September 2008 10-Year Assessment
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Planning Factors section

Planning considerations

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

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

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

Transmission system expansion drivers

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

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

- **Electric load growth** – The load growth driver in this Assessment is similar to that in the previous Assessment. Demand for electricity during peak load periods is projected to grow at a rate of just under 2 percent across our service territory from 2008 through 2018. 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 2008 through 2018 for various areas of our system. Note that most of the high growth (greater than 20 MW) is in the metropolitan Milwaukee, Madison and Fox Valley areas. While these higher-growth areas may require system expansion, there is considerably more existing transmission infrastructure in these areas. Of equal or greater concern is high growth in areas where there is much less existing transmission infrastructure because the capacity of the existing system may be reaching its limits, perhaps requiring additional infrastructure.

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

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

Figures PF-1 and PF-2 have traditionally been incorporated into our Assessments. However, these two figures do not take into account the fact that several ***previously unforecasted*** loads appeared in the Upper Peninsula and in the Lake Geneva areas. The previously unforecasted load increases that are depicted in Figure PF-3 are driving several of the project changes in this Assessment. *Note that Figure PF-3 is a comparison of forecasts for the year 2009 only.* In Figure PF-3, the year 2009 was chosen because we wanted to perform a near-term comparison between the forecast data received in 2006 vs. the data received in 2007. In Figure PF-3:

- Red circles indicate existing interconnections with a greater than 10% load increase since the previous forecast.
- Orange triangles indicate new interconnection points (with previously unforecasted loads) greater than 5 MW.

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

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

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

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

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

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

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

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

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

- **Regional needs** - ATC's transmission system is interconnected directly with neighboring transmission systems and is operated in conjunction with all the 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 on the projects to facilitate MISO's review of the projects. MISO reviews the transmission projects submitted by ATC to ensure they do not provide an adverse affect on transfer capability, do not adversely affect the availability over the transmission facilities which MISO has control and could be combined in conjunction with transmission projects from other transmission projects to develop the most cost-effective alternatives.

  ATC also meets with adjacent transmission owners to coordinate planning on a single-system basis in an effort to develop transmission solutions that resolve multiple system reliability and capacity requirements at the lowest reasonable cost.

  ATC participates in regional studies that address particular transmission facilities across multiple transmission systems. For example, ATC participates in regional studies coordinated by MISO such as studies that look at moving wind energy from the western part of the MISO footprint to states with renewable portfolio standards. ATC has also provided input to regional studies being performed by groups such as CapX that seek to identify and plan regional transmission solutions for groups of utilities with similar transmission needs.

- **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.

Customer needs

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

- **Improved access –** Virtually all of our customers have indicated a desire to have better transmission access to out-of-state markets as well as fewer constraints in transacting with their neighboring utilities within the ATC footprint. In response, we launched an 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 this, ATC has partnered with the industry's leading design, construction, and materials sourcing companies. Our partners' expertise helps ATC maintain and construct transmission system assets with a focus on low long-term costs. Also, our recent addition of a Project Controls Office ensures that we are continually reviewing projects for cost-saving opportunities.

- **Integration of transmission and generation planning –** Our transmission system does not have significant transmission capacity beyond current network needs. 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.

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. 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.

Planning criteria

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

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

The planning criteria are listed under the following headings:

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

SYSTEM PERFORMANCE CRITERIA

System performance 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 will include consideration of the following system load conditions:

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

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

Dynamic stability assessments

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

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

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

1.1 STEADY STATE PERFORMANCE ASSESSMENT

Steady state performance assessments 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:

A. Normal conditions (NERC Category A)

1) No system element (line, transformer, terminal equipment, etc.) should experience loading in excess of its normal rating for NERC Category A conditions. This criterion should apply for a reasonably broad range of generation dispatch conditions.
   (Applicable NERC Standard: TPL-001-0-R1)
2) The acceptable voltage range is 95 percent to 105 percent of nominal voltage for NERC Category A conditions. Such measurements shall be made at the high side of transmission-to-distribution transformers. We will consider voltage levels outside of this range, if they are acceptable to the affected transmission customer. Exceptions for certain interconnected entities are evaluated accordingly. 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)
3) Operating procedures (operating guides) are not preferred under normal conditions, but may be employed by ATC and/or entities with generation and/or distribution facilities interconnected with the ATC transmission system to avoid transmission facility loadings in excess of normal ratings provided such procedures are practical for sustained periods, if they meet the following conditions:
   - do not impose on personnel or public safety
   - do not significantly degrade system reliability,
   - do not result in a significant loss of equipment life or significant risk of damage to a transmission facility
   - and/or do not unduly burden any entity financially.

