2013 10-Year Assessment
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Planning Assessment Practices

This document describes ATC's system planning criteria to plan, design, build and operate its transmission system in a safe, reliable and economic manner to meet the needs of its customers while maintaining and exceeding compliance with NERC and environment standards. This criteria applies to the ATC transmission system operated at 69-kV and above.

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. The criteria described below will be subject to change at any time at ATC's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

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1. INTRODUCTION

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 the response to Part 3 of 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, limitations 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 limitations 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 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, such as ComEd, DPC, NSP, and ITC, within and affected by the Midwest Independent Transmission System Operator, Inc. (MISO) territory in assessing regional needs.

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

ATC also conducts 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.

ATC develops transmission projects to address the congestion issues in its footprint and beyond. ATC uses the PROMOD model to analyze congestion across the ATC footprint and surrounding systems and develops projects that will relieve the congestion.

Further, ATC works with neighboring transmission owners, stakeholders and the MISO to develop transmission projects that provide multiple benefits including reliability, economic and public policy benefits. These projects are often more strategic and regional in nature to help provide benefit to multiple areas as well as maintain reliability here in Wisconsin well into the future. These projects are evaluated using traditional reliability planning tools, PROMOD for economic benefits and a combination of traditional FCITC analysis and economic analysis to quantify their public policy benefits.

As part of the MISO, ATC is participating in the MISO Transmission Expansion Plan (MTEP) 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 MTEP.

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 order was approved conditionally and, after a compliance filing by ATC, it was approved in August 2010. 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.

ATC participates in regional transmission assessments conducted by the Midwest Reliability Organization (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.

2. CAPACITY BENEFIT MARGIN METHODOLOGY

Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved to enable access by Load Serving Entities (LSEs) to generation from interconnected systems to meet generation reliability requirements, such as meeting firm load obligations during a capacity emergency. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

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

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

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

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

3. TRANSMISSION RELIABILITY MARGIN METHODOLOGY

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

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

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

MISO uses the summation of the ARS and 2 percent uncertainty components of TRM in the network analysis for Long-Term Transmission Service Requests. Please reference the MISO Transmission Reliability Margin Identification (TRMID) methodology for a description of the application of TRM to all Transmission Service Requests.
Other ATC planning studies screen at a 3 percent reduction in normal and emergency ratings for assessments within one year and a 5 percent reduction for the assessments beyond one year in the future, except for studies that consider a wide range of system conditions (e.g., load, dispatch, transfers), such as 10-year assessments. The recommended timing of the resultant mitigation measures may be based on less than the 3 percent and 5 percent reductions.

4. FACILITY RATING METHODOLOGY

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

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

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

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

(Applicable NERC Standards: FAC-008-1-R1)

5. MODEL BUILDING METHODOLOGY

We will strive to develop and maintain consistency in the power flow models used for planning efforts and in assessing whether and under what conditions transmission service is available. The starting point for ATC power flow models will be models contained in the NERC and Regional data banks. We will use load forecasts provided by our end-use load-serving customers as input into future model building efforts, both internally and in conjunction with NERC, Regional Entity (RE), and Regional Transmission Operator (RTO) initiatives. These forecasts may be adjusted by ATC if adjustments are needed for transmission planning purposes either with concurrence from our customers or independently of our customers. All ATC power flow models will be developed using PTI PSS/E software.

(Applicable NERC Standards: MOD-010-0, MOD-011, MOD-012-0)

5.1. Voltage Schedule

1. The power flow models will implement ATC's generator voltage schedule. The generator voltage schedule is defined as a:
   a. Target voltage of 102% of the nominal transmission voltage as measured at the point of interconnection between the generator and the transmission network unless another voltage schedule has been identified and,
   b. Normal voltage range of 95% to 105% of nominal transmission voltage.

   Due to limitations imposed by the NERC model building process, the generator voltage schedule target modeled in the NERC power flow models may only approximate ATC's voltage schedule at the point of interconnection. (NERC VAR-001)
2. Generators that do not have automatic voltage regulation (AVR) or are not controllable (unmanned stations and no remote control) have been considered. When modeling these generators, special attention must be given to the limitations of these units.

5.2. Generation Dispatch

1. Generation reported by ATC's members will be dispatched in accordance with contractual and local or regional economic dispatch considerations as applicable.
2. Designated Network Resources will be dispatched out of merit order if they have been identified as must run units.
3. Power-Voltage (P-V) analysis models wind generation at its full output level.
4. Generator Interconnection studies will model wind generation following the guidelines in the MISO Business Practice Manual for Generator Interconnections.
5. Generally, for each system load condition case, wind generation is modeled at 20 percent of its reported capability level for general planning studies, although sensitivity analyses may dispatch wind generators at various output levels.

