Planning Factors

Planning considerations

In evaluating the transmission system and planning for what will be needed in the future, we consider a number of variables such as:

- *At what rate will electricity demand increase in the future? What kind of electricity uses will drive the increases in demand?*
- *What generation is likely to be constructed; what is likely to be retired?*
- *What types of disturbances on the transmission system are particularly serious or problematic?*
- *What existing facilities need to be replaced based on their age or condition?*
- *How can improving access to low-cost power outside of Wisconsin and Michigan's Upper Peninsula best be achieved? Which chronic constraints need to be addressed?*
- *How can improving access between in-state utilities best be achieved? Which chronic constraints need to be addressed?*
- *How much will it cost to provide reliable transmission service and improve access?*
- *What are the benefits associated with transmission system expansion plans and how can they be measured?*
- *What are the social and environmental impacts of our transmission system expansion plans?*
- *What new, proven technologies may be available to help meet the needs more effectively and efficiently?*

These are some key considerations that we take into account, but there are numerous other objectives including improving system efficiency, providing economic development opportunities and helping our customers remain competitive in the future. Throughout this 10-Year Assessment, we are striving to address the issues and questions above to develop the most beneficial and cost-effective expansion plan possible.

Transmission system expansion drivers

There are numerous factors that can drive the need for transmission system expansion. In some cases, more than one factor will signal the need for system expansion. The most common expansion drivers are described below and include:

- ❑ Electric load growth
- ❑ Transmission-distribution interconnections
- ❑ Transmission service limitations
- ❑ New generation
- ❑ Transmission service requests
- ❑ System repair or replacement
- ❑ Economic strategic expansion

- ❑ **Electric load growth** – The load growth driver in this Assessment is similar to that in the previous Assessment. Demand for electricity during peak load periods is projected to grow at a rate of just over 2 percent across our service territory from 2006 through 2016. However, load growth rates in some areas are projected to grow by as much as 8 percent, while no growth is projected in other areas. Not surprisingly, many areas of high load growth correspond to areas where we are proposing system expansion.

  Figure PF-1 shows the projected growth in peak demand, in MW, from 2006 through 2016 for various areas of our system. Note that most of the high growth (greater than 20 MW) is in the metropolitan Milwaukee, Madison and Fox Valley areas. While these higher-growth areas may require system expansion, there is considerably more existing transmission infrastructure in these areas. Of equal or greater concern is high growth in areas where there is much less existing transmission infrastructure because the capacity of the existing system may be reaching its limits, perhaps requiring additional infrastructure.

  Figure PF-2 shows the projected rates of growth on our system. This is perhaps more revealing as it shows what areas are experiencing high rates of growth, regardless of the magnitude of load that exists today. Certain areas of our system have more transmission infrastructure today and are not as likely to need infrastructure additions to support expected load growth. Note that the high rates of growth in and around Madison, Lake Geneva, Green Bay, Marinette, Rhinelander, Wis., and Menominee, Mich. were not depicted as being among the highest MW growth areas in Figure PF-1. These areas of high growth rates actually are better indicators of when and where system expansion is likely to be needed.

  Many of the line or transformer overloads or low voltages during peak load are due to electric load growth. System expansion is required to ensure that the transmission system can operate reliably – mitigating overloads and low voltages.

- **Transmission-distribution interconnections** – A natural extension of load growth is the need for additional transmission-distribution interconnections (TDIs). As the capacity of the transmission system gets more fully utilized when load growth occurs, similarly this often happens on the distribution systems as well, requiring new interconnections to the transmission system.

  In most cases, distribution companies will attempt to unload existing distribution facilities by siting a new TDI near an existing transmission line and redistributing some of the load in the area to the new TDI. In some instances, however, it makes more sense to construct transmission closer to where the load growth is occurring.

  A list of all of the planned TDIs on ATC's system can be found at: *http://www.atcllc.com/oasis/liqueue.xls.*

- **New generation** – When entities plan to construct new generating facilities, there are two key considerations from the transmission owner's perspective:
  - Can the proposed generating facilities be interconnected and remain stable during system disturbances, and will nearby generating facilities remain stable?
  - Can the electricity produced by the generating facilities be delivered reliably to the ultimate customer(s)?

  For each entity that plans to construct a new generating facility, the transmission provider will conduct an interconnection study. If the existing transmission system is inadequate to ensure generator stability or reliable transmission service, the transmission provider will determine what system expansion will be needed.

  We have constructed and are in the process of planning and/or constructing transmission facilities that are needed to interconnect and/or provide transmission service from new generators. The transmission facilities being planned or constructed to accommodate new generation can be found in Tables PR-2 through PR-23**.** In the Need Category column, look for "new generation." Also, see Generation interconnections.

- **Transmission service requests** – In the Midwest Independent System Operator, Inc. (MISO) Day 2 Market, transmission services requests are used less but still are an available option. Power plant owners and local distribution companies can transact with other entities to buy and sell electricity. Power plant owners with surplus generating capacity may attempt to sell that surplus capacity. Entities serving end-use customers may attempt to lower their costs by accessing and purchasing low-cost electricity. In addition to the Day 2 Market another way in which these entities gain access to the transmission system to make these transactions is by making transmission service requests. Transmission service providers, or transmission owners like ATC, evaluate those requests to determine whether the transmission system can be operated reliably if the request is granted. If the request can't be granted, the transmission service provider may determine how the transmission system needs to be expanded to grant the request. The types of requests that would require some sort of system expansion are longer-term requests (transactions lasting longer than one year) and which start at some point in time in the future. Requests for service in the near future may have to simply be denied because system expansion facilities can't be constructed in time.

We have constructed and are in the process of planning and/or constructing, transmission facilities that are required to grant transmission service requests. The transmission facilities being planned or constructed to meet transmission service requests can be found in Tables PR-2 through PR-23. In the Need Category column, look for "service limitation."

- **System repair or replacement** – Many components of our transmission system will need to be repaired or replaced in the coming years due to condition or obsolescence. In some cases, the need to reconstruct a transmission line may provide opportunities to increase the capacity of those components and improve reliability. The transmission facilities being planned or constructed that have condition or obsolescence issues can be found in Tables PR-2 through PR-24. In the Need Category column, look for "condition."

- **Economic/strategic system expansion** – In the electric utility industry, change has become more of the norm rather than the exception. For example, in recent years, wholesale electricity markets have continued to evolve, renewable generation has gained a larger market share, and the generation market, in general, has become more competitive. Utilities and generation developers, which were constructing only natural gas-fired generation in recent years, now are considering the merits of, or have already planned to construct, coal-fired generation. In addition, because both residential and business customers are more mobile, migration of electric customers to other areas is a greater risk consideration for utilities. In order for utilities to remain cost competitive, they must have the flexibility to take advantage of trends that have the potential to lower costs. To the extent that low-cost generation development is occurring in an adjacent state, it may make sense for a transmission provider to construct transmission facilities that would allow its utility customers better access to that low-cost generation.

  Along these lines, we have been investigating ways to take advantage of certain potential developments in the electricity industry to give its customers more ways to lower costs. The primary outgrowth of this effort is our Access Initiative.

Midwest developments

There have been a number of developments in the Upper Midwest that could affect us and/or our customers. Among the more relevant of these include potential changes in state regulations, exploratory transmission initiatives being investigated by MISO and generation developments.

- **State regulations** – The Public Service Commission of Wisconsin compiles information on utility plans every other year in its Strategic Energy Assessment. The SEA evaluates the plans of utilities for the following seven years. In addition, the PSC is considering methods for better integrating generation and transmission planning efforts.

- **MISO exploratory study** – MISO completed its second Transmission Expansion Plan in 2005. As part of that effort, MISO identified several potential transmission expansion scenarios that it intended to further explore. One of those scenarios was predicated on the potential for significant amounts of new wind generation development in southern Minnesota and northern Iowa. The purpose of the exploratory study was to identify the transmission facilities that would be required to interconnect and deliver the output of this potential wind generation. One of the anticipated delivery points for the wind generation is Wisconsin. We have been participating in this effort to determine what impact these plans would have on transmission development in and around Wisconsin.

- **CapX2020 (**Capacity Expansion) **-** By the year 2020, the Capx Utilities have announced four projects that they are going to seek regulatory approval for. We have been participating in the analysis of this effort to determine what impact these plans would have on transmission development in and around Wisconsin. Please refer to Regional analysis for more information.

- **Generation developments** – Since ATC's beginning, the trend in generation development in Wisconsin has moved away from just natural-gas fired generation, which dominated the development picture in the last 15 years, to include coal-fired and wind generation. Thus far, two 650-MW coal-fired units and another 550-MW unit have been approved. We have identified transmission expansion requirements for these units. In addition, Alliant Energy has announced intentions to construct a new base load coal unit at either Nelson Dewey or Columbia.

  Currently, there are 15 proposals to install a total of 1,405.5 MW of wind turbines in Wisconsin in the MISO generation queue. We have identified the transmission requirements associated with ten of these proposals totaling 1,000 MW.

  For more on generation developments in Wisconsin and Michigan's Upper Peninsula, see Generation Interconnections.

Regional and national developments
There are a number of recent and ongoing developments that could affect us and our customers. Changes in the way transmission service is provided within the MISO footprint and changes to the methods for evaluating the impact of new generation and initiatives in the wake of the Aug. 14, 2003 blackout are described below.

MISO Day 2 Market – On April 1, 2005, MISO implemented the Day 2 Market, which provides generation and transmission service to its load-serving customers, as well as manages congestion on the MISO transmission system. The market-based method, which was approved by the Federal Energy Regulatory Commission (FERC), is a significant change from how these functions were handled.

In the past, curtailing or interrupting transmission service was necessary. However, in the Day 2 Market, system operators re-dispatch generating units on a least-cost basis in order to reconfigure the transmission system. In Day 2, market prices (or locational marginal prices) are produced at various points in the MISO footprint. These prices represent the marginal cost of congestion and losses, as well as the marginal cost of generation at the various points in the MISO footprint.

There was uncertainty at the implementation of the market about the market prices that would result. For example, some market participants speculated how the resulting market prices would impact them financially and how the rights to transmission service would be allocated. Some of that concern has been reduced as the market has got underway but some of it still remains. An additional uncertainty is whether the market-driven congestion management process will provide the incentives to eliminate congestion on the transmission system.

Due to the uncertainties of the market, FERC allowed the Wisconsin and Michigan load-serving utilities that make up ATC to reduce the effect of the Day 2 congestion management process for five years. While still participating in the Day 2 energy market, FERC allowed the ATC-specific Wisconsin and Michigan utilities to be reimbursed for congestion costs associated with network resources located outside of WUMS where Financial Transmission Rights (FTRs) were unavailable to these load-serving entities to hedge congestion costs associated with these facilities.

Generation deliverability – Prior to the Day 2 Market**,** a Network Firm transmission service request on the Open Access Same Time Information System (OASIS) was required to obtain transmission service and designation of a generator as a Network Resource. However, in the Day 2 Market, MISO uses an aggregate "deliverability" test, which, rather than studying a specific generator-to-load path, requires showing that the output of a resource is deliverable to the "aggregate" MISO energy pool without overloading the transmission system. If the resource passes the deliverability test, it is designated a

Network Resource. This deliverability analysis is performed as part of the generator-transmission interconnection process.

Reliability initiatives – In the wake of the August 2003 blackout that affected the northeastern portion of the U.S. and adjacent portions of Canada, several root cause investigations have been conducted and preventive initiatives have been proposed. In particular, better documentation on vegetation management in transmission line rights-of-way will be required by FERC. In addition, FERC issued a proposed policy statement on reliability, indicating that federal legislation may be necessary to make adherence to reliability standards mandatory and enforceable.

We have initiated or continue pursuing several measures aimed at improving the capability of our system to withstand major disturbances and avoid widespread blackouts. Key measures include:

- implementing specific projects aimed at lowering vulnerability to extreme disturbances,
- devising new, faster protection schemes to improve system stability during disturbances,
- replacing several circuit breakers, particularly at generating stations, to improve system stability during disturbances,
- implementing complete global positioning system synchronization of relays to capture and analyze disturbance data,
- completing multiple contingency analyses of our system,
- working with MRO and/or RFC on extreme disturbance studies to consider the effectiveness of under-voltage load shedding,
- investigating enhanced visualization tools for ATC's control rooms and
- investigating use of high technology reactive control devices at critical locations on the ATC system.

Customer needs

Our customers provide us with input on their needs and suggestions about areas on which we should focus. Some of the most prevalent issues are described below.

- **Improved access** – Virtually all of our customers have indicated a desire to have better transmission access to out-of-state markets as well as fewer constraints in transacting with their neighboring utilities within the ATC footprint. In response, we launched an Access Initiative, taking a comprehensive look at the economic and technical feasibility of constructing new transmission lines to neighboring states.

- **Transmission-distribution interconnection process** – In response to the relatively large number of planned T-D interconnections by our customers, we have been working on refining that process. Part of the refinement to this process includes incorporating our customers' desire to better coordinate planning for these future interconnections.

While these interconnections ultimately are evaluated on a case-by-case basis, there is the potential for looking at groups of interconnections collectively to develop more optimal solutions for particular areas.

- **Control of transmission construction costs –** Many of our customers have expressed concern about the cost of our construction forecast. To this end, we are looking at our processes for public planning and asset delivery in an effort to find more efficient and economical ways to provide the reliable system that our customers need to keep their costs down. We also are working on prioritization methods to help us identify the projects that best meet the needs of our customers.

- **Least cost planning including integration of transmission and generation planning –** Our transmission system does not have significant excess transmission capacity. As a consequence, generation interconnection cannot be effectively pre-analyzed on a generic basis. This is one reason why, as the Public Service Commission of Wisconsin noted in its last Strategic Energy Assessment, effective integration of generation and transmission planning is difficult. Further complicating the issue, construction of generation facilities can occur through regulated or unregulated entities, subject to varying levels of state regulatory requirements. Federal regulations require that we be responsive to all requests for generation interconnection in a consistent and non-discriminatory manner.

  While many of our customers appear to be interested in a more integrated approach to generation and transmission planning, some also are wary of sharing market-sensitive long-range plans for generation procurement. As a result, we currently are exploring potential methods to allow more effective integration of these areas, in a way that recognizes the limitations of generic analysis and is consistent with both federal regulatory obligations and the confidentiality of market-sensitive generation information.

New technologies

We are committed to research and development of new technologies that promise to bring value to our customers and stakeholders by enabling us to achieve best-in-class performance. In 2006 we are continuing to support and participate in collaborative research through our memberships in:

- Electric Power Research Institute (EPRI), **http://www.epri.com/**;
- Power Systems Engineering Research Center (PSERC), http://www.pserc.org/;
- and Canadian Electric Association Technologies (CEATech), http://www.ceatech.ca/.

We have successfully installed and applied several new technologies on the ATC system to enhance the management of the ATC system in 2006. These technologies include:

- Distributed Superconducting Magnetic Energy Storage (DSMES) devices are installed in the Rhinelander area to assure acceptable voltage stability until crucial long leadtime transmission facilities can be built. The seven installed DSMES units have a total capacity of 24 MVA.

- ❑ Production Modeling (PROMOD) software use has continued and been expanded to analyze the economic impact of proposed system projects and outage plans for system operating scenarios based on locational margin pricing.
- ❑ Physical and Operational Margins/Optimum Mitigation (POM/OPM) software is used to analyze the complex electrical impact of multiple outage contingencies and identify optimal mitigation measures to resolve recognized problems.
- ❑ Commercially available high-temperature, low-sag, twisted pair conductors have been installed on new and existing transmission lines to carry more power in a given right-of-way than conventional conductors.
- ❑ Powerworld software is used to create visual images of adverse electrical system voltage and loading conditions to illustrate the impact of proposed solutions.

In addition, there are a number of new technologies that are under review or development this year. These potential technology applications include:

- ❑ We continue to review the performance of a Dynamic Rating Unit that was installed on the Rocky Run 345/138-kV transformer in summer 2005. This unit provides real-time data on the transformer's condition to allow its full capability to be forecasted for projected load and ambient conditions.
- ❑ We continue to review the performance of a video sagometer that was installed on the Paris-Albers 138-kV line in late 2004 and the related Dynamic Thermal Circuit Rating software. The sagometer and ratings software provide an assessment of the line loading capability under real-time ambient conditions
- ❑ We continue to participate in an EPRI study of the application of several types of power electronic control devices, including the new Magnetically Controlled Reactor, to improve generator stability and voltage stability performance in systems similar to the Presque Isle area.
- ❑ We are participating in a PSERC study to determine the optimum allocation of static and dynamic reactive power resources. This study will provide methodologies and criteria to help us optimize the selection and placement of equipment that provides either static or dynamic reactive power.
- ❑ We continue to participate in a MISO study to enhance grid performance by installing Phasor Measuring Units. The PMUs would be used to obtain advance warning of system overloads and instabilities by monitoring the phase angles at critical locations across MISO.
- ❑ We continue to investigate the impact of high temperature operation of conductors and splices, and the development of new technology to facilitate proper cleaning of conductor and installation of splices.
- ❑ We continue to participate in the development of low cost, durable sensors for high voltage and high temperature applications. These sensors would be used to monitor conductor and equipment to determine dynamic ratings and for condition assessment.

- In addition, we are monitoring more than 35 new and emerging technologies that might improve our system practices or performance.

Planning criteria
We employ various system planning criteria to ensure that we develop a reliable and robust transmission system. Our aim with these criteria is to support effective competition in energy markets, to reliably deliver power to systems connected to our system and customers dependent on our system, to provide support to distribution systems interconnected to our system and to deliver energy from existing and new generation facilities connected to our system.

These criteria may be revised from time to time. Situations that could precipitate such a change could include, but are not limited to new system conditions, new technologies, new operating procedures, extraordinary events, safety issues, operational issues, maintenance issues, customer requests, regulatory requirements and reliability council or NERC requirements.

The planning criteria are listed under the following headings:

- System Performance Criteria
- Capacity Benefit Margin Criteria
- Transmission Reserve Margin Criteria
- Facility Rating Criteria
- Model Building Criteria
- Facility Condition Criteria
- Planning Zones
- System Alternatives
- Load Forecast Criteria
- Economic Criteria
- Environmental Criteria
- Other Considerations

SYSTEM PERFORMANCE CRITERIA

System performance will be assessed at least annually. Such assessments will involve steady state simulations and, as appropriate, dynamic simulations.

Steady state assessments

Steady state assessments will include consideration of the following system load conditions:

1) Summer peak
2) Winter peak
3) Summer shoulder peak

4) Fall/spring off-peak
5) Summer 90/10 peak

The first three load conditions above will be assessed in all long-range planning studies. The last two load conditions will be considered when more detailed analyses are being conducted of specific alternatives developed to solve a particular problem. The Summer 90/10 peak load condition will be considered in the NERC Category B (loss of single element) analysis to help us determine whether extreme weather conditions may require unusual measures to meet unexpected load. The 90/10 forecast will be used to help prioritize and stage projects but it will not necessarily be used as the sole reason to justify projects. The specific criterion associated with each of the load conditions above is provided in Part 5 of Form 715 under Load forecast criteria. For each condition, wind generation is modeled at 20% of its reported output level for general planning studies and its full output level for generator interconnection deliverability studies and Power-Voltage (P-V) analysis.

Dynamic stability assessments

Dynamic stability assessments will include consideration of the following system load conditions:

1) Summer peak
2) Light load (50 percent of peak)

The first condition is typically used for voltage stability studies. The second condition is primarily used for angular stability studies. For all generator interconnection dynamic stability assessments, wind generation is modeled at its full output level.

Steady state performance assessment

Steady state assessments are generally performed to assure avoidance of equipment overloads, prevention of unacceptable system voltage levels, and satisfactory system reactive power resources. The steady state system performance criteria to be utilized by ATC shall include:

A. Normal conditions (NERC Category A)

1) No system element (line, transformer, terminal equipment, etc.) should experience loading in excess of its normal rating for NERC Category A conditions, that is, with all transmission facilities in service. This criterion should apply for a reasonably broad range of generation dispatch conditions.
(Applicable NERC Standard: TPL-001-0)

2) No voltage levels that could cause damage to ATC or ATC customer facilities should be tolerated on a sustained basis. The acceptable voltage range is 95 percent to

105 percent of nominal voltage for NERC Category A conditions. Such measurements shall be made at the high side of transmission-to-distribution transformers. We will consider voltage levels outside of this range, if they are acceptable to the affected transmission customer. These voltage criteria should be met with the generator reactive power limited to 90 percent of the reported reactive power capability.
(Applicable NERC Standards: TPL-001-0)

3) Operating procedures (operating guides) are not preferred under normal conditions, but may be employed by ATC and/or entities with generation and/or distribution facilities interconnected with the ATC transmission system to avoid transmission facility loadings in excess of normal ratings provided such procedures are practical for sustained periods, that is, such procedures do not impose on personnel or public safety, do not significantly degrade system reliability, do not result in a significant loss of equipment life or significant risk of damage to a transmission facility and/or do not unduly burden any entity financially. Supervisory switching options would be preferred over field switching options as a means to reduce facility loadings.

B. Loss of Single Element Conditions (NERC Category B)

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category B contingencies. This criterion should be applied for a reasonably broad range of generation dispatch conditions. Overload relief methods may include supervisory, field, or automatic switching of circuits and generation redispatch. However, load shedding may not be utilized in planning studies for immediate overload relief. System design should ensure that loading in excess of any Interconnection Reliability Operating Limit (IROL) can be reduced to achieve a reliable state within 30 minutes.
(Applicable NERC Standard: TPL-002-0)

2) Under applicable NERC Category B contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. Voltage restoration methods may include: supervisory control of capacitor banks, load tap changers, generating unit voltage regulation, generation redispatch, or line switching. However, load shedding may not be utilized in planning studies for immediate voltage restoration. System design should ensure that voltage levels outside of any Interconnection Reliability Operating Limit (IROL) can be restored to achieve a reliable state within 30 minutes. These voltage criteria should be met with the generator reactive power limited to 95 percent of the reported reactive power capability.
(Applicable NERC Standard: TPL-002-0)

3) The steady state system operating point of selected ATC areas should be at least 10% away from the nose of the P-V curve to assure adequate system voltage stability and reactive power resources. This 10 percent P-V margin is chosen to

reflect uncertainties in load forecasting and modeling, as well as to provide a reasonable margin of safety.

4) Generated real power output should not be limited under NERC Category B contingency conditions. We will consider a lower level of transmission service if requested by a transmission customer.

C. Loss of multiple element conditions (NERC Category C)

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category C contingencies. This criterion should be applied for a reasonably broad range of generation dispatch conditions. Overload relief methods may include manual or automatic switching of circuits, generation redispatch, or firm service curtailments, as well as minimal planned load shedding. The transmission element loading should be reduced to within the normal ratings within the time frame of the applicable ratings.
(Applicable NERC Standard: TPL-003-0)

2) Under applicable NERC Category C contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. Voltage restoration methods may include supervisory control of capacitor banks, load tap changers, generating unit voltage regulation, generation redispatch, line switching or firm service curtailments. Minimal planned load shedding may also be used for voltage restoration. These voltage criteria should be met with the generator reactive power limited to 95 percent of the reported reactive power capability.
(Applicable NERC Standard: TPL-003-0)

D. Extreme disturbance conditions (NERC Category D)

1) The MAIN Extreme Disturbance Criteria and NERC Category D criteria should be used to assess system performance. These criteria may include examining loss of all circuits on a right-of-way and loss of an entire substation, including generation at that substation. These criteria should be used to determine system vulnerabilities, but may not necessarily dictate that potential problems identified need to be remedied with system additions.
(Applicable NERC Standard: TPL-004-0)

Transient and dynamic stability performance assessment

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse, and availability of system reactive power resources within 20 seconds after a system disturbance. The transient and dynamic system stability performance criteria to be utilized by ATC shall include the following factors.

A. Large disturbance stability performance assessment

1) For generator transient stability, faults will be modeled on the high side bus at generating plants.

2) For generating units with actual "as built" or "field setting" dynamic data, add a 0.5 cycle margin to the expected clearing time (ECT) for dynamic contingency simulations. For generating units with assumed, typical, or proposed dynamic data, add a 1.0 cycle margin to the ECT for dynamic contingency simulations. The total clearing time (ECT + margin) must be equal to or less than the calculated critical clearing time (CCT) from the simulation.

3) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category B contingency. These contingencies will typically be sustained three-phase faults of a single generator, transmission line, or transmission transformer with normal fault clearing.
(Applicable NERC Standards: TPL-002-0)

4) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category C contingency. These contingencies will typically be three-phase faults of single elements with prior outage of a generator, line or transformer with normal clearing; single line-to-ground faults on a transmission bus or breaker with normal clearing; single line-to-ground faults on two transmission lines on a common structure with normal clearing; or single line-to-ground faults on a single generator, transmission line, transmission transformer or transmission bus section with delayed clearing.
(Applicable NERC Standards: TPL-003-0)

5) Generator transient stability will be evaluated for at least one key contingency for two types of NERC Category D contingencies. These contingencies are three-phase faults on a transmission line with delayed clearing (D2) and three-phase faults on a transmission transformer with delayed clearing (D3). This ATC criterion is more severe than NERC Category D criteria because it requires every generating unit to maintain transient stability for this condition.
(Applicable NERC Standards: TPL-004-0)

6) Generator transient stability will be reviewed for any other NERC Category D contingencies that are judged to be potentially critical to transmission system adequacy and security.
(Applicable NERC Standards: TPL-004-0)

7) Unacceptable system transient stability performance for NERC Category A, B, and C outages and for ATC'S more severe Category D2 and D3 outages includes the following conditions:

   A. Angular stability assessment

a) Generating unit loses synchronism with the transmission system, unless it is deliberately islanded

b) Cascading tripping of transmission lines or uncontrolled loss of load

c) Poorly damped angular oscillations, as defined below

B. Voltage stability assessment

a) Voltage recovery within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance

b) Voltage recovery within 80 percent and 120 percent of nominal at between 2.0 and 20 seconds following the clearing of a disturbance

c) Voltage instability (collapse) at any time after a disturbance [100 percent constant current modeling for real power load and 100 percent constant impedance modeling for reactive power load may be used in areas where the steady state operating point is at least 10 percent away from the nose of the P-V curve, otherwise appropriate induction motor modeling should be used for the voltage stability assessment.]

(Applicable NERC Standard: TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0)

B. Small disturbance performance assessment

The small disturbance (e.g. switching) stability performance criteria to be utilized by ATC will include:

1. With all generating units at their prescribed base case (normally full) real power output, no unit will exhibit poorly damped angular oscillations [as defined below] or unacceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.

(Applicable NERC Standard: TPL-002-0)

2. With all generating units at their prescribed base case (normally full) real power output, no unit will exhibit poorly damped angular oscillations [as defined below] or unacceptable power swings in response to a (non-fault) loss of any two transmission circuits on a common structure.

Note: Poorly damped angular oscillations do not meet either of the following criteria:

a. The generator rotor angle peak-to-peak magnitude is within 1.0 degree or less at 20 seconds after the switching event.

b. The generator average damping ratio is 15.0 percent or greater at 20 seconds after the switching event. The average damping ratio = (d1+d2+d3+d4)/4 * 100 percent. d1 = p5-p4/p5, d2 = p4-p3/p4, d3 = p3-p2/p3, d4 = p2-p1/p2.

Voltage flicker

The criteria for acceptable voltage flicker levels are defined by the requirements of regulatory entities in the states in which ATC owns and operates transmission facilities, IEEE recommended practices and requirements, and the judgment of ATC.

The following flicker level criteria are to be observed at minimum system strength with all transmission facilities in service. Minimum system strength shall be defined as the condition produced by the generation that is in service in 50 percent peak load case models, minus any generation that is:

1) Electrically close to the actual or proposed flicker-producing load
2) Could significantly affect flicker levels
3) Could reasonably be expected to be out of service under light system load conditions

Although the limits described below are not required to be met during transmission system outages, if these limits are exceeded under outage conditions, the flicker producing load must be operated in a manner that does not adversely affect other loads. Planned outages can be dealt with by coordinating transmission and flicker producing load outages. Because operating restrictions during unplanned outages may be severe, it would be prudent for the owner of the harmonic producing load to study the effect of known, critical, or long term outages before they occur, so that remedial actions or operating restrictions can be designed before an outage occurs. During outages, actual, rather than minimum normal, system strength should be considered.

All ATC buses are required to adhere to the following three criteria.

1) *Relative steady state voltage change* is limited to 3 percent of the nominal voltage for intact system condition simulations. The relative steady state voltage change is the difference in voltage before and after an event, such as capacitor switching or large motor starting. These events should occur at least 10 minutes apart and take less than 0.2 seconds (12 cycles) to go from an initial to a final voltage level.

2) *Single frequency flicker* is to be below the applicable flicker curves described in Table A.1 of IEEE 1453-2004 “Recommended Practice of Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems. Single frequency flicker is created by voltage affecting events that occur at a regular interval and superimpose a single frequency waveform between 0 and 30 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to10 Hz range) sub-synchronous frequencies with magnitudes from 0.5 percent to 3 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 141 (commonly referred to as “The Modified GE Flicker Curve”) to determine the acceptability of single frequency flicker.

