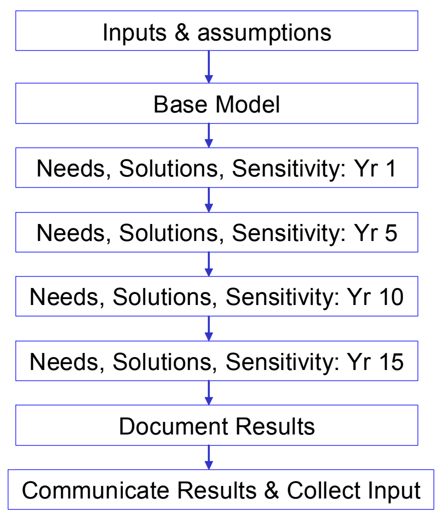
Methodology & assumptions

1.1 Overview

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

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

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



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

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

For NERC Category B, C or D contingencies, system limitations or constraints are identified using slightly different criterion. For these types of system contingency conditions, ATC's Planning Criteria identify system limitations when bus voltages drop below 90 percent or exceed 110 percent of their nominal voltage or when any system element exceeds its emergency rating for the appropriate seasonal model. For these three NERC categories, ATC's Planning criteria requires generators to be limited to 95 percent of their net Q_{max} capability within ATC footprint.

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.

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

1.2 Network assessment methodology

American Transmission Co.'s 2010 10-Year Transmission System Assessment provides current results of planning activities and analyses of the company's transmission facilities. These activities and analyses identify needs for network transmission system enhancement and potential projects responsive to those needs.

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

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

Computer simulation model years for the 2010 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2011 and 2015 were selected to meet the 1-5 year horizon. The years 2020 and 2025 meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2010 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.

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).

This 2010 network Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2011 were included in the 2011 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 2015, 2020 and 2025 models as appropriate based on projected in service dates (See Tables PF-2, PF-3 and PF-4).

1.2.1 Load forecast

Steady state summer peak models are built using our customers' load forecasts (50/50 projections) as a starting point, meaning that there is a 50 percent chance that the load level will either fall below or exceed the customer projection. Customer load forecasts were gathered for all ATC customers through the year 2019 (and in some cases 2020/2025). The forecasts were compared to previous historical and forecasted data to ensure validity and consistency. As a final step, the finalized forecast information was forwarded back to our individual customers to ensure their concurrence. Once consensus was achieved, the data was incorporated into our models.

Certain ATC customers did not provide an 11th-year load forecast for the year 2020. To obtain a forecast for 2020, certain customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.3% compounded annually). Non-scalable loads were held at their 2019 levels using this methodology.

The 2025 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2025, customer-provided forecasts were extended by growing their load by a fixed growth percentage based upon the previous 3-years' growth (approximately 1.3% compounded annually). Non-scalable loads were once again held at their 2019 (or 2020) load levels. It should be noted that the loads utilized in the 2025 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 2025 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
2010	13,681	N/A
2011	14,099	N/A
2015	14,832	1.3% (2011-2015)
2020	15,879	1.4% (2015-2020)
2025	16,973*	1.3% (2020-2025)
Overall		1.4% (2010-2025)

**load model, not a load forecast*

It should be noted that we worked with the distribution companies as much as possible to confirm forecast variations from past trends. In a few cases we revised power factors to reasonable levels to prevent creating expensive transmission projects for voltage support. In most cases these issues would ultimately be solved through distribution system power factor correction. ATC will be in ongoing discussions with our customers to determine the best plan for these situations.

1.2.2 Model building
1.2.2.a Assumptions common to all models

1.2.2.a.1 New generation

There have been numerous generation projects proposed within ATC's service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Several have proceeded to or through the licensing phase and several more are under construction. However, there are numerous proposed generation projects that have dropped out of the generation queue (refer to Generation interconnections), adding considerable uncertainty to the transmission planning process. To address this planning uncertainty, we have adopted a criterion for purposes of this and prior Assessments, to establish which proposed generation projects would be included in the 2010 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 2010 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 2010 and 2011 models showed these generators as out of service. The 2015 and 2020 models should have had these generators in-service and dispatched.

