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 improved 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. Evolving NERC Reliability Standards also continue to affect and be incorporated into ATC's Planning Criteria which help us make sure we are planning to maintain and enhance the system reliability and flexibility for our customers. 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
- New generation or changes
- Transmission service requests
- System repair or replacement
- Regional needs
- Economic/Strategic expansion
- Developing Regulatory and Planning Criteria Changes

In addition, the scope of these expansion drivers is affected by developing regulatory changes.

Electric load growth – The forecasted load growth driver in this Assessment is slightly lower than in the previous Assessment. Demand for electricity during peak load periods is projected to grow at a rate of 1.1 percent across our service territory from 2011 through 2021. 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 enhancements and/or expansion.

Figure PF-1 shows the projected growth in peak demand, in MW, from 2011 through 2021 for various areas of our system. Note that most of the high growth (greater than 20 MW) is in the larger metropolitan Milwaukee and Madison. 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 including areas in Wisconsin like Lake Geneva, Abrams, and Rhinelander, and areas in Michigan like Marquette and St. Ignace were not depicted as being among the highest MW growth areas in Figure PF-1.

These areas of high growth rates may actually be 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 the planned TDIs on ATC's system can be found at: *http://www.atcllc.com/oasis/liqueue.xls.* Please also refer to our Transmission-Distribution Interconnection section for more details.

New generation or changes - 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 or increased 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.

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. Facilities being planned or constructed to address condition or obsolescence issues can be found in Tables PR-2 through PR-23. In the Need Category column, look for "condition." Please also refer to Tables AR-1 through AR-5 for a listing of our asset renewal projects.

Regional needs - Our transmission system is interconnected directly with neighboring systems and is operated in conjunction with all transmission systems within MISO and ultimately the eastern interconnection. Because these transmission systems work together and not independently, regional planning to identify and plan for needs at a regional level is necessary.

ATC provides its system plan to MISO for coordination within MISO's regional plan, known as MISO's Transmission Expansion Plan (MTEP). ATC and MISO collaborate to facilitate MISO's review of the projects. MISO reviews the transmission projects and alternatives where applicable, submitted by ATC to verify the reliability or economic needs, to ensure they do not have an adverse effect over the MISO footprint and to determine if they could be combined in conjunction with transmission projects from other transmission owners to develop the most cost-effective alternatives.

ATC also participates in regional studies that investigate transmission needs across footprints of multiple transmission owners. For example, ATC participates in regional studies coordinated by MISO such as the Regional Generation Outlet Study (RGOS) that investigates transmission plans to integrate wind generation that supports the MISO state Renewable Portfolio Standard (RPS) requirements and beyond. ATC also meets with adjacent transmission owners to coordinate planning in an effort to develop transmission solutions that resolve reliability issues that impact multiple transmission owners at the lowest reasonable cost. Please refer to the Regional Analyses section for more information on ATC's participation in regional planning activities.

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. 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 and compliant, they must have the flexibility to take advantage of trends that have the potential to lower costs and to comply with renewable portfolio requirements. 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 outlined further in our Economic Planning section.

Developing Regulatory and Planning Criteria Changes - Changes in regulatory rules and policy affecting generation and transmission may also drive transmission system expansion. FERC has recently issued Order 1000 which will have a significant impact on how transmission is planned and built in the U.S. The order impacts the way transmission is planned by requiring Regional Transmission Organizations (RTO) such as the Midwest ISO to plan for public policy requirements such as Renewable Portfolio Standards and EPA regulations and to coordinate their planning with their neighboring RTOs and other transmission providers. The order requires every RTO to have a regional cost-allocation method for regional and inter-regional projects. The order also opens the door to more competition in building regional, cost-shared transmission projects although state and local laws regarding transmission construction are not affected. Generation uncertainties are growing due to proposed Environmental Protection Act (EPA) regulations. We are working closely with generation owners and the Midwest ISO to anticipate reliability impacts to our transmission system. NERC is working on increasing the reliability level dictated in its transmission planning standards, very likely eliminating load shedding as options for some multiple outages.

We are also considering the reliability of our system in light of a NERC Category 2 event dropping more than 400 megawatts of load on May 10, 2011. This event was caused by a single lightning strike affecting two lines on a common tower during the maintenance outage of another area line in off-peak load conditions. ATC is considering a guideline to define a new credible contingency suggested by this event and other similar events in the past.

Considering FERC Order 1000 with proposed EPA regulations, changing NERC standards, and new credible contingencies, ATC has embarked on a study of the impacts these changes would have on transmission reinforcements. We are starting with the high-retirements scenario for the Upper Peninsula of Michigan expanding it to northeast Wisconsin and including the new credible contingencies. In the Fall of 2011, ATC expects to identify some preliminary packages of projects that work with the existing northeast Wisconsin and Upper Peninsula projects to position us to continue to address generation change, load change, and new transmission contingency concerns.

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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 for importing and exporting 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 Economic Planning Initiative, taking a comprehensive look at the technical feasibility and economic impacts of constructing new transmission lines within ATC and/or to neighboring states.

- **Transmission-distribution interconnection process** – In response to the relatively large number of proposed T-D interconnections, we have developed a process that provides guidelines for our joint Best Value Planning (BVP) efforts. Four BVP levels have been identified to help ATC and its customers identify the appropriate effort to develop potential interconnections. BVP levels are determined based on the assumed scope of work for ATC according to the most likely option for interconnecting the customer facility(ies). A level one BVP assumes that ATC has virtually no capital costs to interconnect the customer. A level four BVP assumes that ATC has to develop a project that requires PSCW regulatory approval (CA or CPCN). Please refer to ATC's D-T Interconnection Business Practice for details.

- **Control of transmission construction costs –**Our customers desire reliable access to the transmission system as cost-effectively as possible. To accomplish the, ATC has implemented project delivery methodologies based on best in class construction industry practices. These practices include front end planning to identify and lock in scope, partnerships with key suppliers to provide for additional expertise, constructability reviews to improve safety performance and drive costs out utilizing risk management to improve predictability of schedules and costs. We have used these processes and procedures to successfully deliver projects on budget and on schedule.

- **Integration of transmission and generation planning –** Our transmission systems transmission capacity fluctuates with generation installation, retirements and dispatch. As a consequence, generation interconnections cannot be effectively pre-analyzed on a generic basis. 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. EPA regulations including the recently passed clean air act has caused uncertainty with how generation will be affected within the reliability analysis assumptions. Some units will install equipment to satisfy the new requirements, some will retire, some will convert to gas affecting existing output and current assumed order of dispatch.

  We continue to explore potential methods to allow more effective integration of generation and transmission planning in a way that recognizes the limitations of generic analysis and is consistent with federal regulatory obligations while considering the recent uncertainties described above. In addition, we continue to work concurrently with our customers to balance market-sensitive long-range plans, confidential market-sensitive information, and the desire to better integrate these plans.

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Planning criteria

This document describes the system planning criteria that ATC will utilize to ensure that the ATC transmission system is adequate to support effective competition in energy markets, reliably deliver power to systems connected to and customers dependent upon ATC's transmission system, provide support to distribution systems interconnected to ATC's transmission system and deliver energy from existing and new generation facilities connected to the ATC transmission system. This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies being employed and new operating procedures, as appropriate. The criteria described below will be subject to change at any time at ATC's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

The planning criteria are listed under the following headings:

1) System performance criteria
2) Capacity benefit margin criteria
3) Transmission reserve margin criteria
4) Facility rating criteria
5) Model building criteria
6) Facility condition criteria
7) Planning zones
8) System alternatives
9) Load forecast criteria
10) Economic criteria
11) Environmental criteria
12) Other considerations

1. SYSTEM PERFORMANCE CRITERIA

System performance over a ten year planning horizon will be assessed at least annually. Such assessments will involve steady state simulations and, as appropriate, dynamic simulations.

Steady state assessments

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

1) Summer peak
2) Summer 90/10 proxy peak
3) Summer shoulder peak
4) Winter peak
5) Fall/spring off-peak
6) Light load
7) Minimum load

At a minimum, two of the first three load conditions or similar models will be assessed in all long-range planning studies. The last four load conditions may be considered when more detailed analyses are being conducted of specific alternatives developed to solve a particular problem. The specific criterion associated with each of the load conditions above is provided in Section 9, Load Forecasting Criteria**.**

General applications of the steady state cases:

1) **Summer peak** - Determination of summer peaking area seasonal load serving and regional supply limitations, including voltage security assessments.
2) **Summer 90/10 proxy peak** - 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 proxy forecast will be used to help prioritize and stage projects but it will not necessarily be used as the sole reason to justify projects.
3) **Summer shoulder peak** - This intermediate load level case type is used primarily to evaluate contingencies where transmission equipment may be intentionally outaged for maintenance or testing purposes in addition to assessing system biases or high system imports into the ATC foot print.
4) **Winter peak** – Determination of winter peaking area seasonal load serving limitations.
5) **Fall/spring off-peak** - This intermediate load level case is used primarily to evaluate contingencies where transmission equipment may be intentionally

outaged for maintenance or testing purposes and identify seasonal regional transfer impacts.

6) **Light load** - The light load level case is used to study the possibility of high voltages on the power system, capacitor switching studies, and potential equipment overloads near base load power plants due to reduced local demand. (The light load case model is representative of many more hours in the year than the minimum load model).
7) **Minimum load** – The minimum load case is typically used to review the expected voltage range at distribution interconnection points and for determinations of adequate voltage control. Typically the highest bus voltages will occur with an intact transmission system during minimum load conditions.