3) *Multiple frequency flicker* is to be limited to a short term perception (Pst) of 0.8 and a long term perception (Plt) of 0.6. Pst and Plt are calculated using the calculation methods outlined in IEEE standard 1453-2004. These limits can be exceeded 1 percent of the time with a minimum assessment period of one week. Multiple frequency flicker has the same frequency range as single frequency flicker, but is more complex to analyze, especially when flicker magnitudes and frequencies change over time. Multiple frequency flicker is best analyzed using a flicker meter.

Harmonic voltage distortion

In general, it is the responsibility of ATC to meet harmonic voltage limits and the responsibility of the load customers to meet harmonic current limits. The level of harmonics acceptable on the ATC system is defined by state regulations, IEEE Standard 519-1992 (Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems) and the judgment of ATC. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met.

The observance of harmonic limits should be verified whenever a harmonic related problem is discovered or a new harmonic producing load with a reasonable possibility of causing harmonic problems is connected to the ATC system. The following process is utilized by ATC when managing an existing harmonic-related problem or a new harmonic-producing load:

1) *Existing problems* - When a harmonic related problem is found on the ATC system, it is ATC's responsibility to determine the source of the harmonics. If harmonic current limits are violated, the source of the harmonics will be required to decrease their harmonic currents to below the limits specified in the ATC Planning and Service Guide. If, after the harmonic current has been reduced to an acceptable level, the harmonic voltage is still causing a problem and above specified levels, it shall be the responsibility of ATC to bring the harmonic voltages within limits. If limits are not violated and there is still a harmonic related problem (an unlikely situation), it is the responsibility of the entity experiencing the problem to harden its equipment to the effect of harmonics or reduce the harmonics at their location. An existing violation of these harmonic limits that is not causing any problems does not necessarily require harmonic mitigation.

2) *New harmonic producing loads* - It is the responsibility of any customer wanting to connect a harmonic producing load to the ATC system to determine if the proposed load will violate the harmonic current limits and, if these limits are violated, to determine and implement steps necessary to reduce the harmonic currents to acceptable levels. If harmonic voltage limits are not met after harmonic current limits have been met, it is the responsibility of ATC to determine if the harmonic voltage distortion will cause any system problems and, if they will, it is ATC's responsibility to develop and implement a plan to meet the harmonic voltage limits.

Transmission planning assessment practices
American Transmission Company generally subscribes to the zone approach to transmission planning assessment using a multi-level planning concept. Diagrams of the planning zones for which regional plans have been developed by ATC are attached in response to Part 3 of this FERC Form 715 and show the existing transmission facilities, 100 kV and above, within ATC's transmission system.

The concept behind the zone approach to transmission planning is to develop plans that consider all of the needs, problems and developments within each zone and develop an overall plan for the zone (that is, a plan that emphasizes projects that serve multiple purposes or solve multiple problems within the zone). In addition, ATC's transmission planning philosophies incorporate the concept of multi-level transmission planning. When carrying out a comprehensive transmission planning process, consideration must be given not only to individual transmission needs, zone needs, and ATC-wide needs, but also to plans of other transmission providers. Solutions identified via planning activities within each level are vetted against those in adjacent levels until the most effective overall comprehensive plan is developed. ATC's planning process will continue to develop the first three levels (individual, zone, ATC-wide). ATC is participating with other transmission owners within and affected by the MISO territory in assessing regional needs.

ATC is employing the long-standing practice of using power flow analysis to identify needs and problems and to evaluate alternative mitigation measures. ATC identifies problems and needs by simulating non-simultaneous outages of each line, transformer, bus sectionalizer, and generator. ATC does implement operating guides, such as opening lines and bus sections, to mitigate problems (overloads, low voltages, etc.) during emergency conditions.

ATC is also conducting dynamic stability analyses within each of its zones to assess the ability of its system to withstand power system disturbances. Many of these analyses have been or are being conducted in conjunction with proposed generation interconnections. Other independent analyses are being conducted to assess dynamic and/or voltage stability performance.

As part of the MISO, ATC is participating in the Transmission Expansion Plan process.

Traditionally, as a member of MAIN, ATC participated in the seasonal transmission assessments conducted by the MAIN Transmission Assessment Study Group (TASG). Recent MAIN TASG studies are filed separately by the MAIN Coordination Center. Also, ATC participated in the MAIN Future Systems Study Group (FSSG).

The MAIN organization ceased at the end of 2005 and ATC became a member of the two subsequent regional reliability organizations, the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC). In 2006 ATC will participate in regional transmission assessments that will be performed by these organizations.

In addition to the planning criteria listed in Part 4 of this filing, ATC considers a number of other factors in its transmission planning process. Following is a description of such factors.

Public/Stakeholder input

ATC solicits public and other stakeholder input on the identification of ultimate solutions through its iterative planning process. Projects may be modified as potential solutions listed in this plan are further developed to address the specific needs identified by all stakeholders. The solutions selected to address the needs and limitations identified will reflect the input of transmission planning process stakeholders, including customers, state and local officials, the public, and coordination with other planning processes, to the extent possible.

Specific opportunities for public and stakeholder participation in the planning process have and will (at a minimum) include periodic Planning Zone Meetings throughout ATC's service territory. ATC issues a 10-year system assessment annually each summer and an assessment update each winter. Planning Zone Meetings are held each fall, with additional meetings and communications as warranted.

CAPACITY BENEFIT MARGIN CRITERIA

Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

ATC planning studies, except those required for MISO transmission service, will not model CBM.

MISO performs annual studies to determine the import requirement of each study area operated as an isolated system to meet a Loss of Load Expectation (LOLE) of 0.1 day/year. All of ATC is defined as a single stand-alone study area. MISO then compares the flowgate CBM with the Automatic Reserve Sharing (ARS) component of the Transmission Reserve Margin (TRM) for that same flowgate. If the ARS component is greater, no CBM will be preserved on that flowgate. If the ARS component is less, the incremental amount of CBM that is needed above the ARS component will be preserved as CBM for that flowgate.

All MISO transmission service studies use CBM in the flow based analysis of transmission service studies performed by ATC. The network analysis for transmission service studies does not use reductions in equipment ratings for CBM.

We will perform periodic analyses to evaluate (considering planned summer peak load and generation, as well as load forecast error and generator outage characteristics) the probable requirement to import power from external sources to meet a LOLE of 0.1 day per year, and ATC's ability to simultaneously import sufficient power from external sources to meet the 0.1 day per year LOLE reliability standard. If a deficiency is identified, we will incorporate any resulting incremental import capability requirements into ATC's overall transmission expansion plan.

TRANSMISSION RESERVE MARGIN CRITERIA

Transmission Reserve Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

ATC planning studies, except those required for MISO transmission service, will consider a 3 percent reduction in normal and emergency ratings for assessments within one year in the future and a 5 percent reduction for the assessments beyond one year in the future. However, the recommended timing of the resultant mitigation measures may be based on less than the 3 percent and 5 percent reductions.

In the planning horizon, anytime beyond 48 hours, MISO uses reservations from other transmission providers and control area generation merit orders to reduce uncertainty. MISO will apply a 2 percent reduction in normal and emergency ratings for input uncertainties in the planning horizon. This is often referred to as the uncertainty portion of the TRM.

The operating reserve component of TRM is the amount of transmission transfer capability on a constrained interface to provide the amount of regional operating reserves associated with 100 percent of the greatest single contingency impacting the flowgate. For determining the operating reserve portion of TRM, MISO performs analyses to identify the required reserve for each flowgate. The worst case will be determined by tripping units (or line outages when a reserve sharing member can request emergency energy for the line trip) within the region and picking up each reserve sharing member’s share of the emergency energy to replace the unit that tripped. The distribution of each reserve sharing member’s share of the emergency energy among its individual generating units should be a realistic estimate for the conditions for which the TRM is being determined. The worst case will be the case that has the greatest incremental flow over the flowgate in the direction of the constraint. The highest incremental flow on the flowgates for the contingencies evaluated (generation and transmission) will be the amount of Automatic Reserve Sharing (ARS) TRM required to reserve transmission service for operating reserves.

All MISO transmission service studies use the summation of ARS TRM and the 2 percent uncertainty TRM in the flow based analysis of transmission service studies. The network analysis for transmission service studies does not use the ARS or 2 percent TRM, but requires for all network elements a 3 percent reduction in normal and emergency ratings for requests in the next 13 months and a 5 percent reduction in normal and emergency ratings for requests extending beyond the next 13 months.

FACILITY RATING CRITERIA

The following ATC Operating Instructions provide documentation of ATC's facility ratings criteria:

- 01-03 Facility Ratings Update and Application,
- 02-02 Conductor Ampacity Ratings for Overhead Transmission Lines,
- 02-03 Substation Equipment Ampacity Ratings,
- 03-01 Ampacity Ratings of Underground Transmission Lines

We will actively review, replace, and document legacy ratings with ratings based upon ATC criteria in its Substation Equipment and Line Database (SELD). The legacy ratings from the previous transmission facilities owner's planning models will be used in ATC planning models until valid SELD ratings, which are consistent with ATC facility rating criteria become available. The facility ratings criteria for legacy ratings are those of the corresponding contributing utility (e.g. Alliant East, Madison Gas & Electric, Upper Peninsula Power, Wisconsin Public Service, and We Energies). The ATC facility ratings criteria are consistently applied among ATC Planning, Engineering and Operations.

Facilities to be considered include, but are not limited to – overhead line conductors, underground cable, bus conductors, transformers, autotransformers, circuit breakers, disconnect switches, series and shunt reactive elements, VAR compensators, current transformers, wave traps, jumpers, meters, and relays (both overcurrent/directional overcurrent/impedance settings and thermal limits). Ratings derived from the ATC facility rating criteria are to be consistent with the following NERC standard.
(Applicable NERC Standards: FAC-004-0-R1)

MODEL BUILDING CRITERIA

We will strive to develop and maintain consistency in the powerflow models used for its planning efforts and in assessing whether and under what conditions transmission service is available. The starting point for ATC powerflow models will be models contained in the

NERC and Regional data banks. We will use load forecasts provided by its end-use load-serving customers as input into future model building efforts, both internally and in conjunction with the NERC, Regional Reliability Organization (RRO), and Regional Transmission Operator (RTO). All ATC powerflow models will be developed using PTI PSS/E software.
(Applicable NERC Standards: MOD-010-0-B, MOD-011-B, MOD-012-0-B)

FACILITY CONDITION CRITERIA

The facility condition criteria to be utilized by ATC for system planning purposes will include:

1) Any transmission line on structures that are beyond their design life, any transmission line that has exhibited below-average availability or any transmission line that has required above-average maintenance will be considered a candidate for replacement. In assessing potential line replacements, consideration will be given to other needs in the area of the candidate line to determine whether rebuilding the line to a higher voltage would fit into the "umbrella" plan for that planning zone (see Planning zones below). ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
2) Any substation bus that is beyond its design life, has exhibited below-average availability or has required above-average maintenance will be considered a candidate for rebuilding and potential redesign. In assessing potential bus rebuilds, consideration will be given to likely and potential expansion at candidate substations, including consideration of the "umbrella" plan for the planning zone. ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
3) Any substation whose design or configuration prevents maintenance, in a safe manner, on substation equipment or lines terminating at the substation will be considered a candidate for rebuilding and/or potential redesign/reconfiguration. In assessing such rebuilds/redesigns/reconfigurations, consideration will be given to likely and potential expansion at candidate substations, including consideration of the "umbrella" plan for the planning zone. ATC engineering, operation and maintenance and environmental employees work together to coordinate such assessments.
4) Any underground cable that is beyond its design life, has exhibited below-average availability or has required above-average maintenance will be considered a candidate for replacement. In assessing potential cable replacements, consideration will be given to other needs in the area of the candidate cable to determine whether replacing the cable with a cable with a higher ampacity or with a cable capable of a higher voltage would fit into the "umbrella" plan for that planning zone. ATC

engineering, operation and maintenance and environmental employees work together to coordinate such assessments.

5) We will strive to verify the efficacy of all operating guides that require on-site operations.

PLANNING ZONES

We will conduct system planning on a long-range basis by developing plans for the ATC transmission system as a whole, as well as plans for specified zones within the boundaries of ATC's transmission system. These zones are shown in Figures ZS-17 through ZS-21. The idea behind the zone approach to long-range planning is to develop plans that consider all of the needs/problems/developments within each zone. The goal within the ATC footprint would be to develop an "umbrella" plan for the zone, that is, a plan that emphasizes projects that serve multiple purposes or solve multiple problems within the ATC system. The zone approach is intended to address requirements for support to the local distribution systems in that zone on a least cost basis. It is anticipated, however, that several projects that span more than one zone or possibly even the ATC transmission system boundaries, may evolve. Such projects will likely involve coordination with other transmission owners or regional transmission organizations.

The planning zones shown in Figures ZS-17 through ZS-21 deviate significantly from existing control area boundaries and from planning zones traditionally used for joint planning in conjunction with the Wisconsin PSC. The zones were selected considering the need for a manageable number of planning areas and to consolidate areas within the state with similar topology and load characteristics.

SYSTEM ALTERNATIVES

We will consider alternatives to transmission solutions to problems on the transmission system as appropriate. Such alternatives could include, but not be limited to, central station generation, distributed generation, load management and conservation measures. We will use sound judgment in assessing whether non-transmission solutions are applicable on a case-by-case basis, keeping in mind that ATC is not a vertically integrated utility and does not own generation or serve as a load serving entity for retail load.

LOAD FORECASTING CRITERIA

We will initially use load forecasts provided by its end-use load-serving customers. Such customers are required, under ATC's Distribution-Transmission Interconnection Agreements and Network Operating Agreements, to provide ATC with monthly peak demand forecasts for the next ten years. We may, in the future, develop load forecasts either concurrent with or independent of its load-serving customers. In addition, we may, in coordination with its load-serving customers, develop representative load duration curves based on actual and normalized load conditions. The ATC methodology for developing, aggregating and maintaining load forecast information should be in accordance with NERC Standard MOD-010-0 and MOD-011-0.

In utilizing or developing load forecasts, the following criteria will be used:

1) **Summer peak** demand forecasts will be calculated in such a way that there is an almost equal probability of exceeding or falling short of the forecast when average peak making weather does occur.
2) **Winter peak** demand forecasts will be calculated in such a way that there is an almost equal probability of exceeding or falling short of the forecast when average peak making weather does occur.
3) **Summer shoulder peak** demand forecasts will be developed reflecting moderate weather days (75 F-80 F). Such forecasts will be based on a load level that, within a reasonable range, captures as many shoulder peak hours within a representative load duration curve of load connected to the ATC transmission system. These demand forecasts will be developed to evaluate historical high power transfer conditions.
4) **Fall/spring off-peak** demand forecasts will be based on a load level that, within a reasonable range, captures as many off-peak hours within a representative load duration curve of load connected to the ATC transmission system.
5) **Summer 90/10 peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. This peak demand forecast will be calculated in such a way that there is a 90 percent probability of falling short of and a 10 percent probability of exceeding the forecast due to weather conditions. Until we develop the capability for producing a specific 90/10 forecast, we will assume that it can be reasonably approximated through increasing the conforming loads by 5 percent and leaving the non-scalable loads unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
6) **Light load (50 percent of peak)** demand forecasts will be developed that reflects a total load level which is 50 percent of the summer peak demand forecasts. Conforming loads will be scaled and non-scalable loads will remain unchanged.

ECONOMIC CRITERIA

We will conduct appropriate economic analyses when evaluating transmission additions, replacement and modifications. The criteria to be used in such economic analyses for purposes of system planning will include the following:

1) In developing screening level capital cost estimates for transmission lines and substations, terrain, geology and land use will be considered.

2) In conducting transmission system loss analysis, a sufficient number of powerflow cases will be developed to cover a reasonable range of load conditions from which to assess system losses. In addition, the value of losses shall be projected based on the energy futures market or on a credible energy price forecast.
3) In conducting analysis of generation redispatch precipitated by transmission constraints, a sufficient number of powerflow cases will be developed, or historical system loading may be used, in order to reasonably estimate the amount of time that such redispatch may be warranted. In addition, the cost of such redispatch will be projected based on marginal production costs and/or historical redispatch cost data of generating units dispatched to relieve the constraint. ATC will determine the economic feasibility of eliminating generation must-run situations based on these analyses.
4) All transmission projects have both reliability and economic benefits. In certain cases, economic benefit may be the primary driver of a project. In addition, economic analysis of projects may be used in the prioritization and staging of projects. In this effort, an attempt is made to capture all relevant factors to consider in determining the economic benefits of a project. Stakeholder input is utilized by ATC for this purpose. Various tools are also utilized by ATC, including New Energy Associates' PROMOD program; however, other methods and tools are open to consideration.

ENVIRONMENTAL CRITERIA

The overriding environmental criterion to be used by ATC in system planning is that environmental analyses will be conducted at a screening level as opposed to a detailed siting/routing analysis level. The goal of such environmental analyses is to identify potential environmental impacts, avoid such impacts where possible and, where it is not possible, minimize and mitigate such impacts to the extent possible. More detailed analyses will be undertaken to support an application to siting authorities of specific transmission alternatives.

VARIATIONS ON ATC PLANNING CRITERIA

The ATC transmission system consists of assets contributed by entities within the five control areas of the Wisconsin Upper Michigan System. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as ATC has implemented its own planning criteria, portions of the system may require upgrade to meet the more stringent ATC criteria.
This section of the ATC planning criteria describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the ATC criteria.

1) Area does not meet NERC Planning Standards with respect to stability.
   a. Complete projects required for bringing the existing system into compliance with NERC standards with no intentional delay.
   b. New generator interconnections are <u>not</u> permitted until the NERC standards are met with the addition of the generator, if the new generator interconnection aggravates the stability condition. [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet NERC Planning Standards.]
   c. Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the system is in compliance. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a “last interconnected, first restricted” approach.
2) Area meets NERC Planning Standards but not ATC criteria with respect to stability.
   a. Normal schedule for projects required for bringing the existing system into compliance with ATC criteria.
   b. New generator interconnections are permitted as long as the system continues to meet the NERC Planning Standards. If the new generator interconnection causes a violation of NERC standards, 1.b above applies.
   c. Operating procedures will not be required in the interim period until the projects to meet ATC criteria are completed.
3) Area meets ATC planning criteria for existing system but a new generator interconnection causes a violation of:
   a. ATC planning criteria – New generator interconnection is not permitted until ATC criteria are met with the addition of the new generator.
   b. NERC Planning Standards – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

OTHER CONSIDERATIONS

Project constructability

We will consider the constructability of proposed additions, replacements or modifications to the transmission system as part of the system planning process. In particular we will consider:

1) Whether addition, replacement or modification of a transmission line, transformer or other facility would result in violation of the <u>System performance criteria</u> above, and

2) Whether addition, replacement or modification of a transmission line, transformer or other facility precludes the ability of ATC Operations to conduct maintenance activities on other transmission facilities.

Multiple contingency planning

We will conduct system planning in accordance with the system performance criteria above, including planning for single-contingency events. There may be circumstances, however, where the risk to ATC and/or ATC customers of a multiple-contingency event is sufficiently severe to warrant consideration for planning purposes. Examples of such an event would include:

1) The loss of a transmission facility during the period of maintenance or repair of another transmission facility,
2) A multiple contingency arising from a common cause such as a fire, flood, etc., or
3) Failure of a transmission structure supporting multiple circuits.

We will evaluate the probability and consequences of certain selected multiple contingency scenarios to determine whether to apply a multiple contingency standard.

Such multiple contingency scenarios may warrant consideration of operating guides or reinforcements. In these circumstances, we will document the potential event(s), the associated risks and potential mitigation measures, and will coordinate with affected customers, as appropriate.
(Applicable NERC Standards: TPL-003-0, TPL-004-0)

Terminal equipment limitations

Substation terminal equipment should not limit transmission facility ratings under NERC Category A or NERC Category B contingency conditions. This criterion would apply to new transmission facilities and should be reviewed when proposing modifications to existing facilities.

Maximization of existing rights-of-way

We will attempt to maximize use of existing rights-of-way. Existing electric transmission, gas pipeline, railroad and highway corridors will be identified in all comparisons of alternatives and utilized where feasible. As a starting point in each environmental analysis, we will use the broad-brush environmental review employed for all of the new transmission line alternatives considered in prior Advance Plan processes.

Reduction of transmission system losses

We will strive to plan the transmission system such that transmission system losses are minimized. We will undertake this goal by considering system losses along with all other cost factors in all evaluations of alternative transmission projects or plans. See Economic criteria.

Operating flexibility

We will strive to plan the transmission system such that operating flexibility is maximized. We will accomplish this by considering as wide a variety of scenarios as practical, including maintenance scenarios, when evaluating alternative transmission projects or plans.

Radial transmission service

We will evaluate the risk of serving customer load from radial facilities. Such evaluations will consider the amount of load being served, the capability of the underlying distribution system and the amount of time that service is likely to be interrupted for the loss/failure of the radial facility.

Relaxation criteria

At times it may be appropriate to consider a relaxation of ATC-specific criteria, as long as NERC and RRO standards are still satisfied. As system planners perform their work, they should evaluate when it may be appropriate to allow a relaxation of ATC-specific criteria. A decision to relax ATC-specific criteria should be made very carefully considering all of the issues involved (including - but not limited to - ERO and RRO requirements and FERC directives related to transmission service requirements) and then only after performing a detailed assessment of the types and levels of risks involved in the decision. **Planners are not permitted to relax ATC-specific criteria on their own**. Instead, these situations should be identified and discussed with their manager for further evaluation. The final decision in this regard will be made by the Director – System Planning. If any decision of this type is made, then these decisions will be documented and archived for future reference.

Interconnection studies

The following analyses and procedures should be performed for all new or modified interconnection facilities (generation, transmission, and end-user) to the ATC system to properly assess their reliability impact on the interconnected systems. For some analyses, a formal study report may be appropriate. For other analyses, a simple statement of assumptions and rationale may be sufficient.

1. **Types of analysis** - The analyses are to include steady state, short-circuit, and dynamic assessments that include the requirements in NERC Standards TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0.
2. **Compliance with applicable planning criteria** -The analyses and procedures are to comply with all applicable NERC, Regional Reliability Organization, and individual system planning criteria of the affected parties.
3. **Coordination with affected entities** -The results of the analyses will be jointly evaluated and coordinated by the affected entities.

4. **Essential documentation** -All analyses should include the evaluation assumptions, system performance, alternatives considered, and any jointly coordinated recommendations.

Methodology & assumptions

This section describes the methods and techniques that we use to analyze our system for this assessment. We conducted power flow analyses to identify problems or constraints and to evaluate the merits of alternative solutions. This analysis was supplemented by power flow, stability, environmental and economic evaluations of transfer capability limitations, multiple outage impacts and generator interconnection impacts.

Power flow models

We primarily developed this Assessment based on power flow models representing summer peak periods in 2007, 2011 and 2015. In addition, we developed a 2011 shoulder model that reflected load levels at 75 percent of summer peak and associated generation dispatch. Finally, in 2007 and 2011, we developed models for determining the sensitivity of project needs to higher than expected loads (referred to as "90/10" or "hot summer" in this assessment).

Summer peak models are built using our customers' load forecasts (50/50 projections), meaning that there is a 50 percent chance that the load level will either fall below or exceed the customer projection. 90/10 models are built utilizing load data where there is a 10 percent chance of the load level meeting or exceeding the projection. For purposes of this Assessment, total ATC system load includes transmission and distribution losses, as well as load that could be interrupted for generation emergencies.

The 2007 summer peak model was developed to evaluate near-term needs and to verify findings in the 2005 Assessment and Update. The 2007 summer 90/10 (or "hot summer") model was developed in order to determine project need sensitivity to weather that is warmer than forecasted. Select loads were increased 5 percent above projections in order to develop the model. We have taken the approach of evaluating the subsequent summer peak season in each of our annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2011 peak model was developed as an intermediate term model to evaluate emerging needs, to confirm that needs identified in 2007 will increase over time, and to test the performance of reinforcements placed in service prior to 2011.

The 2011 summer 90/10 (or "hot summer") model was developed in order to determine in-service date sensitivity to load growth that is higher or weather that is warmer than forecasted. Once again, peak load was increased 5 percent above 2011 projections in order to develop the model. The 2011 shoulder model was developed to identify needs and test the performance of reinforcements placed in service prior to 2011. Shoulder load periods often place as great or greater demand on the transmission system as do peak periods. During these periods, since loads are not at their highest levels, local peaking generation typically is not operating and power transfers into and across our system often are at maximum levels.

The 2015 model was developed to identify emerging needs in the 2011-2015 timeframe, to confirm that needs identified in 2011 will increase over time and to test the performance of reinforcements to be placed in service prior to 2015. It also reflects a year sufficiently ahead to determine the need for and assess the performance of larger-scale projects (345-kV lines, for example) that could be expected to be in service in that timeframe.

Power flow model development –We started model development for this Assessment by building a system model that represented 2006 summer peak conditions. This 2006 model is referred to as an “as-built” model because essentially everything in the model is certain to be in service by 2006 summer. This model then was modified to create each of the Assessment study models including the changes listed below for that model.

2007 summer peak and hot summer models

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in late 2005/early 2006 for both real and reactive power components of load. Projected peak load including line losses within ATC is modeled at 14,050 MW. We worked with the distribution companies as much as possible to confirm forecast variations from past trends. In a few cases we had to revise power factors to reasonable levels to prevent creating expensive transmission projects for voltage support. In most cases these issues would ultimately be solved through distribution system power factor correction. ATC will be in ongoing discussions with our customers to determine the best plan for these situations.
- ❑ We revised line and equipment ratings based on updates to our Substation Equipment and Line Database. As of June 2006, nearly 40 percent of ATC lines and 55 percent of ATC transformers have ratings in SELD that have been validated. Ratings not yet validated in SELD generally are based on the ratings received from the utilities that contributed the facilities to ATC.
- ❑ Updated future generation attached to the ATC system was included in the models. The specifics are outlined later in this section (Refer to New generation assumptions). Balancing Authority (Control) area generation was dispatched based on economic dispatch for that Balancing Authority.
- ❑ The model for the system external to ATC was taken from the MISO 2006 Series, 2007 summer model. The ATC system interchange was adjusted to match the ATC interchange that was in place in the MISO 2006 Series, 2007 summer model.
- ❑ Included revised system topology based on projects that were placed in service in 2006, or were anticipated to be placed in service by June 2007. Refer to Table PF-1 for projects that were included in the 2007 analysis.

2011 summer peak, hot summer and shoulder models

- We utilized interconnection point load forecasts provided by various distribution companies in late 2005/early 2006. Projected peak load within ATC is modeled at 15,333 MW (1,283 MW increase from 2007, representing an average annual compounded growth rate of 2.2 percent). Similar to the models for the year 2007, we worked with our customers to confirm load forecasts. The shoulder load modeled was about 75 percent of summer peak and was achieved by selectively scaling down loads that generally vary by time-of-day to 75 percent of summer peak.
- The model for the system external to ATC was taken from the MISO 2006 Series, 2010 summer model. The ATC system interchange was adjusted to match the ATC interchange that was in place in the MISO 2006 Series, 2010 summer model.
- Updated future generation to be attached to the ATC system was included in the 2011 models. Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority.
- In addition to the projects listed above for the 2007 case, the following projects were modeled in 2011 because they were assumed to be completed and placed in service prior to the summer of 2011. (Refer to Table PF-2.)

2015 summer peak model

- We utilized interconnection point load forecasts provided by various distribution companies in late 2005/early 2006. Projected peak load within ATC is modeled at 16,602 MW (1,269 MW increase from 2011, representing an average annual compounded growth rate of 2.0 percent). Similar to models for earlier years, we worked with our customers to confirm load forecasts.
- The model for the system external to ATC was taken from the MISO 2006 Series, 2015 summer model. The ATC system interchange was adjusted to match the ATC interchange that was in place in the MISO 2006 Series, 2015 summer model.
- In addition to the projects listed above for the 2011 case, the following projects were assumed to be completed and placed in service prior to 2015 (Refer to Table PF-3**.**)
- Updated future generation to be attached to the ATC system was included in the models. Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority.

All Project Models

The load flow models described above as built for the 10-Year Assessment are special models built exclusively for system analysis in the 10-Year Assessment. Some projects are purposely left out of these models in order to verify system problems exist and which ones get worse over time. When the analysis portion of the 10-Year Assessment is completed, “All Project” models are built. The “All Project” models are built with all planned and proposed projects in the 2007, 2011 and 2015 models. The later models may also include provisional projects. These models are more indicative of the expected system configurations for the three study years. The “All Project” models are more appropriate for internal studies performed by ATC planners throughout the year and for regional models. As part of the 10-Year Assessment, the zone planners perform a contingency analysis on each of the “All Project” models. This analysis will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the 10-Year Assessment process.

New generation assumptions

There have been numerous generation projects proposed within ATC’s service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Several have proceeded to or through the licensing phase and several more are under construction. However, there are numerous proposed generation projects that have dropped out of the generation queue (refer to <u>Generation interconnections</u>), adding considerable uncertainty to the transmission planning process. To address this planning uncertainty, we have adopted a criterion for purposes of this and prior Assessments, to establish which proposed generation projects will be included in the 2006 Assessment models.