   Supervisory switching 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.

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

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category B contingencies. This criterion should be applied for a reasonably broad range of generation dispatch conditions. 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, LTC adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring element loading levels below appropriate limits.

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)

2) Under applicable NERC Category B 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. 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 redispatch may be considered as acceptable measures to bring voltage levels within appropriate limits.

3) 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 E&C Services.
(Applicable NERC Standard: TPL-002-0-R1)

4) 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 stability.

5) 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.

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

1) No transmission element should experience loading in excess of its applicable emergency rating for applicable NERC Category C contingencies. This criterion should be applied for a reasonably broad range of generation dispatch conditions. Overload relief methods may include 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, load tap changers, generating unit voltage regulation, generation redispatch, line switching or firm service curtailments. Minimal planned load shedding may also be used for voltage restoration. These voltage criteria should be met with the 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)*

D. 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 and loss of an entire substation, including generation at that substation. These criteria should be used to determine system vulnerabilities, but may not necessarily dictate that potential problems identified need to be remedied with system additions.
(Applicable NERC Standard: TPL-004-0-R1)

1.2 TRANSIENT AND DYNAMIC STABILITY PERFORMANCE ASSESSMENT

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

A. Large disturbance stability performance assessment

1) For generator transient stability, faults will be modeled on the high side bus at generating plants.
2) For generating units with actual “as built” or “field setting” dynamic data, add a 0.5 cycle margin to the expected clearing time (ECT) for dynamic contingency simulations. For generating units with assumed, typical, or proposed dynamic data, add a 1.0 cycle margin to the ECT for dynamic contingency simulations. The total clearing time (ECT + margin) must be equal to or less than the calculated critical clearing time (CCT) from the simulation.
3) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category B contingency. These contingencies will typically be sustained three-phase faults of a single generator, transmission line, or transmission transformer with normal fault clearing.
(Applicable NERC Standards: TPL-002-0-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 (D2) and three-phase faults on a transmission transformer with delayed clearing (D3). This ATC criterion is more severe than NERC Category D criteria because it requires every generating unit to maintain transient stability for this condition.
(Applicable NERC Standards: TPL-004-0-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, as defined below

   B. Voltage stability assessment

   a. Voltage recovery within 70 percent and 120 percent of nominal immediately following the clearing of a disturbance
   b. Voltage recovery within 80 percent and 120 percent of nominal 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)

B. Small disturbance performance assessment

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

2) With all generating units at their prescribed base case (normally full) real power output, no unit will exhibit poorly damped angular oscillations [as defined below] or unacceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.
   (Applicable NERC Standard: TPL-002-0-R1)

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

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

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

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

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

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

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

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

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

2) *Single frequency flicker* is to be below the applicable flicker curves described in Table A.1 of IEEE 1453-2004 “Recommended Practice of Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems. Single

frequency flicker is created by voltage affecting events that occur at a regular interval and superimpose a single frequency waveform between 0 and 30 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to10 Hz range) sub-synchronous frequencies with magnitudes from 0.5 percent to 3 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 141 (commonly referred to as "The Modified GE Flicker Curve") to determine the acceptability of single frequency flicker.

3) *Multiple frequency flicker* is to be a 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. The level of harmonics acceptable on the ATC system is defined by state regulations, IEEE Standard 519-1992 (Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems) and the judgment of ATC. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met.

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

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

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

Transmission Planning Assessment Practices

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

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

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

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

Other independent analyses are being conducted to assess dynamic and/or voltage stability performance.

Further, ATC develops transmission projects to address the congestion issues in its footprint. ATC uses the PROMOD model to analyze congestion across the ATC footprint and develop projects that will relieve the congestion. ATC submitted to the Public Service Commission of Wisconsin the first economically justified project in MISO and an order was received in the first half of 2008.

As part of the Midwest Independent System Operator, Inc. (MISO), ATC is participating in the MISO Transmission Expansion Plan process. ATC participates actively in all portions of MISO's planning efforts, including numerous committees and task forces, in regional and economic study efforts and in development of the Midwest Transmission Expansion Plan (MTEP).