1.2.2.a.2 Generation retirements

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

There are generators that have been publicly announced as likely candidates for retirement. However, using the disconnection criteria above, in the 2010 10-Year Assessment models we assumed the following generators to be out of service:

Plant Name	*Zone*	*Installed capacity*	*Assumed out of service*
Presque Isle 3	2	58 MW	Jan 2010
Presque Isle 4	2	58 MW	Jan 2010
Point Beach 1	4	103 MW	Jan 2011
Point Beach 2	4	105 MW	Jan 2011
Blount 3	3	39 MW	Jan 2013
Blount 4	3	22 MW	Jan 2013
Blount 5	3	28 MW	Jan 2013
Net decrease in 2010		116 MW	
Net decrease after 2010		297 MW	

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

1.2.2.a.3 Cutoff dates

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

- 2011 models - October 29, 2009
- 2015 models - October 29, 2009
- 2020 models -October 29, 2009, and
- 2025 models - October, 2009.

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

1.2.2.a.4 Generation projects schedule

To maintain the schedule needed to complete this Assessment, the models were developed during late 2009 and early 2010. 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 2010, 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*
Marshfield CT	1	55.2 MW	55.2 MW	May 2010
Oak Creek #2	5	615 MW	615 MW	Aug 2010
Green Lake wind farm	1	32 MW	32 MW	Sep 2010
Quilt Block wind farm	3	19.6 MW	19.6 MW	Dec 2010
Glacier Hills wind farm	3	19.8 MW	19.8 MW	Dec 2010
Stoney Brook wind farm	4	19.7 MW	19.7 MW	Dec 2011
Bowers Road wind farm	3	21 MW	21 MW	Dec 2011
EcoMet wind farm	4	20.1 MW	20.1 MW	Dec 2011
Ledge wind farm	4	30.0 MW	30.0 MW	Dec 2012
Lake Breeze wind farm	4	19.6 MW	19.6 MW	Oct 2013
Net increase by Dec 2011:		802.4 MW		
Net increase 2011-2020:		49.6 MW		

**wind farm Installed capacity lists is 20% of total installed capacity*

A more comprehensive discussion of proposed generation is provided in Generation Interconnections, including a map showing all of the currently active generation interconnection requests that ATC has received (See Figure PR-9**.**)

1.2.2.a.5 Generation outside system

The model for the system external to ATC was taken from the most appropriate model included in the MMWG 2009 Series models. The external system interchange was adjusted from the 2009 MMWG Series models to match the latest ATC members' firm interchange with the exception of the Shoulder 70% model which was built to represent a 3000 MW import into ATC.

1.2.2.a.6 Generation dispatch

Balancing Authority (Control) area generation was dispatched based on economic dispatch for that Balancing Authority with the exception of the Shoulder 70% model.

1.2.2.a.7 Line and equipment ratings

We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD). As of June 2010, nearly 81 percent of all ATC lines and 89 percent of ATC transformers have SELD ratings that have been validated. Additionally, nearly 96 percent of ATC lines 100 kV or higher have ratings in SELD that have been validated.

Ratings not yet validated in SELD generally are based on the ratings received from the utilities that contributed the facilities to ATC.

1.2.2.a.8 Project criteria included in all assessment models
All of the models built for the Assessment include revised system topology based on projects that were placed in service in the model year, or were anticipated to be placed in service by June 15 of that year. Refer to Tables PF-1 through PF-4 for projects that were included in the analyses. Please also refer to the Project deficient seasonal models, Section *1.2.2.b.1*, for more discussion about how projects are chosen for inclusion our models.

1.2.2.b Steady state power flow models

1.2.2.b.1 Project deficient seasonal models
The load flow models built for the 10-Year Assessment are special models built exclusively for system analyses in the Assessment. Some projects were purposely left out of these models in order to verify system problems and determine which problems worsen over time. We have taken the approach of evaluating subsequent summer peak seasons in each of our annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2011, 2015, 2020 and 2025 steady state project deficient summer peak models were developed to evaluate needs, verify findings of the 2009 Assessment, and confirm that previously identified needs will increase over time. The 2020 and 2025 project deficient models reflect years sufficiently forward in time to determine the need for and assess the performance of larger-scale projects (345-kV lines, for example) that could be expected to be in service in that timeframe.

1.2.2.b.2 All project seasonal models
After the initial analyses portion of the 10-Year Assessment was completed, “All Project” models were built. The “All Project” models were built with all planned and proposed projects in the 2011, 2015 and 2020 models. The later models also include the majority of the provisional projects. These models are more indicative of the expected system configurations for the three study years. The “All Project” models are more appropriate for internal studies performed by ATC planners throughout the year and for regional models. As part of the 10-Year Assessment, the zone planners perform contingency analyses on each of the “All Project” models. These analyses will verify whether all of the planned, proposed, and provisional projects will resolve issues revealed in the 10-Year Assessment process.