<u>Dynamic stability assessments overview</u>

The dynamics cases are built to be consistent with the regional dynamics database except for the load modeling, which may consist of appropriate load and motor modeling for voltage stability assessments. Dynamic stability assessments will include consideration of the following system load conditions:

1) Summer peak
2) Light load

General applications of the dynamics cases:

a. **Summer peak** – This load condition is typically used for voltage stability studies to determine whether system disturbances during peak load conditions cause voltage instability. Also, since the performance of wind generators is more closely linked to system voltage performance, summer peak cases should be considered when assessing the performance of wind generation.
b. **Light load** – This load condition is typically used for dynamic stability assessments in order to assess the angular stability of synchronous machines (i.e. fossil fuel generators). Empirically, it is noted that the dynamic performance of synchronous machines is worse in lighter load conditions likely due to lower field excitation current.

1.1 Steady state performance assessment

Steady state performance assessments incorporating Operating Guides are done to identify potential transmission system vulnerabilities over a reasonable range of future scenarios. The steady state system performance criteria to be utilized by ATC shall include:

1.1.1 Normal conditions (NERC Category A)

1) No transmission element (transmission circuit, transformer, etc.) should experience loading in excess of its normal rating for NERC Category A conditions. This criterion should apply for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-001-0-R1)

2) The normal 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. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001). All voltage criteria should be met with the net generator reactive power limited to 90 percent of the reported reactive power capability.
(Applicable NERC Standards: TPL-001-0-R1)

1.1.2 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 forecasted system demands and associated generation dispatch conditions. Load curtailment may not be utilized in planning studies for overload relief. Field switching may not be considered as acceptable measures for achieving immediate overload relief for breaker-to-breaker contingencies. For restoration after breaker-to-breaker contingencies, field switching, Load Tap Changer (LTC) adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring element loading levels below appropriate limits.

2) 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. Temporary excursions above the applicable emergency rating are acceptable if a Special Protection System (SPS) will reduce loadings automatically (i.e. no manual intervention) to an acceptable loading level in an acceptable timeframe. The acceptable loading level after SPS operation cannot exceed the applicable emergency rating and the acceptable timeframe is determined by the type

of violation that will occur if left unmitigated (e.g., clearance violation may take several minutes whereas exceeding a relay trip setting may result in an essentially instantaneous trip).
(Applicable NERC Standard: TPL-002-0-R1)

3) Under applicable NERC Category B contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. We will consider voltage levels outside of this range, if they are acceptable to the affected transmission customer. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001). Load shedding or field switching are not acceptable measures for achieving immediate voltage restoration for breaker-to-breaker contingencies. For restoration after breaker-to-breaker contingencies, field switching, LTC adjustments, Operating Guides and/or generator re-dispatch may be considered as acceptable measures to bring voltage levels within appropriate limits.
4) 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 net generator reactive power limited to 95 percent of the applicable reactive power capability. Temporary excursions below 90% or above 110% of system nominal voltage are acceptable if a Special Protection System (SPS) or control of shunt compensation will automatically (i.e. no operator intervention) restore system voltage to temporary acceptable voltage levels (i.e. 90% to 110%) within an acceptable timeframe. The acceptable timeframe will be situation dependent and may need to be reviewed with Asset Planning & Engineering.
(Applicable NERC Standard: TPL-002-0-R1)
5) 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.
6) For assessments conducted using applicable MRO and RFC region-wide firm load and interchange levels (i.e. no market or non-firm system bias), generator 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.

1.1.3 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 forecasted system demands and

associated generation dispatch conditions. Overload relief methods may include supervisory controlled 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-R1)

2) Under applicable NERC Category C contingencies, the temporary acceptable voltage range is 90 percent to 110 percent of the system nominal voltage. Exceptions for certain interconnected entities are evaluated accordingly. Methods of restoration to normal voltage range may include supervisory control of the following: capacitor banks, LTC's, generating unit voltage regulation, generation re-dispatch, 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 net generator reactive power limited to 95 percent of the applicable reactive power capability. For Category C contingencies, consideration may be given to operating procedures that are designed to shed a minimum amount of load.
(Applicable NERC Standard: TPL-003-0-R1)

1.1.4 Extreme disturbance conditions (NERC Category D)

1) The MRO/RFC 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 or 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-R1)

1.2 Transient and dynamic stability performance assessment

Transient and dynamic stability assessments of the planning horizon are generally performed by the Transmission Planning Department to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse, and system reactive power resources within 20 seconds after a system disturbance.
The ATC Operations Department performs an operating horizon assessment taking into account operating horizon assumptions that may differ from the planning horizon assessment for certain three phase fault scenarios which are documented in certain ATC Transmission Operating Procedures (TOP). The operating procedures reference any special circumstances in the planning studies and assessments and apply real time risk methodologies as outlined in the TOP procedures. (*Note: There may be other potential OPS planning tasks that may interface with Transmission planning tasks*).
The transient and dynamic system stability performance criteria to be utilized by ATC for planning purposes shall include the following factors.

1.2.1 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-R1)
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-R1)
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 due to breaker failure (D2) and three-phase faults on a transmission transformer with delayed clearing due to breaker failure (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-R1)
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-R1)
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 where acceptable damping is defined in Section 1.2.B.2 below

B. Voltage stability assessment

a. Voltage recovery within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance[i].

b. Voltage recovery within 80 percent and 120 percent of nominal for 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-R1, TPL-002-0-R1, TPL-003-0-R1, TPL-004-0-R1)

1.2.2 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, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.
(Applicable NERC Standard: TPL-002-0-R1)

2) With all generating units at their prescribed base case (normally full) real power output, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of any two transmission circuits on a common structure.

Note: Well damped angular oscillations need to meet one of the following two criteria:

1. The generator rotor angle peak-to-peak magnitude is within 1.0 degree or less at 20 seconds after the switching event.
2. The generator average damping factor for the last five cycles of the 20 second simulation is 15.0 percent or greater after the switching event.

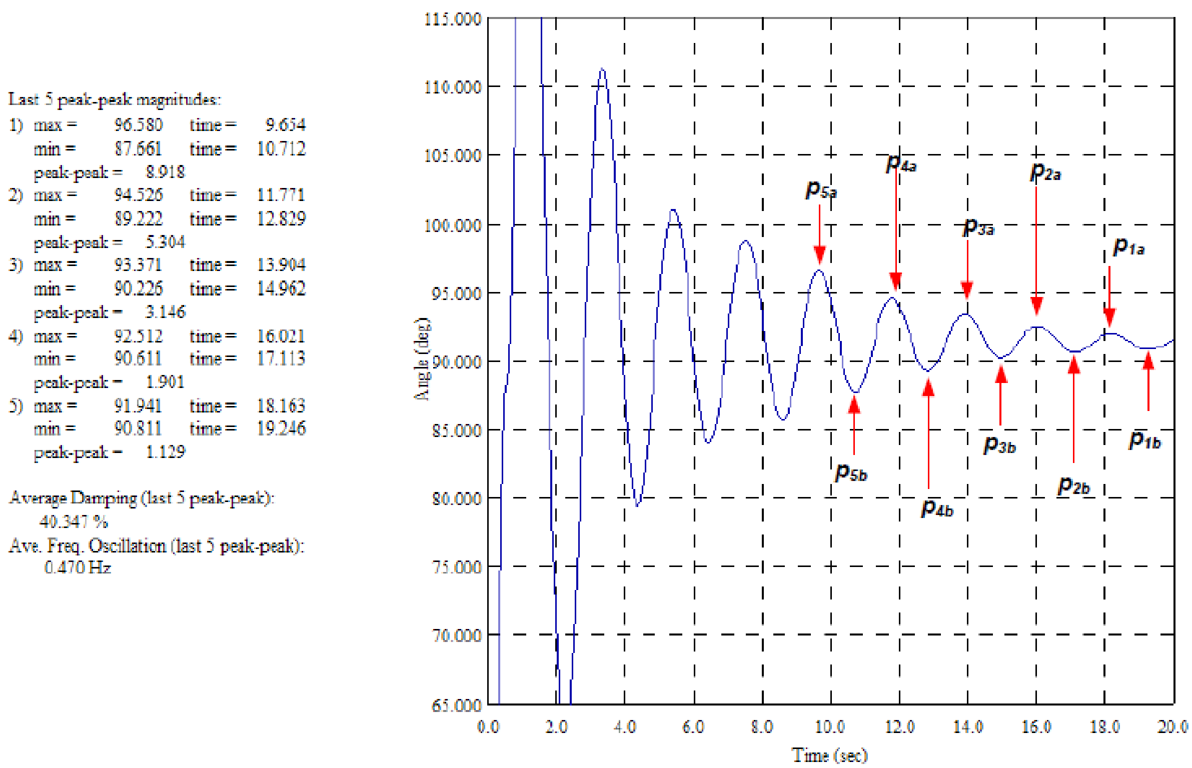
   Average Damping Factor (%) = $\left(\frac{d_1 + d_2 + d_3 + d_4}{4}\right) \times 100$

   Where

   d_n = (1-$SPPR_n$) where $SPPR_n$ (Successive Positive Peak Ratio) is the ratio of the peak-to-peak amplitude of a rotor angle swing (nth cycle back from the 20 second simulation time) to the peak-to-peak amplitude of a rotor angle swing on the previous cycle (n+1th cycle back from the 20 second simulation time).

   $$d_4 = 1 - \frac{p_4}{p_5},\ d_3 = 1 - \frac{p_3}{p_4},\ d_2 = 1 - \frac{p_2}{p_3},\ d_1 = 1 - \frac{p_1}{p_2}$$

Example



$p_1 = p_{1a} - p_{1b} = 1.129$

$p_2 = p_{2a} - p_{2b} = 1.901$

$p_3 = p_{3a} - p_{3b} = 3.146$

$p_4 = p_{4a} - p_{4b} = 5.304$

$p_5 = p_{5a} - p_{5b} = 8.918$

$d_1 = 1 - (1.129/1.901) = 0.406102$

$d_2 = 1 - (1.901/3.146) = 0.395741$

$d_3 = 1 - (3.146/5.304) = 0.406863$

$d_4 = 1 - (5.304/8.918) = 0.405248$

Average Damping Ratio = $(d_1+d_2+d_3+d_4) \times 100 / 4 = 40.35\%$

1.3 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 criteria are described below.