The MAIN organization ceased to exist at the end of 2005 and ATC became a member of the two subsequent regional reliability organizations, the Midwest Reliability Organization (MRO) and the Reliability*First* Corporation (RFC). ATC participates in regional transmission assessments conducted by the MRO Transmission Assessment Subcommittee (TAS), the RFC Transmission Performance Subcommittee (TPS), the MAPP Transmission Reliability Assessment Working Group (TRAWG), the ERAG Reliability Assessments and MISO Reliability Assessments.

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

Public/Stakeholder Input

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

Specific opportunities for public and stakeholder participation in the planning process are provided in accordance with ATC's tariff Attachment FF filed at the FERC in response to the portion of FERC's Order 890 calling for open, inclusive and transparent planning processes. The filing was made on December 7th to be effective February 7th. ATC is implementing the tariff provisions as we await FERC's order response. ATC's Attachment

FF covers six separate planning processes and the opportunities stakeholders have to participate in the processes. The six planning processes include:

- Network adequacy planning
- Economic project planning
- Generation-transmission interconnections
- Transmission-distribution interconnections
- Transmission-transmission interconnections
- Transmission service requests.

Provisions include opportunities for stakeholders to provide input to the planning processes in terms of assumptions and projects, provide review of interim results and see final results.

Capacity Benefit Margin Criteria

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

ATC planning studies, except those required for Midwest ISO (MISO) transmission service, do not model CBM. CBM is instead accommodated in the planning process through the Loss of Load Expectation (LOLE) studies in the Midwest Transmission Expansion Planning (MTEP) process.

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

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

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

Transmission Reserve Margin Criteria

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

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

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

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

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

Facility Rating Criteria

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

- PR-0285 Facility Ratings Update and Application,
- ECS-CR-0061 Conductor Ampacity Ratings for Overhead Transmission Lines,
- CR-0063 Substation Equipment Ampacity Ratings,
- CR-0062 Ampacity Ratings of Underground Transmission Lines

We will actively review, replace, and document legacy ratings with ratings based upon ATC criteria in its Substation Equipment and Line Database (SELD). The legacy ratings from the previous transmission facilities owners' 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-004-0-R1)

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 primarily by our end-use load-serving customers as input into future model building efforts, both internally and in conjunction with the NERC, Regional Reliability Organization (RRO), and Regional

Transmission Operator (RTO). 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)

Facility Condition Criteria

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

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

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

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

Planning Zones

We will conduct system planning on a long-range basis by developing plans for the ATC transmission system as a whole, as well as plans for specified **zones** within the boundaries of ATC's transmission system. These zones are shown in **Figures ZS-22 through ZS-26** (1.61M pdf). The idea behind the zone approach to long-range planning is to develop plans that consider all of the needs/problems/developments within each zone. The goal within the ATC footprint would be to develop an "umbrella" plan for the zone, that is, a plan that emphasizes projects that serve multiple purposes or solve multiple problems within the ATC system. The zone approach is intended to address requirements for support to the local distribution systems in that zone on a least cost basis. It is anticipated, however, that several projects that span more than one zone or possibly even the ATC transmission system boundaries, may evolve. Such projects will likely involve coordination with other transmission owners or regional transmission organizations.

The planning zones shown in **Figures ZS-22 through ZS-26** deviate significantly from existing control area boundaries and from planning zones traditionally used for joint planning in conjunction with the Wisconsin PSC. The zones were selected considering the need for a manageable number of planning areas and to consolidate areas within the state with similar topology and load characteristics.

System Alternatives

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

Load Forecasting Criteria

We will initially use load forecasts provided by 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 its load-serving customers. In addition, we may, in coordination with its load-serving customers, develop representative load duration curves based on actual and normalized load conditions. The ATC methodology for developing, aggregating and maintaining load forecast information should be in accordance with NERC 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 will be calculated in such a way that there is an almost equal probability of exceeding or falling short of the forecast when average peak making weather does occur.
3) **Summer shoulder peak** demand forecasts will be developed reflecting moderate weather days (75 F-80 F). Such forecasts will be based on a load level that, within a reasonable range, captures as many shoulder peak hours within a representative load duration curve of load connected to the ATC transmission system. These demand forecasts will be developed to evaluate historical high power transfer conditions.
4) **Fall/spring off-peak** demand forecasts will be based on a load level that, within a reasonable range, captures as many off-peak hours within a representative load duration curve of load connected to the ATC transmission system.
5) **Summer 90/10 peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. This peak demand forecast will be calculated in such a way that there is a 90 percent probability of falling short of and a 10 percent probability of exceeding the forecast due to weather conditions. Until we develop the capability for producing a specific 90/10 forecast, we will assume that it can be reasonably approximated through increasing the conforming loads by 5 percent and leaving the non-scalable loads unchanged. The ratio of the real to reactive power of the loads will remain unchanged.
6) **Light load (50 percent of peak)** demand forecasts will be developed that reflect light load levels, which are approximately 50 percent of the summer peak demand forecasts. Conforming loads will be scaled and non-scalable loads will remain unchanged.