1.2.2.b.3 Load, dispatch and interchange profiles

1.2.2.b.3.a Load Sensitivities (2015)
ATC planning explored two sensitivity analyses in our 2010 10-Year Assessment analyses, the minimum (light load) scenario and the high wind generation scenario. The modeling details of these sensitivities are outlined below.

Minimum load scenario (2011)

- ATC Peak Load: 5,515 MW
    - 2009 forecast collection, scalable loads reduced to 32% of peak + non-scalable loads = 40% of Peak load
- Total ATC Generation: 5,297 MW
- Includes all planned and proposed projects to be in-service by 6/15/2011
- *Interchange:* Firm interchange only as of 10/29/2009
- *Dispatch:* ATC-wide Merit order as of 10/29/2009

High wind generation scenario (2015)

- ATC Peak Load: 9,678 MW
    - 2009 forecast collection, scalable loads reduced to 62.5% + non-scalable loads = 67% of Peak load as provided in Operations data
- Total ATC Generation: 8,725 MW
- Includes all planned and proposed projects to be in-service by 6/15/2011
- *Interchange:* ATC net as provided in Operations data -1218
- *Dispatch:* ATC-wide Merit order as of 10/29/2009
- *Special additions:*
    - Wind generation in the ATC footprint dispatched to 61% of P_{max} as provided in Operations data,
    - Wind generation west of ATC dispatched to 50% as provided in Operations data,
    - Wind Generation south of ATC dispatched to 95% as provided in Operations data,
    - Reduce surrounding control area load and dispatch to 80% load level

1.2.2.b.3.b Summer peak (2011, 2015, 2020, 2025)

- ❑ We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- ❑ Only firm interchange was included in our analyses.
- ❑ Special additions: none

1.2.2.b.3.b.1 Summer peak 95% Q_{Max} (2011, 2015, 2020, 2025)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 95%.

1.2.2.b.3.b.2 Summer peak 90% Q_{Max} (2011, 2015, 2020, 2025)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009 for both real and reactive power components of load. Please refer to the Load Forecast section for further details.
- Only firm interchange was included in our analyses.
- Special additions: Generator Q_{Max} reduced to 90%.

1.2.2.b.3.c High load model (2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009. The 2015 high load (or "hot summer") model was created by increasing load 5 percent above expected summer peak conditions as a proxy for a 90/10 model in order to determine in-service date sensitivity to load growth that is higher or weather that is warmer than forecasted. Please refer to the Load Forecast section for further details.
- The system external to ATC was taken from the MMWG 2009 Series, 2015 summer model.
- The external system interchange was adjusted from the 2009 MMWG Series 2015 summer interchange to match latest ATC members' firm interchange.
- ATC load forecast increased by 5% above the summer peak load forecast using a constant power factor, Planning/Operations coordinated 69-kV ratings included.

1.2.2.b.3.d Shoulder 70% models (2011, 2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009.
- The 2015 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.
- The shoulder 70% model included a 3000 MW import into ATC. Firm interchange plus economic transactions up to a 3000 MW import were included.
- Planning and operations coordinated 69-kV ratings included.

1.2.2.b.3.e Shoulder 90% models (2011, 2015)

- We utilized interconnection point load forecasts provided by various distribution companies in 2009. The 2015 shoulder 90% model was created by decreasing load 10 percent below expected summer peak conditions. Please refer to the Load Forecast section for further details.
- To simulate a steady state reverse east-west bias power flow, models were developed with 90% load levels, 1700 MW import into ATC, and a 2000 MW transaction from east to west.
- ATC system biased in an East to West direction, Planning/Operations coordinated 69-kV ratings included.

1.2.2.b.3.f Model years

We started model development for this Assessment by building a system model that represented 2010 summer peak conditions. This 2010 model is referred to as an “as-built” model because essentially everything in the model is certain to be in service by 2010 summer. This model then was modified to create each of the subsequent Assessment study models including the changes previously described for each model.