Previously (before the advent of the MISO Day 2 market) the criterion was that those generation projects for which, at the time the models were developed,

1. *ATC had **completed** a generation interconnection impact study, a generation interconnection facility study, a transmission service impact study and a transmission service facility study, **and***
2. *the generation developer or a customer of the developer had **accepted** the transmission service approved by ATC.*

Beginning with the 2006 10-Year Assessment, the criterion was broken into two time frames, years 1 through 5 and 6+ years.

1. For years 1 through 5, only those generators with FERC approved interconnection agreements will be included in the planning models.
2. Beginning with year 6 and continuing into the future, generators are only required to have a Facility Study completed in order to be included in the 10-Year Assessment models.

A number of wind generators in the ATC footprint have suspended FERC approved interconnection agreements. For the first three years following their requested in-service dates, ATC criterion calls for modeling these facilities but dispatching them at the bottom of the dispatch order. After the three years, the generators will be dispatched in their normal dispatch order. The wind generators with suspended agreements were included in the models built for the 10-Year Assessment analysis. The 2006 and 2007 models showed these generators as out of service. The 2011 and 2015 should have had these generators in-service and dispatched. However, the generators were inadvertently left out of service in both the 2011 and 2015 models. The generators were correctly modeled as in- service and dispatched in the 2011 and 2015 "All Project" models.

Generation Retirement Assumptions
On occasion, generators connected to the ATC transmission system are retired or mothballed. As a result, we developed criteria to determine when generators should no longer be included in our 10-Year Assessment models. If the generator has a completed MISO Attachment Y study, the generator will be disconnected in the appropriate load flow study models. In addition, ATC will send an annual letter to each generation owner. Generating companies will be asked to identify generator retirements or mothballing that should be included in ATC's planning horizon. Generators identified as such by the customer will be disconnected in the relevant models.

There are generators that have been publicly announced as likely candidates for retirement. However, using the disconnection criteria above, in the 2006 10-Year Assessment models we assumed that no generators were disconnected. For model building purposes, we assumed a March 1 cutoff date for generation changes. As of this date, no MISO Appendix Y studies had been completed. This was also the first year for the annual letter. Unfortunately, we were unable to confirm any retirements or mothballing by the March 1 deadline. Therefore, we assumed that if the generator was available on March 1, the unit was available throughout the planning horizon.

Generation projects schedule

To maintain the schedule needed to complete this Assessment, the models were developed during the month of March 2006. Only those generation projects that qualified to be included in our planning models as of March 1, 2006, were included in the Assessment models. For generation projects not in service by June 2006, the criterion above resulted in the following proposed generation projects being included in the applicable power flow models:

Plant Name	*Zone*	*Installed capacity increase*	*Dispatched increase*	*Assumed in-service*
Forward Energy Center	4	200 MW	0 MW	2006
Cypress	4	160 MW	0 MW	2006
Green County	3	50 MW	0 MW	2006
Lafayette	3	99 MW	0 MW	2006
Concord	5	12 MW	12 MW	2006
Melissa	4	7 MW	7 MW	2006
Lakefront	4	64 MW	64 MW	2006
Concord	3	12 MW	12 MW	2007
Port Washington (IC002)	5	500 MW	500 MW	2008
Port Washington (IC027)	5	100 MW	100 MW	2008
Weston 4	1	550 MW	400 MW	2009
Oak Creek (IC012)	5	650 MW	650 MW	2009
Weston 4	1	0 MW	150 MW	2010
Oak Creek (IC012)	5	650 MW	650 MW	2010
Oak Creek (IC012)	5	650 MW	650 MW	2013
Net increase by 2007:		604 MW	95 MW	
Net increase 2008-2011:		2,450 MW	2,450 MW	
New increase 2012-2015:		650 MW	650 MW	

Note that in the table above, the installed capacity may not match the dispatched capacity in the in-service year. This mismatch represents the fact that while the entire generator is completed in a given year, firm transmission service may only be requested or available for a portion of a generator's capacity.

A more comprehensive discussion of proposed generation is provided in Generation Interconnections, including a map showing all of the currently active generation interconnection requests that ATC has received (See Figure PR-10.)

Dynamic stability/short-circuit assessments

We conduct transient analyses to evaluate dynamic stability of generators as part of our study of new generation interconnections and voltage stability analysis on portions of the system where severe low voltages are identified. In instances where our stability criteria were not met, remedial projects were devised and included in this Assessment (see Zones & study results). We also conduct short- circuit analyses as part of our study of new generation interconnections to evaluate the adequacy of circuit breakers on the transmission system. In instances where short-circuit duties exceeded existing circuit breaker ratings, plans for circuit breaker replacements have been included in this Assessment.

Transfer capability assessments

The amount of transfer capability within and between the ATC system and neighboring systems is becoming an increasingly important issue. This topic is discussed further in Projects.

Environmental considerations

In addition to the technical and operational factors listed above, environmental considerations associated with alternative solutions identified in the analysis have been taken into account in this Assessment. Screening-level assessments of potential new transmission lines and line rebuilds have been incorporated and are provided in Routing & Siting.

Environmental issues are centered around land use; rivers, streams and wetlands; and threatened, endangered and special concern species. Issues may involve state and federal agencies as well as stakeholder organizations. As planning progresses for specific projects and routes, these considerations will be investigated further to identify potential impacts, alternatives and mitigation measures. We will work with state and federal resource agencies to help identify issues for each specific project.

Assessment development

This 2006 Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2007 were included in the 2007 model, as listed in Table PF-1. Projects for which we have completed our analysis and are either under construction, have filed an application to construct, or are in the process of preparing an application were included in the 2011 and 2015 models as appropriate based on projected in service dates (See Tables PF-2 and PF-3).

- ❑ The needs identified in this Assessment were determined by identifying facilities whose normal or emergency ratings or tolerances are exceeded. The criterion we use to determine what these ratings and tolerances should be is provided in Planning criteria).

Project prioritization
ATC has and is continuing to develop processes that allow us to confirm the need for projects, their urgency, and their priority. These processes include the following.

- Project creation
- Capital Expense Management
- Prioritization

The project creation process is one of the major subjects of the 10-Year Assessment. ATC has planning criteria and is developing stakeholder input processes to help determine which projects bring value and have appropriate justification. With respect to the 2006 Assessment, the following discussion presents an enhanced description of the prioritization index tool that ATC is developing. All of these processes are being enhanced to include appropriate stakeholder input.

Project prioritization is a process to help resolve capital budget and human resource constraint issues. It may also assist company employees in the prioritization of their work and provide guidance for scheduling pre-certification activities. The project prioritization index is being used as a screening tool to identify projects that are candidates for capital budget deferral. However, the final decision of whether a candidate project can be deferred is still reached by considering the specific details of each project, including appropriate stakeholder input.

The present prioritization index methodology generates a composite priority index value for each project based on several weighted factors. Seven of the factors are drawn from ATC's Forming Party Agreement (FPA). The FPA factors have been used since 2001. In addition, four threshold factors were introduced in 2005 to enhance the prioritization method. The methodology assigns a weighting to each FPA factor and threshold factor and then computes a deterministic index value. Emergency and blanket (bucket) work orders are initially assigned a default value of 999 or 1, respectively.

Forming party agreement factors

Each of the seven FPA factors is assigned a weighted index value and a driver designation. The weighted index values are given below and the driver designations are Primary, Secondary, Tertiary, or None.

The FPA factors and their driver designations are applied to a project in the following way. Each project is considered to determine which of the FPA factors are drivers for the project. The Primary designation assigns the full (100 percent) applicable index value. The Primary designation should always be used and only used once. Secondary designation assigns 2/3 (67 percent) of the applicable index value. The Secondary designation is optional, but should not be used more than two times. The Tertiary designation assigns 1/3 (33 percent) of the applicable index value. The Tertiary designation is optional and may be used multiple times. For example, a strategic expansion project [Primary] that also provides verifiable system reliability benefits [Secondary] and updates infrastructure that is in poor condition [Tertiary] would get a FPA score of (100 percent x 3.4) + (67 percent x 10.3) + (33 percent x 1.7) = 10.9.

FPA Factors	Primary	Secondary	Tertiary
1. Safety or service restoration	12.0	8.0	4.0
2. System reliability or security	10.3	6.9	3.4
3. Regulatory mandates	8.6	5.7	2.9
4. Load or generation interconnection	6.9	4.6	2.3
5. Transaction limit alleviation	5.1	3.4	1.7
6. Strategic expansion	3.4	2.3	1.1
7. Infrastructure update	1.7	1.1	0.6

The FPA factors are defined as follows:

Safety or service restoration
The project will significantly reduce or remove a safety hazard to employees, contractors, or the general public. Safety examples include obtaining acceptable line clearance and replacing high safety risk equipment with lower risk equipment. The project will restore sudden, unplanned equipment damage or failure. Service Restoration examples include repairing or replacing equipment due to snowstorm, tornado, thunderstorm, or vehicle collision induced outages.

System reliability or security

The project will achieve or preserve acceptable operational reliability (i.e. meet ATC planning criteria, meet NERC reliability standards). System reliability or security examples include fixes for emerging equipment overloads, bus undervoltages, bus overvoltages, system voltage instability, and generating unit instability. Reliability factors have been given further definition as shown in the following table.

Reliability Factor Values	**Primary**	**Secondary**	**Tertiary**
0. Project improves or preserves system reliability or security and it does not involve system overloads or undervoltages.	P=10.3	S=6.9	T=3.4
1. Project alleviates a thermal overload between 100% and 105% or an under voltage between 95% and 93%. This designation assigns 105% of the base index value.	P1=10.8	S1=7.2	T1=3.5
2. Project alleviates a thermal overload between 105% and 110% or an under voltage between 93% and 90%. This designation assigns 110% of the base index value.	P2=11.3	S2=7.5	T2=3.7
3. Project alleviates a thermal overload of 110% or greater or an under voltage of less than 90%. This designation assigns 115% of the base index value.	P3=11.8	S3=7.9	T3=3.9
4. Project prevents a large - but local - voltage collapse, cascade, separation, or generator instability. This designation assigns 120% of the base index value.	P4=12.4	S4=8.3	T4=4.1
5. Project prevents a large, regional cascading event. This designation assigns 125% of the base index value.	P5=13.0	S5=8.7	T5=4.3

Regulatory mandates

The projects will fulfill a regulatory agency (i.e. state public service commissions, municipals) requirement. Regulatory mandate examples include line relocations for road widening, CA stipulation beyond ATC proposed project scope, or CPCN stipulations beyond the ATC proposed project scope.

Load serving or generation interconnection
The project will establish a new or revised distribution load serving interconnection or generation facility interconnection. Load serving Interconnection examples would include new distribution substations and transformer additions at existing distribution substations, as well as transmission system upgrades needed to support the load interconnection. Generation interconnection examples include a new generation facility, generator additions at existing generation facilities, or uprates to existing generator units.

Transaction limit alleviation
The project will reduce or eliminate transmission service request rejections or curtailments. Transaction limit alleviation also includes transmission system upgrades to support transmission service from new or revised generation interconnections.

Strategic expansion
The project will create or enhance transmission interconnections (i.e. transmission import or export capability) with other transmission systems, such as Commonwealth Edison, Xcel Energy, Consumers Power, Dairyland Power Cooperative, etc.

Infrastructure update
The project will provide routine maintenance, repair, or replacement of equipment. Infrastructure update projects may be triggered by poor equipment condition (e.g. near end-of-life), equipment that requires excessive maintenance, or equipment for which replacement parts are no longer available.

Threshold factors

Somewhat similar to the FPA factors, each of the four threshold factors is assigned a weighted index value and a level designation. The weighted index values are given below and the level designations are High, Medium, Low, or None.

The High designation assigns the full (100 percent) applicable index value. The Medium designation assigns 2/3 (67 percent) of the applicable index value. The Low designation assigns 1/3 (33 percent) of the applicable index value. For example, a project with a High level in-service date, a Medium level of equipment damage, a Low level of cascading outage impact, and no redispatch/TLR impact would get a threshold score of (100 percent x 12.0) + (67 percent x 6.0) + (33 percent x 9.0) = 19.0.

Threshold Factors	High	Medium	Low
1. In-service date	12.0	8.0	4.0
2. Cascading outage	9.0	6.0	3.0
3. Equipment damage/loss of load	6.0	4.0	2.0
4. Reduced redispatch/congestion	3.0	2.0	1.0

Following are threshold factor definitions.

In-service date

The In-Service Date (ISD) factor is a measure of the criticality and flexibility of the ISD. The ISD criticality can be affected by the importance and urgency of the project, including whether the ISD is related to safety or necessary for NERC compliance. The ISD flexibility refers to how easily the project ISD can be changed, especially deferred. Flexibility would depend on whether the ISD is part of a legal contract, there are interdependencies with other projects, and the project implementation plan has critical path issues. Use “High” when the ISD should not be changed. Use “Medium” when the ISD could be moved by one year. Use “Low” when the ISD could be moved by two years. Use “None” when the ISD could be moved by more than two years.

Cascading outage

The Cascading Outage factor is a measure of how much the project may limit or prevent cascading outages. Use “High” when the project would prevent or limit widespread (regional) system disturbance/collapse. Use “Medium” when the project would prevent or limit significant ATC system disturbance or collapse. Use “Low” when the project would prevent or limit local (up to several buses) system disturbance/collapse. Use “None” when the project does not address cascading outages.

Equipment damage/loss of load

This factor is a measure of how much the project may limit or prevent equipment damage and/or contained loss of load. Use “High” when the project would limit or prevent several million dollars of equipment damage or loss of several hundred MWs of load. Use “Medium” when the project would limit or prevent several hundred thousand dollars of equipment damage or loss of several tens of MWs of load. Use “Low” when the project would limit or prevent several tens of thousands of dollars of equipment damage or loss of less than 10 MW of load. Use “None” when the project does not address equipment damage or loss of load.

Reduced redispatch/congestion

This factor is a measure of how much the project may reduce or eliminate redispatch or congestion. The measure depends on the frequency, duration, and magnitude of redispatch or congestion. Use “High” when the project would reduce or eliminate redispatch or congestion that occurs more than 50 times/year or more than 500 hours/year or more than 50,000 MWh/year. Use “Medium” when the project would reduce or eliminate redispatch or congestion that occurs more than 10 times/year or more than 100 hours/year or more than 10,000 MWh/year. Use “Low” when the project would reduce or eliminate redispatch or congestion that occurs more than 2 times/year or more than 20 hours/year or more than 2,000 MWh/year. Use “None” when the project does not address reduction or elimination of redispatch or congestion.

Note on Index Use

ATC re-emphasizes that the prioritization index by itself can not cause a project to be delayed. It is only a tool for screening projects that seem to have less urgency than other projects. If limited resources require ATC to trim its budget, ATC will take the projects with the lowest indices and review them manually with appropriate input from stakeholders. The review will assess the impact of delaying the project. If a project is found to be truly delayable albeit at some increased risk or cost, only then can it truly be delayed.

NERC Compliance

ATC is one of the limited number of companies that was designated in the North American Electric Reliability Council (NERC) 2005 Compliance Enforcement Program Report as fully compliant with the NERC Reliability Standards in 2005. We achieved this result even though this was one of the years in which we received a comprehensive audit by our designated compliance monitor, the Mid-American Interconnected Network (MAIN).

In 2006, we are committed to maintaining our fully compliant status with all of the existing and newly approved NERC standard requirements. Since the MAIN organization was replaced by the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC) at the beginning of 2006, we will now be demonstrating our compliance with NERC Standards to both regional compliance monitors this year. This dual reporting occurs because ATC serves customers that are members in each of these Regional Reliability Organizations.

The new mandatory NERC Reliability Standards assign accountability for specific requirements based on newly defined entity functions. ATC registered with both the MRO and RFC as performing the following entity functions - Transmission Owner, Transmission Operator, Transmission Planner and Planning Authority[1]. The following discussion of NERC compliance in this document will focus on ATC's Transmission Planner accountabilities. One purpose of this section is to enhance our ability to provide documentation of ATC compliance with Transmission Planner accountabilities.

The primary Transmission Planner responsibilities include system performance assessments and system modeling. The system performance assessment standards include checking for exceeded voltage criteria limits, system equipment overloads, adequate stability, cascading outages, loss of load, and firm transfer curtailments under a wide range of system operating conditions.

[1] NERC has since replaced the Planning Authority function with Planning Coordinator.

There are thirty (30) operating conditions to consider for compliance which are grouped into in four (4) categories. The requirements associated with each of the four categories are contained in four separate NERC standards:

A. Normal (Standard TPL-001-0)
B. Single element contingencies (Standard TPL-002-0)
C. Multiple element contingencies (Standard TPL-003-0)
D. Extreme events (Standard TPL-004-0)

The assessments presented in this document were developed using power system models that were derived from cases that were provided by the Multi- Modeling Working Group (MMWG) which prepares cases for industry-wide use. Details regarding the specific system models that were used in this assessment are given in the Methodology & assumptions section. Additional explanation of the methods and the frequency of system model updating is given in the Model building criteria section of the Planning criteria section.

The system performance assessments for the 2007 through 2011 timeframe address the near-term planning horizon requirements. The assessments beyond 2011 through 2015 deal with long-term planning horizon requirements.

A complete listing of the planning criteria that we apply, including those which are beyond the NERC, MRO, and RFC planning criteria, can be found in the Planning criteria section.

The system performance assessments for Category A (normal) and Category B (single element contingencies) conditions are given in the Introduction and Reactive power analysis section.

The system performance assessments for Category C (multiple element contingencies) and Category D (extreme event) conditions are contained in the Multiple outage analysis and Reactive power analysis sections.

The compliance requirements dealing with system stability, generator stability, and voltage stability for all four Category (A, B, C, and D) conditions are dealt with in the System stability, Generator stability, and Voltage stability sections.

The listing of potential bulk power system reinforcements to address identified near-term and long-term planning horizon needs are provided in Tables PR-2 through PR-23.

Information regarding studies that are specific to generation interconnection requests is described in the Generation interconnections section. Any publicly available generation interconnection request details and completed study reports can be accessed through the MISO Web site at **http://oasis.midwestiso.org/documents/ATC/queue.html**.

Descriptions of the system performance studies that are prepared jointly with other interconnection companies, regional groups, or government bodies are given in the Regional analysis section.

Table PF-1
Projects included in the 2007 10-Year Assessment Model

System additions	Planning zone
Construct Venus-Metonga 115-kV line	1
Uprate White Pine-Victoria 69-kV line clearance to 200 degrees F	2
Uprate Victoria-Ontonagon 69-kV line clearance to 185 degrees F	2
Uprate Victoria-Mass 69-kV line clearance to 185 degrees F	2
Install 2-8.16 MVAR capacitor banks at Ontonagon 138 kV	2
Construct new 69-kV line from Columbia to Rio to feed the proposed Wyocena Substation	3
Construct new line from Southwest Delavan to Bristol at 138 kV, operate at 69 kV	3
Install 32.66 MVAR capacitor bank at Rubicon 138-kV Substation	3
Convert Kegonsa-McFarland-Femrite 69-kV line to 138 kV	3
Construct Sprecher-Femrite 138-kV line	3
Install 138/69-kV transformer at Femrite	3
Install 138/69-kV transformer at Reiner	3
Convert Sycamore-Reiner-Sprecher from 69 kV to 138 kV	3
Construct double circuit 138-kV line from Forest Junction/Howards Grove/Charter Steel to Plymouth #4	4
Install 2-16.3 MVAR capacitor bank at Canal 69 kV	4

Table PF-2
Projects included in the 2011 10-Year Assessment Model

System additions	Planning zone
Reconductor Weston-Northpoint 115-kV line	1
Construct Stone Lake-Arrowhead 345-kV line	1
Install second 50 MVAR capacitor bank at Arpin	1
Install 1-75 MVAR capacitor bank and 1-45 MVAR inductor at Stone Lake 345 kV	1
Construct new Arrowhead 345-kV Substation, install 2-75 MVAR capacitor banks, 1-800 MVA PST and 1-800 MVA 345/230-kV transformer	1
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at the Berlin 69-kV Substation	1
Construct new Central Wisconsin 345-kV Substation	1
Construct Gardner Park-Central Wisconsin 345-kV line	1
Install 2-24.5 MVAR capacitor banks at Wautoma 138 kV and one-16.33 MVAR capacitor bank at 69 kV	1
Uprate Metomen-North Fond du Lac 69-kV line terminal equipment	1
Uprate Mass-Winona 69-kV line clearance to 185 degrees F	2
Install 1-5.4 MVAR capacitor bank at the Munising 69-kV Substation	2
Uprate Winona-Atlantic 69-kV line clearance to 185 degrees F	2
Construct a Jefferson-Lake Mills-Stony Brook 138-kV line	3
Uprate Rockdale to Jefferson 138-kV line	3
Uprate Rockdale to Boxelder 138-kV line	3
Uprate Boxelder to Stonybrook 138-kV line	3
Construct a new 138-kV line from North Madison to Huiskamp (was Waunakee)	3
Rebuild the Verona to Oregon 69-kV line Y119	3
Install 2-24.5 MVAR 138-kV capacitor banks at North Beaver Dam	3
Construct a Rubicon-Hustisford 138-kV line	3
Rebuild Hustisford-Horicon 69 kV to 138 kV	3
Construct 138/69 kV substation at a site near Horicon and install a 138/69-kV transformer	3
Install 3-16.33 MVAR capacitor bank at South Monroe the 69-kV Substation and remove existing 10.8 MVAR bank	3
Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona	3
Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138 kV bus	3
Construct a new 138/69-kV substation near Huiskamp and install a 100 MVA 138/69-kV transformer	3
Rebuild and uprate North Lake Geneva-Lake Geneva 69-kV line	3
Uprate McCue-Janesville 69-kV line	3
Uprate North Appleton-Mason Street 138-kV line	4
Uprate North Appleton-Lost Dauphin 138-kV line	4
Construct Morgan-Werner West 345-kV line	4
String a new 138-kV line from Clintonville-Werner West primarily on Morgan-Werner West 345-kV line structures	4

Table PF-2 (continued)
Projects included in the 2011 10-Year Assessment Model

System additions	Planning zone
A second distribution transformer at Somers requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	5
Construct a 138-kV bus at Brookdale to permit 3rd distribution transformer interconnection	5
Reconductor Pleasant Valley-Saukville 138-kV line	5
Reconductor Pleasant Valley-St Lawrence 138-kV line	5
Reconductor Oak Creek-Allerton 138-kV line	5
Loop Ramsey5-Harbor 138-kV line into Norwich and Kansas to form new Ramsey-Norwich and Harbor-Kansas 138-kV lines	5
Install second 500 MVA 345/138-kV transformer at Oak Creek	5
Reconductor Oak Creek-Ramsey 138-kV line	5
Expand Oak Creek 345-kV switchyard to interconnect two new generators	5
Uprate Oak Creek-Nicholson 138-kV line	5
Uprate Oak Creek-Root River 138-kV line	5

Table PF-3
Projects included in the 2015 10-Year Assessment Model

System additions	Planning zone
Rebuild Weston-Sherman St. and Sherman St.-Hilltop 115-kV lines as double circuits with a new Gardner Park-Hilltop 115-kV line	1
Construct new Eagle River Muni distribution substation directly adjacent to the existing Cranberry 115-kV Substation	1
Rebuild/convert Conover-Plains 69-kV line to 138 kV	1
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Ripon 69-kV Substation	1
Construct a 69-kV line from SW Ripon to the Ripon-Metomen 69-kV line	1
Install 1-5.4 MVAR capacitor bank at Sawyer 69-kV Substation	2
Install 1-5.4 MVAR capacitor bank at Roberts 69-kV Substation	2
Relocate Cedar Substation (North Lake)	2
Rebuild Atlantic-Osceola 69-kV line (Laurium #1)	2
Increase ground clearance of Atlantic-Osceola (Laurium #2) 69-kV line from 120 to 167 degrees F	2
Install 1-5.4 MVAR capacitor bank at L'Anse 69 kV	2
Install 1-5.4 MVAR capacitor bank at Munising 69 kV	2
Install second 345/138-kV transformer at Plains	2
Construct 138-kV ring bus at Hiawatha Substation	2
Install 138-kV substation modifications at Indian Lake Substation	2
Convert rebuilt Hiawatha-Indian Lake circuit (operated at 69 kV) to 138 kV	2
Relocate Iron River Substation (Iron Grove)	2
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove Substation	2
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Aspen	2
Construct Cranberry-Conover 115-kV line	2
Uprate Rock River 138/69-kV transformer to 65 MVA and uprate Rock River-Turtle 69-kV line to 94 MVA	3
Uprate Brick Church-Zenda 69-kV line to 115 MVA	3
Uprate Colley Road-Park Ave Tap 69-kV line to 95 MVA	3
Install 2-8.16 MVAR capacitor banks at new Brewer 69-kV Substation (Richland Center)	3
Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	3
Uprate Darlington-Rock Branch 69-kV line	3
Install a second 138/69-kV transformer at Hillman	3
Construct new 138-kV line from South Lake Geneva to White River	3
Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva	3
Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	3
Construct 345-kV line from Rockdale to West Middleton	3
Construct a 345-kV bus and install a 345/138 kV 500 MVA transformer at West Middleton	3
Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn and install 2-24.5 MVAR 138-kV capacitor banks at Artesian	3
Uprate Lakefront-Revere 69-kV line	4

Table PF-3 (continued)
Projects included in the 2015 10-Year Assessment Model

System additions	Planning zone
Uprate Oak Creek-Root River 138-kV line	5
Uprate Oak Creek-Nicholson 138-kV line	5
Construct a 345/138-kV switchyard at Hale (Brookdale) to accommodate two 345-kV lines, a 500 MVA 345/138-kV transformer and 4-138-kV lines plus three 138-26.2 kV transformers	5
Install two 345-kV line terminations at Pleasant Prairie and loop Zion-Arcadian 345-kV line into Pleasant Prairie Substation	5
Construct an Oak Creek-Hale (Brookdale) 345-kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	5
Construct a Hale (Brookdale)-Granville 345-kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/reconductoring 3 mi. 138 kV on existing 345-kV structures	5
Restring Bluemound-Butler 138-kV line (KK5051) on new 345-kV structures installed with Hale (Brookdale)-Granville line	5
Expand Oak Creek 345-kV switchyard to interconnect three new generators plus one new 345-kV line and 138 kV switchyard to accommodate new St. Martins line	5

Figure PF-1

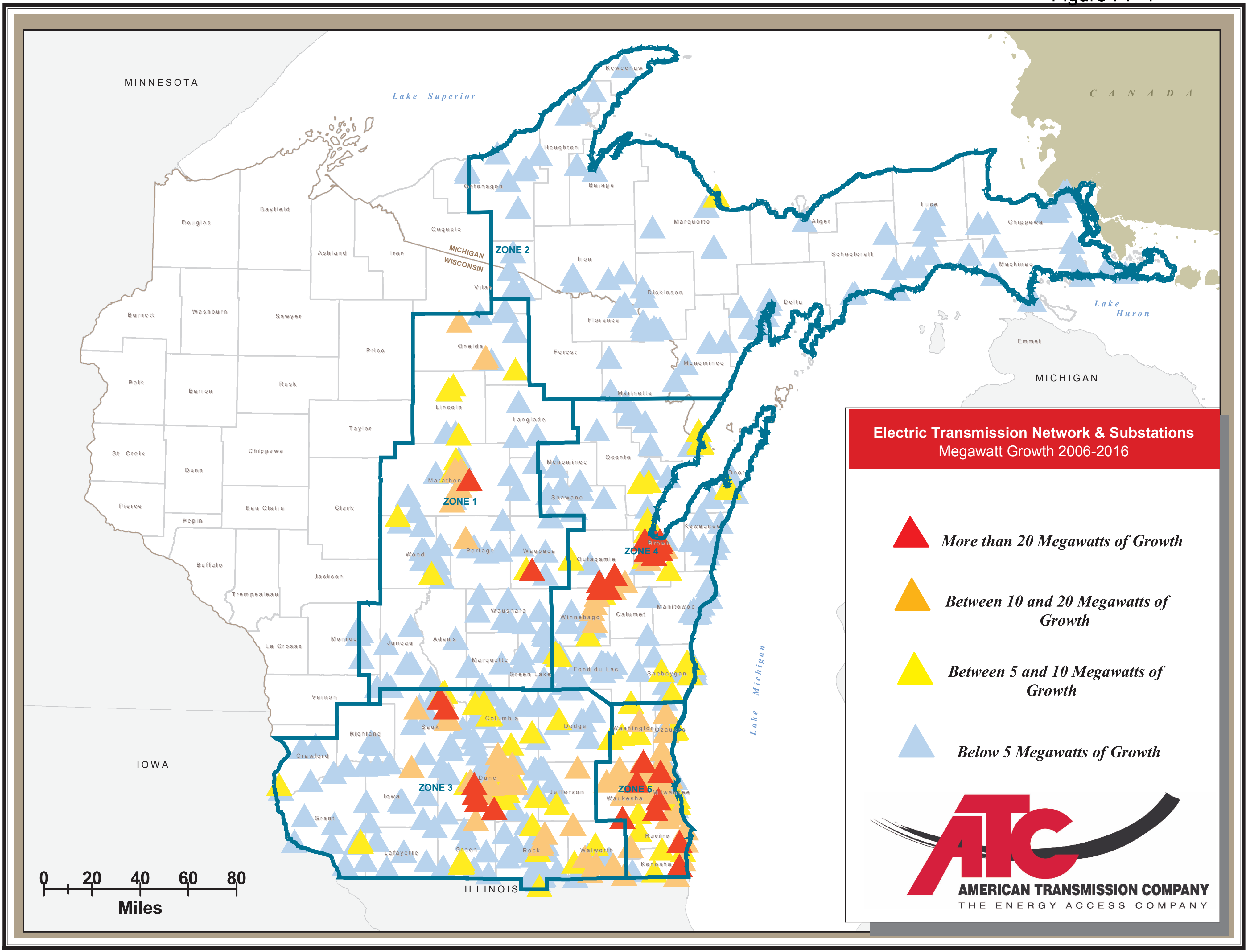

Electric Transmission Network & Substations
Megawatt Growth 2006-2016
More than 20 Megawatts of Growth
Between 10 and 20 Megawatts of Growth
Between 5 and 10 Megawatts of Growth
Below 5 Megawatts of Growth
ATC
AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY
0 20 40 60 80
Miles
MINNESOTA
IOWA
ILLINOIS
MICHIGAN
CANADA
Lake Superior
Lake Michigan
Lake Huron
MICHIGAN
WISCONSIN
ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
Keweenaw
Houghton
Baraga
Ontonagon
Gogebic
Iron
Marquette
Alger
Luce
Chippewa
Schoolcraft
Mackinac
Delta
Dickinson
Menominee
Emmet
Douglas
Bayfield
Ashland
Vilas
Burnett
Washburn
Sawyer
Price
Oneida
Florence
Forest
Marinette
Polk
Barron
Rusk
Lincoln
Langlade
Taylor
St. Croix
Dunn
Chippewa
Oconto
Door
Pierce
Pepin
Eau Claire
Clark
Marathon
Shawano
Kewaunee
Buffalo
Wood
Portage
Waupaca
Outagamie
Brown
Jackson
Trempealeau
Waushara
Winnebago
Calumet
Manitowoc
Monroe
La Crosse
Juneau
Adams
Marquette
Green Lake
Fond du Lac
Sheboygan
Vernon
Sauk
Columbia
Dodge
Washington
Ozaukee
Richland
Crawford
Dane
Jefferson
Waukesha
Milwaukee
Iowa
Grant
Lafayette
Green
Rock
Walworth
Racine
Kenosha

