

## Methodology and Assumptions

### 1.1 Overview

This section describes the methods and techniques that we used to develop assumptions, analyze our transmission network and share results for the 2014 10-Year Assessment. Economic, regional, and asset management planning processes are covered on the ATC website, [www.atc10yearplan.com](http://www.atc10yearplan.com).

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. ATC meets with stakeholders to discuss assumptions and results. ATC's network planning process is summarized in Figure1.

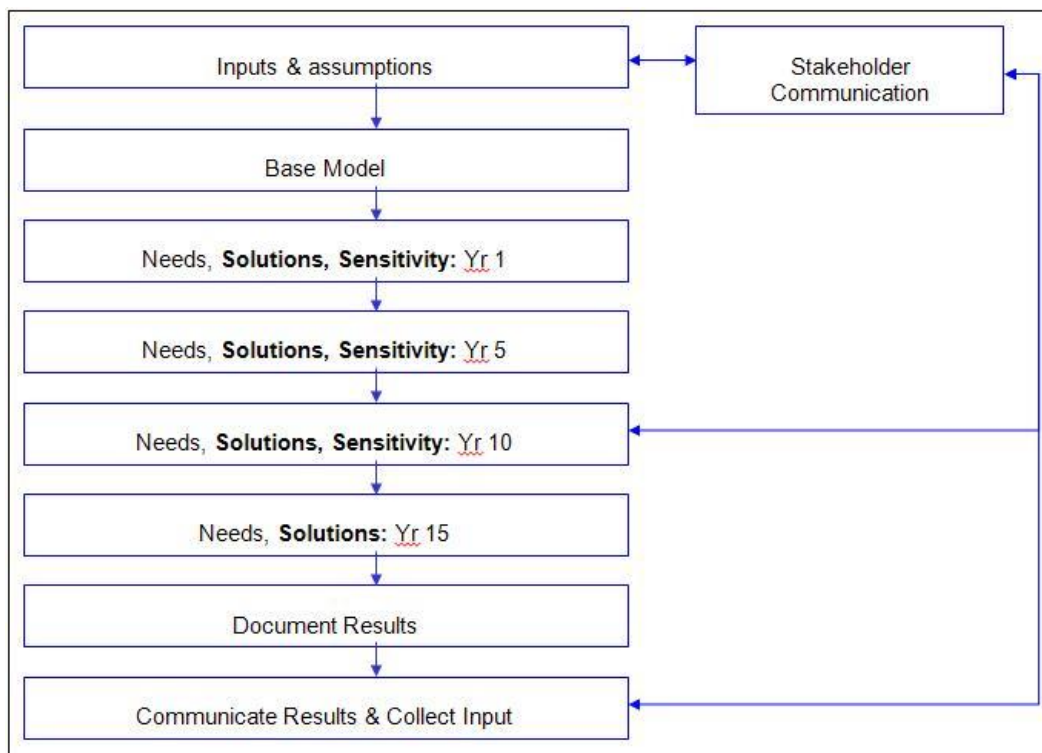


Figure 1: 10-Year Assessment Process

### Open Planning Process

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. ATC is committed to continuing our open and transparent processes for planning our transmission system. We value the input of all of our stakeholders. We also strive to meet or exceed requirements in FERC Orders 890 and 1000. There has been increasing emphasis on how public policy requirements are addressed in ATC's 10-Year Assessment process. ATC's efforts in this area are described below.

The ATCLLC section in attachment FF of MISO's tariff, describes seven planning functions at ATC. For each appropriate function, specific ATC actions are identified which will support incorporation of public policy requirements in ATC's planning process. ATC's 10-Year Assessment process is identified in the section describing ATC's planning function called Network Adequacy Planning. This section identifies specific efforts ATC will engage in to assure public policy requirements are addressed in its 10-Year Assessment process. Below is a summary of how the 2014 assessment process has attempted to incorporate public policy requirements.

ATC's 10-Year Assessment input process is very amenable to identifying stakeholder and customer concerns regarding Public Policy Requirements. Looking at the basic structure of our process identified in Figure 1, ATC has at least three phases in the process where we can discuss with Stakeholders how these requirements could be addressed.

- Assumptions Phase
- Needs Phase
- Solutions Phase

Documentation of the content and schedule for these 10-Year assessment discussions is included in notices on the Economic Benefits page of the ATC website, [www.atc10yearplan.com](http://www.atc10yearplan.com). The intent of the discussion with stakeholders in each of the three phases is described in the following paragraphs.

In the assumptions phase of the process, ATC develops and proposes a study design for the coming assessment. We schedule a meeting with stakeholders to provide a summary of the study design that can facilitate discussion of planning criteria, study methods, assumptions for models, and potential needs. This input will affect decisions about which models to build and study, as well as resources and loads to model. This meeting is also an additional opportunity to collect responses to the results of the previous year's assessment. In the 2014 process, we primarily relied on ATC economic benefits studies and MISO regional efforts to identify and incorporate public policy requirements. For the 10-Year Assessment, to some extent some of these requirements are indirectly considered by ATC in the model data we gather from customers for loads and resources.