Computer simulation model years for the 2010 network Assessment analyses were selected in order to meet NERC requirements for a 1-5 year horizon and beyond the 5 year horizon. The years 2011 and 2015 were selected to meet the 1-5 year horizon. The years 2020 and 2025 meet the beyond 5 year horizon. The years 2011, 2015 and 2020 were chosen to coordinate with the most recently released MMWG models that were available.

The 2011, 2015, 2020 and 2025 models were developed to evaluate needs, verify findings of the 2009 Assessment, and confirm that previously identified needs will increase over time. The 2020 and 2025 models reflect years sufficiently forward in time to determine the need for and assess the performance of larger-scale projects (345-kV lines, for example) that could be expected to be in service in that timeframe.

1.2.2.c Dynamic stability/short-circuit assessment models

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 System stability).

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.

1.2.3 Needs and solution development

1.2.3.a Steady state project-deficient needs assessment

1.2.3.a.1 System intact and single contingency simulations
ATC performed system intact and single contingency simulations on the 2011, 2015, 2020 and 2025 models. Single contingency simulations include the following: single element (line, transformer, generator, bus and switched shunt) and event-based breaker-to-breaker outages. We run these simulations for summer peak and under the sensitivity situations described in Section 1.2.2.b.3.

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

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

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

1.2.3.b Solution development

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

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

Cost estimates are requested from the Project Control Office for solution options that effectively address the identified constraint. After cost information has been obtained, the zone planner selects the most efficient solution option from a cost-benefit standpoint and develops a provisional project request form. Finally, the provisional project request form is processed through ATC's Project Approval Process.

1.2.3.b.2 Repeat constraint

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

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

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

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

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

1.2.3.c All Projects assessment

After the 10-Year Assessment analysis is completed, models are built that include all planned, proposed, and some provisional projects. These models are called "All Projects" models and are more indicative of the expected system configurations for 2011, 2015 and 2020 study years. These models are more appropriate for internal planning studies performed throughout the year.

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

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

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

As we did in the 2009 Assessment, this year we attempted to address the first two questions. We built year 2011, 2015 and year 2020 models that included reinforcements reflecting our best thoughts on all of the most likely planned, proposed, and provisional projects to address the identified issues. These projects are those identified in the project tables for this Assessment with specific in-service dates. First contingency analysis was performed on these new models, including selected outages on neighboring systems. This analysis showed that the reinforcements in total did indeed deal with the issues identified and did not create any new issues to be resolved. Please refer to the All Projects section for details of our analyses.

1.2.3.d Stability review & analysis

1.2.3.d.1 System angular stability assessment

For each 10-Year Assessment, generator stability is screened or assessed at all major generating stations connected to the ATC system. Numerous generator interconnection studies add to our knowledge of the ATC system stability response to selected Category B2, C3 and D2 outages that constitute the worst case scenarios for stability perspective. A MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully complaint with NERC Standards that cover multiple outages (Category C), including the system's stability response to multiple outages.

In the 2010 10-Year Assessment, we revisited a select list of generator stations as described below, conducting simulations by applying NERC Standards for categories B2, C3 and D2 using the 2015 Light Load All Project model. As generator stability concerns arise they are evaluated and appropriate corrective actions are developed and implemented. Generator stations with total net output above 100 MW and associated transmission lines operating above 100 kV are generally selected to assess system angular stabilities.

The methodology used in screening or assessing the major generator stations includes a review to determine that no significant system topological changes have occurred near the generator stations other than local load growth. In addition, the methodology includes a review of the parameter values and the model types used to represent the dynamic response of the units at the generator stations in system angular stability simulations to determine that no significant changes have occurred. This methodology also includes a review of the date the last time a stability study was conducted for a major generator station to determine that the elapsed time does not exceed five years. Considering the number of existing major generator stations shown in Table ZS-7 - ATC System Angular Stability Assessment this requires that at least six major generator stations be included in the system angular stability analysis for each 10-Year Assessment in order to complete a study of all major generator stations in a 5-year sequence.

If these criteria are confirmed, the generator stability results of the previous existing studies remain applicable and are acceptable for the following years with proposed system upgrades. If any of these criteria are not met then the generator stability is screened or restudied, and the preliminary needs and results of the analyses are communicated to our stakeholders. Please refer to System stability analysis for more details.