Figure PF-2

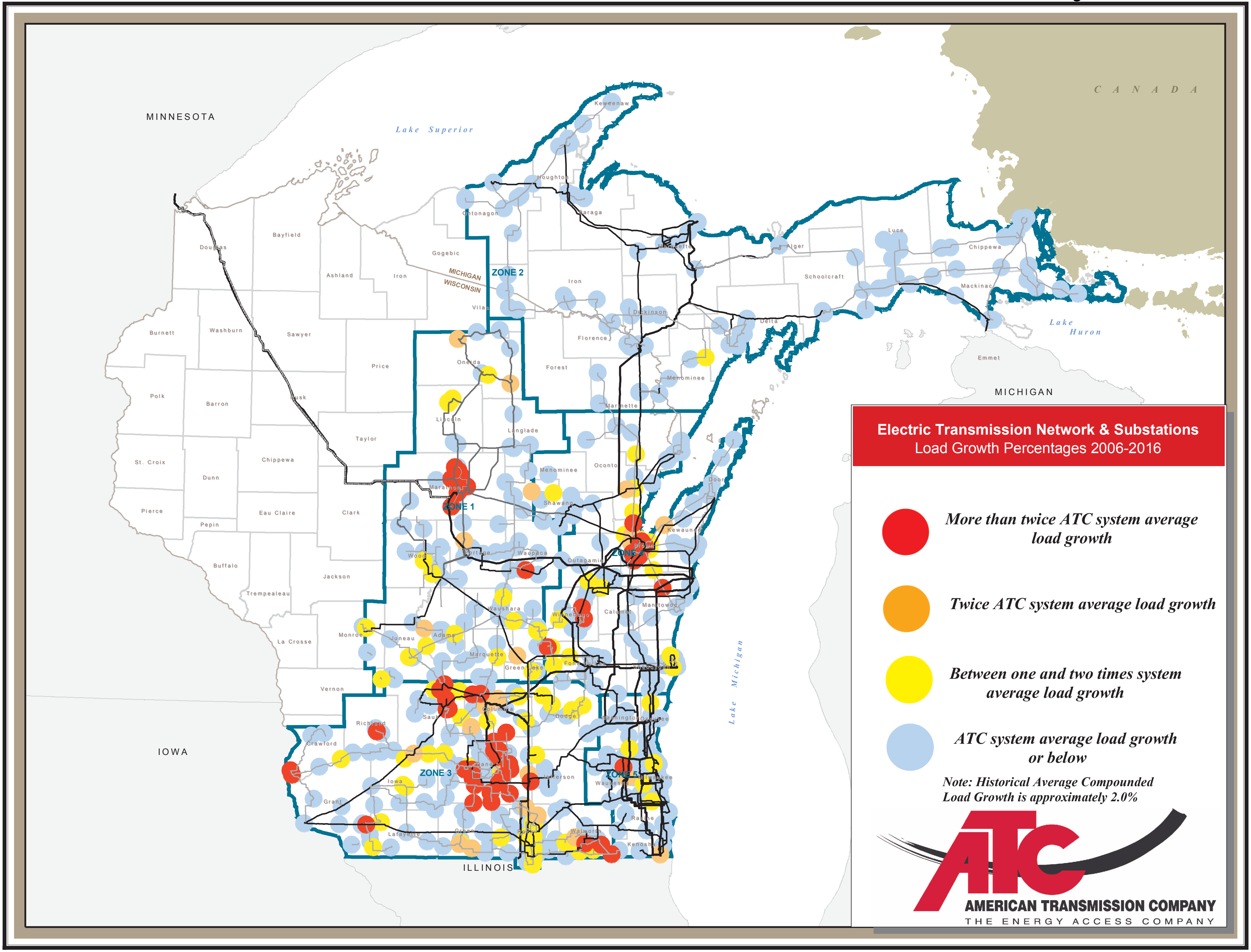

Electric Transmission Network & Substations
Load Growth Percentages 2006-2016
More than twice ATC system average load growth
Twice ATC system average load growth
Between one and two times system average load growth
ATC system average load growth or below
Note: Historical Average Compounded Load Growth is approximately 2.0%
AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY
MINNESOTA
IOWA
ILLINOIS
MICHIGAN
CANADA
Lake Superior
Lake Michigan
Lake Huron
MICHIGAN
WISCONSIN
ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
Keweenaw
Houghton
Ontonagon
Baraga
Marquette
Alger
Luce
Chippewa
Schoolcraft
Mackinac
Delta
Dickinson
Iron
Gogebic
Menominee
Emmet
Douglas
Bayfield
Ashland
Iron
Vilas
Burnett
Washburn
Sawyer
Price
Oneida
Florence
Forest
Marinette
Polk
Barron
Rusk
Lincoln
Langlade
Taylor
St. Croix
Dunn
Chippewa
Menominee
Oconto
Door
Marathon
Shawano
Pierce
Pepin
Eau Claire
Clark
Kewaunee
Wood
Portage
Waupaca
Outagamie
Brown
Buffalo
Jackson
Trempealeau
Waushara
Calumet
Manitowoc
Winnebago
Monroe
Juneau
Adams
La Crosse
Marquette
Green Lake
Fond du Lac
Sheboygan
Vernon
Sauk
Columbia
Dodge
Washington
Ozaukee
Richland
Crawford
Dane
Jefferson
Waukesha
Milwaukee
Iowa
Grant
Racine
Lafayette
Green
Rock
Walworth
Kenosha

Table PR-2
Transmission System Additions for 2006

System additions	**System need year**	**Projected In-service year**	**Planning zone**	**Need category**	**Planned, Proposed or Provisional**	**Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table**
Install a 345/161-kV transformer at Stone Lake Substation (temporary installation for construction outages)	2006	2006	1	reliability	Planned	F1546 & F1685
Construct Gardner Park-Stone Lake 345-kV line	1997	2006	1	service limitation, reliability, import capability & Weston stability	Planned	F1325, F1546, F1564 & F1685
Reconductor Stratford-McMillan 115-kV line (MEWD portion)	2006	2006	1	reliability	Planned	F0845
Construct new Eagle River Muni distribution substation directly adjacent to the existing Cranberry 115-kV Substation	2006	2006	1	T-D interconnection	Planned	F1643
Increase size of existing Summit Lake 115-kV capacitor bank from 11.3 to 16.9 MVAR	2006	2006	1	reliability	Planned	F1899
Uprate Victoria-Ontonagon 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned	F1903
Uprate Victoria-Mass 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned	F1903
Uprate Mass-Winona 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned	F1903
Uprate Winona-Atlantic 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned	F1903
Rebuild Stiles-Amberg double circuit 138-kV line	1996	2006	2 & 4	reliability, service limitation, condition	Planned	F1431
Reconnect the 138/69-kV transformers at Kilbourn Substation on separate breakers to operate individually	2006	2006	3	reliability	Planned	F1430
Construct new 138-kV line from North Beaver Dam to East Beaver Dam Substation	2006	2006	3	T-D interconnection	Planned	F1561
Construct a 345/138-kV switchyard at a new Werner West Substation; install a 345/138-kV transformer. Loop existing Rocky Run to North Appleton 345 kV and existing Werner to White Lake 138-kV lines into Werner West	2004	2006	4	reliability, service limitation	Planned	F1432

Table PR-2 (continued)
Transmission System Additions for 2006

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct a 138-kV substation at a new Forward Energy Center; loop existing Butternut-South Fond du Lac line into Forward Energy Center	2006	2006	4	new generation	Planned	F1716
Construct a 345-kV substation at new Cypress; loop existing Forest Junction-Arcadian line into new Cypress	2006	2006	4	new generation	Planned	F1513
Improve clearance on Kenosha-Lakeview 138-kV line KK9341	2006	2006	5	congestion, reliability	Proposed	F0845

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-3
Transmission System Additions for 2007

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Rebuild Weston-Sherman St. and Sherman St.-Hilltop 115-kV lines as double circuits with a new Gardner Park-Hilltop 115-kV line	2007	2007	1	new generation, reliability	Planned	F0833
Reconductor Weston-Northpoint 115-kV line	2007	2007	1	achieve transfer capability associated with Arrowhead-Gardner Park, reliability, new generation	Planned	F1700
Construct Venus-Metonga 115-kV line	2007	2007	1	T-D interconnection	Planned	F1291
Uprate Metomen-North Fond du Lac 69-kV line terminal equipment	2006	2007	1	reliability	Planned	F1427
Install 2-24.5 MVAR capacitor banks at the Wautoma 138-kV and one-16.33 MVAR capacitor bank at 69-kV Substation	2007	2007	1	reliability	Planned	F2054
Install 1-5.4 MVAR capacitor bank at Sawyer 69-kV Substation	2007	TBD	2	reliability	Provisional	F1818
Install 1-8.16 MVAR capacitor bank at Lincoln 69-kV Substation	2007	2007	2	reliability	Planned	F1376
Relocate Brule Substation (Aspen)	2007	2007	2	reliability, condition	Planned	F1659
Uprate White Pine-Victoria 69-kV line clearance to 200 degrees F	2007	2007	2	new generation	Planned	F1735
Uprate Victoria-Ontonagon 69-kV line clearance to 185 degrees F	2007	2007	2	new generation	Planned	F1735
Uprate Victoria-Mass 69-kV line clearance to 185 degrees F	2007	2007	2	new generation	Planned	F1735
Install 2-8.16 MVAR capacitor banks at Ontonagon 138 kV	2007	2007	2	reliability	Proposed	F1816
Convert Kegonsa-McFarland-Femrite 69-kV line to 138 kV	2007	2007	3	reliability, new generation	Planned	F1241
Construct Sprecher-Femrite 138-kV line	2007	2007	3	reliability, new generation	Planned	F1241
Install 138/69-kV transformer at Femrite Substation	2007	2007	3	reliability, new generation	Planned	F1241
Install 138/69-kV transformer at Reiner Substation	2007	2007	3	reliability, new generation	Planned	F1241
Convert Sycamore-Reiner-Sprecher from 69 kV to 138 kV	2007	2007	3	reliability	Planned	F1241

Table PR-3 (continued)
Transmission System Additions for 2007

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Uprate Rock River 138/69-kV transformer to 65 MVA and uprate Rock River-Turtle 69-kV line to 94 MVA	2006	TBD	3	reliability	Provisional	N/A
Upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at New Glarus Substation	2006	TBD	3	reliability	Provisional	N/A
Uprate Colley Road-Park Ave Tap 69-kV line to 95 MVA	2006	2007	3	reliability	Proposed	F1868
Construct Butler Ridge 138-kV Substation	2007	2007	3	new generation	Provisional	F1367
Uprate Brodhead-South Monroe 69-kV line	2006	2007	3	reliability	Proposed	F1834
Construct new 69-kV line from Columbia to Rio to feed the proposed Wyocena Substation	2004	2007	3	T-D interconnection, reliability	Planned	F1393
Install 2-16.33 MVAR capacitor banks at Rubicon 138-kV Substation	2006	2007	3	reliability	Planned	F1395
Construct new line from Southwest Delavan to Bristol at 138 kV and operate at 69 kV	2007	2007	3	T-D interconnection	Planned	F1667
Uprate Janesville-Parkview 69-kV line to 92 MVA	2007	2007	3	reliability	Proposed	F1836
Uprate North Lake Geneva-Lake Geneva 69-kV line to 84 MVA	2006	2007	3	reliability	Proposed	F1868
Uprate Lakefront-Revere 69-kV line	2006	2007	4	reliability, service limitation	Provisional	F1800
String a new Ellinwood-Sunset Point 138-kV line on existing structures	2007	2007	4	reliability	Planned	F1353
Install 2-16.3 MVAR capacitor bank at Canal 69-kV Substation	2007	2007	4	reliability	Planned	F1471
Uprate North Appleton-Lawn Road-White Clay 138-kV line	2007	2007	4	reliability	Planned	F1601

Table PR-3 (continued)
Transmission System Additions for 2007

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct double circuit 138-kV line from Forest Junction/Howards Grove/Charter Steel to Plymouth #4 Substation	2007	2007	4	T-D interconnection	Planned	F1682

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-4
Transmission System Additions for 2008

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Upgrade Kelly-Whitcomb 115-kV line conductor clearances to 300F	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned	F0373
Construct Stone Lake-Arrowhead 345-kV line	1997	2008	1	service limitation, reliability, import capability & Weston stability	Planned	F1191
Construct the new permanent Stone Lake 345/161-kV Substation	2008	2008	1	reliability, import capability & Weston stability	Planned	F1556
Install 1-75 MVAR capacitor bank and 1-45 MVAR inductor at Stone Lake 345-kV Substation	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned	F1195
Construct new Arrowhead 345-kV Substation, install 2-75 MVAR capacitor banks, 1-800 MVA PST and 1-800 MVA 345/230-kV transformer	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned	F1196
Construct Cranberry-Conover 115-kV line	2008	2008	1	reliability, transfer capability	Planned	F1363
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Berlin 69-kV Substation	2008	2008	1	reliability	Planned	F1476
Construct Brandon-Fairwater 69-kV line	2008	2008	1	T-D interconnection	Proposed	F1844
Construct 138 kV bus and install 138/115-kV 150 MVA and 138/69-kV 60 MVA transformers at Conover Substation	2008	2008	2	reliability, transfer capability	Planned	F1363
Install 1-5.4 MVAR capacitor bank at Munising 69-kV Substation	2008	2008	2	reliability	Proposed	F1820
Relocate Cedar Substation (North Lake)	2005	2008	2	reliability, condition	Proposed	F1605
Install 1-5.4 MVAR capacitor bank at Roberts 69-kV Substation	2007	2008	2	reliability	Proposed	F1849
Install second 345/138-kV transformer at Plains Substation	2008	2008	2	reliability, transfer capability	Proposed	F1568
Rebuild Atlantic-Osceola 69-kV line (Laurium #1)	2006	2008	2	reliability, condition	Planned	F1684
Uprate Mass-Winona 69-kV line clearance to 185 degrees F	2008	2008	2	generation	Planned	F1735

Table PR-4 (continued)
Transmission System Additions for 2008

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Uprate Winona-Atlantic 69-kV line clearance to 185 degrees F	2008	2008	2	generation	Planned	F1735
Increase ground clearance of Atlantic-Osceola (Laurium #2) 69-kV line from 120 to 167 degrees F	2008	2008	2	reliability	Proposed	F1780
Install 1-5.4 MVAR capacitor bank at L'Anse 69-kV Substation	2007	2008	2	reliability	Provisional	F1819
Install 2-5.4 MVAR capacitor banks at Osceola 69-kV Substation	TBD	TBD	2	reliability	Provisional	N/A
Increase ground clearance of M38-Atlantic 69-kV line from 120 to 167 degrees F	2008	TBD	2	reliability	Provisional	N/A
Uprate Brick Church-Zenda 69-kV line to 115 MVA	2008	2008	3	reliability	Proposed	F2084
Install 1-16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2007	2008	3	reliability	Provisional	F2084
Uprate Portage-Trienda 138-kV line to 339 MVA	2008	2008	3	reliability	Proposed	F2098
Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	2008	2008	3	reliability	Provisional	F1868
Install 2-16.33 MVAR capacitor bank at the South Monroe 69-kV Substation and remove existing 10.8 MVAR bank	2007	2008	3	reliability	Proposed	F1476
Uprate Rockdale to Jefferson 138-kV line	2008	2008	3	reliability	Planned	F0930
Uprate Rockdale to Boxelder 138-kV line	2008	2008	3	reliability	Planned	F0930
Uprate Boxelder to Stonybrook 138-kV line	2008	2008	3	reliability	Planned	F0930
Construct a Jefferson-Lake Mills-Stony Brook 138-kV line	2006	2008	3	reliability	Planned	F0924
Construct a Rubicon-Hustisford 138-kV line	2008	2008	3	reliability	Proposed	F0956
Rebuild Hustisford-Horicon 69 kV to 138 kV	2008	2008	3	reliability	Proposed	F0956
Construct 138/69-kV substation at a site near Horicon and install a 138/69-kV transformer	2008	2008	3	reliability	Proposed	F0956
Construct a new 138-kV line from North Madison to Huiskamp (was Waunakee)	2008	2008	3	reliability	Proposed	F1626

Table PR-4 (continued)
Transmission System Additions for 2008

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct a new 138/69-kV substation near Huiskamp and install a 187 MVA 138/69-kV transformer	2008	2008	3	reliability	Proposed	F1626
Rebuild the Verona to Oregon 69-kV line Y119	2008	2008	3	reliability	Proposed	F1731
Rebuild Brodhead to South Monroe 69-kV line	2008	2008	3	generation interconnection, reliability	Proposed	F1635
Uprate Darlington-Rock Branch 69-kV line	2008	2008	3	reliability	Proposed	F1868
Rebuild Crivitz-High Falls 69-kV double-circuit line	2008	2008	4	reliability	Proposed	F1357
Expand the Menominee 69-kV Substation and install 138 kV terminals. Loop the West Marinette-Bay De Noc 138-kV line into the Substation	2008	2008	4	reliability	Provisional	F1621
Install 138/69-kV transformer at the expanded Menominee Substation	2008	2008	4	reliability	Provisional	F1621
Uprate North Appleton-Mason Street 138-kV line	2008	2008	4	reliability, service limitation	Proposed	F1765
Uprate North Appleton-Lost Dauphin 138-kV line	2008	2008	4	reliability, service limitation	Proposed	F1765
Install 2-4.1 MVAR capacitor bank at Sister Bay 69-kV Substation	2008	2008	4	reliability	Provisional	F1920
Reconductor Pleasant Valley-Saukville 138-kV line	2008	2008	5	new generation	Planned	F1324
Reconductor Pleasant Valley-St Lawrence 138-kV line	2008	2008	5	new generation	Planned	F1324
Install series reactor at Cornell Substation	2007	2008	5	congestion, generator deliverability	Proposed	F1688
Install 200 MVAR capacitor bank at Bluemound Substation	2007	2008	5	reliability	Provisional	F2085

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-5
Transmission System Additions for 2009

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct Gardner Park-Central Wisconsin 345-kV line	2009	2009	1	service limitation, reliability, import capability and Weston stability	Planned	F0301
Construct new Central Wisconsin 345-kV Substation	2009	2009	1	service limitation, reliability, import capability and Weston stability	Planned	F0301
Rebuild Hiawatha-Pine River 69-kV line ESE_6908	2009	2009	2	maintenance	Proposed	F2075
Rebuild/convert Conover-Plains 69-kV line to 138 kV	2009	2009	2	reliability, transfer capability	Planned	F1363
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove Substation	2009	2009	2	reliability, transfer capability	Planned	F1363
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Aspen Substation	2009	2009	2	reliability	Planned	F1363
Relocate Iron River Substation (Iron Grove)	2009	2009	2	reliability	Planned	F1363
Install 2-24.5 MVAR 138-kV capacitor banks at North Beaver Dam Substation	2005	2009	3	reliability	Provisional	F1476
Install a second 138/69-kV transformer at Hillman Substation	2008	2009	3	reliability	Provisional	F0339
Install 2-8.16 MVAR capacitor banks at new Brewer 69-kV Substation	2009	2009	3	reliability	Proposed	F1476
Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138-kV bus	2008	2009	3	reliability	Planned	F1690
Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona Substation	2009	2009	3	reliability	Proposed	F1407
Uprate North Lake Geneva-Lake Geneva 69-kV line to 115 MVA	2009	2009	3	reliability	Provisional	F2084

Table PR-5 (continued)
Transmission System Additions for 2009

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Uprate Walworth- North Lake Geneva 69-kV to 69 MVA	2009	2009	3	reliability	Provisional	F2084
Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn Substation and install 2-24.5 MVAR 138-kV capacitor banks at Artesian Substation	2009	2009	3	reliability	Provisional	F1712
String a new 138-kV line from Clintonville-Werner West primarily on Morgan-Werner West 345-kV line structures	2004	2009	4	reliability, service limitation	Planned	F0823
Construct Morgan-Werner West 345-kV line	2004	2009	4	reliability, service limitation	Planned	F0823
Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	2009	2009	4	reliability	Proposed	F1361
Replace relaying on 230-kV circuits at Oak Creek Substation	2009	2009	5	new generation	Proposed	F0283
Replace two 345-kV circuit breakers at Pleasant Prairie Substation on the Racine and Zion lines with IPO breakers and upgrade relaying	2009	2009	5	new generation	Proposed	F0283
Expand Oak Creek 345-kV switchyard to interconnect one new generator	2009	2009	5	new generation	Proposed	F1729
Reconductor Oak Creek-Ramsey 138-kV line	2009	2009	5	new generation	Proposed	F0763
Reconductor Oak Creek-Allerton 138-kV line	2009	2009	5	new generation	Proposed	F0763
Install second 500 MVA 345/138-kV transformer at Oak Creek Substation	2009	2009	5	new generation	Proposed	F0763
Loop Ramsey5-Harbor 138-kV line into Norwich and Kansas to form new Ramsey-Norwich and Harbor-Kansas 138-kV lines	2009	2009	5	new generation	Provisional	F0763
Replace current transformers at Racine 345-kV Substation	2009	2009	5	new generation	Proposed	F1165
Construct a 345-kV bus at Bain Substation	2005	2009	5	reliability	Provisional	F0033

Table PR-5 (continued)
Transmission System Additions for 2009

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct a 138-kV bus at Hale Substation to permit third Brookdale distribution transformer interconnection	2009	2009	5	T-D interconnection	Proposed	F2097
Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	2009	2009	5	T-D interconnection	Proposed	F2086

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-6
Transmission System Additions for 2010

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct Monroe County-Council Creek 161-kV line	2010	2010	1	access initiative, reliability	Provisional	F1727
Install a 161/138-kV transformer at Council Creek Substation	2010	2010	1	access initiative, reliability	Provisional	F1727
Uprate Council Creek-Petenwell 138-kV line	2010	2010	1	access initiative, reliability	Provisional	F1727
Rebuild/reconductor Petenwell-Saratoga 138-kV line	2010	2010	1	access initiative, reliability	Provisional	F1727
Replace 138/69-kV transformer at Metomen Substation	2010	2010	1	reliability	Provisional	F1867
Convert Indian Lake-Hiawatha 69-kV line to double-circuit 138-kV operation, construct new Hiawatha 138-kV Substation	2010	TBD	2	reliability	Provisional	N/A
Construct new Mackinac 138/69-kV Substation	2010	TBD	2	reliability	Provisional	N/A
Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	2010	TBD	2	reliability	Provisional	N/A
Uprate Empire-Forsyth 138-kV line terminal equipment	2010	TBD	2	reliability	Provisional	N/A
Uprate Chandler-Cornell 69-kV line clearance from 120 to 167 deg F	2010	TBD	2	reliability	Provisional	N/A
Construct second Paddock-Rockdale 345-kV line	2010	2010	3	access initiative	Proposed	F1981
Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	2006	2010	3	reliability	Provisional	F2088
Install 2-16.33 MVAR capacitor banks at Spring Green 69-kV Substation	2010	2010	3	reliability	Provisional	F1476
Install a 138/69-kV transformer at Bass Creek Substation	2010	2010	3	reliability	Provisional	F1869
Rebuild/reconductor Town Line Road-Bass Creek 138-kV line	2010	2010	3	reliability	Provisional	F1869
Install the second 16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2010	2010	3	reliability	Provisional	F2084

Table PR-6 (continued)
Transmission System Additions for 2010

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Install two 69-kV breakers at Beardsley Street Substation	2010	2010	4	reliability	Provisional	F2082
Expand 345-kV switchyard at Oak Creek to interconnect one new generator	2010	2010	5	new generation	Proposed	F0763
Uprate Oak Creek-Root River 138-kV line	2010	2010	5	new generation	Proposed	F0763
Uprate Oak Creek-Nicholson 138-kV line	2010	2010	5	new generation	Proposed	F0763

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-7
Transmission System Additions for 2011

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Ripon 69-kV Substation	2011	2011	1	reliability	Provisional	F1476
Uprate McCue-Milton Lawns 69-kV line	2011	2011	3	reliability	Provisional	F1836
Construct 345-kV line from Rockdale to West Middleton	2011	2011	3	reliability	Proposed	F1435
Construct a 345-kV bus and install a 345/138 kV 500 MVA transformer at West Middleton Substation	2011	2011	3	reliability	Proposed	F1435
Loop the Deforest to Token Creek 69-kV line into the Yahara River Substation	2011	2011	3	reliability	Provisional	F1641
Uprate Yahara River -Token Creek 69-kV line	2011	2011	3	reliability	Provisional	F1868
Replace the 400 amp metering CT at North Mullet River 69-kV Substation	2011	2011	4	reliability	Provisional	F1164
Install 2-16.3 MVAR capacitor bank at Mears Corners 138-kV Substation	2011	2011	4	reliability	Provisional	F1924
Install 2-16.3 MVAR capacitor bank at Rosiere 138-kV Substation	2011	2011	4	reliability	Provisional	F1925
A second distribution transformer at Somers Substation requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	2011	2011	5	T-D interconnection	Provisional	F2095

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-8
Transmission System Additions for 2012

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct a 69-kV line from SW Ripon Substation to the Ripon-Metomen 69-kV line	2012	2012	1	T-D interconnection	Provisional	F1847
Uprate Gardner Park-Black Brook 115-kV line – scope TBD	2012	2012	1	reliability	Provisional	F1355
Rebuild Blaney Park-Munising 69 kV to 138 kV	2012	2012	2	reliability, condition	Provisional	F0365
Uprate M38 138/69-kV transformer	TBD	TBD	2	reliability	Provisional	N/A
Install 2-8.16 MVAR capacitor banks at M38 69-kV Substation	TBD	TBD	2	reliability	Provisional	N/A
Construct North Lake Geneva-White River 138-kV line	2012	2012	3	T-D interconnection	Provisional	F1609
Uprate Brick Church-Walworth 69-kV line to 115 MVA	2012	2012	3	reliability	Provisional	F2084
Construct Huiskamp-Blount 138-kV line	2012	2012	3	reliability	Proposed	F1642
Uprate North Monroe-Idle Hour 69-kV line	2012	2012	3	reliability	Provisional	F1868
Construct Shoto-Custer 138-kV line	2012	2012	4	reliability	Provisional	F2081
Install 138/69-kV transformer at Custer Substation	2012	2012	4	reliability	Provisional	F2081
Construct 138-kV line from Canal to Dunn Road	2012	2012	4	reliability	Proposed	F1358
Install 60 MVA 138/69-kV transformer at Dunn Road Substation	2012	2012	4	reliability	Proposed	F1358
Install 1-5.4 MVAR capacitor bank at MTU or Henry Street 69-kV Substation	TBD	TBD	2	reliability	Provisional	N/A

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-9
Transmission System Additions for 2013