The following flicker level criteria are to be observed at minimum nominal system strength with all transmission facilities in service. Minimum nominal 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 flicker 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 nominal, system strength should be considered.

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

1) *Relative steady state voltage change* is typically limited to 3 percent of the nominal voltage for intact system condition simulations. For new projects, it is also typically limited to 5 percent under outage conditions. The relative steady state voltage change is the difference in voltage before and after an event, such as capacitor switching, load 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 0.001 and 24 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to12 Hz range) sub-synchronous frequencies with magnitudes from 0.35 percent to 8 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 1453-2004 (Table A.1) 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.

1.4 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. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met. 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. The voltage distortion limits and current distortion limits are specified in the Tables 1-4 below.

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. 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.

Table 1 – IEEE 519 Voltage Distortion Limits

Bus Voltage at Point of Common Coupling	Individual Voltage Distortion (%)	Total Voltage Distortion (%)
69kV and below	3.0%	5.0%
69.001kV through 161kV	1.5%	2.5%
161.001kV and above	1.0%	1.5%

Note 1: These limits should be used as system design values for the "worst case" for normal operation (conditions lasting longer than one hour). For periods lasting less than one hour, these limits may be exceeded by 50%.

Note 2: High-voltage systems (>161kV) can have up to 2% Total Voltage Distortion when caused by an HVDC terminal whose harmonics are attenuated by the time it is tapped by a

Table 2 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 120V to 69kV and All Power Generation Equipment Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<20	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25% of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the I_{SC}/I_L<20 limits listed in this table, regardless of actual I_{SC}/I_L.

Table 3 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 69.001kV and 161kV Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<20	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
20<50	3.5%	1.75%	1.25%	0.5%	0.25%	4.0%
50<100	5.0%	2.25%	2.0%	0.75%	0.35%	6.0%
100<1000	6.0%	2.75%	2.5%	1.0%	0.5%	7.5%
>1000	7.5%	3.5%	3.0%	1.25%	0.7%	10.0%

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25% of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the I_{SC}/I_L<20 limits listed in this table, regardless of actual I_{SC}/I_L.

Table 4 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Above 161kV Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order					
	< 11	11<=*h*<17	17<=*h*<23	23<=*h*<35	35<=*h*	TDD
<50	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
>50	3.0%	1.5%	1.15%	0.45%	0.22%	3.75%

2. CAPACITY BENEFIT MARGIN CRITERIA

Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved to enable access by LSEs to generation from interconnected systems to meet generation reliability requirements, such as meeting firm load obligations during a capacity emergency. 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.

As in MISO planning studies, ATC planning studies (other than the flow based analysis required for Midwest ISO (MISO) transmission service studies) will not model CBM. CBM is instead accommodated by ensuring that zones have the necessary emergency import capability through Loss of Load Expectation (LOLE) studies performed by the Midwest ISO and governed by the obligations of the MISO Module E of Energy Markets Tariff (EMT). If a deficiency is identified, we will incorporate any resulting incremental import capability requirements into ATC's overall transmission expansion plan.

MISO performs annual LOLE studies to determine the installed planning reserve margin that would result in the Midwest ISO system experiencing one loss of load event every ten years on average. This equates to a yearly LOLE value of 0.1 days per year. This value is determined through analysis using the GE Multi-Area Reliability Simulation (MARS) software. PROMOD software is used to perform a security constrained economic dispatch analysis which determines congestion related zones which are used in the MARS modeling. This analysis occurs on an annual basis to determine the zones and planning reserve margin for the next planning year as well as two other analysis years in the ten-year horizon.

As part of the LOLE studies, MISO calculates the Generation Capability Import Requirement (GCIR) for each zone. An import level equal to the GCIR level for each zone is simulated, and the MW impacts on each defined flowgate are recorded. For each flowgate, the highest MW impact due to a GCIR import into a zone becomes the calculated CBM for that flowgate

Then, for each flowgate MISO compares the flowgate's calculated CBM to the Automatic Reserve Sharing (ARS) component of the Transmission Reserve Margin (TRM) for that same flowgate. Since the worst case loss of a single resource is already covered by the ARS component of TRM, this amount of capacity is not redundantly preserved as part of CBM. If the ARS component is greater than the calculated CBM, no CBM will be preserved on that flowgate. If the ARS component is less than the calculated CBM, the incremental amount of CBM that is needed above the ARS component will be preserved as CBM for that flowgate.

3. TRANSMISSION RELIABILITY MARGIN CRITERIA

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure during changing system conditions, particularly during Reserve Sharing events such as the loss of a critical single unit. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

In the planning horizon, anytime beyond 48 hours, MISO uses reservations from other transmission providers and Balancing Authority 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 component of the TRM.

The Automatic Reserve Sharing (ARS) component of TRM is the amount of transmission transfer capability required on a flowgate to deliver contingency reserves. These contingency reserves are defined as 100 percent of the greatest single contingency impacting the flowgate. The worst single contingency is determined by tripping units (or transmission elements) within the region and replacing the lost resource with a realistic dispatch for each reserve sharing member's share of the emergency energy. The worst case is the case that has the greatest incremental flow across the flowgate. The highest incremental flow on the flowgate for the contingencies evaluated (generation and transmission) will be the amount of ARS TRM required.

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.

Other ATC planning studies utilize a 3 percent reduction in normal and emergency ratings for assessments within one year and a 5 percent reduction for the assessments beyond one year in the future, except for studies that consider a wide range of system conditions (e.g., load, dispatch, transfers), such as 10-year assessments. The recommended timing of the resultant mitigation measures may be based on less than the 3 percent and 5 percent reductions.

4. FACILITY RATING CRITERIA

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

1) PR-0285 Facility Ratings Update and Application,
2) CR-0061 Conductor Ampacity Ratings for Overhead Transmission Lines,
3) CR-0063 Substation Equipment Ampacity Ratings,
4) CR-0062 Ampacity Ratings of Underground Transmission Lines

We will actively review, replace, and document legacy ratings with ratings based upon ATC criteria in our Substation Equipment and Line Database (SELD). The legacy ratings from the previous transmission facilities owner's planning and operations 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-008-1-R1)

5. MODEL BUILDING CRITERIA

We will strive to develop and maintain consistency in the powerflow models used for 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 our end-use load-serving customers as input into future model building efforts, both internally and in conjunction with NERC, Regional Entity (RE), and Regional Transmission Operator (RTO) initiatives. These forecasts may be adjusted by ATC if adjustments are needed for transmission planning purposes either with concurrence from our customers or independently of our customers. 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)

5.1 Voltage Schedule

1) The powerflow models will implement ATC's generator voltage schedule. The generator voltage schedule is defined as a:

    a. Target voltage of 102% of the nominal transmission voltage as measured at the point of interconnection between the generator and the transmission network unless another voltage schedule has been identified and,

    b. Normal voltage range of 95% to 105% of nominal transmission voltage.

   Due to limitations imposed by the NERC model building process, the generator voltage schedule target modeled in the NERC powerflow models may only approximate ATC's voltage schedule at the point of interconnection.
   (NERC VAR-001)

2) Generators that do not have automatic voltage regulation (AVR) or are not controllable (unmanned stations and no remote control) have been considered. When modeling these generators, special attention must be given to the limitations of these units.

5.2 Generation Dispatch

1) Generation reported by ATC's members will be dispatched in accordance with contractual and local or regional economic dispatch considerations as applicable.

2) Designated Network Resources will be dispatched out of merit order if they have been identified as must run units.

3) Power-Voltage (P-V) analysis models wind generation at its full output level.

4) Generator Interconnection studies will model wind generation following the guidelines in the MISO Business Practice Manual for Generator Interconnections.

5) Generally, for each system load condition case, wind generation is modeled at 20% of its reported output level for general planning studies, although sensitivity analyses may dispatch wind generators at various output levels.

5.3 Net Scheduled Interchange

1) Net scheduled interchange for the ATC system will be coordinated with the necessary regional and interregional parties.
2) Net scheduled interchange for the ATC system may be altered to evaluate realistic system conditions of significance for system planning purposes.

6. 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.

7. 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. 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 is to develop an “umbrella” plan for each 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 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.

8. SYSTEM ALTERNATIVES

We will consider alternatives to transmission solutions to problems on the transmission system as appropriate. Such alternatives could include, but are not 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.

9. LOAD FORECASTING CRITERIA

We will initially use load forecasts provided by our 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 our load-serving customers. In addition, we may, in coordination with our 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 will follow the NERC Standards 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 are assumed to be 80% of summer peak unless directed otherwise by the Load Distribution Company (LDC). Non-scalable loads remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
3) **Summer shoulder peak** demand forecasts are assumed to be 70% of summer peak. Non-scalable loads remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.

4) **Fall/spring off-peak** demand forecasts are assumed to be 70% of summer peak unless directed otherwise by the LDC. Non-scalable loads remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
5) **Summer 90/10 proxy peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. A true summer 90/10 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 summer peak conforming load forecast by about 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 such that is the conforming loads are scaled to 50 percent of the summer peak demand forecasts. Non-scalable loads will remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
7) **Minimum load (40 percent of peak)** demand forecasts will be developed such that the conforming loads are scaled to 40 percent of the summer peak demand forecasts. Non-scalable loads will remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged.

10. 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 the economic analysis of changes in transmission system losses, hourly line flow data and associated area Locational Marginal Prices (LMPs) for the entire analysis year from PROMOD will be used to analyze the potential savings from reduced transmission line losses associated with a new project (or package of projects).
3) The reduction in the need to build additional generation to serve the peak load will be calculated by comparing the losses from the power flows for the peak load hour with and without the project. To correctly do the accounting, the reduction in the generation needed to serve the peak load will be increased by the Midwest ISO's planning reserve margin. The dollar value of this savings will be based on the construction cost of a combustion turbine.