For the needs phase of the assessment, we schedule another meeting with stakeholders to summarize how the results of analysis may be impacting existing needs or creating new needs. Stakeholders are invited to participate and discuss needs that they think should



have been identified and were not, or were identified and elicit questions. To identify needs that might be driven by public policy requirements ATC chose not to identify specific requirements individually, but instead, continued our practice of developing sensitivity studies for bias flows across our system: west-to-east and east-to-west, for example. We also chose not to create a model that included extremely high renewable resources in the west with an appropriate transmission overlay because such scenarios have been and are being considered at the MISO regional level. Instead, given our knowledge of existing requirements, we felt that our bias sensitivities would be a good proxy for potential flows from such public policy and renewable scenarios.

In the preliminary solutions phase, we hold a third meeting for stakeholders to participate and discuss whether appropriate solutions have been considered for identified needs. The projects making up the solutions we've identified in this assessment have multiple need drivers such as load growth, generation changes, asset renewal, public policy, and economic benefits. Reduced load growth has also been reflected in the delays and even cancellations of some projects. It is not always easy to tell how much each driver affects the need for a specific project in the screening studies that contribute to the assessment.

The Stakeholder process culminates in the publication of the assessment, both a printed summary and a posting on the 10-Year Assessment web site. ATC is involved in the assumptions and processes through which the MISO regional Public Policy studies are carried out and relies on that involvement to ensure the reliability of our system can be maintained.

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.

### Analysis Introduction

Included in this section is a discussion of the 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 used these models in testing the robustness of potential system reinforcements. Per ATC's Transmission System Planning Criteria, constraints or system limitations were identified for NERC Category A type system conditions.



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, system limitations are identified according to ATC Transmission System Planning Criteria.

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

### **1.2 Network Assessment Methodology**

American Transmission Company's 2014 10-Year Assessment provides current results of planning activities and analyses of the ATC 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 Attachment FF-ATCLLC in the MISO tariff's Attachment FF describes ATC's open planning processes.

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 2014 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 2015 and 2019 were selected to meet the 1-5 year horizon. The years 2024 and 2029 were selected to meet the beyond 5 year horizon. A range of system conditions and study years were developed and analyzed for the 2014 Assessment. Steady state peak load models for all four years were created. In order to address uncertainty in reactive power capability and preserve some margin for the ATC area, an additional model was created for each year. For each of the additional models the maximum and minimum reactive power capability was reduced by 10 percent for appropriate generators within the ATC footprint. These models were used for intact system condition (TPL-001-0) analysis and any contingency analysis.



The needs identified were determined by identifying facilities whose normal or emergency limits are exceeded. The criteria we used to determine what these limits are provided in the ATC Transmission System Planning Criteria.

This assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2014 were included in the 2015 model, as listed in the Table PF-1. Projects that have completed the 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 2019, 2024 and 2029 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 were 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. In 2013, customer load forecasts were gathered for all ATC customers through at least the year 2023 (in most cases through the year 2029). The forecasts were compared to historic data and previous load forecasts to ensure validity and consistency. As a final step, the final forecast information was forwarded back to individual customers to ensure their concurrence. Once consensus was achieved, the data was incorporated into our models.

Certain ATC customers did not provide an 11<sup>th</sup>-year load forecast for the year 2024. To obtain a forecast for 2024, certain customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their levels at the last year forecast. Non-scalable loads were also held at their load levels at the last year forecast using this methodology.

The 2029 summer peak load model was developed utilizing similar methodology. To obtain a projection for 2029, customer-provided forecasts were extended by growing their load by using a 3-year linear growth rate calculated over the last three years of the forecasts provided by the customer. Load power factors were held at their levels at the last year forecast. Non-scalable loads were once again held at their load levels at the last year forecast. It should be noted that the loads utilized in the 2029 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 2029 projection is not to develop projects to address all issues, but to develop a sense for the need(s) for long lead-time projects.

**2014 10-Year Assessment**  
**www.atc10yearplan.com**

*ATC summer peak total load projections (MW)*

Year	MW load	Study period compounded growth rate
2014	13,038	Not applicable
2015	13,128	Not applicable
2019	13,533	0.75% (2014-2019)
2024	14,020	0.71% (2019-2024)
2029	14,511	0.69% (2024-2029)
Overall		0.72% (2014-2029)

It should be noted that, we worked with the distribution companies as much as possible to confirm forecast variations from past trends.