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR and install a second new 10.8 MVAR capacitor bank	2013	2013	1	reliability	Provisional	F1476
Rebuild/convert Holmes-Chandler 69 kV to 138-kV operation	2013	2013	2 & 4	reliability, condition	Provisional	F1269
Install 1-8.16 MVAR capacitor bank at Boscobel 69-kV Substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank	2013	2013	3	reliability	Provisional	F1476
Uprate Sheepskin-Dana 69-kV line to 95 MVA	2013	2013	3	reliability	Provisional	F1868
Construct a Lake Delton-Birchwood 138-kV line	2013	2013	3	reliability	Provisional	F1638
Expand Oak Creek 345-kV switchyard to interconnect three new generators plus one new 345-kV line and 138-kV switchyard to accommodate new St. Martins line	2013	2013	5	new generation	Provisional	F1865
Construct a 345/138-kV switchyard at Hale (Brookdale) to accommodate two 345-kV lines, a 500 MVA 345/138-kV transformer and 4-138-kV lines plus three 138-26.2 kV transformers	2013	2013	5	new generation	Provisional	F1865
Install two 345-kV line terminations at Pleasant Prairie and loop Zion-Arcadian 345-kV line into Pleasant Prairie Substation	2013	2013	5	new generation	Provisional	F1865
Construct an Oak Creek-Hale (Brookdale) 345-kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	2013	2013	5	new generation	Provisional	F1865
Construct Oak Creek-St. Martins 138-kV circuit #2 installing 16.6 mi. conductor on existing towers	2013	2013	5	new generation	Provisional	F1865

Table PR-9 (continued)
Transmission System Additions for 2013

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct a Hale (Brookdale)-Granville 345-kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/reconductoring 3 mi. 138 kV on existing 345-kV structures	2013	2013	5	new generation	Provisional	F1865
Restring Bluemound-Butler 138-kV line (KK5051) on new 345-kV structures installed with Hale (Brookdale)-Granville line	2013	2013	5	new generation	Provisional	F1865
String Butler-Tamarack 138-kV line on new 345-kV structures installed with Hale (Brookdale)-Granville line	2013	2013	5	new generation	Provisional	F1865

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-10
Transmission System Additions for 2014

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Construct Fairwater-Mackford Prairie 69-kV line	2014	2014	1	reliability	Provisional	N/A
Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	2014	2014	1	reliability	Provisional	N/A
Install a second 138/69-kV transformer at McCue Substation	2014	2014	3	reliability	Provisional	F1637
Install 2-16.33 MVAR 69-kV capacitor banks at Eden Substation	2014	2014	3	reliability	Provisional	F1476
Install 2-16.33 MVAR 69-kV capacitor banks and 2-24.5 MVAR capacitor banks at Femrite Substation	2014	2014	3	reliability	Provisional	F1476
Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation	2014	2014	3	reliability	Provisional	F1476
Construct a 345-kV bus, install a 345/138-kV 500 MVA transformer at North Randolph and loop the Columbia to South Fond Du Lac 345-kV line into the substation	2014	2014	3	reliability	Provisional	F2093
Uprate X-67 Portage-Trienda 138-kV line to 373 MVA	2014	2014	3	reliability	Provisional	F2092
Install 2-16.33 MVAR capacitor banks at Montrose Substation	2014	2014	3	reliability	Provisional	F1476
Construct a Horicon-East Beaver Dam 138-kV line	2014	2014	3	reliability	Provisional	F1640
Replace the existing 138/69-kV transformer at South Sheboygan Falls Substation with 100 MVA transformer	2014	2014	4	reliability	Provisional	F1681
Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	2014	2014	4	reliability	Proposed	F1714
Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers	2014	2014	4	reliability	Provisional	F2079
Uprate the Melissa-Tayco to 229 MVA (300F)	2014	2014	4	reliability	Provisional	F1874

Table PR-10 (continued)
Transmission System Additions for 2014

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Reconductor Cornell-Range Line 138-kV line	2014	2014	5	new generation	Proposed	F1737

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-11
Transmission System Additions for 2015

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Install a second 138/69-kV transformer at Wautoma Substation	2015	2015	1	reliability	Provisional	F0817
Install 2-16.3 MVAR capacitor bank at Aviation Substation	2015	2015	4	reliability	Provisional	F1923
Install 28.8 MVAR capacitor bank at Butternut 138-kV Substation	2015	2015	4	reliability	Provisional	F1403
Replace two existing 138/69-kV transformers at Sunset Point with 100 MVA transformers	2015	2015	4	reliability	Provisional	F2080
Reconductor Pulliam-Danz 69-kV line	2015	2015	4	reliability	Provisional	F1622
Reconductor Danz-Henry Street 69-kV line	2015	2015	4	reliability	Provisional	F1623
Reconductor Pulliam-Van Buren 69-kV line	2015	2015	4	reliability	Provisional	F1624

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-12
Transmission System Additions for 2016

System additions	System need year	Projected In-service year	Planning zone	Need category	Planned, Proposed or Provisional	Cost Estimate - Refer to *Funding Project* and *Sum of Total (2006-2015)* in Financial Table
Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	2016	2016	1	reliability	Provisional	F1476
Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation	2016	2016	3	reliability	Provisional	F1417 & F1609
Construct new 138-kV line from South Lake Geneva to White River Substation	TBD	TBD	3	reliability, T-D interconnection	Provisional	N/A
Construct West Middleton-Blount 138-kV line	2016	2016	3	reliability	Provisional	N/A
Uprate the Royster to Sycamore 69-kV line to 115 MVA	2016	2016	3	reliability	Provisional	F1871
Construct West Middleton-North Madison 345-kV line	2016	2016	3	reliability, access initiative	Proposed	F1458
Construct Evansville-Brooklyn 69-kV line	2016	2016	3	reliability	Provisional	F1848
Construct a Northside-City Limits 138-kV line	2016	2016	4	reliability	Provisional	F1406
Rebuild/Convert Bayport-Suamico-Sobieski-Pioneer 69-kV line to 138 kV	2016	2016	4	reliability, condition	Provisional	F1619 & F1830
Construct a second Dunn Road-Egg Harbor 69-kV line	2016	2016	4	reliability	Proposed	F0181

Defined in Previous 10-Year Assessment
Revised in scope from Previous 10-Year Assessment
New to this 10-Year Assessment

Table PR-13
Transmission System Additions for Zone 1

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Install a 345/161-kV transformer at Stone Lake Substation (temporary installation for construction outages)	2006	2006	1	reliability	Planned
Construct Gardner Park-Stone Lake 345-kV line	1997	2006	1	service limitation, reliability, import capability & Weston stability	Planned
Reconductor Stratford-McMillan 115-kV line (MEWD portion)	2006	2006	1	reliability	Planned
Construct new Eagle River Muni distribution substation directly adjacent to the existing Cranberry 115-kV Substation	2006	2006	1	T-D interconnection	Planned
Increase size of existing Summit Lake 115-kV capacitor bank from 11.3 to 16.9 MVAR	2006	2006	1	reliability	Planned
Rebuild Weston-Sherman St. and Sherman St.-Hilltop 115-kV lines as double circuits with a new Gardner Park-Hilltop 115-kV line	2007	2007	1	new generation, reliability	Planned
Reconductor Weston-Northpoint 115-kV line	2007	2007	1	achieve transfer capability associated with Arrowhead-Gardner Park, reliability, new generation	Planned
Construct Venus-Metonga 115-kV line	2007	2007	1	T-D interconnection	Planned
Uprate Metomen-North Fond du Lac 69-kV line terminal equipment	2006	2007	1	reliability	Planned
Install 2-24.5 MVAR capacitor banks at the Wautoma 138-kV and one-16.33 MVAR capacitor bank at the 69-kV Substation	2007	2007	1	reliability	Planned
Upgrade Kelly-Whitcomb 115-kV line conductor clearances to 300F	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned
Construct Stone Lake-Arrowhead 345-kV line	1997	2008	1	service limitation, reliability, import capability & Weston stability	Planned
Construct the new permanent Stone Lake 345/161-kV Substation	2008	2008	1	reliability, import capability & Weston stability	Planned
Install 1-75 MVAR capacitor bank and 1-45 MVAR inductor at Stone Lake 345-kV Substation	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned
Construct new Arrowhead 345-kV Substation, install 2-75 MVAR capacitor banks, 1-800 MVA PST and 1-800 MVA 345/230-kV transformer	2008	2008	1	achieve transfer capability associated with Arrowhead-Gardner Park	Planned

Table PR-13
Transmission System Additions for Zone 1 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Construct Cranberry-Conover 115-kV line	2008	2008	1	reliability, transfer capability	Planned
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Berlin 69-kV Substation	2008	2008	1	reliability	Planned
Construct Brandon-Fairwater 69-kV line	2008	2008	1	T-D interconnection	Proposed
Construct Gardner Park-Central Wisconsin 345-kV line	2009	2009	1	service limitation, reliability, import capability and Weston stability	Planned
Construct new Central Wisconsin 345-kV Substation	2009	2009	1	service limitation, reliability, import capability and Weston stability	Planned
Construct Monroe County-Council Creek 161-kV line	2010	2010	1	access initiative, reliability	Provisional
Install a 161/138-kV transformer at Council Creek Substation	2010	2010	1	access initiative, reliability	Provisional
Uprate Council Creek-Petenwell 138-kV line	2010	2010	1	access initiative, reliability	Provisional
Rebuild/reconductor Petenwell-Saratoga 138-kV line	2010	2010	1	access initiative, reliability	Provisional
Replace 138/69-kV transformer at Metomen Substation	2010	2010	1	reliability	Provisional
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at the Ripon 69-kV Substation	2011	2011	1	reliability	Provisional
Construct a 69-kV line from SW Ripon Substation to the Ripon-Metomen 69-kV line	2012	2012	1	T-D interconnection	Provisional
Uprate Gardner Park-Black Brook 115-kV line – scope TBD	2012	2012	1	reliability	Provisional
Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR and install a second new 10.8 MVAR capacitor bank	2013	2013	1	reliability	Provisional
Construct Fairwater-Mackford Prairie 69-kV line	2014	2014	1	reliability	Provisional

Table PR-13
Transmission System Additions for Zone 1 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	2014	2014	1	reliability	Provisional
Install a second 138/69-kV transformer at Wautoma Substation	2015	2015	1	reliability	Provisional
Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	2016	2016	1	reliability	Provisional

Table PR-14
Transmission System Additions for Zone 2

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Uprate Victoria-Ontonagon 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned
Uprate Victoria-Mass 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned
Uprate Mass-Winona 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned
Uprate Winona-Atlantic 69-kV line clearance to 135 degrees F	2006	2006	2	new generation	Planned
Rebuild Stiles-Amberg double circuit 138-kV line	1996	2006	2 & 4	reliability, service limitation, condition	Planned
Install 1-5.4 MVAR capacitor bank at the Sawyer 69-kV Substation	2007	TBD	2	reliability	Provisional
Install 1-8.16 MVAR capacitor bank at the Lincoln 69-kV Substation	2007	2007	2	reliability	Planned
Relocate Brule Substation (Aspen)	2007	2007	2	reliability, condition	Planned
Uprate White Pine-Victoria 69-kV line clearance to 200 degrees F	2007	2007	2	new generation	Planned
Uprate Victoria-Ontonagon 69-kV line clearance to 185 degrees F	2007	2007	2	new generation	Planned
Uprate Victoria-Mass 69-kV line clearance to 185 degrees F	2007	2007	2	new generation	Planned
Install 2-8.16 MVAR capacitor banks at Ontonagon 138-kV Substation	2007	2007	2	reliability	Proposed
Construct 138 kV bus and install 138/115-kV 150 MVA and 138/69-kV 60 MVA transformers at Conover Substation	2008	2008	2	reliability, transfer capability	Planned
Install 1-5.4 MVAR capacitor bank at Munising 69-kV Substation	2008	2008	2	reliability	Proposed
Relocate Cedar Substation (North Lake)	2005	2008	2	reliability, condition	Proposed
Install 1-5.4 MVAR capacitor bank at the Roberts 69-kV Substation	2007	2008	2	reliability	Proposed
Install second 345/138-kV transformer at Plains Substation	2008	2008	2	reliability, transfer capability	Proposed
Rebuild Atlantic-Osceola 69-kV line (Laurium #1)	2006	2008	2	reliability, condition	Planned

Table PR-14
Transmission System Additions for Zone 2 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Uprate Mass-Winona 69-kV line clearance to 185 degrees F	2008	2008	2	generation	Planned
Uprate Winona-Atlantic 69-kV line clearance to 185 degrees F	2008	2008	2	generation	Planned
Increase ground clearance of Atlantic-Osceola (Laurium #2) 69-kV line from 120 to 167 degrees F	2008	2008	2	reliability	Proposed
Install 1-5.4 MVAR capacitor bank at L'Anse 69-kV Substation	2007	2008	2	reliability	Provisional
Install 2-5.4 MVAR capacitor banks at Osceola 69-kV Substation	TBD	TBD	2	reliability	Provisional
Increase ground clearance of M38-Atlantic 69-kV line from 120 to 167 degrees F	2008	TBD	2	reliability	Provisional
Rebuild Hiawatha-Pine River 69-kV line ESE_6908	2009	2009	2	maintenance	Proposed
Rebuild/convert Conover-Plains 69-kV line to 138 kV	2009	2009	2	reliability, transfer capability	Planned
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove Substation	2009	2009	2	reliability, transfer capability	Planned
Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Aspen Substation	2009	2009	2	reliability	Planned
Relocate Iron River Substation (Iron Grove)	2009	2009	2	reliability	Planned
Convert Indian Lake-Hiawatha 69-kV line to double-circuit 138-kV operation, construct new Hiawatha 138-kV Substation	2010	TBD	2	reliability	Provisional
Construct new Mackinac 138/69-kV Substation	2010	TBD	2	reliability	Provisional
Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	2010	TBD	2	reliability	Provisional
Uprate Empire-Forsyth 138-kV line terminal equipment	2010	TBD	2	reliability	Provisional
Uprate Chandler-Cornell 69-kV line clearance from 120 to 167 deg F	2010	TBD	2	reliability	Provisional
Rebuild Blaney Park-Munising 69 kV to 138 kV	2012	2012	2	reliability, condition	Provisional
Uprate M38 138/69-kV transformer	TBD	TBD	2	reliability	Provisional

Table PR-14
Transmission System Additions for Zone 2 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Install 2-8.16 MVAR capacitor banks at M38 69-kV Substation	TBD	TBD	2	reliability	Provisional
Install 1-5.4 MVAR capacitor bank at MTU or Henry Street 69-kV Substation	TBD	TBD	2	reliability	Provisional
Rebuild/convert Holmes-Chandler 69 kV to 138-kV operation	2013	2013	2 & 4	reliability, condition	Provisional

Table PR-15
Transmission System Additions for Zone 3

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Reconnect the 138/69-kV transformers at Kilbourn Substation on separate breakers to operate individually	2006	2006	3	reliability	Planned
Construct new 138-kV line from North Beaver Dam to East Beaver Dam Substation	2006	2006	3	T-D interconnection	Planned
Convert Kegonsa-McFarland-Femrite 69-kV line to 138 kV	2007	2007	3	reliability, new generation	Planned
Construct Sprecher-Femrite 138-kV line	2007	2007	3	reliability, new generation	Planned
Install 138/69-kV transformer at Femrite Substation	2007	2007	3	reliability, new generation	Planned
Install 138/69-kV transformer at Reiner Substation	2007	2007	3	reliability, new generation	Planned
Convert Sycamore-Reiner-Sprecher from 69 kV to 138 kV	2007	2007	3	reliability	Planned
Uprate Rock River 138/69-kV transformer to 65 MVA and uprate Rock River-Turtle 69-kV line to 94 MVA	2006	TBD	3	reliability	Provisional
Upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at New Glarus Substation	2006	TBD	3	reliability	Provisional
Uprate Colley Road-Park Ave Tap 69-kV line to 95 MVA	2006	2007	3	reliability	Proposed
Construct Butler Ridge 138-kV Substation	2007	2007	3	new generation	Provisional
Uprate Brodhead-South Monroe 69-kV line	2006	2007	3	reliability	Proposed
Construct new 69-kV line from Columbia to Rio to feed the proposed Wyocena Substation	2004	2007	3	T-D interconnection, reliability	Planned
Install 2-16.33 MVAR capacitor banks at Rubicon 138-kV Substation	2006	2007	3	reliability	Planned
Construct new line from Southwest Delavan to Bristol at 138 kV and operate at 69 kV	2007	2007	3	T-D interconnection	Planned
Uprate Janesville-Parkview 69-kV line to 92 MVA	2007	2007	3	reliability	Proposed
Uprate North Lake Geneva-Lake Geneva 69-kV line to 84 MVA	2006	2007	3	reliability	Proposed
Uprate Brick Church-Zenda 69-kV line to 115 MVA	2008	2008	3	reliability	Proposed

Table PR-15
Transmission System Additions for Zone 3 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Install 1-16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2007	2008	3	reliability	Provisional
Uprate Portage-Trienda 138-kV line to 339 MVA	2008	2008	3	reliability	Proposed
Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	2008	2008	3	reliability	Provisional
Install 2-16.33 MVAR capacitor bank at the South Monroe 69-kV Substation and remove existing 10.8 MVAR bank	2007	2008	3	reliability	Proposed
Uprate Rockdale to Jefferson 138-kV line	2008	2008	3	reliability	Planned
Uprate Rockdale to Boxelder 138-kV line	2008	2008	3	reliability	Planned
Uprate Boxelder to Stonybrook 138-kV line	2008	2008	3	reliability	Planned
Construct a Jefferson-Lake Mills-Stony Brook 138-kV line	2006	2008	3	reliability	Planned
Construct a Rubicon-Hustisford 138-kV line	2008	2008	3	reliability	Proposed
Rebuild Hustisford-Horicon 69 kV to 138 kV	2008	2008	3	reliability	Proposed
Construct 138/69 kV substation at a site near Horicon Substation and install a 138/69-kV transformer	2008	2008	3	reliability	Proposed
Construct a new 138-kV line from North Madison to Huiskamp (was Waunakee)	2008	2008	3	reliability	Proposed
Construct a new 138/69-kV substation near Huiskamp and install a 187 MVA 138/69-kV transformer	2008	2008	3	reliability	Proposed
Rebuild the Verona to Oregon 69-kV line Y119	2008	2008	3	reliability	Proposed
Rebuild Brodhead to South Monroe 69-kV line	2008	2008	3	generation interconnection, reliability	Proposed
Uprate Darlington-Rock Branch 69-kV line	2008	2008	3	reliability	Proposed
Install 2-24.5 MVAR 138-kV capacitor banks at North Beaver Dam Substation	2005	2009	3	reliability	Provisional
Install a second 138/69-kV transformer at Hillman Substation	2008	2009	3	reliability	Provisional
Install 2-8.16 MVAR capacitor banks at new Brewer 69-kV Substation	2009	2009	3	reliability	Proposed
Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138 kV bus	2008	2009	3	reliability	Planned

Table PR-15
Transmission System Additions for Zone 3 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona Substation	2009	2009	3	reliability	Proposed
Uprate North Lake Geneva-Lake Geneva 69-kV line to 115 MVA	2009	2009	3	reliability	Provisional
Uprate Walworth- North Lake Geneva 69-kV to 69 MVA	2009	2009	3	reliability	Provisional
Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn Substation and install 2-24.5 MVAR 138-kV capacitor banks at Artesian Substation	2009	2009	3	reliability	Provisional
Construct second Paddock-Rockdale 345-kV line	2010	2010	3	access initiative	Proposed
Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	2006	2010	3	reliability	Provisional
Install 2-16.33 MVAR capacitor banks at Spring Green 69-kV Substation	2010	2010	3	reliability	Provisional
Install a 138/69-kV transformer at Bass Creek Substation	2010	2010	3	reliability	Provisional
Rebuild/reconductor Town Line Road-Bass Creek 138-kV line	2010	2010	3	reliability	Provisional
Install the second 16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2010	2010	3	reliability	Provisional
Uprate McCue-Milton Lawns 69-kV line	2011	2011	3	reliability	Provisional
Construct 345-kV line from Rockdale to West Middleton	2011	2011	3	reliability	Proposed
Construct a 345-kV bus and install a 345/138 kV 500 MVA transformer at West Middleton Substation	2011	2011	3	reliability	Proposed
Loop the Deforest to Token Creek 69-kV line into the Yahara River Substation	2011	2011	3	reliability	Provisional
Uprate Yahara River-Token Creek 69-kV line	2011	2011	3	reliability	Provisional
Uprate Brick Church-Walworth 69-kV line to 115 MVA	2012	2012	3	reliability	Provisional
Construct Huiskamp-Blount 138-kV line	2012	2012	3	reliability	Proposed
Uprate North Monroe-Idle Hour 69-kV line	2012	2012	3	reliability	Provisional

Table PR-15
Transmission System Additions for Zone 3 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Construct North Lake Geneva-White River 138-kV line	2012	2012	3	T-D interconnection	Provisional
Install 1-8.16 MVAR capacitor bank at Boscobel 69-kV Substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank	2013	2013	3	reliability	Provisional
Uprate Sheepskin-Dana 69-kV line to 95 MVA	2013	2013	3	reliability	Provisional
Construct a Lake Delton-Birchwood 138-kV line	2013	2013	3	reliability	Provisional
Install a second 138/69-kV transformer at McCue Substation	2014	2014	3	reliability	Provisional
Install 2-16.33 MVAR 69-kV capacitor banks at Eden Substation	2014	2014	3	reliability	Provisional
Install 2-16.33 MVAR 69-kV capacitor banks and 2-24.5 MVAR capacitor banks at Femrite Substation	2014	2014	3	reliability	Provisional
Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation	2014	2014	3	reliability	Provisional
Construct a 345-kV bus, install a 345/138-kV 500 MVA transformer at North Randolph and loop the Columbia to South Fond Du Lac 345-kV line into the substation	2014	2014	3	reliability	Provisional
Uprate X-67 Portage-Trienda 138-kV line to 373 MVA	2014	2014	3	reliability	Provisional
Install 2-16.33 MVAR capacitor banks at Montrose Substation	2014	2014	3	reliability	Provisional
Construct a Horicon-East Beaver Dam 138-kV line	2014	2014	3	reliability	Provisional
Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation	2016	2016	3	reliability	Provisional
Construct new 138-kV line from South Lake Geneva to White River Substation	TBD	TBD	3	reliability, T-D interconnection	Provisional
Construct West Middleton-Blount 138-kV line	2016	2016	3	reliability	Provisional
Uprate the Royster to Sycamore 69-kV line to 115 MVA	2016	2016	3	reliability	Provisional

Table PR-15
Transmission System Additions for Zone 3 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Construct West Middleton-North Madison 345-kV line	2016	2016	3	reliability, access initiative	Proposed
Construct Evansville-Brooklyn 69-kV line	2016	2016	3	reliability	Provisional

Table PR-16
Transmission System Additions for Zone 4

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Construct a 345/138-kV switchyard at a new Werner West Substation; install a 345/138-kV transformer. Loop existing Rocky Run to North Appleton 345 kV and existing Werner to White Lake 138-kV lines into Werner West	2004	2006	4	reliability, service limitation	Planned
Construct a 138-kV substation at a new Forward Energy Center; loop existing Butternut-South Fond du Lac line into Forward Energy Center	2006	2006	4	new generation	Planned
Construct a 345-kV substation at new Cypress; loop existing Forest Junction-Arcadian line into new Cypress	2006	2006	4	new generation	Planned
Rebuild Stiles-Amberg double circuit 138-kV line	1996	2006	2 & 4	reliability, service limitation, condition	Planned
Uprate Lakefront-Revere 69-kV line	2006	2007	4	reliability, service limitation	Provisional
String a new Ellinwood-Sunset Point 138-kV line on existing structures	2007	2007	4	reliability	Planned
Install 2-16.3 MVAR capacitor bank at Canal 69-kV Substation	2007	2007	4	reliability	Planned
Uprate North Appleton-Lawn Road-White Clay 138-kV line	2007	2007	4	reliability	Planned
Construct double circuit 138-kV line from Forest Junction/Howards Grove/Charter Steel to Plymouth #4 Substation	2007	2007	4	T-D interconnection	Planned
Rebuild Crivitz-High Falls 69-kV double circuit line	2008	2008	4	reliability	Proposed
Expand the Menominee 69-kV Substation and install 138 kV terminals. Loop the West Marinette-Bay De Noc 138-kV line into the Substation	2008	2008	4	reliability	Provisional
Install 138/69-kV transformer at the expanded Menominee Substation	2008	2008	4	reliability	Provisional
Uprate North Appleton-Mason Street 138-kV line	2008	2008	4	reliability, service limitation	Proposed
Uprate North Appleton-Lost Dauphin 138-kV line	2008	2008	4	reliability, service limitation	Proposed

Table PR-16
Transmission System Additions for Zone 4 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Install 2-4.1 MVAR capacitor bank at Sister Bay 69-kV Substation	2008	2008	4	reliability	Provisional
String a new 138-kV line from Clintonville-Werner West primarily on Morgan-Werner West 345-kV line structures	2004	2009	4	reliability, service limitation	Planned
Construct Morgan-Werner West 345-kV line	2004	2009	4	reliability, service limitation	Planned
Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	2009	2009	4	reliability	Proposed
Install two 69-kV breakers at Beardsley Street Substation	2010	2010	4	reliability	Provisional
Replace the 400 amp metering CT at North Mullet River 69-kV Substation	2011	2011	4	reliability	Provisional
Install 2-16.3 MVAR capacitor bank at Mears Corners 138-kV Substation	2011	2011	4	reliability	Provisional
Install 2-16.3 MVAR capacitor bank at Rosiere 138-kV Substation	2011	2011	4	reliability	Provisional
Construct Shoto to Custer 138-kV line	2012	2012	4	reliability	Provisional
Install 138/69-kV transformer at Custer Substation	2012	2012	4	reliability	Provisional
Construct 138-kV line from Canal to Dunn Road	2012	2012	4	reliability	Proposed
Install 60 MVA 138/69-kV transformer at Dunn Road Substation	2012	2012	4	reliability	Proposed
Rebuild/convert Holmes-Chandler 69 kV to 138-kV operation	2013	2013	2 & 4	reliability, condition	Provisional
Replace the existing 138/69-kV transformer at South Sheboygan Falls Substation with 100 MVA transformer	2014	2014	4	reliability	Provisional
Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	2014	2014	4	reliability	Proposed
Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers	2014	2014	4	reliability	Provisional
Uprate the Melissa-Tayco to 229 MVA (300F)	2014	2014	4	reliability	Provisional
Install 2-16.3 MVAR capacitor bank at Aviation Substation	2015	2015	4	reliability	Provisional

Table PR-16
Transmission System Additions for Zone 4 (continued)

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Install 28.8 MVAR capacitor bank at Butternut 138-kV Substation	2015	2015	4	reliability	Provisional
Replace two existing 138/69-kV transformers at Sunset Point with 100 MVA transformers	2015	2015	4	reliability	Provisional
Reconductor Pulliam-Danz 69-kV line	2015	2015	4	reliability	Provisional
Reconductor Danz-Henry Street 69-kV line	2015	2015	4	reliability	Provisional
Reconductor Pulliam-Van Buren 69-kV line	2015	2015	4	reliability	Provisional
Construct a Northside-City Limits 138-kV line	2016	2016	4	reliability	Provisional
Rebuild/Convert Bayport-Suamico-Sobieski-Pioneer 69-kV line to 138 kV	2016	2016	4	reliability, condition	Provisional
Construct a second Dunn Road-Egg Harbor 69-kV line	2016	2016	4	reliability	Proposed

Table PR-17
Transmission System Additions for Zone 5

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
Improve clearance on Kenosha-Lakeview 138-kV line KK9341	2006	2006	5	congestion, reliability	Proposed
Reconductor Pleasant Valley-Saukville 138-kV line	2008	2008	5	new generation	Planned
Reconductor Pleasant Valley-St Lawrence 138-kV line	2008	2008	5	new generation	Planned
Install series reactor at Cornell Substation	2007	2008	5	congestion, generator deliverability	Proposed
Install 200 MVAR capacitor bank at Bluemound Substation	2007	2008	5	reliability	Provisional
Replace relaying on 230-kV circuits at Oak Creek Substation	2009	2009	5	new generation	Proposed
Replace two 345-kV circuit breakers at Pleasant Prairie Substation on the Racine and Zion lines with IPO breakers and upgrade relaying	2009	2009	5	new generation	Proposed
Expand Oak Creek 345-kV switchyard to interconnect one new generator	2009	2009	5	new generation	Proposed
Reconductor Oak Creek-Ramsey 138-kV line	2009	2009	5	new generation	Proposed
Reconductor Oak Creek-Allerton 138-kV line	2009	2009	5	new generation	Proposed
Install second 500 MVA 345/138-kV transformer at Oak Creek Substation	2009	2009	5	new generation	Proposed
Loop Ramsey5-Harbor 138-kV line into Norwich and Kansas to form new Ramsey-Norwich and Harbor-Kansas 138-kV lines	2009	2009	5	new generation	Provisional
Replace CTs at Racine 345-kV Substation	2009	2009	5	new generation	Proposed
Construct a 345-kV bus at Bain Substation	2005	2009	5	reliability	Provisional
Construct a 138-kV bus at Hale Substation to permit third Brookdale distribution transformer interconnection	2009	2009	5	T-D interconnection	Proposed
Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	2009	2009	5	T-D interconnection	Proposed
Expand 345-kV switchyard at Oak Creek to interconnect one new generator	2010	2010	5	new generation	Proposed
Uprate Oak Creek-Root River 138-kV line	2010	2010	5	new generation	Proposed
Uprate Oak Creek-Nicholson 138-kV line	2010	2010	5	new generation	Proposed