1.2.3.d.2 System voltage stability assessment

ATC is still developing a rigorous process for assessing voltage stability across the system. Currently we monitored single and multiple contingency voltages for the Rhinelander area which was started in the 2009 10-Year Assessment using the 2008, 2009, and 2013 summer peak all project system models to screen for indications of where voltage stability may be an issue. Additional studies will need to be conducted since the load breakdown data by customer class supplied changed significantly from what had historically been provided and because of the results obtained for some of the NERC C3 contingencies will require additional analysis. We then compare the stability performance against our Planning criteria, document the preliminary needs and results, and communicate those results to our stakeholders.

The MRO/RFC joint on-site review completed in December 2008 determined that ATC was fully compliant with the voltage stability assessment requirements in the applicable NERC standards. Please refer to System stability analysis for more details.

1.2.3.e Multiple outage review & analysis

1.2.3.e.1 Overview
ATC's steady-state multiple outage assessment started with Commonwealth Associates (CAI) performing more extensive analysis of our transmission system in 2004 to identify NERC Category C type contingencies that potentially could lead to cascading. Since then, we have taken this initial screening and enhanced our review in succeeding years.

1.2.3 e.2 Model development
For the 2010 work, ATC used the 2015 and 2020 summer peak models with 95% Q_{max} including all projects identified in the 10-Year Assessment for additional steady state multiple outage analysis. Physical Operational Margin (POM)-Optimal Mitigation Measure (OPM) software was used to determine available mitigation measures that could be used to alleviate identified system constraints that could potentially cause problems. The mitigation measures used were generation re-dispatch, generator reactive power re-dispatch, transformer under load tap changing, capacitor bank adjustment, phase shifter angle adjustment and load-shedding.

1.2.3.e.3 Contingencies studied
NERC Category C contingencies are specific sets of multiple outages including lines, transformers and generators. For this Assessment, we revisited Category C event analysis by evaluating the existing severe multiple outages list, which included:

- 43 multiple outages selected and tested in 2005 studies,
- 16 breaker failure (NERC Category C2) multiple outages selected from 2009 studies,
- 4 bus section (NERC Category C1) multiple outages selected from 2009 studies,
- 30 selected contingencies from Zone 3,
- 5 selected contingencies from Zone 5, and
- 30 selected contingencies from Zone 1 identified in the 2009 studies.

In addition to the above selected multiple outages, 15 selected outages that resulted from new projects in the 2020 model were tested.

In addition to the re-evaluation of previously defined multiple outages, in 2010 we performed additional Category C analyses by screening all 345-kV branches and generators connected to the bulk electric system and all ties into our service territory (100 kV and above). Furthermore, we performed detailed Category C analyses for ATC planning Zones 2 and 4 for 100 kV and above and generators connected to the bulk electric system.

1.2.3.e.4 Contingency types
As part of these analyses, several contingency types are identified. They are as follows:

- C3: N-1-1, combination of transmission lines, transformers and/or generators,
- C5: N-2, two circuits on a common tower,
- C2: Breaker (failure or internal fault), and
- C1: Bus section.

1.2.3.e.5 Contingency thresholds
The screening thresholds are identified as follows:

- Generators connected to Bulk Electric System,
- Voltage level of 100 kV and above for transmission lines,
- Transformer size ≥100 kV, both high and low voltage sides,
- Monitored buses: 69 kV and above, and
- Severe outages: outages that cause system constraints that require loss of load to mitigate in addition to other non load shed remedial actions.

1.2.3.e.6 Contingency analysis
Our contingency analysis was performed by carrying out a full analysis for both the 2015 and the 2020 summer peak models. In addition to the selected multiple outages applied to the 2015 model, multiple outages resulting from new projects were tested using the 2020 model. For both 2015 and 2020 models, a full analysis of ATC Zone 2 and Zone 4 was performed.

1.2.3 e.7 Contingency results
Our results consist of lists of contingencies resulting in thermal constraints, voltage constraints, and voltage stability constraints. Also available are simulation results of available mitigation measures, as estimated by POM-OPM software that can be employed to alleviate identified system constraints. Please refer to Multiple Outages for the results of our analyses.

1.2.4 Documentation

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

- ❑ Requests are made for the latest financial, environmental, demographics, asset renewal and economics information from other ATC departments.
- ❑ Drafts of each section’s text, figures and tables are compiled for peer review.

- A comprehensive meeting is held with all Planning and Asset Renewal managers and team leaders in order to review and approve the information.
- A summary presentation of all Assessment information is reviewed and approved by ATC management.

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