## 1.2.2 Model building

### 1.2.2.a Assumptions common to all models

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

- New Generation
- Generation Retirements
- Cutoff Dates
- Generation Project Schedule
- Generation Outside of the System
- Generation Dispatch
- Line and Equipment ratings
- Project Criteria

#### 1.2.2.a.1 New Generation

There have been generation projects proposed within the ATC service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. Some have proceeded to or through the licensing phase and one or more are under construction. However, there are also proposed generation projects that have dropped out of the generation queue (refer to Appendix A, Generation Interconnections), adding 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 2014 Assessment models.

In the 2014 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.



**2014 10-Year Assessment**  
**www.atc10yearplan.com**

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.

*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 2014 10-Year Assessment models we assumed the following generators were to be out of service (ATC cannot comment on whether these units have completed MISO Attachment Y studies).

*ATC assumed the following generators were to be out of service*

Plant Name	Zone	Installed capacity	Assumed out of service
Edgewater #3	4	57 MW	57 MW
Nelson Dewey #1	3	107 MW	107 MW
Nelson Dewey #2	3	104 MW	104 MW
Kewaunee #1	4	576 MW	576 MW
Net decrease before 2014		576 MW	576 MW
Net decrease after 2014		268 MW	268 MW

*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.

- 2015 models – December 26, 2013
- 2019 models – December 26, 2013
- 2024 models – December 26, 2013
- 2029 models – December 26, 2013

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 2013 and early 2014. 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 2014, the criterion above resulted in the following proposed generation projects being included in the applicable power flow models.

*Proposed generation projects being included in the applicable power flow models*

Plant Name	Zone	Installed capacity increase	Dispatched increase	Assumed in-service
Garden wind farm	2	13.4 MW	13.4 MW	Oct 2015
Glacier Hills wind farm	3	17.4 MW	0 MW	Dec 2014
Twin Falls Hydro	2	3.7 MW	0.5 MW	June 2016
Net increase by Dec 2014		0 MW		
Net increase 2015-2029		34.5 MW		

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

A more comprehensive discussion of proposed generation is provided on the Generation Interconnections page of the 10-Year Assessment website.

#### 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 2013 Series models. The external system interchange was adjusted from the 2013 MMWG Series models to match the latest ATC members' firm interchange with the exception of the East to West Bias and the West to East Bias models which were built to represent 400 MW imports into ATC and an ATC Western Interface bias of 1400 MW into ATC and a 600 MW ATC Western Interface bias out of ATC, respectively.

#### 1.2.2.a.6 Generation dispatch

Balancing Authority area generation was dispatched based on economic dispatch for that Balancing Authority with the exception of the West to East Bias and Light Load models.

#### 1.2.2.a.7 Line and equipment ratings

We revised line and equipment ratings based on updates to our Substation Equipment and Line Database (SELD).

#### 1.2.2.a.8 Project criteria

The steady state models built for the 2014 10-Year 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.

#### **1.2.2.b Steady state power flow models**

##### **1.2.2.b.1 Normal (Category A) Conditions**

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

##### **1.2.2.b.2 Planned Maintenance and Construction Outages**

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

##### **1.2.2.b.3 Protection Systems**

All existing and planned protection systems, including any backup or redundant systems that would be applicable to a given contingency were simulated in the studies and analyses. In the steady state simulations, we simulated event based contingencies that reflect all of the elements that would be removed by the existing or planned protection system. Dynamic studies, in particular, simulate protection system operating times, associated breaker clearing times, and back up device tripping functionality.

##### **1.2.2.b.4 Control Devices**

All existing and planned control devices that would be applicable to a given contingency were simulated in the studies and analyses. These control devices include transformer automatic tap changers, capacitor bank automatic controls, SVC and the back-to-back HVDC (VSC) power flow controller.

##### **1.2.2.b.5 Project deficient seasonal models**

**2014 10-Year Assessment**  
**www.atc10yearplan.com**

The load flow models built for the 10-Year Assessment are 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 2015, 2019, 2024 and 2029 steady state project deficient summer peak models were developed to evaluate needs, verify Assessment findings of the previous years, and confirm that previously identified needs will increase over time. The 2024 and 2029 project deficient models reflect years sufficiently forward in time to determine the need for and assess the performance of larger-scale projects (345 kV lines, for example) that could be expected to be in service in that timeframe.

*1.2.2.b.6 All project seasonal models*

After the initial analyses portion of the 10-Year Assessment was completed, “All Project” models were built. The “All Project” models were built with all planned and proposed projects included as well as the majority of the provisional projects. These models are more indicative of the expected system configurations for the three study years. The “All Project” models are more appropriate for internal studies performed by ATC planners throughout the year and for regional models. As part of the 10-Year Assessment, the zone planners perform contingency analyses on each of the “All Project” models. These analyses will verify whether all of the planned, proposed and provisional projects will resolve issues revealed in the 10-Year Assessment process and will not introduce any new limitations.