Table PR-17
Transmission System Additions for Zone 5

System additions	System need year	Projected in-service year	Planning zone	Need category	Planned, Proposed or Provisional
A second distribution transformer at Somers Substation requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	2011	2011	5	T-D interconnection	Provisional
Expand Oak Creek 345-kV switchyard to interconnect three new generators plus one new 345-kV line and 138 kV switchyard to accommodate new St. Martins line	2013	2013	5	new generation	Provisional
Construct a 345/138-kV switchyard at Hale (Brookdale) to accommodate two 345-kV lines, a 500 MVA 345/138-kV transformer and 4-138-kV lines plus three 138-26.2 kV transformers	2013	2013	5	new generation	Provisional
Install two 345-kV line terminations at Pleasant Prairie and loop Zion-Arcadian 345-kV line into Pleasant Prairie Substation	2013	2013	5	new generation	Provisional
Construct an Oak Creek-Hale (Brookdale) 345-kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	2013	2013	5	new generation	Provisional
Construct Oak Creek-St. Martins 138-kV circuit #2 installing 16.6 mi. conductor on existing towers	2013	2013	5	new generation	Provisional
Construct a Hale (Brookdale)-Granville 345-kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138-kV double-circuit tower line and converting/reconductoring 3 mi. 138 kV on existing 345-kV structures	2013	2013	5	new generation	Provisional
Restring Bluemound-Butler 138-kV line (KK5051) on new 345-kV structures installed with Hale (Brookdale)-Granville line	2013	2013	5	new generation	Provisional
String Butler-Tamarack 138-kV line on new 345-kV structures installed with Hale (Brookdale)-Granville line	2013	2013	5	new generation	Provisional
Reconductor Cornell-Range Line 138-kV line	2014	2014	5	new generation	Proposed

Table PR-18
Identified Needs and Transmission Lines Requiring New Right-of-Way

Identified need	Potential solutions	Approx. line mileage		System need year	Projected In-service year	Planning zone
		Total	New ROW			
reduce service limitations, relieve overloads or low voltages under contingency, improve transfer capability & Weston stability	Construct Gardner Park-Stone Lake 345-kV line	140	73.4	1997	2006	1
T-D interconnection request	Construct new 138-kV line from North Beaver Dam to East Beaver Dam Substation	1.5	1.5	2006	2006	3
T-D interconnection request	Construct Venus-Metonga 115-kV line	12.5	11.5	2007	2007	1
relieve overloads or low voltages under contingency, accommodate new generation	Construct Sprecher-Femrite 138-kV line	2	2	2007	2007	3
T-D interconnection request, relieve overloads or low voltages under contingency	Construct new 69-kV line from Columbia to Rio to feed the proposed Wyocena Substation	8.16	8.16	2004	2007	3
T-D interconnection request	Construct new line from Southwest Delavan to Bristol at 138 kV and operate at 69 kV	3.5	3.5	2007	2007	3
T-D interconnection request	Construct double circuit 138-kV line from Forest Junction/Howards Grove/Charter Steel to Plymouth #4	1.75	1.75	2007	2007	4
reduce service limitations, relieve overloads or low voltages under contingency, improve transfer capability & Weston stability	Construct Stone Lake-Arrowhead 345-kV line	70	36.6	1997	2008	1
relieve overloads or low voltages under contingency, transfer capability	Construct Cranberry-Conover 115-kV line	14	14	2008	2008	1
T-D interconnection request	Construct Brandon-Fairwater 69-kV line	4	4	2008	2008	1
relieve overloads or low voltages under contingency	Construct a Jefferson-Lake Mills-Stony Brook 138-kV line	12	12	2006	2008	3
relieve overloads or low voltages under contingency	Construct a Rubicon-Hustisford 138-kV line	5	5	2008	2008	3
relieve overloads or low voltages under contingency	Construct a new 138-kV line from North Madison to Huiskamp (was Waunakee)	5	5	2008	2008	3
relieve overloads or low voltages under contingency	Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona Substation	9	3	2009	2009	3

Table PR-18
Identified Needs and Transmission Lines Requiring New Right-of-Way

Identified need	Potential solutions	Approx. line mileage		System need year	Projected In-service year	Planning zone
		Total	New ROW			
relieve overloads or low voltages under contingency, reduce service limitations	String a new 138-kV line from Clintonville-Werner West primarily on Morgan-Werner West 345-kV line structures	16	2	2004	2009	4
relieve overloads or low voltages under contingency, reduce service limitations	Construct Morgan-Werner West 345-kV line	47	47	2004	2009	4
relieve overloads or low voltages under contingency	Construct 345-kV line from Rockdale to West Middleton	35	35	2011	2011	3
relieve overloads or low voltages under contingency	Loop the Deforest to Token Creek 69-kV line into the Yahara River Substation	1	1	2011	2011	3
T-D interconnection request	Construct a 69-kV line from SW Ripon Substation to the Ripon-Metomen 69-kV line	1.5	1.5	2012	2012	1
T-D interconnection request	Construct a North Lake Geneva-White River 138-kV line	1.4	1.4	2012	2012	3
relieve overloads or low voltages under contingency	Construct Shoto to Custer 138-kV line	9.94	9.94	2012	2012	4
relieve overloads or low voltages under contingency	Construct a Lake Delton-Birchwood 138-kV line	5	5	2013	2013	3
accommodate new generation	Construct an Oak Creek-Hale (Brookdale) 345-kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	25.2	4	2013	2013	5
relieve overloads or low voltages under contingency, replace aging facilities	Rebuild/convert Holmes-Chandler 69 kV to 138-kV operation	54	14	2013	2013	2 & 4
relieve overloads or low voltages under contingency	Construct Fairwater-Mackford Prairie 69-kV line	5	5	2014	2014	1
relieve overloads or low voltages under contingency	Construct a Horicon-East Beaver Dam 138-kV line	9	9	2014	2014	3
relieve overloads or low voltages under contingency, T-D interconnection request	Construct new 138-kV line from South Lake Geneva to White River Substation	3	3	TBD	TBD	3
relieve overloads or low voltages under contingency, access initiative	Construct West Middleton-North Madison 345-kV line	20	20	2016	2016	3
relieve overloads or low voltages under contingency	Construct Evansville-Brooklyn 69-kV line	8	8	2016	2016	3

Table PR-18
Identified Needs and Transmission Lines Requiring New Right-of-Way

Identified need	Potential solutions	Approx. line mileage		System need year	Projected In-service year	Planning zone
		Total	New ROW			
relieve overloads or low voltages under contingency	Construct a second Dunn Road-Egg Harbor 69-kV line	12.66	12.66	2016	2016	4

Table PR-19
Transmission Line Rebuilds/Reconductors, New Circuits and Voltage Conversions on Existing Right-of-Way

Identified need	Lines to be rebuilt/reconductored on existing ROW	Approx. mileage of rebuilt, reconductored or uprated lines	System need year	Projected In-service year	Planning zone
relieve overloads or low voltages under contingency	Reconductor Stratford-McMillan 115-kV line (MEWD portion)	10	2006	2006	1
relieve overloads or low voltages under contingency, reduce service limitations, replace aging facilities	Rebuild Stiles-Amberg double circuit 138-kV line	45	1996	2006	2 & 4
accommodate new generation, relieve overloads or low voltages under contingency	Rebuild Weston-Sherman St. and Sherman St.-Hilltop 115-kV lines as double circuits with a new Gardner Park-Hilltop 115-kV line	9.5	2007	2007	1
achieve transfer capability associated with Arrowhead-Gardner Park, relieve overloads or low voltages under contingency, accommodate new generation	Reconductor Weston-Northpoint 115-kV line	24	2007	2007	1
relieve overloads or low voltages under contingency, accommodate new generation	Convert Kegonsa-McFarland-Femrite 69-kV line to 138 kV	5.9	2007	2007	3
relieve overloads or low voltages under contingency	Convert Sycamore-Reiner-Sprecher from 69 kV to 138 kV	6.5	2007	2007	3
relieve overloads or low voltages under contingency	String a new Ellinwood-Sunset Point 138-kV line on existing structures	3.58	2007	2007	4
relieve overloads or low voltages under contingency	Uprate North Appleton-Lawn Road-White Clay 138-kV line	29.8	2007	2007	4
achieve transfer capability associated with Arrowhead-Gardner Park	Upgrade Kelly-Whitcomb 115-kV line conductor clearances to 300F	24	2008	2008	1
relieve overloads or low voltages under contingency, replace aging facilities	Rebuild Atlantic-Osceola 69-kV line (Laurium #1)	13.7	2006	2008	2
relieve overloads or low voltages under contingency	Increase ground clearance of M38-Atlantic 69-kV line from 120 to 167 degrees F	22	2008	TBD	2
relieve overloads or low voltages under contingency	Rebuild Hustisford-Horicon 69 kV to 138 kV	8	2008	2008	3
relieve overloads or low voltages under contingency	Rebuild the Verona to Oregon 69-kV line Y119	11	2008	2008	3

Table PR-19
Transmission Line Rebuilds/Reconductors, New Circuits and Voltage Conversions on Existing Right-of-Way

Identified need	Lines to be rebuilt/reconductored on existing ROW	Approx. mileage of rebuilt, reconductored or uprated lines	System need year	Projected In-service year	Planning zone
generation interconnection, relieve overloads or low voltages under contingency	Rebuild Brodhead to South Monroe 69-kV line	18	2008	2008	3
relieve overloads or low voltages under contingency	Rebuild Crivitz-High Falls 69-kV double circuit line	14.5	2008	2008	4
relieve overloads or low voltages under contingency, reduce service limitations	Uprate North Appleton-Mason Street 138-kV line	21	2008	2008	4
relieve overloads or low voltages under contingency, reduce service limitations	Uprate North Appleton-Lost Dauphin 138-kV line	12	2008	2008	4
accommodate new generation	Reconductor Pleasant Valley-Saukville 138-kV line	12	2008	2008	5
accommodate new generation	Reconductor Pleasant Valley-St Lawrence 138-kV line	7	2008	2008	5
reduce service limitations, relieve overloads or low voltages under contingency, improve transfer capability and Weston stability	Construct Gardner Park-Central Wisconsin 345-kV line	47	2009	2009	1
maintenance	Rebuild Hiawatha-Pine River 69-kV line ESE_6908	48.28	2009	2009	2
relieve overloads or low voltages under contingency, transfer capability	Rebuild/convert Conover-Plains 69-kV line to 138 kV	73	2009	2009	2
relieve overloads or low voltages under contingency	Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138 kV bus	27.74	2008	2009	3
relieve overloads or low voltages under contingency	Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	2.37	2009	2009	4
accommodate new generation	Reconductor Oak Creek-Ramsey 138-kV line	8.5	2009	2009	5
accommodate new generation	Reconductor Oak Creek-Allerton 138-kV line	5.41	2009	2009	5

Table PR-19
Transmission Line Rebuilds/Reconductors, New Circuits and Voltage Conversions on Existing Right-of-Way

Identified need	Lines to be rebuilt/reconductored on existing ROW	Approx. mileage of rebuilt, reconductored or uprated lines	System need year	Projected In-service year	Planning zone
accommodate new generation	Loop Ramsey5-Harbor 138-kV line into Norwich and Kansas to form new Ramsey-Norwich and Harbor-Kansas 138-kV lines	5.72	2009	2009	5
access initiative, relieve overloads or low voltages under contingency	Construct Monroe County-Council Creek 161-kV line	20	2010	2010	1
access initiative, relieve overloads or low voltages under contingency	Uprate Council Creek-Petenwell 138-kV line	32	2010	2010	1
access initiative, relieve overloads or low voltages under contingency	Rebuild/reconductor Petenwell-Saratoga 138-kV line	23	2010	2010	1
relieve overloads or low voltages under contingency	Convert Indian Lake-Hiawatha 69-kV line to double-circuit 138-kV operation, construct new Hiawatha 138-kV Substation	40	2010	TBD	2
access initative	Construct second Paddock-Rockdale 345-kV line	35	2010	2010	3
relieve overloads or low voltages under contingency	Rebuild/reconductor Town Line Road-Bass Creek 138-kV line	9	2010	2010	3
accommodate new generation	Uprate Oak Creek-Nicholson 138-kV line	6.8	2010	2010	5
T-D interconnection request	A second distribution transformer at Somers Substation requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	8	2011	2011	5
relieve overloads or low voltages under contingency, replace aging facilities	Rebuild Blaney Park-Munising 69 kV to 138 kV	50	2012	2012	2
relieve overloads or low voltages under contingency	Construct Huiskamp-Blount 138-kV line	5	2012	2012	3
relieve overloads or low voltages under contingency	Construct Canal-Dunn Road 138-kV line	7.64	2012	2012	4
accommodate new generation	Construct Oak Creek-St. Martins 138-kV circuit #2 installing 16.6 mi. conductor on existing towers	16.6	2013	2013	5

Table PR-19
Transmission Line Rebuilds/Reconductors, New Circuits and Voltage Conversions on Existing Right-of-Way

Identified need	Lines to be rebuilt/reconductored on existing ROW	Approx. mileage of rebuilt, reconductored or uprated lines	System need year	Projected In-service year	Planning zone
accommodate new generation	Construct a Hale (Brookdale)-Granville 345-kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/reconductoring 3 mi. 138 kV on existing 345 kV structures	15.6	2013	2013	5
accommodate new generation	Restring Bluemound-Butler 138-kV line (KK5051) on new 345-kV structures installed with Hale (Brookdale)-Granville line	5.41	2013	2013	5
accommodate new generation	String Butler-Tamarack 138-kV line on new 345-kV structures installed with Hale (Brookdale)-Granville line	4.12	2013	2013	5
relieve overloads or low voltages under contingency	Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	5	2014	2014	1
accommodate new generation	Reconductor Cornell-Range Line 138-kV line	2.43	2014	2014	5
relieve overloads or low voltages under contingency	Reconductor Pulliam-Danz 69-kV line	3	2015	2015	4
relieve overloads or low voltages under contingency	Reconductor Danz-Henry Street 69-kV line	1.5	2015	2015	4
relieve overloads or low voltages under contingency	Reconductor Pulliam-Van Buren 69-kV line	2	2015	2015	4
relieve overloads or low voltages under contingency	Construct West Middleton-Blount 138-kV line	5	2016	2016	3
relieve overloads or low voltages under contingency	Uprate the Royster to Sycamore 69-kV line to 115 MVA	3.35	2016	2016	3
relieve overloads or low voltages under contingency	Construct a Northside-City Limits 138-kV line	3.16	2016	2016	4
relieve overloads or low voltages under contingency, replace aging facilities	Rebuild/Convert Bayport-Suamico-Sobieski-Pioneer 69-kV line to 138 kV	21.5	2016	2016	4

Table PR-20
New Substations, Transformer Additions and Replacements

Identified need	Potential additions or replacements	Transformer Capacity (MVA)		System need year	Projected In-service year	Planning zone
		Install	Replace			
relieve overloads under contingency	Install a 345/161-kV transformer at Stone Lake Substation (temporary installation for construction outages)	300	0	2006	2006	1
relieve overloads under contingency, reduce service limitations	Construct a 345/138-kV switchyard at a new Werner West Substation; install a 345/138-kV transformer. Loop existing Rocky Run to North Appleton 345 kV and existing Werner to White Lake 138-kV lines into Werner West	500	0	2004	2006	4
accommodate new generation	Construct a 138-kV substation at a new Forward Energy Center Substation; loop existing Butternut-South Fond du Lac line into Forward Energy Center	N/A	0	2006	2006	4
accommodate new generation	Construct a 345-kV substation at new Cypress Substation; loop existing Forest Junction-Arcadian line into new Cypress	N/A	0	2006	2006	4
relieve overloads under contingency, replace aging facilities	Relocate Brule Substation (Aspen)	N/A	0	2007	2007	2
relieve overloads under contingency, accommodate new generation	Install 138/69-kV transformer at Femrite Substation	187	0	2007	2007	3
relieve overloads under contingency, accommodate new generation	Install 138/69-kV transformer at Reiner Substation	100	0	2007	2007	3
relieve overloads under contingency, improve transfer capability & Weston stability	Construct the new permanent Stone Lake 345/161-kV Substation	N/A	0	2008	2008	1
relieve overloads under contingency, transfer capability	Construct 138 kV bus and install 138/115-kV 150 MVA and 138/69-kV 60 MVA transformers at Conover Substation	210	0	2008	2008	2
relieve overloads under contingency, replace aging facilities	Relocate Cedar Substation (North Lake)	N/A	0	2005	2008	2
relieve overloads under contingency, transfer capability	Install second 345/138-kV transformer at Plains Substation	500	0	2008	2008	2
relieve overloads under contingency	Construct 138/69 kV substation at a site near Horicon and install a 138/69-kV transformer	100	0	2008	2008	3
relieve overloads under contingency	Construct a new 138/69-kV substation near Huiskamp and install a 187 MVA 138/69-kV transformer	187	0	2008	2008	3

Table PR-20
New Substations, Transformer Additions and Replacements

Identified need	Potential additions or replacements	Transformer Capacity (MVA)		System need year	Projected In-service year	Planning zone
		Install	Replace			
relieve overloads under contingency	Install 138/69-kV transformer at the expanded Menominee Substation	100	0	2008	2008	4
reduce service limitations, relieve overloads under contingency, improve transfer capability and Weston stability	Construct new Central Wisconsin 345-kV Substation	N/A	N/A	2009	2009	1
relieve overloads under contingency, transfer capability	Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove Substation	60	0	2009	2009	2
relieve overloads under contingency	Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Aspen Substation	60	0	2009	2009	2
relieve overloads under contingency	Relocate Iron River Substation (Iron Grove)		0	2009	2009	2
relieve overloads under contingency	Install a second 138/69-kV transformer at Hillman Substation	47	0	2008	2009	3
accommodate new generation	Install second 500 MVA 345/138-kV transformer at Oak Creek Substation	500	0	2009	2009	5
relieve overloads under contingency	Construct a 345-kV bus at Bain Substation	N/A	0	2005	2009	5
T-D interconnection request	Construct a 138-kV bus at Hale Substation to permit third Brookdale distribution transformer interconnection	N/A	0	2009	2009	5
access initiative, relieve overloads under contingency	Install a 161/138-kV transformer at Council Creek Substation	100	0	2010	2010	1
relieve overloads under contingency	Replace 138/69-kV transformer at Metomen Substation	100	47	2010	2010	1
relieve overloads under contingency	Construct new Mackinac 138/69-kV Substation	N/A	0	2010	TBD	2
relieve overloads under contingency	Install a 138/69-kV transformer at Bass Creek Substation	100	0	2010	2010	3
relieve overloads under contingency	Construct a 345-kV bus and install a 345/138 kV 500 MVA transformer at West Middleton Substation	500	0	2011	2011	3
relieve overloads under contingency	Uprate M38 138/69-kV transformer	64	47	TBD	TBD	2
relieve overloads under contingency	Install 60 MVA 138/69-kV transformer at Dunn Road Substation	60	0	2012	2012	4
relieve overloads or low voltages under contingency	Install 138/69-kV transformer at Custer Substation	100	0	2012	2012	4

Table PR-20
New Substations, Transformer Additions and Replacements

Identified need	Potential additions or replacements	Transformer Capacity (MVA)		System need year	Projected In-service year	Planning zone
		Install	Replace			
accommodate new generation	Construct a 345/138-kV switchyard at Hale (Brookdale) to accommodate two 345-kV lines, a 500 MVA 345/138-kV transformer and 4-138-kV lines plus three 138-26.2 kV transformers	500	0	2013	2013	5
relieve overloads under contingency	Install a second 138/69-kV transformer at McCue Substation	100	0	2014	2014	3
relieve overloads under contingency	Construct a 345-kV bus, install a 345/138-kV 500 MVA transformer at North Randolph and loop the Columbia to South Fond Du Lac 345-kV line into the substation	500	0	2014	2014	3
relieve overloads under contingency	Replace the existing 138/69-kV transformer at South Sheboygan Falls Substation with 100 MVA transformer	100	60	2014	2014	4
relieve overloads under contingency	Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers	200	116	2014	2014	4
relieve overloads under contingency	Install a second 138/69-kV transformer at Wautoma Substation	100	0	2015	2015	1
relieve overloads under contingency	Replace two existing 138/69-kV transformers at Sunset Point with 100 MVA transformers	200	142	2015	2015	4
relieve overloads under contingency	Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation	100	0	2016	2016	3

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
T-D interconnection request	Construct new Eagle River Muni distribution substation directly adjacent to the existing Cranberry 115-kV Substation	N/A	2006	2006	1
relieve overloads or low voltages under contingency	Increase size of existing Summit Lake 115-kV capacitor bank from 11.3 to 16.9 MVAR	5.6	2006	2006	1
relieve overloads or low voltages under contingency	Install 1-5.4 MVAR capacitor bank at Sawyer 69-kV Substation	5.4	2007	TBD	2
accommodate new generation	Uprate Victoria-Ontonagon 69-kV line clearance to 135 degrees F	N/A	2006	2006	2
accommodate new generation	Uprate Victoria-Mass 69-kV line clearance to 135 degrees F	N/A	2006	2006	2
accommodate new generation	Uprate Mass-Winona 69-kV line clearance to 135 degrees F	N/A	2006	2006	2
accommodate new generation	Uprate Winona-Atlantic 69-kV line clearance to 135 degrees F	N/A	2006	2006	2
relieve overloads or low voltages under contingency	Reconnect the 138/69-kV transformers at Kilbourn Substation on separate breakers to operate individually	N/A	2006	2006	3
congestion, relieve overloads or low voltages under contingency	Improve clearance on Kenosha-Lakeview 138-kV line KK9341	N/A	2006	2006	5
relieve overloads or low voltages under contingency	Uprate Metomen-North Fond du Lac 69-kV line terminal equipment	N/A	2006	2007	1
relieve overloads or low voltages under contingency	Install 2-24.5 MVAR capacitor banks at Wautoma 138-kV Substation and one-16.33 MVAR capacitor bank at 69 kV	65.3	2007	2007	1
relieve overloads or low voltages under contingency	Install 1-8.16 MVAR capacitor bank at Lincoln 69-kV Substation	8.16	2007	2007	2
accommodate new generation	Uprate White Pine-Victoria 69-kV line clearance to 200 degrees F	N/A	2007	2007	2
accommodate new generation	Uprate Victoria-Ontonagon 69-kV line clearance to 185 degrees F	N/A	2007	2007	2
accommodate new generation	Uprate Victoria-Mass 69-kV line clearance to 185 degrees F	N/A	2007	2007	2
relieve overloads or low voltages under contingency	Install 2-8.16 MVAR capacitor banks at Ontonagon 138-kV Substation	16.32	2007	2007	2
relieve overloads or low voltages under contingency	Uprate Rock River 138/69-kV transformer to 65 MVA and uprate Rock River-Turtle 69-kV line to 94 MVA	N/A	2006	TBD	3

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
relieve overloads or low voltages under contingency	Upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at New Glarus Substation	5.4	2006	TBD	3
relieve overloads or low voltages under contingency	Uprate Colley Road-Park Ave Tap 69-kV line to 95 MVA	N/A	2006	2007	3
accommodate new accommodate new generation	Construct Butler Ridge 138-kV Substation	N/A	2007	2007	3
relieve overloads or low voltages under contingency	Uprate Brodhead-South Monroe 69-kV line	N/A	2006	2007	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR capacitor banks at Rubicon 138-kV Substation	32.66	2006	2007	3
relieve overloads or low voltages under contingency	Uprate Janesville-Parkview 69-kV line to 92 MVA	N/A	2007	2007	3
relieve overloads or low voltages under contingency	Uprate North Lake Geneva-Lake Geneva 69-kV line to 84 MVA	N/A	2006	2007	3
relieve overloads or low voltages under contingency, reduce service limitations	Uprate Lakefront-Revere 69-kV line	N/A	2006	2007	4
relieve overloads or low voltages under contingency	Install 2-16.3 MVAR capacitor bank at Canal 69-kV Substation	32.6	2007	2007	4
achieve transfer capability associated with Arrowhead-Gardner Park	Install 1-75 MVAR capacitor bank and 1-45 MVAR inductor at Stone Lake 345-kV Substation	75	2008	2008	1
achieve transfer capability associated with Arrowhead-Gardner Park	Construct new Arrowhead 345-kV Substation, install 2-75 MVAR capacitor banks, 1-800 MVA PST and 1-800 MVA 345/230-kV transformer	150	2008	2008	1
relieve overloads or low voltages under contingency	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Berlin 69-kV Substation	12.3	2008	2008	1
relieve overloads or low voltages under contingency	Install 1-5.4 MVAR capacitor bank at Munising 69-kV Substation	5.4	2008	2008	2
relieve overloads or low voltages under contingency	Install 1-5.4 MVAR capacitor bank at Roberts 69-kV Substation	5.4	2007	2008	2
accommodate new generation	Uprate Mass-Winona 69-kV line clearance to 185 degrees F	N/A	2008	2008	2
accommodate new generation	Uprate Winona-Atlantic 69-kV line clearance to 185 degrees F	N/A	2008	2008	2
relieve overloads or low voltages under contingency	Increase ground clearance of Atlantic-Osceola (Laurium #2) 69-kV line from 120 to 167 degrees F	N/A	2008	2008	2

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
relieve overloads or low voltages under contingency	Install 1-5.4 MVAR capacitor bank at L'Anse 69-kV Substation	5.4	2007	2008	2
relieve overloads or low voltages under contingency	Install 2-5.4 MVAR capacitor banks at Osceola 69-kV Substation	10.8	TBD	TBD	2
relieve overloads or low voltages under contingency	Uprate Brick Church-Zenda 69-kV line to 115 MVA	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Install 1-16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	16.33	2007	2008	3
relieve overloads or low voltages under contingency	Uprate Portage-Trienda 138-kV line to 339 MVA	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR capacitor bank at South Monroe 69-kV Substation and remove existing 10.8 MVAR bank	32.66	2007	2008	3
relieve overloads or low voltages under contingency	Uprate Rockdale to Jefferson 138-kV line	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Uprate Rockdale to Boxelder 138-kV line	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Uprate Boxelder to Stonybrook 138-kV line	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Uprate Darlington-Rock Branch 69-kV line	N/A	2008	2008	3
relieve overloads or low voltages under contingency	Expand the Menominee 69-kV Substation and install 138 kV terminals. Loop the West Marinette-Bay De Noc 138-kV line into the Substation	N/A	2008	2008	4
relieve overloads or low voltages under contingency	Install 2-4.1 MVAR capacitor bank at Sister Bay 69-kV Substation	8.2	2008	2008	4
congestion, generator deliverability	Install series reactor at Cornell Substation	N/A	2007	2008	5
relieve overloads or low voltages under contingency	Install 200 MVAR capacitor bank at Bluemound Substation	200	2007	2008	5
relieve overloads or low voltages under contingency	Install 2-24.5 MVAR 138-kV capacitor banks at North Beaver Dam Substation	49	2005	2009	3
relieve overloads or low voltages under contingency	Install 2-8.16 MVAR capacitor banks at new Brewer 69-kV Substation	16.32	2009	2009	3
relieve overloads or low voltages under contingency	Uprate North Lake Geneva-Lake Geneva 69-kV line to 115 MVA	N/A	2009	2009	3

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
relieve overloads or low voltages under contingency	Uprate Walworth- North Lake Geneva 69-kV to 69 MVA	N/A	2009	2009	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn Substation and install 2-24.5 MVAR 138-kV capacitor banks at Artesian Substation	81.66	2009	2009	3
accommodate new accommodate new generation	Replace relaying on 230-kV circuits at Oak Creek Substation	N/A	2009	2009	5
accommodate new accommodate new generation	Replace two 345-kV circuit breakers at Pleasant Prairie Substation on the Racine and Zion lines with IPO breakers and upgrade relaying	N/A	2009	2009	5
accommodate new accommodate new generation	Expand Oak Creek 345-kV switchyard to interconnect one new generator	N/A	2009	2009	5
accommodate new accommodate new generation	Replace CTs at Racine 345-kV Substation	N/A	2009	2009	5
T-D interconnection request	Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	N/A	2009	2009	5
relieve overloads or low voltages under contingency	Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	N/A	2010	TBD	2
relieve overloads or low voltages under contingency	Uprate Empire-Forsyth 138-kV line terminal equipment	N/A	2010	TBD	2
relieve overloads or low voltages under contingency	Uprate Chandler-Cornell 69-kV line clearance from 120 to 167 deg F	N/A	2010	TBD	2
relieve overloads or low voltages under contingency	Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	N/A	2006	2010	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR capacitor banks at Spring Green 69 kV	32	2010	2010	3
relieve overloads or low voltages under contingency	Install the second 16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	16.33	2010	2010	3
relieve overloads or low voltages under contingency	Install two 69-kV breakers at Beardsley Street Substation	N/A	2010	2010	4
accommodate new accommodate new generation	Expand 345-kV switchyard at Oak Creek to interconnect one new generator	N/A	2010	2010	5
accommodate new accommodate new generation	Uprate Oak Creek-Root River 138-kV line	N/A	2010	2010	5