Economic Criteria

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

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

Environmental Criteria

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

Variations on ATC Planning Criteria

The ATC transmission system consists of assets contributed by entities within the five control areas of the Wisconsin Upper Michigan System. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as ATC has implemented its own planning criteria, portions of the system may require upgrade to meet the more stringent ATC criteria.

This section of the ATC planning criteria describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the ATC criteria.

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

b. NERC Planning Standards – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

Other Considerations

Project constructability

We will consider the constructability of proposed additions, replacements or modifications to the transmission system as part of its 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.

Multiple contingency planning

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

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

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

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

Terminal equipment limitations

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

Maximization of existing rights-of-way
We will attempt to maximize use of existing rights-of-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.

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

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

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

Relaxation criteria

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

Interconnection studies

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

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.

Compliance with Applicable Planning Criteria
The analyses and procedures are to comply with all applicable NERC, Regional Reliability Organization, and individual system planning criteria of the affected parties.

Coordination with Affected Entities
The results of the analyses will be jointly evaluated and coordinated by the affected entities.

Essential Documentation
All analyses should include the evaluation assumptions, system performance, alternatives considered, and any jointly coordinated recommendations.

Methodology & assumptions
This section describes the methods and techniques that we use to analyze our transmission system for this assessment. As part of this 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.

To facilitate an understanding of the status of the various future projects, we classify projects into one of three possible categories – Planned, Proposed or Provisional. Each classification has specific criteria based on the status of the project as outlined below:

Planned projects:
- ATC planning is complete;
- if required, we have applied for regulatory approvals, which may be pending or have been issued;
- project may be under construction or in construction planning phase; and
- project typically is included in power flow models used to analyze transmission service and interconnection requests.

Proposed projects:
- ATC planning is not complete;
- ATC has not yet pursued regulatory approvals;
- project represents ATC's preliminary preferred project alternatives from a system performance perspective; and
- project typically is not included in power flow models used to analyze transmission service and interconnection requests.

Provisional projects:
- ATC planning is not complete;
- ATC has not yet sought regulatory approvals;
- project does not necessarily represent ATC's preliminary preferred project alternative, but does reflect meeting the need identified; and
- project is not included in power flow models used to analyze transmission service and interconnection requests.

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 assessment of the transmission system, ATC 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 ATC's 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 net Q_{max} capability within ATC footprint.

For NERC Category B, C or D contingencies, system limitations or constraints are identified using a slightly different criteria. 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 net Q_{max} capability within ATC footprint.

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

In all of the models, normal operating procedures were modeled for the applicable normal system conditions. 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. 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. No specific facility outages are modeled in the planning horizon at the demand levels that were studied due to lack of future outage schedules. As the future unfolds and facility outages are scheduled, they will be timed for conditions that provide acceptable reliability.

Assessment development

This 2008 Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2009 were included in the 2009 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 2013 and 2018 models as appropriate based on projected in service dates (See Tables PF-2, PF-3 and PF-4).

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

Steady State Power flow models

Computer simulation model years for the 10-Year Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2009 and 2013 were selected to meet the 1-5 year horizon. The years 2018 and 2023 meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2008 Assessment. Steady state peak load models for all four years were created. In order to determine how close ATC generators were to their maximum var output, two additional models were created for each year. The one model reduced ATC generator net Q_{max} by 10 percent for each year studied. These models were utilized to determine generator var output under intact system conditions (TPL-001-0). A second model for each year was created with net Q_{max} reduced by 5 percent. These models were used for our N-1 (TPL-002-0) analysis.

In addition to the steady state summer peak models, we developed 2009 and 2013 shoulder peak models that reflected load levels at approximately 70 percent of summer peak. The shoulder peak models included a 2000 MW import into ATC. To simulate a steady state reverse east-west bias power flow, models were developed in 2009 and 2013 with 90% load levels, 1700 MW import into ATC, and a 2000 MW transaction from ECAR to MAPP. Finally, in 2013, we developed steady state models for determining the sensitivity of project needs to higher than expected loads (referred to as “90/10” or “hot summer” in this assessment).

