260	2,100	139	$139	70°
3k	Arrowhead–Weston 230 kV Plano-Plano Tap red & blue 345 kV	2,160	2,010	113	$118	83°
5a	Chisago-Apple River-Weston 345 kV Eliminate need for Chisago-Apple Rv 230 kV Plano-Plano Tap red & blue 345 kV	2,280	2,130	134	$149	48°
6c	Chisago-Rocky Run 500 kV Rocky Run–S. Fond du Lac 345 kV Plano-Plano Tap red & blue 345 kV	2,320	2,160	173	$212	38°
8b	Wilmarth-Byron-Columbia 345 kV Plano-Plano Tap red & blue 345 kV	2,090	1,970	102	$143	80°
9a	Huron-Split Rock-Lakefield Jct -Adams-Genoa-Columbia 345 kV Plano-Plano Tap red & blue 345 kV	2,570	1,960	143	$263	72°
12	Plano-Plano Tap red & blue 345 kV	1,910	1,850	73	$58	98°
13c	Arrowhead-Plains 345 kV Morgan-North Appleton 345 kV Plano-Plano Tap red & blue 345 kV	2,250	2,070	124	$165	77°

[1] with 1,000 MW simultaneous import bias on the opposite interface

[2] loss savings relative to the base case (1,000 MW simultaneous import on each interface)

[3] 1998 $

[4] current operating guide requires operator intervention to achieve an Arpin phase angle separation of less than 60° upon loss of western interface—target value for this study is 60° or less.

Several ComEd system improvements are required by all plans. In eleven of the twelve plans, these improvements include a new 345 kV line from the Plano substation to a tap point on a new 345 kV line ComEd already proposes to construct southwest of Chicago and upgrades of existing 345 kV circuits and associated terminal equipment northwest of Chicago. The remaining plan (Plan 3e) illustrates how a new 345 kV line between the Plano substation in Illinois and a 345 kV substation in Wisconsin could have a similar impact.

The ComEd area system improvements, combined with the upgrade of several existing facilities in Wisconsin and between Wisconsin and Illinois (Plan 12), come close to meeting the study's transfer capability goals. Although this plan is the lowest cost, it falls just short of the WIRE study's performance goals. It also results in the lowest electrical loss savings and the highest Arpin phase angle separation following a 345 kV line trip. Plan 12 is included on the short list to illustrate the significant contribution of the ComEd area reinforcements toward satisfying the goal of increasing transfer capability.

Additional transfer capability, increased loss savings, and reductions in the Arpin phase angle are achieved by building a new high-voltage transmission circuit between MAPP and WUMS. Reinforcement plans were developed with endpoints in MAPP from Dubuque, Iowa up to Duluth, Minnesota. Two plans also look at endpoints further west in MAPP near Mankato, Minnesota and at Huron, South Dakota.

Based on indicative cost estimates, the plans' capital costs range from $60 to $260 million. These indicative estimates do not account for any differences among the plans due to loss reductions, their ability to defer or eliminate planned load-serving transmission options, or the cost of additional facilities which may be necessary upon further analyses. Section 6 of this report shows the specific cost assumptions made for each option.

At a WUMS simultaneous import of 2,000 MW (1,000 MW from the south and 1,000 MW from the west), the plans' projected impact on electrical losses range from reductions of 73 MW to 173 MW compared to the existing system. This analysis is only intended to give a quick indication of the relative ability of each plan to reduce losses.

An important present-day operating concern is the "Arpin phase angle" resulting from a trip of the existing 345 kV tie between Minnesota and Wisconsin. Current operating practice requires the Arpin phase angle to be reduced to 60° or less before attempting to re-close the 345 kV line following the trip of any section of the line between the King and Rocky Run substations. The ability to re-close the line promptly after the sudden loss of the western interface due to a temporary fault is critical for power system reliability. Those options which result in a phase angle greater than 60° will require continued reliance on operating guides to adjust regional generation patterns prior to re-establishment of the 345 kV line. However, recent operating experience continues to demonstrate that it is difficult and time consuming to reduce the phase angle via adjustment of regional generation patterns during peak load conditions. The post-contingent Arpin phase angle varies significantly among the twelve plans from 38° to 98°.

More discussion of the plans' impact on losses and Arpin phase angle can be found in Section 5 of this report.

These study results are preliminary and represent the early stages of the transmission planning process. It would be premature to choose a preferred plan based solely on the information contained in this report. The impact of these plans on the existing stability-constrained simultaneous transfer limits in MAPP must be fully evaluated with dynamic stability studies. Voltage stability also needs to be considered at the higher transfer levels contemplated in this study. The impact of each plan on the ability to re-close after a trip of the existing 345 kV tie between Minnesota and Wisconsin must also receive further consideration in future studies. Finally, detailed environmental and economic analyses are necessary before the relative merits of each plan can be evaluated. The results contained in this report provide a focused basis for these additional studies, but are not sufficient alone to determine the best transmission expansion plan(s) to alleviate regional transmission constraints.

Conclusions and recommendations

Phase 1 of the WIRE study consists of a screening analysis of alternatives for increasing transfer capability into the eastern Wisconsin region. Since this analysis primarily considers thermal limitations to transfer capability, conclusions based on this limited-scope analysis must be considered preliminary–subject to the results of more-detailed steady-state and dynamic power system studies. With this caveat, the following preliminary conclusions and observations can be drawn based on studies to-date.

1. Local load serving facilities provide 1,800 - 2,000 MW simultaneous import capability.
2. Local load serving facilities alone will not eliminate need for operating guides.
3. $21 million in upgrades and $35 million in new construction are required to remove thermal limitations.
4. Removal of thermal limitations does not eliminate Arpin phase angle problem.
5. $150 - $250 million of high-voltage transmission construction is required to obtain 3000 MW of simultaneous import capability.

6. Transmission construction within Wisconsin alone will not provide the target import capability.
7. Direct Current (DC) transmission provides no incremental benefit to AC options.

Based on these conclusions and observations, the WIRE study group makes the following recommendations:

1. Perform additional study work.
2. Optimize regional expansion plans.
3. Perform a resource adequacy study.
4. Continue regional reliability forums.

Please refer to Section 7 for a detailed discussion of each conclusion and recommendation point.

List of Tables and Figures