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
relieve overloads or low voltages under contingency	Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Ripon 69-kV Substation	12.3	2011	2011	1
relieve overloads or low voltages under contingency	Uprate McCue-Milton Lawns 69-kV line	N/A	2011	2011	3
relieve overloads or low voltages under contingency	Uprate Yahara-Token Creek 69-kV line	N/A	2011	2011	3
relieve overloads or low voltages under contingency	Replace the 400 amp metering CT at North Mullet River 69-kV Substation	N/A	2011	2011	4
relieve overloads or low voltages under contingency	Install 2-16.3 MVAR capacitor bank at Mears Corners 138-kV Substation	32.6	2011	2011	4
relieve overloads or low voltages under contingency	Install 2-16.3 MVAR capacitor bank at Rosiere 138-kV Substation	32.6	2011	2011	4
relieve overloads or low voltages under contingency	Uprate Gardner Park-Black Brook 115-kV line - scope TBD	N/A	2012	2012	1
relieve overloads or low voltages under contingency	Install 2-8.16 MVAR capacitor banks at M38 69-kV Substation	16.32	TBD	TBD	2
relieve overloads or low voltages under contingency	Uprate Brick Church-Walworth 69-kV line to 115 MVA	N/A	2012	2012	3
relieve overloads or low voltages under contingency	Uprate North Monroe-Idle Hour 69-kV line	N/A	2012	2012	3
relieve overloads or low voltages under contingency	Install 1-5.4 MVAR capacitor bank at MTU or Henry Street 69-kV Substation	5.4	TBD	TBD	2
relieve overloads or low voltages under contingency	Install 1-8.16 MVAR capacitor bank at Boscobel 69-kV Substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank	10.8	2013	2013	3
relieve overloads or low voltages under contingency	Uprate Sheepskin-Dana 69-kV line to 95 MVA	N/A	2013	2013	3
accommodate new accommodate new generation	Expand Oak Creek 345-kV switchyard to interconnect three new generators plus one new 345-kV line and 138-kV switchyard to accommodate new St. Martins line	N/A	2013	2013	5
accommodate new accommodate new generation	Install two 345-kV line terminations at Pleasant Prairie and loop Zion-Arcadian 345-kV line into Pleasant Prairie Substation	N/A	2013	2013	5
relieve overloads or low voltages under contingency	Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR and install a second new 10.8 MVAR capacitor bank	15.3	2013	2013	1

Table PR-21
Substation Equipment Additions and Replacements

Identified need	Potential additions or replacements	Capacitor bank Capacity (MVAR)	System Need Year	Projected In-Service Year	Planning Zone
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR 69-kV capacitor banks at Eden Substation	32.66	2014	2014	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR 69-kV capacitor banks and 2-24.5 MVAR capacitor banks at Femrite Substation	32.66	2014	2014	3
relieve overloads or low voltages under contingency	Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation	24.5	2014	2014	3
relieve overloads or low voltages under contingency	Uprate X-67 Portage-Trienda 138-kV line to 373 MVA	N/A	2014	2014	3
relieve overloads or low voltages under contingency	Install 2-16.33 MVAR capacitor banks at Montrose Substation	32.66	2014	2014	3
relieve overloads or low voltages under contingency	Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	N/A	2014	2014	4
relieve overloads or low voltages under contingency	Uprate the Melissa-Tayco to 229 MVA (300F)	N/A	2014	2014	4
relieve overloads or low voltages under contingency	Install 2-16.3 MVAR capacitor bank at Aviation Substation	32.6	2015	2015	4
relieve overloads or low voltages under contingency	Install 28.8 MVAR capacitor bank at Butternut 138-kV Substation	28.8	2015	2015	4
relieve overloads or low voltages under contingency	Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	12.2	2016	2016	1

Table PR-22

Alternative Solutions to Proposed or Provisional Additions

Primary Solution(s)	Alternate Solution(s)	Projected In-Service Year	Planning Zone
New Cranberry-Conover 138-kV line and Convert Conover-Iron River-Plains 69-kV to 138 kV	1.) Weston-Venus 345-kV line 2.) Weston-Venus-Plains 345 kV line 3.) Cranberry-Conover 138-kV line and convert Conover-Winona to 138 kV 4.) Venus-Crandon-Laona-Goodman-Plains 138-kV line 5.) Venus-Crandon-Laona-Goodman-Amberg 138-kV line 6.) Generation in upper portion Rhinelander Loop 7.) Park Falls-Clear Lake 115-kV line 8.) Convert Whitcomb-Aurora St. 69-kV to 115 kV	2008	1
Berlin area reinforcements: Reconfigure North Randolph-Ripon 69 kV line to North Randolph-Fairwater-Metomen & Metomen-Ripon 69-kV lines. Install capacitor banks at Ripon and Berlin.	1.) New Omro Industrial-Fitzgerald 69-kV line. Install capacitor banks at Ripon and Berlin Substation 2.) Convert Metomen-Ripon-Berlin 69-kV line to 138-kV with a new 138/69-kV xfmr at Berlin Substation 3.) Rebuild the Metomen-Ripon-Berlin 69-kV line to a 138-69-kV double circuit with new 138/69-kV xfmr at Berlin Substation	2007 - 2015	1
Rebuild Weston-Sherman St. and Sherman St-Hilltop 115-kV lines as double circuits with a new Gardner Park-Hilltop 115-kV line	1). Convert WPS's 46-kV system from Maine-Brokaw-Strowbridge-Wausau Hydro-Townline-Kelly to 115 kV 2.) Convert WPS's 46-kV system from Sherman St.-Wausau Hydro-Strowbridge-Townline-Kelly to 115 kV 3.) Rebuilding/uprating both existing Weston-Sherman St. 115-kV lines and the Sherman St.-Hilltop 115-kV line along with the rebuild of the Sherman St. Substation	2007	1
Monroe County-Council Creek 161-kV line	1). New Jackson County-Council Creek 161-kV line 2.) New Hillsboro-Council Creek 161-kV line 3.) Rebuild existing Monroe County-Council Creek 69-kV line with a larger conductor 4) Convert Kilbourn-Hilltop-council Creek 69-kV circuits to 138 kV	2010	1
Increase ground clearance of Winona-Atlantic 69-kV line from 120 to 167 degrees F	Dispatch Portage generation	2007	2
Increase ground clearance of M38-Atlantic 69-kV line from 120 to 167 degrees F	Dispatch Portage generation	2008	2
Install 2-5.4 MVAR capacitor banks at Osceola 69 kV	Dispatch Portage generation	2008	2
Construct second Hiawatha-Pine River-Mackinac (Straits) 138-kV line	Rebuild Hiawatha-Pine River 69-kV line to 138 kV, Install a Phase Shifter at Mackinac to limit flows and add 138-kV capacitors at Brevort or Lakehead Substation	2009	2

Table PR-22

Alternative Solutions to Proposed or Provisional Additions

Primary Solution(s)	Alternate Solution(s)	Projected In-Service Year	Planning Zone
Construct a new 138-kV line from North Madison to Huiskamp and a new substation with a 138/69-kV transformer near Huiskamp Substation	1.) Convert North Madison-Dane-Waunakee 69-kV line to 138 kV 2.) Construct Waunakee-Yahara River 69-kV line 3.) Construct Sycamore-Ruskin 69-kV line	2008	3
Install a 138/69-kV transformer at Bass Creek Substation and reconductor Townline Road to Bass Creek 138-kV line	1.) Construct Brooklyn-Evansville 69-kV line 2.) Install capacitor banks on 69-kV buses	2010	3
Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	Rebuild Fitchburg-Royster 69-kV line, install 69-kV capacitor banks	2010	3
Install a 138/69-kV transformer at Yahara River Substation and loop the Token Creek 69-kV line into and out of Yahara River	1.) Reconfigure Sun Prairie 69-kV system, install second 138/69-kV transformer at North Madison Substation 2.) Rebuild Columbia-Deforest 69-kV line, install capacitor banks on 69-kV buses	2011	3
Construct a new Rockdale-West Middleton 345-kV line	1.) Construct a new 345-kV line from North Madison to West Middleton 2.) Construct a new 345-kV line from Paddock to West Middleton 3) Construct three new 138-kV lines between Rockdale-West Middleton 4.) Construct a second Kegonsa to Reiner 138-kV line, construct a new Boxelder to Reiner 138-kV line, construct a new Huiskamp-Blount 138-kV line and construct West Middleton-Bount 138-kV line	2011	3
Add 138-kV conductor for Ellinwood-Sunset Point 138-kV on existing structures	1.) Replace Ellinwood 138/69-kV transformer 2.) Add a third Ellinwood 138/69-kV transformer	2007	4
Rebuild Crivitz-High Falls 69-kV double-circuit line	1.) Construct a new Amberg/Daves Falls-Goodman 69-kV line 2.) Construct a new Metonga-Goodman 115-kV line 3.) Construct a new Pine-Goodman 69-kV line	2008	4
Construct a Canal-Dunn Road 138-kV line and add a 138/69-kV transformer at Dunn Road Substation	1.) Add a third 138/69-kV transformer at Canal Substation 2.) Add generation to the 69-kV system in Northern Door County 3.) Replace Canal 138/69-kV transformers 1 and 2	2012	4

Table PR-22

Alternative Solutions to Proposed or Provisional Additions

Primary Solution(s)	Alternate Solution(s)	Projected In-Service Year	Planning Zone
Replace South Sheboygan Falls 138/69-kV transformer with a minimum of 125 MVA unit	1.) Tap the Forest Junction-Cedarsauk 138-kV line to Sheboygan Falls and add a 138/69-kV transformer 2.) Construct a 138-kV line to the 69-kV Plymouth Sub #2 and convert Plymouth Sub #2 to 138-kV operation 3.) Construct 2.5 miles of 138-kV line from Lodestar to Sheboygan Falls Substation and install a 138/69-kV, 60 MVA transformer at Sheboygan Falls 4.) Construct 3 miles of 69-kV line from Plymouth #4 Substation to Plymouth #3 Substation. Install a 138/69-kV transformer at Plymouth #4 Substation	2014	4
Construct a second Dunn Road-Egg Harbor 69-kV line	1.) Construct a new 138-kV line from Dunn Road to Egg Harbor Substation 2.) Add generation to the 69-kV system in northern Door County	2016	4
Construct a 345-kV bus at Bain Substation	Reconfigure 345-kV bus at Pleasant Prairie Substation	2009	5
Install two 345-kV IPO breakers at Pleasant Prairie Substation on lines to Racine (L631) and Zion (L2221)	Reconfigure 345-kV lines on bus sections 3 and 4. Reconfigure Pleasant Prairie 345-kV straight bus into ring bus. Construct a 345-kV bus at Bain Substation	2009	5
Construct Rockdale-Concord-Bark River-Mill Road 345-kV line with 345/138-kV transformers at Concord, Bark River and Mill Road Substations	1.) Construct a 345-kV line from Rockdale-Concord-St Lawrence 2.) Add a 345/138-kV transformer at St. Lawrence Substation 3.) Add a 345/138-kV transformer at Concord Substation 4.) Install a 4-position 345-kV ring bus and a 345/138-kV transformer at Germantown Substation	2018	3 & 5
Construct Rockdale-Concord-Bark River-Mill Road 345-kV line with 345/138-kV transformers at Concord, Bark River and Mill Road Substations	1.) Construct a Bark River-Concord 138-kV line 2.) Construct a Bark River- Hartford 138-kV line 3.) Add a 138-kV switching station at Mill Road site 4.) Rebuild existing Rockdale-Concord-Cooney-Summit 138-kV to double-circuit 138 kV; construct 8-position ring buses at Jefferson and Concord Substations 5.) Uprate Stonybrook-Boxelder 138-kV line 6.) Install 32 MVAR capacitor bank at Summit and Hartford 138-kV Substations	2018	3 & 5

Table PR-23

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

PROJECTS CANCELLED	Former In-Service Date	Planning Zone	Reason for Removal
Uprate Wautoma-Berlin 69-kV line terminal equipment at Wautoma Substation	2010	1	New line or equipment ratings
Install additional 13.6 MVAR capacitor bank at Clear Lake 115-kV Substation	2015	1	Replaced with cap bank in Cranberry-Conover-Plains project
Uprate Rocky Run-Plover 115-kV line terminal equipment	2009	1	New line or equipment ratings
Uprate Metomen-Ripon 69-kV line - scope TBD	2014	1	Replaced project with a different solution for this area
Construct Fitzgerald-Omro Industrial 69-kV line	2015	1	Replaced project with a different solution for this area
Install second 50 MVAR capacitor bank at Arpin Substation	2008	1	Updated study results
Uprate Atlantic 138/69-kV transformer	2008	2	Revised rating information
Relocate 69-kV Rexton tap to 69-kV Hiawatha-Pine River line (6909)	2009	2	Replaced with 6908 rebuild project
Relocate 69-kV Trout Lake tap to 69-kV Hiawatha-Pine River line (6909)	2009	2	Replaced with 6908 rebuild project
Rebuild Hiawatha-Pine River-Mackinac 69 kV to 138 kV	2009	2	Eastern U.P. review in progress
Construct 138-kV bus and install one 138/69-kV, 50 MVA transformer at Pine River Substation	2009	2	Eastern U.P. review in progress
Install 138-kV substation modifications at Indian Lake Substation	2009	2	Part of Indian Lake-Hiawatha 138 kV project, date TBD
Install 2-5.4 MVAR capacitor banks at M-38 69-kV Substation	2015	2	Revised load/model information
Uprate Colley Road to Brick Church 69-kV line to 72 MVA	2006	3	Revised load/model information
Construct new 138-kV bus and 138/69 kV 100 MVA transformer at Montrose Substation	2009	3	Location changed to Verona Substation

Table PR-23

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

PROJECTS CANCELLED (continued)	Former In-Service Date	Planning Zone	Reason for Removal
Loop the Femrite to Royster 69-kV line into AGA Gas Substation	2010	3	Replaced by looping Nine Springs to Pflaum 69-kV line into Femrite Substation
Install 4-25 MVAR capacitor banks at Trienda 138-kV Substation	2009	3	Replaced by installing 2-16.33 MVAR capacitor banks at Kilbourn 69-kV Substation and 2-24.5 MVAR capacitor banks at Artesian 138-kV Substation
Uprate Sun Prairie-Bird Street 69-kV line	2012	3	Revised load/model information
Salem-Spring Green-West Middleton 345-kV proxy for Large Access Project, includes rebuild Nelson Dewey-Spring Green-West Middleton 138/69-kV to double-circuit 345/138 kV	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Expand 345 kV to 6 positions at Paddock Substation	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Expand 138 kV to 7 positions at Paddock Substation	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Install second 345/138-kV transformer at Paddock (500 MVA normal/625 MVA emergency) Substation	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Rebuild Paddock-Town Line Road 138 kV to double-circuit 1600 Amps minimum summer emergency each	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Reconductor Town Line Road-Russell 138 kV to 1600 Amps minimum summer emergency	2013	3	This is the previous Access Initiative project which was replaced by second Paddock-Rockdale 345-kV project
Install a 69-kV bus and 138/69-kV 100 MVA transformer at Northwest Beloit Substation	2010	3	Revised load/model information
Reroute Paddock to Shirland Avenue 69-kV line into and out of Northwest Beloit Substation	2010	3	Revised load/model information
Convert Hillman to Eden 69-kV line to 138-kV operation	2011	3	Replaced by installing 2-16.33 MVAR capacitor banks at Eden 69-kV Substation
Rebuild and convert Stagecoach-Spring Green 69-kV line to 138 kV	2012	3	Revised load/model information
Construct West Middleton-Stagecoach double-circuit 138/69-kV line	2012	3	Revised load/model information

Table PR-23

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

PROJECTS CANCELLED (continued)	Former In-Service Date	Planning Zone	Reason for Removal
Construct 69-kV line Eden through Muscoda to Richland Center Substation	2012	3	Replaced by capacitor bank addition project at Boscobel Substation
Move Lone Rock 69-kV phase shifter to Richland Center Substation	2012	3	Replaced by capacitor bank addition project at Boscobel Substation
Convert South Lake Geneva to Twin Lakes 69-kV line to 138-kV operation	2013	3	Revised load/model information
Construct new 138-kV line from Twin Lakes to Spring Valley	2013	3	Revised load/model information
Install 1-16.32 MVAR capacitor bank at Burke 69-kV Substation	2014	3	Replaced by Yahara River transformer project
Replace the Colley Road 138/69-kV transformer	2015	3	Revised load/model information
Replace the Kilbourn Substation 47 MVA 138/69-kV transformer with a 100 MVA unit	2010	3	Revised line/equipment ratings
Construct new 69-kV line from South Lake Geneva to Lake Shore Substation	2013	3	Deferred to 2017 by several line uprate projects and capacitor bank project at South Lake Geneva Substation
Install a second 138/69-kV transformer at North Monroe Substation	2014	3	Deferred as a result of Bass Creek Substation transformer project
Replace the 300A current transformer at Sheboygan Falls 69-kV Substation	2013	4	Another project selected (driven by maintenance and protection)
Retap 400A primary CT at Edgewater Substation to 600A	2012	4	Updated rating information
Retap 48 MVA CT at South Sheboygan Falls 138/69-kV transformer	2010	4	Updated rating information
Replace 300 A metering CT at Edgewater 69-kV Substation	2013	4	Updated rating information
Replace 300 A metering CT at Riverside 69-kV Substation	2013	4	Updated rating information
Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	2016	1	Was 2012
Install 1-5.4 MVAR capacitor bank at Sawyer 69-kV Substation	TBD	2	Was 2006; best value planning process to determine scope

Table PR-23 (continued)

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

PROJECTS DEFERRED	New date	Planning Zone	Reason for Deferral
Convert Indian Lake-Hiawatha 69-kV line to double-circuit 138-kV operation, construct new Hiawatha 138-kV Substation	TBD	2	Was 2009; Eastern U.P. review in progress
Construct new Mackinac 138/69-kV Substation	TBD	2	Was 2009; Eastern U.P. review in progress
Install 1-5.4 MVAR capacitor bank at Munising 69-kV Substation	2008	2	Was 2006; revised load/model information
Relocate Cedar Substation (North Lake)	2008	2	Was 2007; construction timelines
Install 2-16.33 MVAR capacitor banks at South Monroe Substation	2008	3	Was 2007; resource constraints
Uprate Brodhead-South Monroe 69-kV line	2007	3	Was 2006 and provisional; time and resource constraints
Install 2-8.16 MVAR capacitor banks at new Brewer 69-kV Substation	2009	3	Was Richland Center in 2008; revised load/model information
Convert Rock River to Bristol to Elkhorn 138-kV operation; rebuild Bristol with a new 138-kV bus	2009	3	Was 2008; regulatory application process.
Install 1-8.16 MVAR capacitor bank at Boscobel 69-kV Substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank	2013	3	Was 2010; revised load/model information
Construct a Lake Delton-Birchwood 138-kV line	2013	3	Was 2011; revised load/model information
Install a second 138/69-kV transformer at McCue Substation	2014	3	Was Janesville transformer in 2011; revised load/model information, better system performance by installing a second transformer at McCue versus Janesville
Construct a Horicon-East Beaver Dam 138-kV line	2014	3	Was 2013; revised load/model information
Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation	2016	3	Was 2010; deferred due to several line uprates and cap bank project at South Lake Geneva Substation
Construct new 138-kV line from South Lake Geneva to White River Substation	2016	3	Was 2010; deferred due to several line uprates and cap bank project at South Lake Geneva Substation
Uprate the Royster to Sycamore 69-kV line to 115 MVA	2016	3	Was 2012; revised load/model information
Construct West Middleton-North Madison 345-kV line	2016	3	Was 2014; revised load/model information
Construct Evansville-Brooklyn 69-kV line	2016	3	Was 2011; deferred by Bass Creek Substation transformer project
Install 2-16.3 MVAR capacitor bank at Aviation Substation	2015	4	Was 2015
Construct a Northside-City Limits 138-kV line	2016	4	Was 2015

Table PR-23 (continued)

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

PROJECTS DEFERRED (continued)	New date	Planning Zone	Reason for Deferral
Rebuild/Convert Bayport-Suamico-Sobieski-Pioneer 69-kV line to 138 kV	2016	4	Was 2015
Construct a 345-kV bus at Bain Substation	2009	5	Was 2007
OTHER PROJECT CHANGES AND POSSIBLE CHANGES	**Date**	**Planning Zone**	**Nature of Change or Update**
Upgrade Mckenna 6.3 MVAR capacitor bank to 10.8 MVAR and install a second new 10.8 MVAR capacitor bank	2013	1	Was 1-10.8 capacitor bank in 2014
Install a second 138/69-kV transformer at Wautoma Substation	2015	1	Was transformer uprate only
Install 2-24.5 MVAR capacitor banks at Wautoma 138-kV Substation and one-16.33 MVAR capacitor bank at 69 kV	2007	1	Was proposed, now planned
Upgrade 4.1 MVAR capacitor bank to 8.2 MVAR and install a new 8.2 MVAR capacitor bank at Berlin 69-kV Substation	2008	1	Was proposed, now planned
Construct Brandon-Fairwater 69-kV line	2008	1	Was provisional, now proposed
Install 1-5.4 MVAR capacitor bank at Roberts 69-kV Substation	2009	2	Was 2008; removal of Hiawatha-Engadine line
Install 2-5.4 MVAR capacitor banks at Osceola 69-kV Substation	TBD	2	Was proposed in 2008; revised load/model information
Uprate M38 138/69-kV transformer	TBD	2	Was 2012; revised load/model information
Install 2-8.16 MVAR capacitor banks at M38 69-kV Substation	TBD	2	Was proposed in 2012; revised load/model information
Install 1-5.4 MVAR capacitor bank at MTU or Henry Street 69-kV Substation	TBD	2	Was proposed in 2013; revised load/model information
Uprate Janesville-Parkview 69-kV line to 92 MVA	2007	3	Was McCue-Janesville (name change only)
Install 2-16.33 MVAR capacitor banks at Spring Green 69-kV Substation	2010	3	Was uprate existing 18-MVAR bank with a 50-MVAR bank
Construct West Middleton-Blount 138-kV line	2016	3	Was 2017
Uprate North Lake Geneva-Lake Geneva 69-kV line to 84 MVA	2007	3	Was provisional rebuild/uprate
Rebuild Brodhead to South Monroe 69-kV line	2008	3	Was provisional project in 2010

Table PR-23 (continued)

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

OTHER PROJECT CHANGES AND POSSIBLE CHANGES	Date	Planning Zone	Nature of Change or Update
Uprate Portage-Trienda 138-kV line to 339 MVA	2008	3	Was provisional project in 2010; now proposed in 2008
Uprate Darlington-Rock Branch 69-kV line	2008	3	Was provisional project in 2010; now proposed in 2008
Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona Substation	2009	3	Was Montrose-Oak Ridge (name change only)
Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn Substation and install 2-24.5 MVAR 138-kV capacitor banks at Artesian Substation	2009	3	Was capacitors at Kilbourn Substation only
Construct a 345-kV substation at new Cypress; loop existing Forest Junction-Arcadian line into new Cypress Substation	2006	4	Was 2007
String a new Ellinwood-Sunset Point 138-kV line on existing structures	2007	4	Was provisional, now planned
Install 200 MVAR capacitor bank at Bluemound Substation	2008	5	Was 2007
Replace CTs at Racine 345-kV Substation	2009	5	Was 2013
NEW PROJECTS	In-Service Date	Planning Zone	Reason for Project
Construct Fairwater-Mackford Prairie 69-kV line	2014	1	Replaces prior identified solution in the greater Berlin area
Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap	2014	1	Replaces prior identified solution in the greater Berlin area
Rebuild Hiawatha-Pine River 69-kV line ESE_6908	2009	2	Eastern U.P. reliability needs
Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings	TBD	2	Eastern U.P. studies identified these circuits as possible transfer capability limiters in 2010, date TBD
Uprate Empire-Forsyth 138-kV line terminal equipment	TBD	2	Eastern U.P. studies identified these circuits as possible transfer capability limiters in 2010, date TBD
Uprate Chandler-Cornell 69-kV line clearance from 120 to 167 deg F	TBD	2	Eastern U.P. studies identified these circuits as possible transfer capability limiters in 2010, date TBD
Uprate Rock River 138/69-kV transformer to 65 MVA and uprate Rock River-Turtle 69-kV line to 94 MVA	TBD	3	Improve reliability
Upgrade the 5.4 MVAR capacitor bank to 10.8 MVAR at New Glarus Substation	TBD	3	Improve reliability
Uprate Colley Road-Park Ave Tap 69-kV line to 95 MVA	2007	3	Improve reliability
Uprate Brick Church-Zenda 69-kV line to 115 MVA	2008	3	Improve reliability
Install 1-16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2008	3	Improve reliability

Table PR-23 (continued)

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

NEW PROJECTS (continued)	In-Service Date	Planning Zone	Reason for Project
Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	2008	3	Improve reliability
Install 2-24.5 MVAR 138-kV capacitor banks at North Beaver Dam Substation	2009	3	Improve reliability
Uprate North Lake Geneva-Lake Geneva 69-kV line to 115 MVA	2009	3	Improve reliability
Uprate Walworth- North Lake Geneva 69-kV to 69 MVA	2009	3	Improve reliability
Construct second Paddock-Rockdale 345-kV line	2010	3	Improve reliability
Loop Nine Springs-Pflaum 69-kV line into Femrite Substation	2010	3	Improve reliability
Rebuild/reconductor Town Line Road-Bass Creek 138-kV line	2010	3	Improve reliability
Install the second 16.33 MVAR 69-kV capacitor bank at South Lake Geneva Substation	2010	3	Improve reliability
Uprate McCue-Milton Lawns 69-kV line	2011	3	Improve reliability
Uprate Brick Church-Walworth 69-kV line to 115 MVA	2012	3	Improve reliability
Construct North Lake Geneva-White River 138-kV line	2012	3	T-D interconnection
Uprate Sheepskin-Dana 69-kV line to 95 MVA	2013	3	Improve reliability
Install 2-16.33 MVAR 69-kV capacitor banks at Eden Substation	2014	3	Improve reliability
Install 2-16.33 MVAR 69-kV capacitor banks and 2-24.5 MVAR capacitor banks at Femrite Substation	2014	3	Improve reliability
Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation	2014	3	Improve reliability
Construct a 345-kV bus, install a 345/138-kV 500 MVA transformer at North Randolph and loop the Columbia to South Fond Du Lac 345-kV line into the substation	2014	3	Improve reliability
Uprate X-67 Portage-Trienda 138-kV line to 373 MVA	2014	3	Improve reliability
Install 2-16.33 MVAR capacitor banks at Montrose Substation	2014	3	Improve reliability
Install two 69-kV breakers at Beardsley Street Substation	2010	4	Improve reliability
Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers	2014	4	Improve reliability
Replace two existing 138/69-kV transformers at Sunset Point Substation with 100 MVA transformers	2015	4	Improve reliability
Uprate Lakefront-Revere 69-kV line	2007	4	Improve reliability
Construct Shoto-Custer 138-kV line	2012	4	Improve reliability
Install 138/69-kV transformer at Custer Substation	2012	4	Improve reliability
Improve clearance on Kenosha-Lakeview 138-kV line KK9341	2006	5	Improve reliability
Construct a 138-kV bus at Hale Substation to permit third Brookdale distribution transformer interconnection	2009	5	T-D interconnection
Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	2009	5	T-D interconnection

Table PR-23 (continued)

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2006 10-Year Assessment

NEW PROJECTS (continued)	In-Service Date	Planning Zone	Reason for Project
A second distribution transformer at Somers Substation requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	2011	5	T-D interconnection

Table PR-24
Maintenance, Operations or Protection Projects over $0.5 Million (2007-2011)