The 2009 steady state summer peak model was developed to evaluate near-term needs and to verify findings in the 2008 Assessment. We have taken the approach of evaluating the subsequent summer peak season in each of our annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2013 steady state summer peak model was developed as an intermediate term model to evaluate emerging needs, to confirm that needs identified in 2009 will increase over time, and to test the performance of reinforcements placed in service prior to 2013. The 2013 summer 90/10 (or “hot summer”) model was developed in order to determine in-service date sensitivity to load growth that is higher or weather that is warmer than forecasted. The 2013 shoulder model was developed to identify needs and test the performance of reinforcements placed in service prior to 2013. Shoulder load periods often place as great or greater demand on the transmission system as do peak periods. During these periods, since loads are not at their highest levels, local peaking generation typically is not operating and power transfers into and across our system often are at maximum levels.

The 2018 steady state summer peak model was developed to identify emerging needs in the 2013-2018 timeframe, to confirm that needs identified in 2013 will increase over time and to test the performance of reinforcements to be placed in service prior to 2018. It also reflects a year 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.

The 2023 steady state summer peak model was developed to identify emerging needs in the 2018-2023 timeframe, to confirm that needs identified in 2018 will increase over time and to test the performance of reinforcements to be placed in service prior to 2018. It also reflects a year 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.

Steady State Power flow model development

We started model development for this Assessment by building a system model that represented 2008 summer peak conditions. This 2008 model is referred to as an “as-built” model because essentially everything in the model is certain to be in service by 2008 summer. This model then was modified to create each of the Assessment study models including the changes listed below for that model.

2009 summer peak

- We utilized interconnection point load forecasts provided by various distribution companies in 2007 for both real and reactive power components of load. Please refer to the <u>Load Forecast</u> section for further details.
- We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD). As of June 2008, nearly 50 percent of ATC lines and 17 percent of ATC transformers have ratings in SELD that have been validated. Ratings not yet validated in SELD generally are based on the ratings received from the utilities that contributed the facilities to ATC.
- Updated future generation attached to the ATC system was included in the models. The specifics are outlined later in this section (Refer to <u>New generation assumptions</u>). Balancing Authority (Control) area generation was dispatched based on economic dispatch for that Balancing Authority.
- The model for the system external to ATC was taken from the MMWG 2006 Series, 2008 summer model. The external system interchange was adjusted from the 2006

MMWG Series 2008 summer interchange to match the latest ATC members' firm interchange.

- Included revised system topology based on projects that were placed in service in 2008, or were anticipated to be placed in service by June 2009. Refer to Table PF-1 for projects that were included in the 2009 analyses. Please also refer to the Steady State All Project Models section for more discussion about how projects are chosen for inclusion our our models.

2013 summer peak, hot summer and shoulder models

- We utilized interconnection point load forecasts provided by various distribution companies in 2007. Please refer to the Load Forecast section for further details.
- The model for the system external to ATC was taken from the MMWG 2007 Series, 2013 summer model. The external system interchange was adjusted from the 2007 MMWG Series 2013 summer interchange to match latest ATC members' firm interchange. Updated future generation to be attached to the ATC system was included in the 2013 models. Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority.
- In addition to the projects listed above for the 2009 case, the following projects were modeled in 2013 because they were assumed to be completed and placed in service prior to the summer of 2013. (Refer to Table PF-2.) Please also refer to the Steady State All Project Models section for more discussion about how projects are chosen for inclusion our models.

2018 summer peak model

- We utilized interconnection point load forecasts provided by various distribution companies in 2007. Please refer to the Load Forecast section for further details.
- The model for the system external to ATC was taken from the MMWG 2007 Series, 2018 summer model. The external system interchange was adjusted from the 2007 MMWG Series 2018 summer interchange to match the latest ATC members' firm interchange.
- In addition to the projects listed above for the 2013 case, the following projects were assumed to be completed and placed in service prior to 2018 (Refer to Table PF-3.) Please also refer to the Steady State All Project Models section for more discussion about how projects are chosen for inclusion our our models.

- Updated future generation to be attached to the ATC system was included in the models. Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority.