4) The LMP market simulation tool, PROMOD, will be the primary tool used to analyze the economics of projects. ATC's Customer Benefit Metric will typically be used to analyze the market savings of projects. Generally PROMOD will be run with and without the project, or package of projects, to determine the market savings. Other economic benefits may also be calculated, such as the "insurance benefit" associated with having a more robust transmission grid to respond to low probability, but high impact transmission and generation outages, which can cause market prices and costs to spike.
5) All transmission projects have both reliability and economic impacts. In certain cases, economic benefits 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 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 the Ventyx PROMOD software; however, other methods and tools are open to consideration.

11. 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.

12. VARIATIONS ON ATC PLANNING CRITERIA

The ATC transmission system consists of assets contributed by entities within the five Balancing Authorities of the Wisconsin-Upper Michigan Systems. 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 upgrades 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 Standards TPL-001, -002 or -003 with respect to stability.

a. Complete projects required for bringing the existing system up to NERC Standards TPL-001, -002 or -003 performance requirements with no intentional delay.

b. New generator interconnections are not 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 Standards TPL-001, -002 or -003. See NERC Standard FAC-002 for new generator interconnections.]

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 projects are completed. 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 Standards TPL-001, -002 or -003 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 Standards TPL-001, -002 or -003. If the new generator interconnection causes the system to be unable to meet the performance requirements of these 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 Standards TPL-001, -002 or -003 under FAC-002 – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

13. OTHER CONSIDERATIONS

13.1 Project constructability

We will consider the constructability of proposed additions, replacements or modifications to the transmission system as part of our 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 **System performance criteria** 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.

13.2 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 consider the relative 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 Standard: TPL-003-0-B, TPL-004-0-B)

13.3 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.

13.4 Maximization of existing rights-of-way

We will attempt to maximize use of existing rights-of-ways. Existing electric transmission, gas pipeline, railroad and highway corridors will be identified in all comparisons of alternatives and utilized where feasible. Environmental features of a right of way are also important to our operations. Environmental assessments are built into planning at a high level, and are continued into project assessments as projects move forward through to construction. In addition to avoiding and protecting environmentally sensitive areas, ATC is committed to working in partnership with regulators, environmental organizations and landowners to enhance areas of environmental significance.

Since 2001, ATC has been an active partner in the Wisconsin karner blue butterfly partnership and manages rights of way in the karner blue butterfly range for host and nectar plants. ATC has also sponsored education and added management partnerships for this species. ATC is also recognized as a Green Tier company, with acceptance in October 2005. Green Tier is a program administered by the state of Wisconsin to recognize excellence in environmental performance. Through this program we continue to work closely with the Wisconsin Department of Natural resources to continually improve our environmental performance.

13.5 Reduction of transmission system losses

ATC considers the benefit of reducing system losses along with other performance benefits and cost factors in evaluations of alternative transmission projects or plans. See **Economic criteria**.

<u>Transmission system operating considerations in the planning process</u>

1) Operating procedures (operating guides)
   a) 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, if they meet the following conditions:

(i) Do not compromise personnel or public safety

(ii) Do not degrade system reliability

(iii) Do not result in a significant loss of equipment life or significant risk of damage to a transmission facility.

(iv) Do not unduly burden any entity financially.

b) Supervisory switching capability is required to accomplish these operating procedures. Field switching will not be relied upon as a means to reduce facility loadings or to restore voltages to within acceptable levels.

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

2) System Planning - ATC 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.

13.6 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.

13.7 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 – Electric Reliability Organization (ERO) and RE requirements and Federal Energy Regulatory Commission (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 decisions of this type are made, then these decisions will be documented and archived for future reference.

14. 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 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 Entity, 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.

5) Specific Study Methodologies

Generator Interconnection studies will follow the study guidelines as described in the MISO Business Practice Manual for Generator Interconnections.

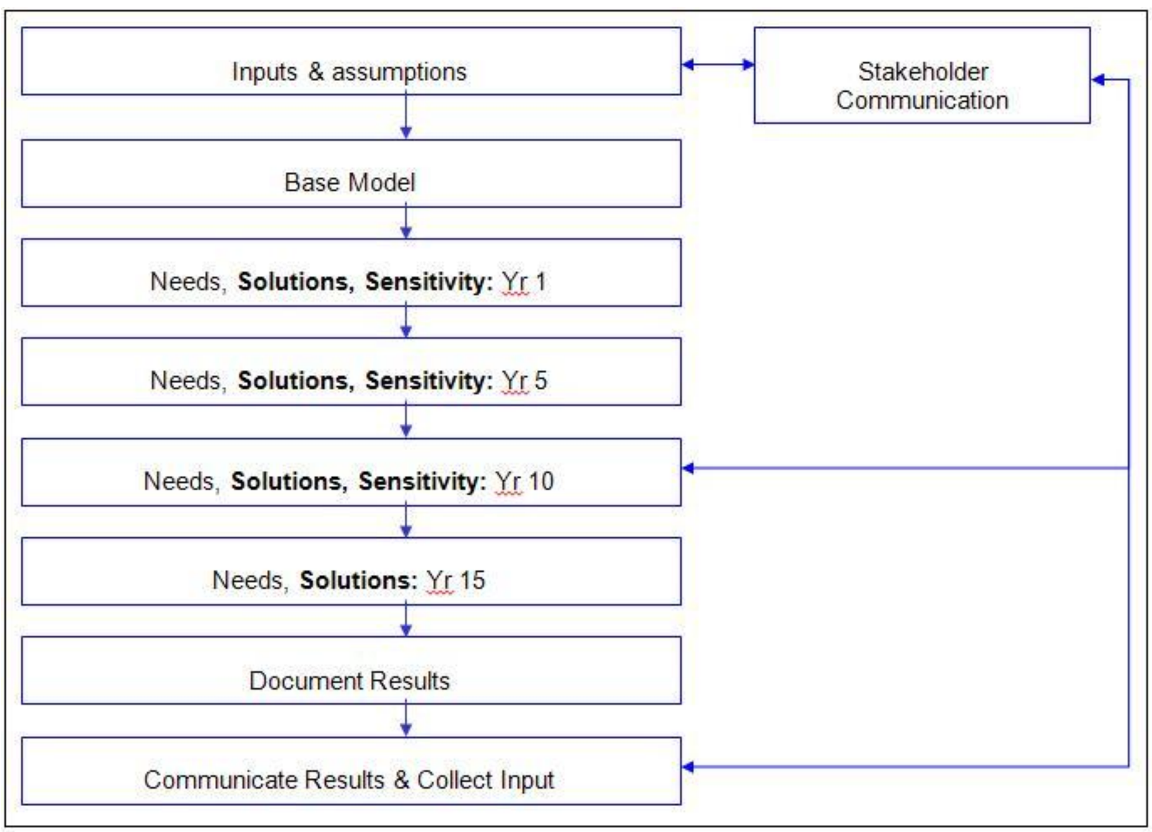
Methodology and Assumptions

1.1 Overview

This section describes the methods and techniques that we use to analyze our network transmission system for this assessment. Economic, regional, environmental and asset management planning processes are covered on other sections of this Web site.

As part of the network assessment, ATC conducted power flow analyses to identify problems or constraints on the transmission system and evaluated the merits of potential reinforcements to address the system limitations that were identified. Once these analyses are complete, ATC meets with our stakeholders to discuss the preliminary results.

ATC's network planning process is summarized in the below figure:



Included in this section is a discussion of which years ATC identified to model to satisfy both the near-term (1 – 5 year horizon) and long-term (5 year and beyond horizon) NERC standards for assessing the transmission system. Also included in this section is discussion on how ATC built each of the models used in this assessment. Discussion items include topics such as load forecasting, which reinforcements and new generation to include in models, which system load levels, import levels and system bias scenarios to evaluate.

During the network assessment of our transmission system, we performed simulations on a variety of models as discussed below in this section. ATC not only uses these models to identify where constraints or system limitations may exist, but we also use these models in testing the robustness of potential system reinforcements. Per our Planning criteria, constraints or system limitations are identified for NERC Category A type system conditions when bus voltages drop below 95 percent or exceed 105 percent of their nominal voltage or when any system element exceeds it normal rating for the appropriate seasonal model. For NERC Category A or system intact conditions, ATC's Planning criteria also requires for generators to be limited to 90 percent of their maximum reactive power capability within ATC's footprint.

For NERC Category B, C or D contingencies, system limitations or constraints are identified using slightly different criterion. For these types of system contingency conditions, ATC's Planning Criteria identify system limitations when bus voltages drop below 90 percent or exceed 110 percent of their nominal voltage or when any system element exceeds its emergency rating for the appropriate seasonal model. For these three NERC categories, ATC's Planning Criteria requires generators to be limited to 95 percent of their maximum reactive power capability within ATC's footprint. Exceptions to the voltage range criteria apply for certain interconnected entities, and are evaluated in accordance to their signed interconnection agreements. Voltage range exceptions also apply to underground and underwater cables.

The analyses conducted in this transmission system assessment included steady state power flow analyses, stability simulations, multiple outage impacts as well as economic evaluations, generator interconnection impacts, transmission-distribution interconnection impacts and environmental assessment impacts.

1.2 Network Assessment Methodology

American Transmission Co.'s 2011 10-Year Transmission System Assessment provides current results of planning activities and analyses of the company's transmission facilities. These activities and analyses identify needs for network transmission system enhancement and potential projects responsive to those needs.

Since 2001, we have engaged in open and collaborative efforts to share information and solicit input on our plans. We believe that in making our planning efforts transparent and available to the public, the proposals for needed facilities can be more readily understood and accepted by communities that stand to benefit from them. In recent years the federal government has taken additional steps to ensure that transmission-owning utilities have produced and shared planning information with the public and local stakeholders.

The information in this report provides further foundation for continued public discussions on the transmission planning process, identified transmission needs and limitations, possible resolutions to those needs and coordination with other public infrastructure planning processes.