5.3. Net Scheduled Interchange

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

6. FACILITY CONDITION METHODOLOGY

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

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

7. PLANNING ZONES

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

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

8. SYSTEM ALTERNATIVES

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

9. LOAD FORECASTING METHODOLOGY

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

In utilizing or developing load forecasts, the following methodology 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) **Shoulder peak** demand forecasts will be developed such that the scalable loads are scaled to a pre-calculated percent of the Summer peak demand forecasts while holding the non-scalable loads smaller than or equal to 5 MW constant and applying

shoulder load ratios[1] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Shoulder peak model is ~70 percent of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

3) **Winter peak** demand forecasts will be developed such that the scalable loads are scaled to Local Distribution Company (LDC) chosen percentages for the month of January. Non-scalable loads remain unchanged. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

4) **Fall/spring off-peak** demand forecasts will be developed such that the scalable loads are scaled to LDC chosen percentages for the month of November for fall or the month of April for spring. Non-scalable loads smaller than or equal to 5 MW remain unchanged while applying shoulder load ratios[1] for the non-scalable loads greater than 5 MW. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

5) **Summer 90/10 proxy peak** demand forecasts will be developed that reflect above-average summer weather and peak demand conditions. A true summer 90/10 forecast will be calculated in such a way that there is a 90 percent probability of falling short of and a 10 percent probability of exceeding the forecast due to weather conditions. Until we develop the capability for producing a specific 90/10 forecast, we will assume that it can be reasonably approximated through increasing the summer peak conforming load forecast by about 5 percent and leaving the non-scalable loads unchanged. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

6) **Light load (50 percent of peak)** demand forecasts will be developed such that the conforming loads are scaled to a pre-calculated percent of the Summer peak demand forecasts while holding the non-scalable loads smaller than or equal to 5 MW constant and applying light load ratios[1] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Light load model is ~50% of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

7) **Minimum load (40 percent of peak)** demand forecasts will be developed such that the conforming loads are scaled to a pre-calculated percent of the Summer peak demand forecasts, while holding the non-scalable loads smaller than or equal to 5 MW constant and applying light load ratios[1] for the non-scalable loads greater than 5 MW. The resultant overall ATC load in the Minimum load model is ~40% of the Summer peak. The ratio of the real to reactive power of the loads will remain unchanged from the summer peak ratio.

[1] To enhance the modeling of shoulder and light load conditions for the ATC Planning analysis, during the load forecast process, ATC requested local distribution companies to provide shoulder-to-peak ratios and light-to-peak ratios for the non-scalable loads greater than 5 MW.

10. ECONOMIC METHODOLOGY

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

1. In developing screening level capital cost estimates for transmission lines and substations, terrain, geology and land use will be considered.
2. In conducting the economic analysis of changes in transmission system losses, hourly line flow data and associated area Locational Marginal Prices (LMPs) for the entire analysis year from PROMOD will be used to analyze the potential savings from reduced transmission line losses associated with a new project (or package of projects).
3. The reduction in the need to build additional generation to serve the peak load will be calculated by comparing the losses from the power flows for the peak load hour with and without the project. To correctly do the accounting, the reduction in the generation needed to serve the peak load will be increased by the Midwest ISO's planning reserve margin. The dollar value of this savings will be based on the construction cost of a combustion turbine.
4. The LMP market simulation tool, PROMOD, will be the primary tool used to analyze the economics of projects in the energy market. ATC's Customer Benefit Metric will typically be used to analyze the energy market savings of projects. Generally PROMOD will be run with and without the project, or package of projects, to determine the energy market savings. Other energy market economic benefits may also be calculated, such as the "insurance benefit" associated with having a more robust transmission grid to respond to low probability, but high impact transmission and generation outages, which can cause energy market prices and costs to spike.
5. All transmission projects have both reliability and energy market economic impacts. In certain cases, energy market economic benefits may be the primary driver of a project. In addition, energy market economic analysis of projects may be used in the prioritization and staging of projects. In this effort, an attempt is made to capture all relevant factors in determining the energy market economic benefits of a project. Stakeholder input is utilized by ATC for this purpose. Various tools are also utilized by ATC, including the Ventyx PROMOD software; however, other methods and tools are open to consideration.

11. ENVIRONMENTAL METHODOLOGY

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 and avoid such impacts where possible. Where it is not possible to avoid such impact, minimize and mitigate such impacts to the extent possible. More detailed analyses will be undertaken to support an application to siting authorities of specific transmission alternatives.

12. VARIATIONS ON ATC PLANNING CRITERIA

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

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

1. Area does not meet NERC Standards TPL-001-1, -002-1 or -003-1 with respect to stability.
    a. Complete projects required for bringing the existing system up to NERC Standards TPL-001-1, -002-1 or -003-1 performance requirements with no intentional delay.
    b. New generator interconnections are not permitted until the NERC standards are met with the addition of the new generator, if the new generator interconnection aggravates the stability condition. [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet NERC Standards TPL-001-1, -002-1 or -003-1. See NERC Standard FAC-002-1 for new generator interconnections.]
    c. Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the projects are completed. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a "last interconnected, first restricted" approach.