2023 summer peak model

- Please refer to the Load Forecast section for details about how the load was projected.
- The model for the system external to ATC was taken from the MMWG 2007 Series, 2018 summer model. The external system interchange was adjusted from the 2007 MMWG Series 2018 summer interchange to match the latest ATC members' firm interchange
- In addition to the projects listed above for the 2018 case, the following projects were assumed to be completed and placed in service prior to 2023 (Refer to Table PF-4) Please also refer to the Steady State All Project Models section for more discussion about how projects are chosen for inclusion our our models.

- Updated future generation to be attached to the ATC system was included in the models. Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority.

Steady State All Project Models

The load flow models described above as built for the 10-Year Assessment are special models built exclusively for system analyses in the 10-Year Assessment. Some projects were purposely left out of these models in order to verify system problems exist and which problems get worse over time. When the analysis 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 in the 2009, 2013 and 2018 models. The later models also include most 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.

Dynamic stability/short-circuit assessment models

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

Load forecast

Summer peak models (2009, 2013, 2018, and 2023)

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 2017 (and in some cases 2018/2023), and our 2009 and 2013 summer peak models were developed using these forecasts.

Certain ATC customers did not provide an 11th-year load forecast for the year 2018. To obtain a forecast for 2018, certain customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.7% compounded annually). Non-scalable loads were held at their 2017 levels using this methodology.

The 2023 summer peak model was developed utilizing similar methodology. To obtain a projection for 2023, customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.5% compounded annually). Non-scalable loads were once again held at their 2017 (or 2018) load levels. It should be noted that the loads utilized in the 2023 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 2023 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
2009	14,318	N/A
2013	15,405	1.8% (2009-2013)
2018	16,767	1.7% (2013-2018)
2023	18,070*	1.5% (2018-2023)
Overall		1.7% (2009-2023)

**load model, not a load forecast*

High load models (2013)

The 2013 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. Please refer to the Load forecasting criteria for definition of the 90/10 model. For purposes of this Assessment, total ATC system load includes transmission and distribution losses, as well as load that could be interrupted for generation emergencies.

ATC worked collaboratively with our customers to determine a reasonable approximation for the hot summer case. As a result of this customer feedback, the 2013 90/10 proxy model was created by increasing load by 5 percent above expected summer peak conditions.

Shoulder models (2013)
The 2013 shoulder model was 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.

Trends and future plans
Finally, 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.

New generation assumptions

There have been numerous generation projects proposed within ATC's service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Several have proceeded to or through the licensing phase and several more are under construction. However, there are numerous proposed generation projects that have dropped out of the generation queue (refer to <u>Generation interconnections</u>), adding considerable uncertainty to the transmission planning process. To address this planning uncertainty, we have adopted a criterion for purposes of this and prior Assessments, to establish which proposed generation projects would be included in the 2008 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 2008 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 2008 and 2009 models showed these generators as out of service. The 2013 and 2018 should have had these generators in-service and dispatched

Generation Retirement Assumptions
On occasion, generators connected to the ATC transmission system are retired or mothballed. As a result, we developed criteria to determine when generators should no longer be included in our 10-Year Assessment models. If the generator has a completed MISO Attachment Y study, the generator will be disconnected in the appropriate load flow study models. In addition, ATC 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 2008 10-Year Assessment models we assumed the following generators were to be out of service:

Plant Name	*Zone*	*Installed capacity*	*Assumed out of service*
Presque Isle #1	2	25 MW	2007
Presque Isle #2	2	37 MW	2007
Pulliam 3	3	26 MW	2007
Pulliam 4	3	29 MW	2007
Blount 3	3	39 MW	2011
Blount 4	3	22 MW	2011
Blount 5	3	28 MW	2011
Net decrease after 2007		117 MW	
Net decrease in 2011		89 MW	

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:

- 2009 models - October 4, 2007
- 2013 models - November 1, 2007
- 2018 models -November 12, 2007, and
- 2023 models - November 26, 2007.