Computer simulation model years for the 2011 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2012 and 2016 were selected to meet the 1-5 year horizon. The years 2021 and 2026 meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2011 Assessment. Steady state peak load models for all four years were created. In order to determine how close ATC generators were to their maximum reactive power output, two additional models were created for each year. The first model for each year studied reduced ATC generator maximum reactive power by 10 percent. These models were utilized to determine generator reactive power output under intact system conditions (TPL-001-0). A second model for each year was created with net maximum reactive power capability reduced by 5 percent. These models were used for our N-1 (TPL-002-0) analysis.

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

This 2011 network Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2012 were included in the 2012 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 2016, 2021 and 2026 models as appropriate based on projected in service dates (See Tables PF-2, PF-3 and PF-4).

1.2.1 Load forecast

Steady state summer peak models are built using our customers' load forecasts (50/50 projections) as a starting point, meaning that there is a 50 percent chance that the load level will either fall below or exceed the customer projection. Customer load forecasts were gathered for all ATC customers through the year 2020 (and in some cases 2021/2026). The forecasts were compared to previous historical and forecasted data to ensure validity and consistency. As a final step, the finalized forecast information was forwarded back to our individual customers to ensure their concurrence. Once consensus was achieved, the data was incorporated into our models.

Certain ATC customers did not provide an 11th-year load forecast for the year 2021. To obtain a forecast for 2021, certain customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their 2020 levels. Non-scalable loads were also held at their 2020 levels using this methodology.

The 2026 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2026, customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their 2020 (or 2021) levels. Non-scalable loads were once again held at their 2020 (or 2021) load levels. It should be noted that the loads utilized in the 2026 summer peak model do not reflect an actual load forecast, but merely a projection (or “load model”) based upon the best available information. The purpose for the 2026 projection is not to develop projects to address all issues, but to develop a sense for the need(s) for long lead-time projects.

ATC Peak Load Projections (MW) including line losses

Year	MW load	Compounded growth rate
2011	13,111	N/A
2012	13,258	N/A
2016	13,805	1.02% (2012-2016)
2021	14,531	1.03% (2016-2021)
2026	15,292*	1.03% (2021-2026)
Overall		1.03% (2011-2026)

**load model, not a load forecast*

It should be noted that we worked with the distribution companies as much as possible to confirm forecast variations from past trends. In a few cases we revised 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.

1.2.2 Model building

1.2.2.a Assumptions common to all models

The following assumptions are common to all models studied in the 10-Year Assessment. Any exceptions are listed within the respective assumption section:

- New Generation
- Generation Retirements

- Cuttoff dates
- Generation Project Schedule
- Generation outside of the System
- Generation Dispatch
- Line and Equipment ratings
- Project Criteria

1.2.2.a.1 New generation

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 Generation interconnections), 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 would be included in the 2011 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.

In the 2011 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 2011 and 2012 models showed these generators as out of service. The 2016 and 2021 models should have had these generators in-service and dispatched.

1.2.2.a.2 Generation retirements
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 sent an annual letter to each generation owner. Generating companies were 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 modeled off line 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 2011 10-Year Assessment models we assumed the following generators were to be out of service:

Plant Name	***Zone***	***Installed capacity***	***Assumed out of service***
Rock River 1	3	71 MW	Jan 2011
Rock River 2	3	75 MW	Jan 2011
Blackhawk 3	3	24 MW	Jan 2011
Blackhawk 4	3	25 MW	Jan 2011
Blount 3	3	39 MW	Jan 2013
Blount 4	3	22 MW	Jan 2013
Blount 5	3	28 MW	Jan 2013
Net decrease in 2011		195 MW	
Net decrease after 2011		284 MW	

Please note that recently some of our customer generators reduced their maximum MW outputs, but those reductions occurred after the cutoff points defined below.

1.2.2.a.3 Cutoff dates
For model building purposes, we assumed cutoff dates for generation changes to be included in models. In order to include the latest data in the models, cutoff dates correspond to the dates the models were built as follows:

- 2012 models - October 25, 2010
- 2016 models - October 25, 2010
- 2021 models - October 25, 2010

- 2026 models - October 25, 2010

It was assumed that if the generator was available as of the cutoff date, it was available for dispatch in that grouping of models.

1.2.2.a.4 Generation projects schedule
To maintain the schedule needed to complete this Assessment, the models were developed during late 2010 and early 2011. Only those generation projects that qualified to be included in our planning models as of the various cutoff dates, were included in the Assessment models. For generation projects not in service by June 2011, 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***
Point Beach #1	4	103 MW	103 MW	Dec 2011
Point Beach #2	4	105 MW	105 MW	Jul 2011
Quilt Block wind farm	3	19.6 MW	19.6 MW	Dec 2012
Glacier Hills wind farm	3	49.8 MW	49.8 MW	Dec 2011
Stoney Brook wind farm	4	19.7 MW	19.7 MW	Mar 2012
EcoMet wind farm	4	20.1 MW	20.1 MW	Dec 2012
Ledge wind farm	4	30.0 MW	30.0 MW	Dec 2012
Lake Breeze wind farm	4	19.6 MW	19.6 MW	Oct 2013
Net increase by Dec 2011		802.4 MW		
Net increase 2011-2020		49.6 MW		

**wind farm Installed capacity lists is 20% of total installed 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-9**.**)

1.2.2.a.5 Generation outside system
The model for the system external to ATC was taken from the most appropriate model included in the MMWG 2010 Series models. The external system interchange was adjusted from the 2010 MMWG Series models to match the latest ATC members' firm interchange with the exception of the Shoulder 70%, East to West Bias and the West to East Bias models which were built to represent a 3000, 1700 and 700 MW imports into ATC respectively.

1.2.2.a.6 Generation dispatch

Balancing Authority (Control) area generation was dispatched based on economic dispatch for that Balancing Authority with the exception of the Shoulder 70%, West to East Bias and Light Load models.

1.2.2.a.7 Line and equipment ratings

We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD). As of April 2011, nearly 76 percent of all ATC lines and 91 percent of ATC transformers have SELD ratings that have been validated. Additionally, nearly 97 percent of ATC lines 100 kV or higher 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.

1.2.2.a.8 Project criteria

All of the models built for the Assessment include revised system topology based on projects that were placed in service in the model year, or were anticipated to be placed in service by June 15 of that year. Refer to Tables PF-1 through PF-4 for projects that were included in the analyses. Please also refer to the Project deficient seasonal models for more discussion about how projects are chosen for inclusion our models.

1.2.2.b Steady state power flow models

1.2.2.b.1 Normal (Category A) Conditions

The load flow models for the 10-Year Assessment are built to include established (pre-contingency) operating procedures to assess system performance under the normal (Category A) conditions as required in the TPL-001-0 Reliability Standard. The relevant operating procedures are generally standing operating procedures that apply for the planning horizon. These procedures include, but are not limited to, normal open points and switched capacitor banks. Normal Open points are assumed to remain normally open in the base cases. Changes in the status of Normally Open points are provided by the system planners that participate in the decision to change the status of a Normally Open point. Switched non-mobile capacitor banks are assumed to be available for use by the system operators, except in the case of planned outages. This availability is represented by modeling these capacitor banks in the discrete adjustment voltage regulating mode. Mobile capacitor banks are modeled in the base case when there is a known date and location in the planning horizon during which the mobile capacitor bank is planned to be in service.

1.2.2.b.2 Planned Maintenance and Construction Outages

The load flow models for the 10-Year Assessment are built to include maintenance and construction outages that are planned to occur in planning horizon. These outages are typically conditions that are expected to last for a period of six months or more. The modeled outages are provided by the system planners that participate in the decision to schedule the maintenance or construction outage.

1.2.2.b.3 Protection Systems

All existing and planned protection systems, including any backup or redundant systems that would be applicable to a given contingency were simulated in the studies and analyses.

1.2.2.b.4 Control Devices

All existing and planned control devices that would be applicable to a given contingency were simulated in the studies and analyses. These control devices include transformer automatic tap changers, capacitor bank automatic controls, and Distribution Superconducting Magnetic Energy Storage (DSMES) units

1.2.2.b.5 Project deficient seasonal models

The load flow models built for the 10-Year Assessment are special models built exclusively for system analyses in the Assessment. Some projects were purposely left out of these models in order to verify system problems and determine which problems worsen over time. We have taken the approach of evaluating subsequent summer peak seasons in each of our annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2012, 2016, 2021 and 2026 steady state project deficient summer peak models were developed to evaluate needs, verify findings of the previous year's Assessment, and confirm that previously identified needs will increase over time. The 2021 and 2026 project deficient models reflect years sufficiently forward in time 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.

1.2.2.b.6 All project seasonal models

After the initial analyses portion of the 10-Year Assessment was completed, "All Project" models were built. The "All Project" models were built with all planned and proposed projects included as well as the majority of the 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 contingency analyses on each of the "All Project" models. These analyses will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the 10-Year Assessment process and will not introduce any new limitations.

1.2.2.b.7 Load, dispatch and interchange profiles

1.2.2.b.7.a Load Sensitivities (2016)
ATC planning explored two sensitivity analyses in our 2011 10-Year Assessment analyses, the minimum (light load) scenario and the west to east bias scenario. The modeling details of these sensitivities are outlined below.