2. Area meets NERC Standards TPL-001-1, -002-1 or -003-1 but not ATC criteria with respect to stability.
    a. Normal schedule for projects required for bringing the existing system into compliance with ATC criteria.
    b. New generator interconnections are permitted as long as the system continues to meet the NERC Standards TPL-001-1, -002-1 or -003-1. If the new generator

interconnection causes the system to be unable to meet the performance requirements of these NERC standards, 1.b above applies.

   c. Operating procedures will not be required in the interim period until the projects to meet ATC criteria are completed.

3. Area meets ATC planning criteria for existing system but a new generator interconnection causes a violation of:

4. ATC planning criteria – New generator interconnection is not permitted until ATC criteria are met with the addition of the new generator.

   a. NERC Standards TPL-001-1, -002-1 or -003-1 under FAC-002-1 – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

13. OTHER CONSIDERATIONS

13.1. Project constructability

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

1. Whether addition, replacement or modification of a transmission line, transformer or other facility would result in violation of the System Performance Criteria, and
2. Whether addition, replacement or modification of a transmission line, transformer or other facility precludes the ability of ATC Operations to conduct maintenance activities on other transmission facilities.

13.2. Multiple contingency planning

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 and/or,
2. A multiple contingency arising from a common cause, such as a fire, flood, lightning etc., and/or a highly probable multiple contingency based on historical observance where studies indicate that there is potential for Adverse Reliability Impact,
3. Failure of a transmission structure supporting multiple circuits.
4. The loss of two transformers that are connected through a common breaker.

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

For more details regarding our multiple outage selection process, please refer to **Multiple Outage Selection Process** PR-0212-V03 and **Detailed Multiple Outage Analysis Process** PR-0213-V02.

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-003-1, TPL-004-1)

13.3. Terminal equipment limitations

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

13.4. Maximization of existing rights-of-way

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

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

13.5. Reduction of transmission system losses

ATC considers the benefit of reducing system losses along with other performance benefits and cost factors in evaluations of alternative transmission projects or plans. See Section 10, Economic Methodology.

13.6. Transmission system operating considerations in the planning process

1. Operating Guides
   a) Operating guides are not preferred under normal conditions, but may be employed by ATC and/or entities with generation and/or distribution facilities interconnected with the ATC transmission system to avoid transmission facility loadings in excess of normal and emergency ratings provided such guides are practical for sustained periods, if they meet the following conditions:
      (i) Do not compromise personnel or public safety
      (ii) Do not degrade system reliability
      (iii) Do not result in a significant loss of equipment life or significant risk of damage to a transmission facility.
      (iv) Do not unduly burden any entity financially.
   b) Supervisory switching capability is available to accomplish these operating guides. Field switching will not be relied upon as a means to reduce facility loadings or to restore voltages to within acceptable levels.
   c) ATC will strive to verify the efficacy of all operating guides that require on-site operations.
2. System Planning - ATC will strive to plan the transmission system such that operating flexibility is maximized. We will accomplish this by considering as wide a variety of scenarios as practical, including maintenance scenarios, when evaluating alternative transmission projects or plans.

13.7. Radial transmission service

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

13.8. Relaxation of criteria

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

13.9. Steady state voltage stability margin identification

The steady state operating point will be identified by finding the nose of the P-V curve and applying the required 10% margin. If a P-V curve nose is not identifiable (no power flow solutions beyond the nose of the curve), then the last solved point prior to the nose will be used as the P-V curve nose. A pre-contingency margin of more than 10% will be identified, if needed, to avoid allowing a steady state operating point beyond the nose of the curve immediately following the worst case Category B or C contingency.

13.10. Operations assumptions for three phase fault scenarios

The ATC Operations Department performs an operating horizon assessment taking into account operating horizon assumptions that may differ from the planning horizon assessment for certain three phase fault scenarios which are documented in certain ATC Transmission Operating Procedures (TOP). The operating procedures reference any special circumstances in the planning studies and assessments and apply real time risk methodologies as outlined in the TOP procedures. (Note: There may be other potential OPS planning tasks that may interface with Transmission planning tasks).

14. INTERCONNECTION STUDIES

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

1. Types of Analysis

   The analyses are to include steady state, short-circuit, and dynamic assessments that include the requirements in TPL-001-1, TPL-002-1, TPL-003-1, and TPL-004-1.

2. Compliance with Applicable Planning Criteria

   The analyses and procedures are to comply with all applicable NERC, Regional Entity, and individual system planning criteria of the affected parties.

3. Coordination with Affected Entities

   The results of the analyses will be jointly evaluated and coordinated by the affected entities.

4. Essential Documentation

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

5. Specific Study Methodologies

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

15. REFERENCES

None.

16. ADMINISTRATION

Review – This document will be reviewed annually**.**

Retention – The previous version of this document will be retained for at least five years after is becomes retired.

17. REVISION HISTORY

Revision	Author(s)	Manager(s)	Director(s)	Summary of Changes
14	Connie Lunde, et alia	David Smith, Paul Walter	Ron Snead	Primary – split Criteria and Practices into separate documents, moved Operations fault assumptions text; Details – Summary of Planning Criteria V14 and Practices V1 Revisions document