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

Generation projects schedule
To maintain the schedule needed to complete this Assessment, the models were developed during the month of October and November of 2007. 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 2008, 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*
Green Field wind farm	4	16 MW	16 MW	Jan 2008
Blue Sky wind farm	4	16 MW	16 MW	Jan 2008
Lake Breeze wind farm	4	19.6 MW	19.6 MW	Jan 2008
Forward Energy Center	4	19.8 MW	19.8 MW	Jan 2008
Port Washington (IC002)	5	540 MW	540 MW	June 2008
Weston 4	1	550 MW	400 MW	June 2008
Cedar Ridge wind farm	4	16 MW	16 MW	Oct 2008
Butler Ridge Wind farm	3	10.9 MW	10.9 MW	Oct 2008
Marshfield CT	1	55.2 MW	55.2 MW	June 2009
Oak Creek #1	5	650 MW	650 MW	June 2009
Randolph wind farm	3	16 MW	16 MW	June 2009
Green Lake wind farm	1	32 MW	32 MW	Dec 2009
Lafayette wind farm	3	19.6 MW	19.6 MW	Jan 2010
Whistling Wind wind farm	3	10 MW	10 MW	Jan 2010
Oak Creek #2	5	650 MW	650 MW	June 2010
Twin Creeks wind farm	4	19.6 MW	19.6 MW	Oct 2010
Nelson Dewey #3	3	263.5 MW	263.5 MW	July 2012
Net increase by Dec 2008:		1188.3 MW	1188.3 MW	
Net increase 2009-2018:		1715.9 MW	1715.9 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**.**)

Environmental considerations

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

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

Project justification, development, and prioritization

ATC has and is continuing to develop processes that allow us to identify system needs and opportunities, to develop proper project scope and schedule and to assess project value and priority. These processes include the following.

- Project justification (system needs and opportunities assessments)
- Project development
- Project Prioritization

All of these processes are being 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 is developing 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 a project's development – Solution Option Evaluation, Provisional Project Request, Preferred Alternative Identification, and Proposed Project Request.

Solution Option Evaluation

After one or more future transmission system needs are identified, Solution Options that may solve address the identified needs are solicited within ATC and from 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.

Provisional Project Request

If a Proposed Project Request is not needed until a 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 budget.

Preferred Alternative Identification

All of the Solution Options that work are classified as Alternatives. 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 is compared to each other to determine which one is the Preferred Alternative. The Preferred Alternative selection is reviewed and approved within ATC and by any pertinent Customers. The comparisons and conclusion are recorded in a Project Scoping Document.

Proposed Project Request

Detailed project scope and cost estimates are developed for the Preferred Alternative. The Proposed Project is reviewed and approved within ATC and by any pertinent Customers. The project description is recorded in the Project Scoping document and a Proposed Project Request is submitted to add the project to the ATC capital budget.

<u>Project prioritization</u>

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

The present prioritization index methodology generates a composite priority index value for each project based on several weighted factors. Seven of the factors are drawn from ATC's

Forming Party Agreement (FPA). The FPA factors have been used since 2001. In addition, four threshold factors were introduced in 2005 to enhance the prioritization method. The methodology assigns a weighting to each FPA factor and threshold factor and then computes a deterministic index value. Emergency and blanket (bucket) projects are initially assigned a default value of 999 or 1, respectively.

Forming party agreement factors

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

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

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

The FPA factors are defined as follows:

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

repairing or replacing equipment due to snowstorm, tornado, thunderstorm, or vehicle collision induced outages.

System reliability or security

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

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

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

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

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

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

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

Threshold factors

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

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

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

Following are threshold factor definitions.

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

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

Equipment damage/loss of load
This factor is a measure of how much the project may limit or prevent equipment damage and/or contained loss of load. Use “High” when the project would limit or prevent several million dollars of equipment damage or loss of several hundred MWs of load. Use “Medium” when the project would limit or prevent several hundred thousand dollars of equipment damage or loss of several tens of MWs of load. Use “Low” when the project would limit or prevent several tens of thousands of dollars of equipment damage or loss of

less than 10 MW of load. Use “None” when the project does not address equipment damage or loss of load.

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

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

NERC Compliance
ATC was fully compliant with the North American Electric Reliability Council (NERC) Reliability Standards in 2007. In 2008 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 new 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

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

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, 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 2008), 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 2008) that support the 2008 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 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 (2009 to 2013) 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 (2014 to 2018) 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 2008 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. Most of the project plans that were noted in the 2007 Update remain unchanged in light of the newer assessments. However, the 2008 10-Year Assessment describes project scope and need date changes that are required to achieve compliance based on the latest assessments.

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, the 2008 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 2008 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 2008 Assessment of Transmission System Performance

Given the full set of simulations ATC completed for the 2008 Assessment and earlier assessments, ATC assesses its system as being compliant with NERC Standards TPL-001, 2, 3, and 4 for each year 2009 through 2013 and for the rest of the 10-year planning horizon.