Project Description	System Need Year	In-Service Year	Initiated	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (in Millions)
Chaffee Creek-Kilbourn (Y100) line	2006	2007	Maintenance	1	Poor condition	Planned	2.5
Castle Rock Substation breaker replacement	2007	2007	Maintenance	1	Poor condition	Planned	0.9
Harrison Substation upgrades	2007	2007	Protection	1	Improve reliability	Planned	0.8
Aspen new substation	2007	2007	Maintenance	2	Poor condition	Planned	4.8
Pine River Substation upgrades	2007	2007	Maintenance	2	Poor condition	Planned	4.7
Gwinn Substation upgrades	2006	2007	Protection	2	Improve protection	Planned	1.0
Brule Substation removal	2007	2007	Maintenance	2	Poor condition	Planned	0.6
Aspen Substation tap	2007	2007	Maintenance	2	Poor condition	Planned	0.6
Spring Green-Stagecoach (Y62) line rebld	2007	2007	Maintenance	3	Poor condition	Planned	3.9
Eden-Nelsen Dewey (X16) pole replace	2007	2007	Maintenance	3	Poor condition	Planned	2.9
Nelson Dewey Substation maintenance	2006	2007	Maintenance	3	Poor condition	Planned	0.7
North Monroe Substation upgrades	2007	2008	Protection	3	Improve protection	Planned	0.6
Deforest Substation upgrades	2007	2007	Protection	3	Improve protection	Planned	0.6
North Fond du Lac Substation upgrades	2007	2007	Protection	4	Improve protection	Planned	2.1
Elkhart-Fredonia (Blaw Knox)	2007	2007	Maintenance	4	Poor condition	Planned	1.8
Edgewater 69-kV Substation upgrades	2007	2007	Protection	4	Improve protection	Planned	1.0
Bluemound Substation upgrades	2007	2007	Protection	5	Improve protection	Planned	2.2
Cooney Substation upgrades	2007	2007	Protection	5	Improve protection	Planned	0.7
Rozelleville-Sigel (Y107) line rebuild	2008	2008	Maintenance	1	Poor condition	Planned	4.0
Whitcomb Substation relay upgrades	2006	2008	Operation	1	Improve reliability	Planned	1.5
Iola Substation breaker replacement	2008	2008	Maintenance	1	Poor condition	Proposed	0.7
Boscobel 69-kV Substation upgrades	2008	2008	Maintenance	3	Poor condition	Planned	1.1
Dam Height-Dane (Y8) line rebuild	2007	2008	Maintenance	3	Poor condition	Planned	1.0
Academy Substation breaker replacement	2008	2008	Maintenance	3	Poor condition	Planned	0.7
Caroline Substation upgrades	2007	2008	Operation	4	Improve reliability	Proposed	1.8
Montello-Wautoma (Y17) line rebuild	2007	2009	Maintenance	1	Poor condition	Planned	4.4
Chaffee Creek-Hancock (Y90) line rebld	2009	2009	Maintenance	1	Poor condition	Planned	3.2
Montello Substation 69-kV breakers	2009	2009	Maintenance	1	Poor condition	Planned	1.2
Straits Substation equipment removal	2009	2009	Maintenance	2	Poor condition	Planned	0.5
Mt Horeb-Rock Branch (Y135) line rebld	2007	2009	Maintenance	3	Poor condition	Planned	3.7
Fredonia-Saukville (Blaw Knox) line rebld	2009	2009	Maintenance	4	Poor condition	Planned	1.0
Colley Road Substation upgrades	2006	2010	Maintenance	3	Poor condition	Provisional	0.7

Figure PR-10
Generation Interconnection Requests
as of 7/1/06

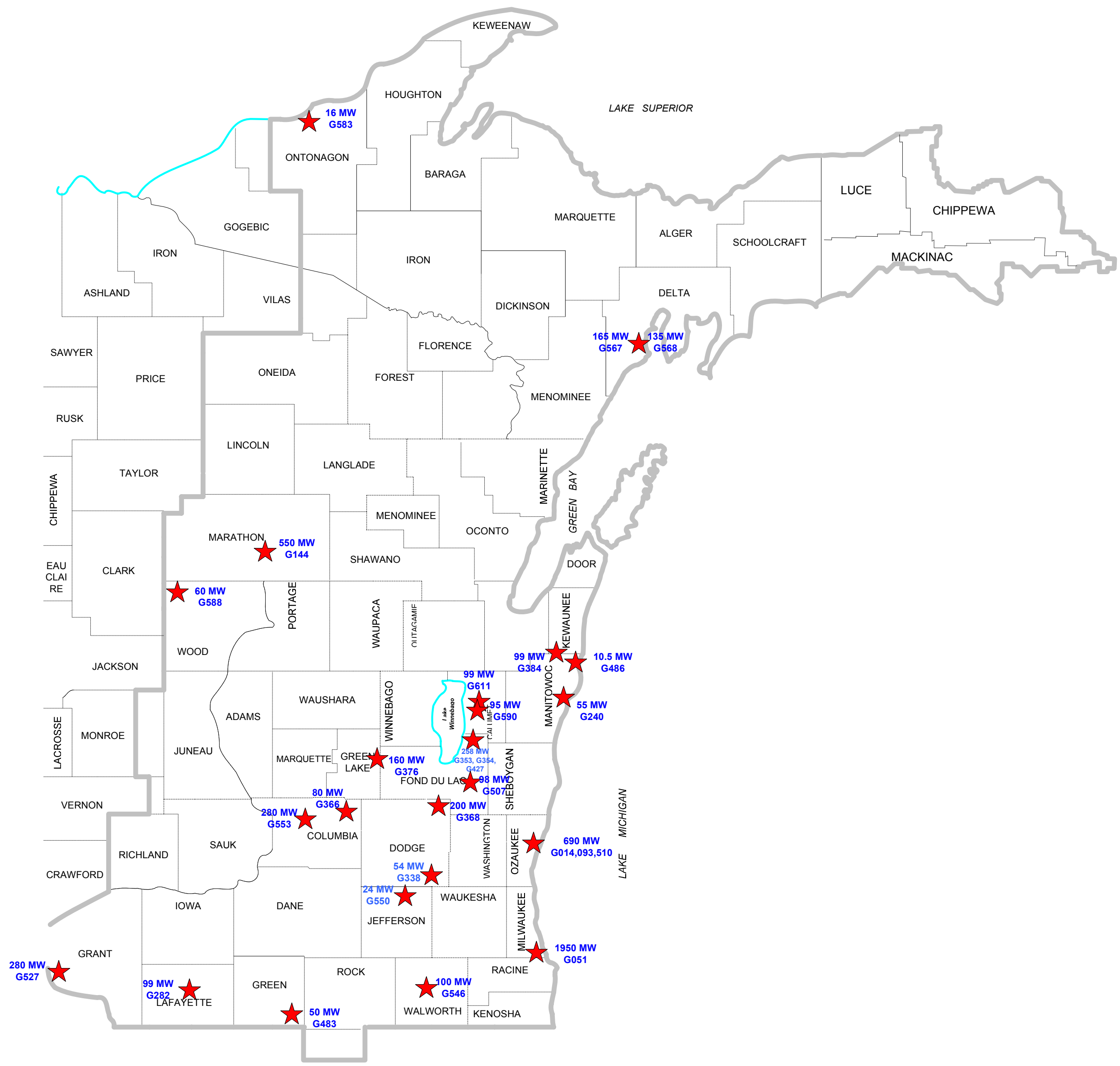
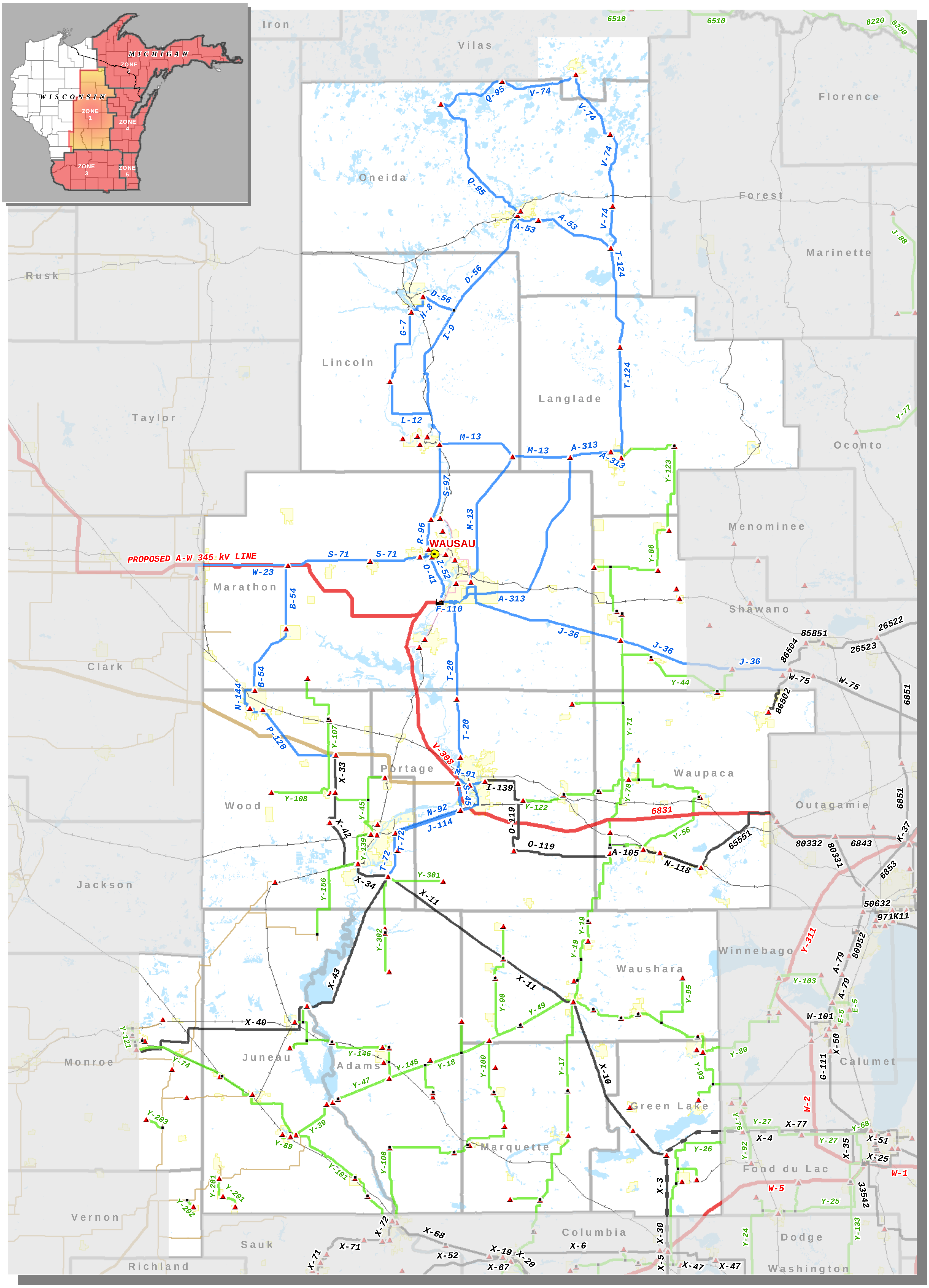


Figure ZS-17



Electric Transmission Network & Substations

PLANNING ZONE 1

0 2.5 5 10 15 Miles

AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Currently, ATC owns or operates transmission facilities in 50 Wisconsin counties and in 15 Michigan counties. Facilities include:
- *Approximately 8900 miles of transmission lines*
- *101 wholly owned substations*
- *394 jointly owned substations*
- *Offices in Madison (2), Cottage Grove, Pewaukee, De Pere Wausau and Kingsford, MI*

Transmission Line Voltage

69 kV
115 kV
138 kV
230 kV
345 kV
69 kV Double Circuit
115 kV Double Circuit
138 kV Double Circuit
230 kV Double Circuit
345 kV Double Circuit
69 kV Underground
138 kV Underground
Non-ATC Line

Transmission Related Facilities

Substation or Switchyard
Tap or Switching Structure
Facility (Design or Construction)
ATC Office Location
Generation

The information presented in this map document is advisory and is intended for reference purposes only. American Transmission Company owned and operated facility locations are approximate.

Zone4 11x17.mxd Modified: March 23, 2006

Figure ZS-18

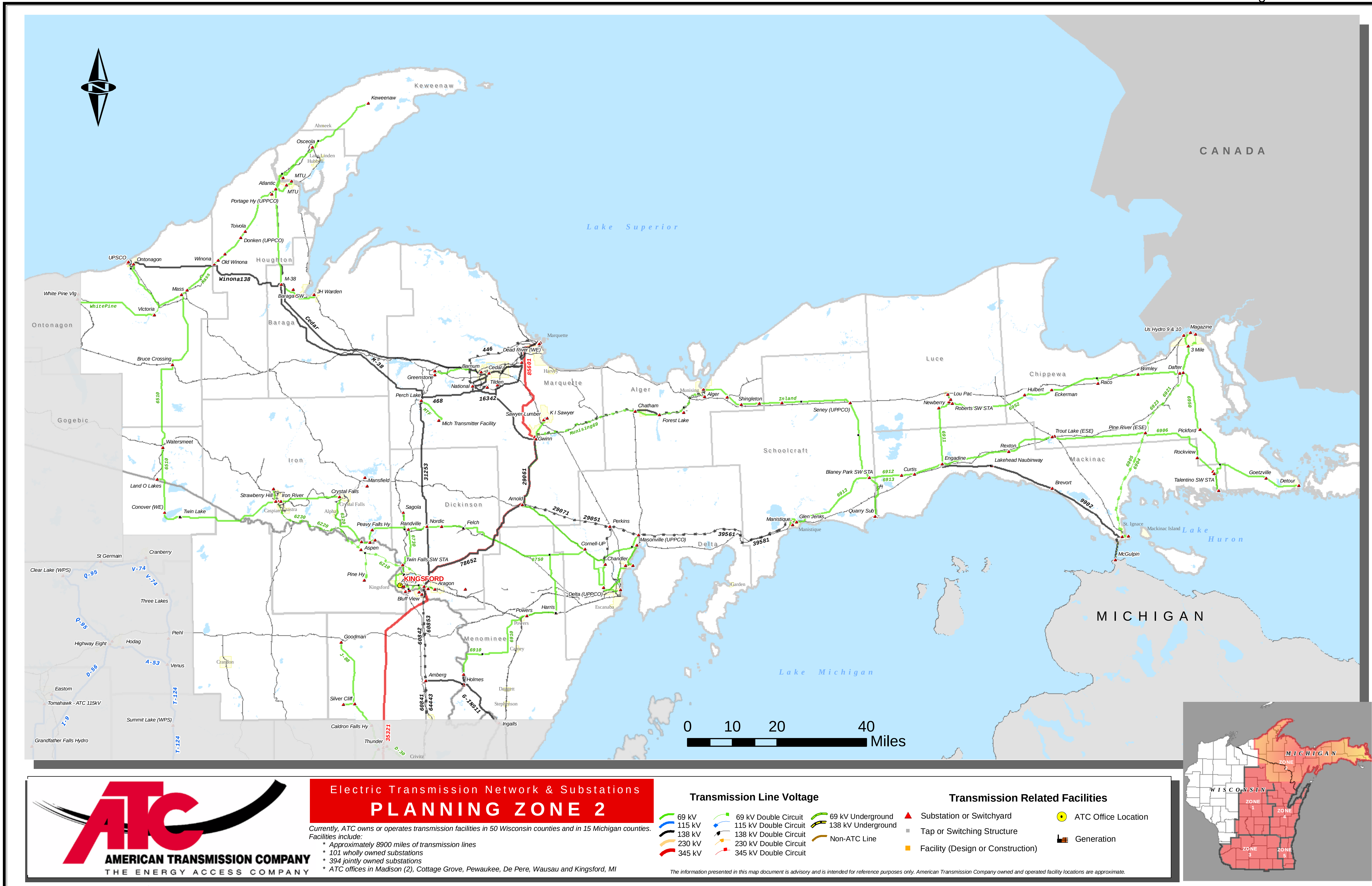

Electric Transmission Network & Substations
PLANNING ZONE 2
Currently, ATC owns or operates transmission facilities in 50 Wisconsin counties and in 15 Michigan counties. Facilities include:
* Approximately 8900 miles of transmission lines
* 101 wholly owned substations
* 394 jointly owned substations
* ATC offices in Madison (2), Cottage Grove, Pewaukee, De Pere, Wausau and Kingsford, MI
AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY
Transmission Line Voltage
69 kV
115 kV
138 kV
230 kV
345 kV
69 kV Double Circuit
115 kV Double Circuit
138 kV Double Circuit
230 kV Double Circuit
345 kV Double Circuit
69 kV Underground
138 kV Underground
Non-ATC Line
Transmission Related Facilities
Substation or Switchyard
Tap or Switching Structure
Facility (Design or Construction)
ATC Office Location
Generation
The information presented in this map document is advisory and is intended for reference purposes only. American Transmission Company owned and operated facility locations are approximate.
0 10 20 40 Miles
CANADA
MICHIGAN
Lake Superior
Lake Michigan
Lake Huron
Keweenaw
Houghton
Baraga
Ontonagon
Gogebic
Iron
Marquette
Alger
Luce
Chippewa
Schoolcraft
Mackinac
Delta
Dickinson
Menominee
KINGSFORD
MICHIGAN
WISCONSIN
ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
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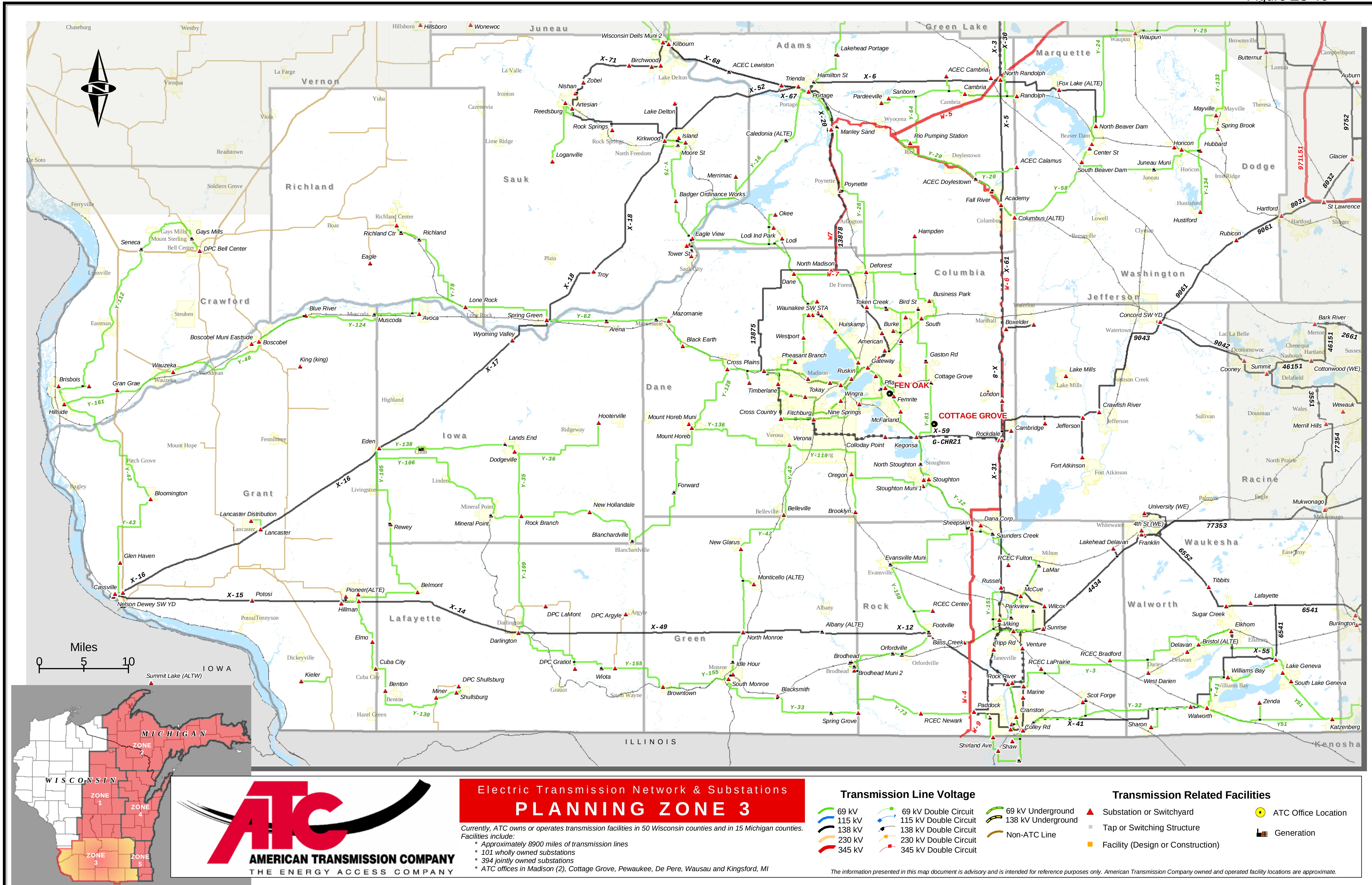
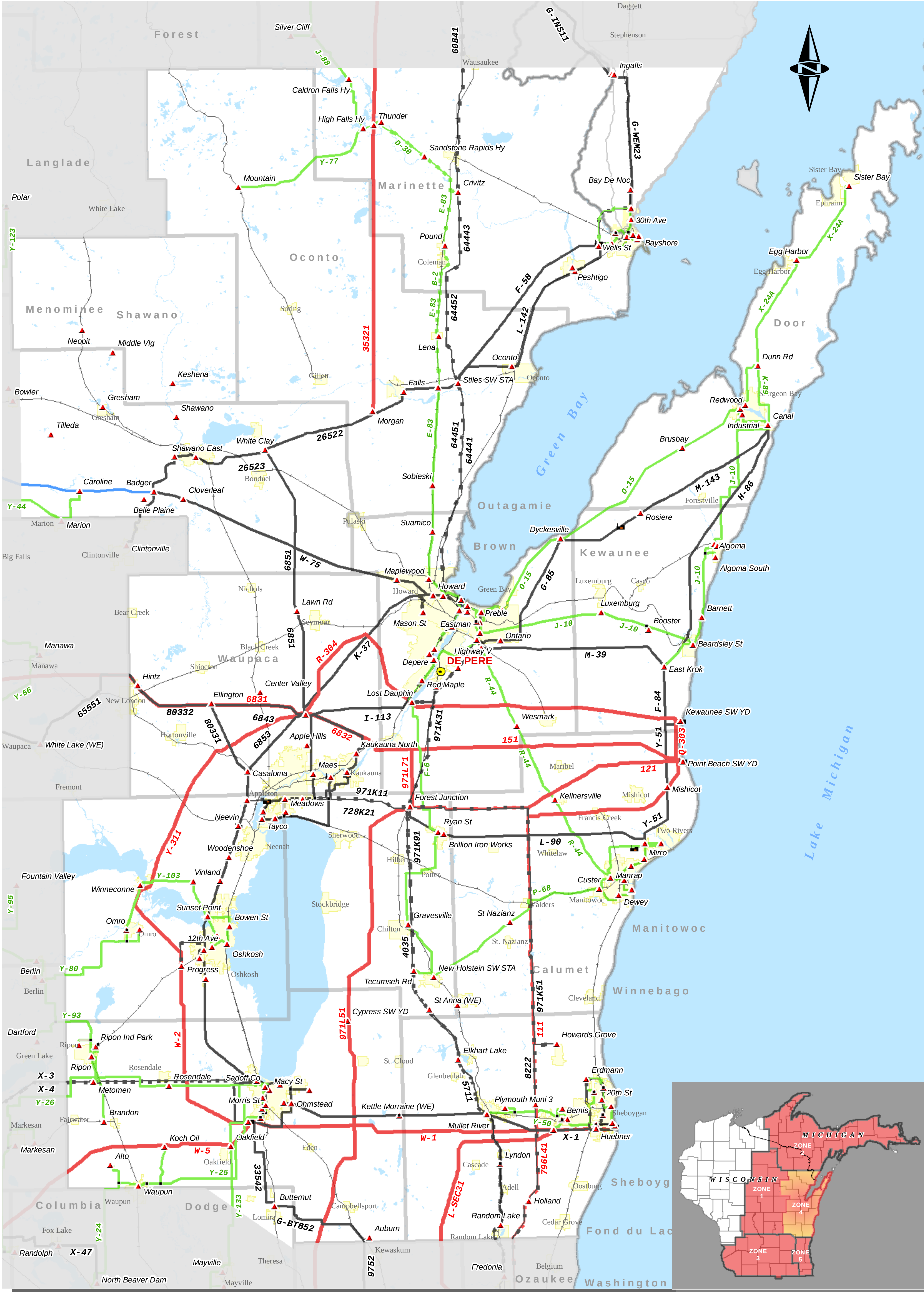
Figure ZS-19



Zone3 11x17.mxd Modified: March 23, 2006

Figure ZS-20



AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Electric Transmission Network & Substations

PLANNING ZONE 4

0 5 10 20 Miles

Currently, ATC owns or operates transmission facilities in 50 Wisconsin counties and in 15 Michigan counties. Facilities include:

* Approximately 8900 miles of transmission lines
* 101 wholly owned substations
* 394 jointly owned substations
* Offices in Madison (2), Cottage Grove, Pewaukee, De Pere Wausau and Kingsford, MI

Transmission Line Voltage

- 69 kV
- 115 kV
- 138 kV
- 230 kV
- 345 kV
- 69 kV Double Circuit
- 115 kV Double Circuit
- 138 kV Double Circuit
- 230 kV Double Circuit
- 345 kV Double Circuit
- 69 kV Underground
- 138 kV Underground
- Non-ATC Line

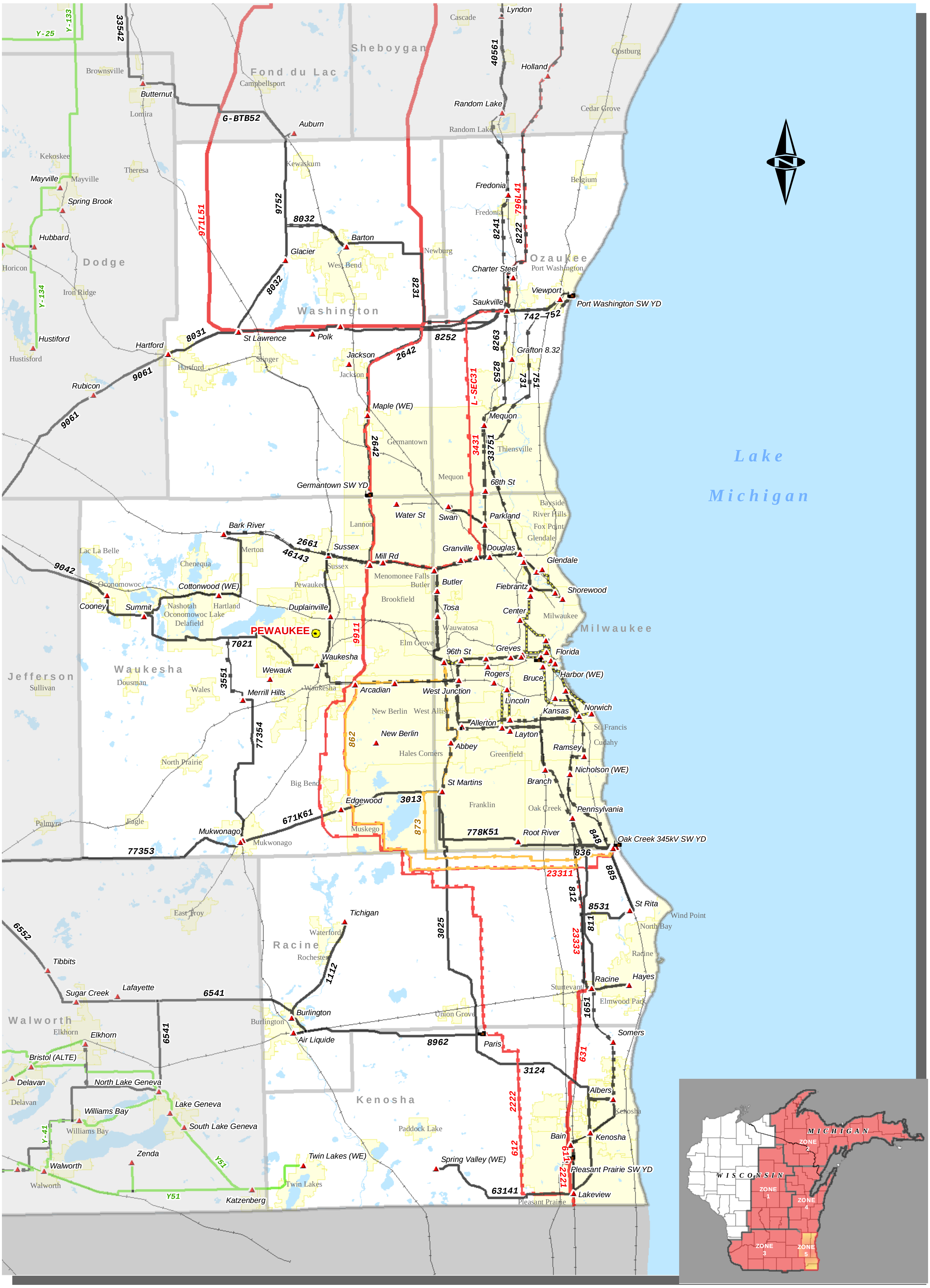
Transmission Related Facilities

- Substation or Switchyard
- Tap or Switching Structure
- Facility (Design or Construction)
- ATC Office Location
- Generation

The information presented in this map document is advisory and is intended for reference purposes only. American Transmission Company owned and operated facility locations are approximate.

Zone4 11x17.mxd Modified: March 23, 2006

Figure ZS-21



AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Electric Transmission Network and Substations

PLANNING ZONE 5

0 5 10 Miles

Currently, ATC owns or operates transmission facilities in 50 Wisconsin counties and in 15 Michigan counties. Facilities include:

* Approximately 8900 miles of transmission lines
* 98 wholly owned substations
* 358 jointly owned substations
* Offices in Madison (2), Cottage Grove, Pewaukee, De Pere Wausau and Kingsford, MI

Transmission Line Voltage

69 kV
115 kV
138 kV
230 kV
345 kV
69 kV Double Circuit
115 kV Double Circuit
138 kV Double Circuit
230 kV Double Circuit
345 kV Double Circuit
69 kV Underground
138 kV Underground
Non-ATC Line

Transmission Related Facilities

Substation or Switchyard
Tap or Switching Structure
Facility (Design or Construction)
ATC Office Location
Generation

The information presented in this map document is advisory and is intended for reference purposes only. American Transmission Company owned and operated facility locations are approximate.

Zone5 11x17.mxd Modified: March 23, 2006