1.2.2.b.7.a.1 Minimum load scenario (2012)

- ATC Load: 6,035 MW
    - 2010 forecast collection, scalable loads reduced to 40% of peak + non-scalable loads = 46% of Peak load
- Total ATC Generation: 5,856 MW
- Includes all planned and proposed projects to be in-service by 6/15/2012
- *Interchange:* Firm interchange only as of 10/25/2010
- *Dispatch:* ATC-wide Merit order as of 10/25/2010

1.2.2.b.7.a.2 West to East Bias scenario (2016, 2021)

- ATC Peak Load: 9,496 MW
    - 2010 forecast collection, scalable loads reduced to 65% + non-scalable loads = 69% of Peak load as drawn from Operations historical data
- Total ATC Generation: 9,160 MW
- Includes all planned and proposed projects to be in-service by 6/15/2016
- *Interchange:* ATC net as provided in Operations data -700 MW
- *Dispatch:* ATC-wide Merit order as of 10/25/2010
- *Special additions:*
    - Wind generation in the ATC footprint dispatched to 45% of P_{max} as drawn from Operations historical data,
    - Wind generation west of ATC dispatched to 50% as drawn from Operations historical data,
    - Wind Generation south of ATC dispatched to 55% as drawn from Operations historical data,
    - Minnesota-Wisconsin Export interface (MWEX) loaded to 1400 MW
    - Manitoba Hydro Exports set to 1,350 MW
    - All generation increases were modeled to generation reductions south and east of ATC

1.2.2.b.7.b Summer peak (2012, 2016, 2021, 2026)

- We utilized interconnection point load forecasts provided by various distribution companies in 2010 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.

❑ Only firm interchange was included in our analyses.

- Special additions: none

1.2.2.b.7.b.1 Summer peak 95% Q_{Max} (2012, 2016, 2021, 2026)
- We utilized interconnection point load forecasts provided by various distribution companies in 2010 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 95%.

1.2.2.b.7.b.2 Summer peak 90% Q_{Max} (2012, 2016, 2021, 2026)
- We utilized interconnection point load forecasts provided by various distribution companies in 2010 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 90%.

1.2.2.b.7.c High load model (2016)
- We utilized interconnection point load forecasts provided by various distribution companies in 2010. The 2016 high load (or "hot summer") model was created by increasing load 5 percent above expected summer peak conditions as a proxy for a 90/10 model in order to determine in-service date sensitivity to load growth that is higher or weather that is warmer than forecasted. Please refer to the Load Forecast section for further details.
- The system external to ATC was taken from the MMWG 2010 Series, 2016 summer model.
- The external system interchange was adjusted from the 2010 MMWG Series 2016 summer interchange to match latest ATC members' firm interchange.
- ATC load forecast increased by 5% above the summer peak load forecast using a constant power factor.

1.2.2.b.7.d Shoulder 70% models (2016, 2021)
- We utilized interconnection point load forecasts provided by various distribution companies in 2010.
- The 2016 and 2021shoulder models were created by selectively scaling down loads that generally vary by time-of-day to approximately 70 percent of the summer peak condition. A 70 percent load level was chosen to represent the shoulder model because under this scenario, flows are changing as a result of the Ludington pumping cycle. However, we recognize that loads at individual points will vary under real-time shoulder conditions.
- The shoulder 70% model included a 3000 MW import into ATC. Firm interchange plus economic transactions up to a 3000 MW import were included.

1.2.2.b.7.e Shoulder 90% models (2016, 2021)

- We utilized interconnection point load forecasts provided by various distribution companies in 2010. The 2016 shoulder 90% model was created by decreasing load 10 percent below expected summer peak conditions. Please refer to the Load Forecast section for further details.
- To simulate a steady state reverse east-west bias power flow, models were developed with 90% load levels, 1700 MW import into ATC, and a 2000 MW transaction from east to west.
- ATC system biased in an East to West direction.

1.2.2.b.7.f Model years

We started model development for this Assessment by building a system model that represented 2011 summer peak conditions. This 2011 model is referred to as an "as-planned" model because essentially everything in the model is certain to be in service by 2011 summer. This model then was modified to create each of the subsequent Assessment study models including the changes previously described for each model.

Computer simulation model years for the 2011 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2012 and 2016 were selected to meet the 1-5 year horizon. The years 2021 and 2026 meet the beyond 5 year horizon. The years 2012, 2016 and 2021 were chosen to coordinate with the most recently released MMWG models that were available.

The 2012, 2016, 2021 and 2026 models were developed to evaluate needs, verify findings of the 2010 Assessment, and confirm that previously identified needs will increase over time. The 2021 and 2026 models reflect years sufficiently forward in time 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.

1.2.2.c Dynamic stability/short-circuit assessment models

ATC conducts 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 System stability).

ATC also conducts a short circuit analysis of the entire system on an annual basis or 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.

1.2.3 Preliminary needs and solution development

1.2.3.a Steady state project-deficient needs assessment

1.2.3.a.1 System intact and single contingency simulations
ATC performed system intact and single contingency simulations on the 2012, 2016, 2021 and 2026 models. Single contingency simulations include the following: single element (line, transformer, generator, bus and switched shunt) and event-based breaker-to-breaker outages. We run these simulations for summer peak and under the sensitivity situations described above .

1.2.3.a.2 Comparison of results vs. Planning Criteria
The models described above are analyzed and compared to our Planning Criteria. Limits that approach or exceed our criteria are then listed in Tables ZS-1 through ZS-4.

1.2.3.a.3 Reconciliation of significant changes to power flow results
To reconcile changes in power flow results between Assessments, zone planners run data comparisons to determine if limitations identified in prior Assessments have become more severe, less severe, or have been mitigated. Steps are taken to verify topology and other model changes to ensure that the results are consistent with all of the available information.

1.2.3.a.4 Future considerations
In future Assessments, we plan to communicate needs and solicit solution development options to our stakeholders earlier in the process.

1.2.3.b Preliminary Solution Development

1.2.3.b.1 New Limitation
If a new limitation is found in the initial screening, the zone planner will take steps to ensure that the limitation is valid, including verification of the power flow model. If the new limitation is within the current five-year timeframe, the zone planner will then check for potential delayability, including investigation of operating guides or other mitigation measures.

After all potential mitigation measures for a given limitation or need have been evaluated, system solution options are developed. Potential projects that may resolve identified needs are vetted internally and with our external customers. Each solution option is subject to sufficient evaluation to determine its effect upon the identified limitation. After all discussion and collaboration has concluded, the results for all the solution options evaluation are recorded in a project development document.

Cost estimates are developed for solution options that effectively address the identified limitation. After cost information has been obtained, the zone planner selects the most efficient solution option from a cost-benefit standpoint and initiates the project development process by completing the project request form to create a provisional project. Finally, the project request is processed through ATC's Project Approval Process.

1.2.3.b.2 Repeat Limitation

If a previously identified limitation is found in our initial screening, the zone planner will re-verify that existing solution options address that limitation. If an in-service date or scope change is warranted, updated cost estimates are developed. The project request form is then updated with the revised in-service date, cost, scope, and/or justification. The updated project request form is then resubmitted through ATC's Project Approval Process.

1.2.3.b.3 Unspecified Network Project (Placeholder) Process

Unspecified Network Projects are defined as those projects which may shift into the 10-year timeframe as a result of:

- Changing load forecast,
- Changes in generation and distribution interconnection projects,
- Changes in mandatory reliability or renewable portfolio standards, and/or
- Additional projects that are driven by economic benefits or multiple outage impacts.

Several million dollars were set aside in ATC's budget in order to address Unspecified Network Projects. ATC's placeholder process begins with internal discussions to determine how to best serve our customers' local and regional needs. In these discussions, we collaboratively determine which potential projects may be built or incur costs within the 10-year Assessment period. Projects with a 50 percent probability of occurrence or greater are estimated. The cost/benefit results are discussed, vetted and approved by our AIM Executive committee. After consensus is reached, our capital forecast is updated to include these placeholder dollars.

1.2.3.c All Projects Assessment

After the 10-Year Assessment analysis is completed, models are built that include all planned, proposed, and some provisional projects. These models are called "All Projects" models and are more indicative of the expected system configurations for 2012, 2016, 2021 and 2026 study years. These models are more appropriate for internal planning studies performed throughout the year.

As part of the 10-Year Assessment, zone planners perform a contingency analysis on each of the "All Projects" models. The contingency analysis includes systematically removing each line, generator, transformer, switched shunt and modeled bus ties individually to determine the effect on the transmission system. The analysis will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the Assessment process.

The zone analysis discussions presented in this Assessment provides a list of reinforcements that are beginning to optimize our reinforcement plans, at least at the one- or maybe two-zone level. Three important questions regarding this plan include the following:

- ❑ How do the reinforcements for all the zones perform together?
- ❑ Does applying a solution in one zone create a problem that was not seen before in another zone?
- ❑ Are some zone solutions redundant when all the solutions are applied to the system?

As we did in the 2010 Assessment, this year we attempted to address the first two questions. We built year 2012, 2016, 2021 and year 2026 models that included reinforcements reflecting our best thoughts on all of the most likely planned, proposed, and provisional projects to address the identified issues. These projects are those identified in the project tables for this Assessment with specific in-service dates. First contingency analysis was performed on these new models, including selected outages on neighboring systems. This analysis showed that the reinforcements in total did indeed deal with the issues identified and did not create any new issues to be resolved. Please refer to the All Projects section for details of our analyses.

1.2.3.d Stability review & analysis

For system stability analyses methodology and results see the Generator Stability, Voltage Stability and Small Signal Stability sections of the System Stability section.

1.2.3.e Multiple Outage Review and Analysis

We conduct a variety of multiple outage analyses. For steady state analyses methodology and results see the Multiple Outage Analysis section.

1.2.4 Documentation

1.2.4.a Writing/approval processes

The 10-Year Assessment is written and developed by several contributors. The following steps are performed in order to ensure cohesive, consistent information:

- Requests are made for the latest financial, environmental, demographics, asset renewal and economics information from other ATC departments.
- Drafts of each section's text, figures and tables are compiled for peer review.
- A comprehensive meeting is held with all Planning and Asset Renewal managers and team leaders in order to review and approve the information.
- A summary presentation of all Assessment information is reviewed and approved by ATC management.

Once the information has been approved by all parties, the hard copy Summary Report and Zone Summaries are printed and distributed, and the Full Report text is posted at www.atc10yearplan.com.

1.2.4.b NERC Compliance

ATC was fully compliant with the North American Electric Reliability Council (NERC) Reliability Standards in 2010. In 2011 we continue to be committed to maintaining fully compliant status with all of the existing and newly approved NERC standard requirements.

As noted in previous Assessments, ATC is registered with two of the regional reliability compliance entities, the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC). This dual reporting arrangement was established because ATC serves customers that are members in each of these Regional Reliability Organizations.

The mandatory NERC Reliability Standards assign accountability for specific requirements based on defined entity functions. ATC registered as the following entities - 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 the Transmission Planner accountabilities.

The primary Transmission Planner compliance responsibilities are system performance assessments and system modeling. The system performance assessment standards include checking for exceeded voltage criteria limits, system equipment overloads,

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

adequate stability, cascading outages, loss of load, and firm transfer curtailments under a wide range of system operating conditions.

The Transmission Planning reliability standards call for the consideration of thirty (30) operating conditions. These conditions are grouped into four (4) categories. The requirements associated with each of the applicable categories are contained in four separate NERC Transmission Planning standards:

A. Normal conditions (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)

ATC has performed assessments annually (from 2001 to 2011), which demonstrated that its portion of the bulk electric system is planned to supply the projected LDC load and firm transmission service for the contingency conditions given in the four applicable NERC Transmission Planning standards. In addition, ATC has performed studies and simulations annually (from 2001 to 2011) that support the 2011 Assessment using the projected LDC load and firm transmission service for the contingency conditions given in the four applicable NERC Transmission Planning standards.

Studies and analyses were performed for the appropriate Category A conditions, as well as Category B, Category C, and Category D contingencies. The Category B contingencies that would produce the more severe system results or impacts are described in the TPL-002 Rationale. The Category C contingencies that would produce the more severe system results or impacts are described in the TPL-003 Rationale. The Category D contingencies that would produce the more severe system results or impacts are described in the TPL-004 Rationale.

All of the identified compliance requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 of the near term (2012 to 2016) Assessment were addressed by the new five-year projects and/or operating procedures that could support our plans to comply with these standards. All of the identified compliance requirements of TPL-001-0, TPL-002-0, and TPL-003-0 of the long term (2017 to 2021) Assessment were addressed by the new 10-year projects and/or operating procedures that could support our plans to comply with these standards.

All existing and planned protection systems, including any backup or redundant systems that would be applicable to a given contingency were simulated in studies and analyses. All existing and planned control devices that would be applicable to a given contingency were simulated in studies and analyses. These control devices include transformer automatic tap changers, capacitor bank automatic controls, and six DSMES units. No specific facility outages are scheduled for the planning horizon at the demand levels that were studied. As the future unfolds and facility outages are scheduled, they will be scheduled for conditions that provide acceptable reliability.

The first set of requirements (R1) in each of these standards deals with the frequency, timeframes, simulations, and conditions of the transmission system assessments. Most of the R1 requirements are met by documentation in this 10-Year Assessment (see references below).

Some R1 requirements are met by a combination of this 10-Year Assessment and the documentation in earlier Assessments. For example, the assessments in the 2010 10-Year Assessment are supported by both the system-wide simulations that were used in this Assessment and project-specific simulations that were performed for earlier assessments. Together these supporting simulations were used to revise the assessment of expected system performance in the near-term (1- to 5-year) planning horizon and other system performance in the long-term (6- to 10-year) planning horizon.

The second set of requirements (R2) in each of the four standards deals with the plans that are proposed to achieve the required system performance. Many of the project plans that were noted in last year's 10-Year Assessment remain unchanged based on subsequent analysis and assessment. However, the 2011 10-Year Assessment describes project scope and need date changes that are required to achieve compliance based on later forecasts, analysis, and studies.

The third set of requirements (R3) in each of the four standards covers documenting and communicating the Assessment and project plans to the MRO and RFC. Taken together, this 2011 10-Year Assessment and earlier Assessments fulfill this requirement.

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/Cluster_8_Queue.html

Compliance Documentation in the 2011 10-Year Assessment

The power system models are 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 conditions and models that were used in the assessment are given in the Methodology & assumptions section. Additional explanations of the modeling methods and the frequency of system model updating are given in the Model building criteria section of the Planning criteria section.

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.

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.

ATC's 2011 Assessment of Transmission System Performance

Given the full set of simulations ATC completed for the 2011 Assessment and earlier assessments, ATC assesses its system as being compliant with NERC Standards TPL-001, 2, 3, and 4 for each year of 2012 through 2016 and for the rest of the 10-year planning horizon.

Project justification, development, and prioritization

ATC has developed and is continuing to enhance processes that allow us to identify system needs and opportunities, to develop proper project scopes and schedules, and to assess project value and priority. These processes include the following listed below.

- Project justification (system needs and opportunities assessments)
- Project development
- Project benefit identification and prioritization

All of these processes continue to be enhanced to include appropriate stakeholder input.

Project justification
The system needs and opportunities assessments are the key drivers for the project creation and justification process. They are also one of the major subjects of the 10-Year Assessment. ATC has planning criteria and continues to develop stakeholder input processes to help determine which projects bring value and have appropriate justification.

Project development
There are four possible stages in the planning portion of ATC's project development process.

- System Needs and Opportunities Identification
- Project or Program Development and Continued Need Investigation
- Project Alternatives or Program Solutions Development and Preferred Alternative Identification
- Project/Program Scope and Project Request Development

System Needs and Opportunities Identification
ATC system needs and opportunities are investigated and identified on an ongoing basis. However, particular attention is given to the system reliability needs assessment on an annual basis as required for compliance with the NERC Reliability Standards on transmission system performance. All identified system needs or opportunities are evaluated and compared to each other for possible interrelationships and coordination. In addition, comments on identified needs and opportunities are solicited within ATC and from external customers when it is appropriate.

Project or Program Development and Continued Need Investigation
After one or more future transmission system needs or opportunities are identified, Solution Options that may address the identified needs are solicited within ATC and from appropriate external Customers. Each Solution Option is subject to sufficient evaluation to determine whether it would work to mitigate the identified needs. The results of the Solution Option evaluation are recorded in a project development document. The continuity of identified needs is investigated on at least an annual basis when the system reliability needs assessment is updated.

If a Proposed Project Request is not needed until a sufficiently far off future date, a Provisional Project Request is prepared for one of the Solution Options that works. Preliminary project scope and cost estimates are developed for the selected Solution Option. The Provisional Project description is recorded in a project request document and is submitted to add the project to the ATC capital forecast.

Project Alternatives or Program Solutions Development and Preferred Alternative Identification

All of the Solution Options that are feasible and appropriately mitigate identified needs are classified as project Alternatives. A preliminary project scope and cost estimates are prepared and documented for each Alternative. Any other relevant Alternative considerations are also identified and documented. The Alternatives are compared to each other to determine which one is the Preferred Alternative. The Preferred Alternative selection is reviewed and approved within ATC and by appropriate Customers. The comparisons and conclusion are recorded in a Project Scope Document.

Project/Program Scope and Proposed Project Request Development

Detailed project/program scope and cost estimates are developed for the Preferred Alternative. The Proposed Project/Program is reviewed and approved within ATC and by appropriate customers. For projects, the justification is recorded in the Project Scope Document and a Proposed Project Request is submitted within ATC to add to or revise the ATC capital forecast.

Project Benefit Identification and Prioritization

Project benefit identification helps us to understand the value of different projects compared to their cost. Project prioritization is a consideration 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. When needed, ATC will use project benefit identification and prioritization considering (1) project/program cost, (2) project/program benefits, and (3) project/program advancement and deferral flexibility.

We emphasize that project benefit and prioritization would be used as a screening tool to identify projects that are candidates for capital budget advancement or deferral. Project benefit identification and prioritization by itself does not cause a project to be advanced or delayed. It would only be a tool for screening projects that may have reason to be advanced or delayed compared to others. If there are compelling reasons to modify the capital budget, then we will consider using this tool. With appropriate input from stakeholders, we will evaluate the possible effects and risks of advancing or delaying selected projects. However, the final decision of whether a candidate project will be advanced or deferred is still reached by considering the specific details of each project, including appropriate stakeholder input.

Table PF-1
Projects included in the 2012 10-Year Assessment Model

System additions	Planning zone
Council Creek transformer #1 replacement	1
G588 MEWD current transformer	1
Badger West T-D interconnection	1
Whitcomb-Wittenberg 69-kV rebuild	1
Y-95 asset management uprate	1
McKenna and Chaffee Creek capacitor banks	1
Monroe County second 161/69-kV transformer	1
Woodmin T-D interconnection	1
Straits-McGulpin 138-kV line uprate	2
Indian Lake 69-kV capacitor banks	2
Presque Isle updates	2
Nordic-Perch Lake 69-kV asset management uprate	2
Autrain line uprate	2
Forsyth-Munising 138-kV line uprate	2
Nine Mile-Roberts asset management uprate	2
Chandler second 138/69-kV transformer	2
Indian Lake-Hiawatha 138/69 LTC	2
Stoughton North T-D interconnection	3
Nine Springs-Pflaum asset management uprate	3
Y61 69-kV line uprate	3
Blue River-Muscoda asset management rerate	3
Hillman Substation upgrade	3
REC Milton T-D interconnection	3
Gran Grae-Boscobel asset management project	3
Blount-Ruskin underground project	3
Y62 maintenance rebuild	3
Bass Creek 138/69-kV transformer and X12 uprate	3
Stage Coach-Timberlane 69-kV asset management rerate	3
Oregon-Stoughton uprate	3
Dane County corrective plan (Kegonsa and Femrite capacitor banks)	3
Spring Green 69-kV capacitor banks	3
Femrite #4 T-D interconnection	3
Y128 asset management uprate	3
Walnut T-D interconnection	3
Brodhead-South Monroe 69-kV line rebuild	3
McCue-Milton Lawns 69-kV line uprate	3
Glacier Hills G706/H012 G-T interconnection and associated uprates	3
Dam Heights T-D interconnection	3
Richmond T-D interconnection	3
Fountain Prairie T-D interconnection	3
Beloit Gateway T-D interconnection	3
Ellinwood transformer #2 replacement	4

Table PF-1 (continued)
Projects included in the 2012 10-Year Assessment Model

System additions	Planning zone
North Fond du Lac transformer #31/32 replacements	4
Kewaunee-East Krok asset management uprate	4
Kewaunee second transformer	4
Sunset Point-Pearl 69-kV line rebuild	4
G833-J022-J023 G-T interconnections	4
Point Beach GSU	4
G590 G-T interconnection	4
Canal-Dunn Road 138-kV line project	4
Bain-Kenosha 138-kV line uprate	5
Shorewood-Humboldt second underground cable	5
Harbor transformer replacement T-D interconnection	5
Barland T-D interconnection	5
Pleasant Prairie-Zion 345-kV line uprate	5
Bluemound #1 and #3 transformer replacements	5

Table PF-2
*Projects included in the 2016 10-Year Assessment Model**

System additions	Planning zone
Council Creek-Petenwell line uprate	1
Construct Monroe County-Council Creek 161-kV line and Timberwolf 69-kV switching station	1
G749 G-T interconnection	3
G282 G-T interconnection	3
Uprate Fitchburg-Nine Springs 69-kV and Royster-Pflaum 69-kV lines and move AGA load to the Royster-Femrite 69-kV line	3
Rockdale-Cardinal 345-kV line	3
Blount distribution capacitor bank retirement	3
Hawk T-D interconnection	3
West Middleton T7 T-D interconnection	3
Y-8 asset management rebuild	3
Little Suamico T-D interconnection	4
G611/G927 G-T interconnection	4
G773 G-T interconnection	4
Forest Avenue T-D interconnection	4
G427 G-T interconnection	4
Milwaukee County T-D interconnection	5

**Projects included in addition to those listed in Table PF-1*

Table PF-3
*Projects included in the 2021 10-Year Assessment Model**

System additions	Planning zone
Close Seney-Blaney/Uprate 69-kV Inland line	2
G8334-J0223 G-T interconnection/Barnhart-Branch River project	4
Center third transformer T-D interconnection	5

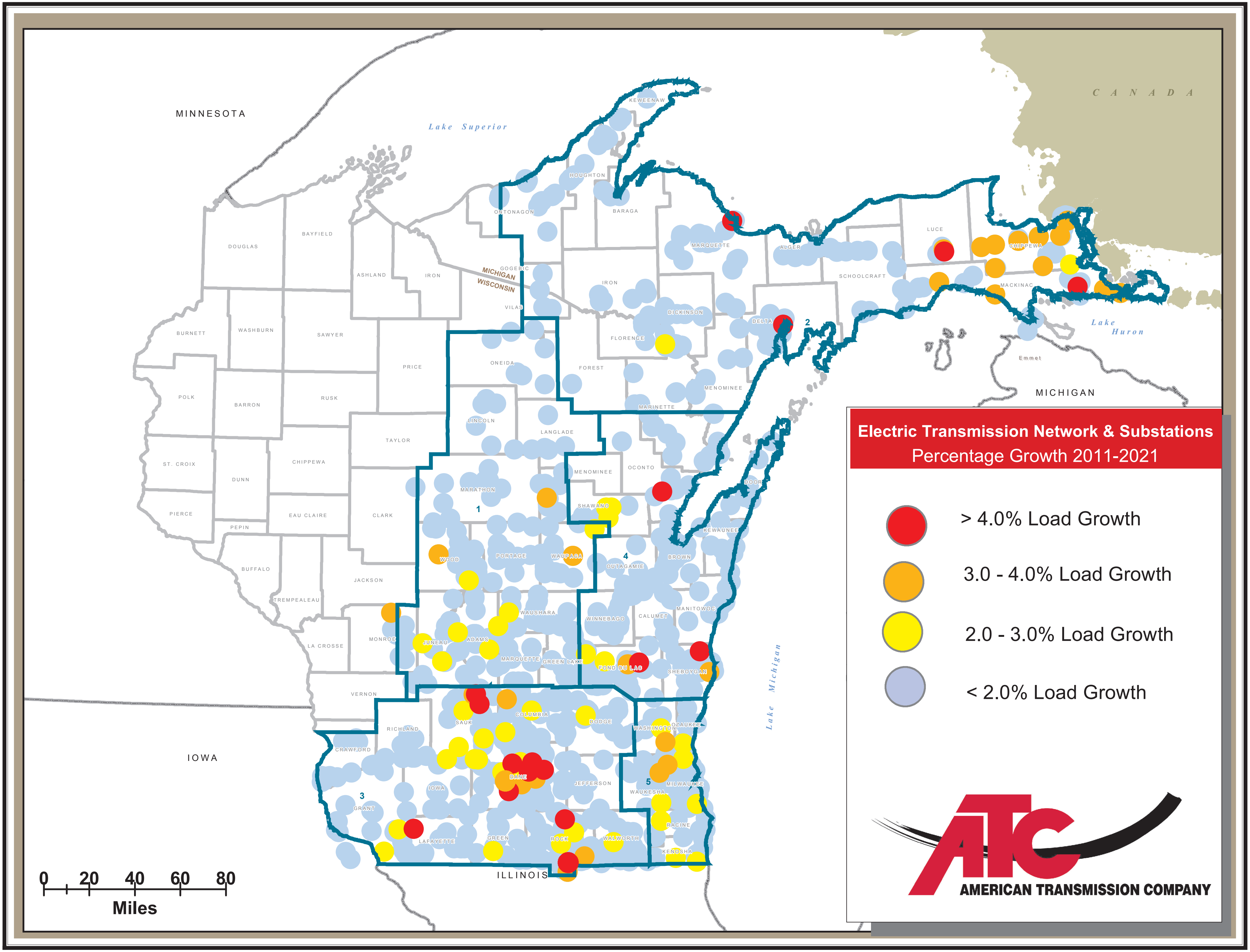
**Projects included in addition to those listed in Tables PF-1 and PF-2*

Table PF-4
*Projects included in the 2026 10-Year Assessment Model**

System additions	**Planning zone**
None	

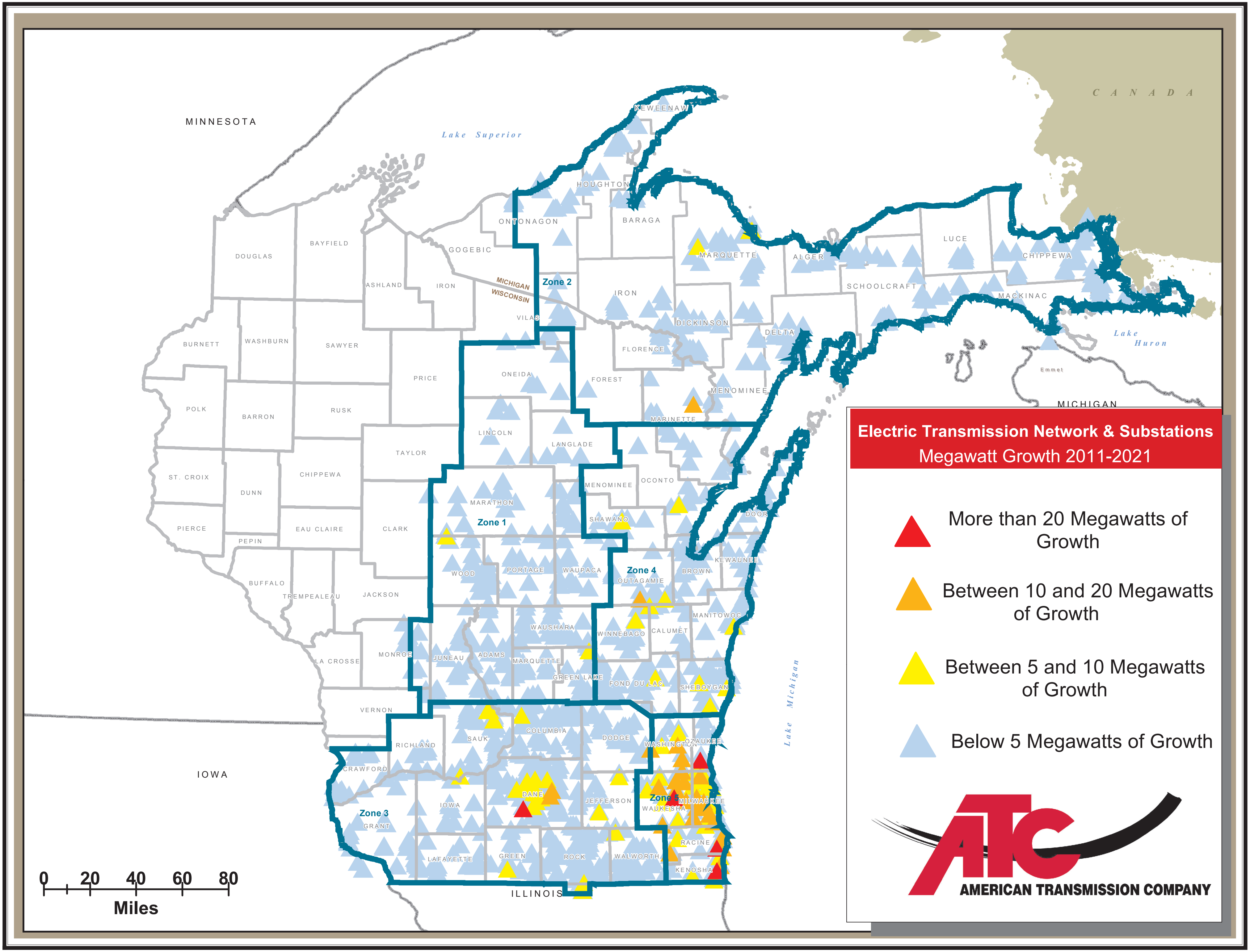
**Projects included in addition to those listed in Tables PF-1, PF-2 and PF-3*

Figure PF-1



Created: April 4, 2011

Figure PF-2



Created: April 4, 2011