*1.2.2.b.7 Load, dispatch and interchange profiles*

*1.2.2.b.7.a Load Range Models*

*1.2.2.b.7.a.1 Summer Peak (2015, 2019, 2024 and 2029)*

- We utilized interconnection point load forecasts provided by various distribution companies in 2013 for both real and reactive power components of load. Please refer to the Section 4.2.1, Load Forecast, for further details.
- Only firm interchange was included in the analyses.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW for the 2014+ model years.

*1.2.2.b.7.a.2 Summer Peak 90% QMax/Qmin (2015, 2019, 2024, 2029)*

- We utilized interconnection point load forecasts provided by various distribution companies in 2013 for both real and reactive power components of load. Please refer to the Section 4.2.1, Load Forecast, for further details.

**2014 10-Year Assessment**  
**www.atc10yearplan.com**

- Only firm interchange was included in our analyses.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW for the 2014+ model years.
- Special additions: Generator QMax/Qmin reduced to 90%.

*1.2.2.b.7.a.3 Shoulder Models (2019 and 2024)*

- We utilized interconnection point load forecasts provided by various distribution companies in 2013. Please refer to the Section 4.2.1, Load Forecast, for further details.
- Scalable loads in Zone 2, northern Zone 4, and the remainder of the ATC system were reduced such that when non-scalable loads were reset to the LDC provided shoulder load levels, the overall Zone 2 load was modeled at 90% of summer peak, northern Zone 4 was modeled at 80% of summer peak, and the remainder of the ATC system load level was modeled at 70% of summer peak. These load levels were chosen to represent the shoulder models because they are the load levels where acceptable windows to perform maintenance occur, based on historical data. However, it is recognized that loads at individual points will vary under real-time shoulder conditions.
- The external system interchange was adjusted from the 2013 MMWG Series 2019 and 2024 summer interchange, respectively, to match latest ATC members' firm interchange.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW.
- Special additions: Generator QMax/Qmin reduced to 90%.

*1.2.2.b.7.a.4 Minimum Load Scenario (2015 and 2019)*

- ATC Load: 5,201 MW and 5,361 MW, respectively.
- 2013 forecast collection, scalable loads reduced to 33% of peak + non-conforming off-peak loads = 40% of Peak load.
- Total ATC Generation: 4,992 MW and 5,116 MW, respectively.
- Includes all planned and proposed projects to be in-service by 6/15/2015 and 6/15/2019, respectively.
- Interchange: Firm interchange only as of 12/26/2013.
- Dispatch: ATC-wide Merit order as of 12/26/2013.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW for the 2014+ model years.
- Special additions: Generator QMax/Qmin reduced 90%.

*1.2.2.b.7.b Load Sensitivities*

*1.2.2.b.7.b.1 East to West Bias Scenario (2019 and 2024)*

- ATC Load: 9,620 MW and 9,961 MW, respectively.

**2014 10-Year Assessment**  
**www.atc10yearplan.com**

- 2013 load forecast utilized.
- Scalable loads in Zone 2, northern Zone 4, and the remainder of the ATC system were reduced such that when non-scalable loads were reset to the LDC provided shoulder load levels, the overall Zone 2 load was modeled at 90% of summer peak, northern Zone 4 was modeled at 80% of summer peak, and the remainder of the ATC system load level was modeled at 70% of summer peak.
- Total ATC Generation: 9,475 MW and 9,808 MW respectively.
- Includes all planned and proposed projects to be in-service by 6/15/2019 and 6/15/2024 respectively.
- Interchange: Firm interchange + additional imports or exports, based on on-line generation after firm interchange is taken into account, to model a 400 MW net ATC import. 400 MW level based on 200 MW as seen in the top 10 hours over the last 2 years plus a 200 MW adder.
- Dispatch: Merit order by control area as of 12/26/2013.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW.
- Special additions:
  - ATC system biased by a 600 MW net export through the ATC Western ties.
  - Bias achieved by scaling load or generation as applicable based on the external model that was used for each study year.
  - Generator QMax/Qmin reduced to 90%.

**1.2.2.b.7.b.2 West to East Bias Scenario (2019 and 2024)**

- ATC Load: 9,620 MW and 9,961 MW, respectively.
- 2013 load forecast utilized.
- Scalable loads in Zone 2, northern Zone 4, and the remainder of the ATC system were reduced such that when non-scalable loads were reset to the LDC provided shoulder load levels, the overall Zone 2 load was modeled at 90% of summer peak, northern Zone 4 was modeled at 80% of summer peak, and the remainder of the ATC system load level was modeled at 70% of summer peak.
- Total ATC Generation: 9,467 MW and 9,831 MW respectively.
- Includes all planned and proposed projects to be in-service by 6/15/2019 and 6/15/2024, respectively.
- Interchange: Firm interchange + additional imports or exports, based on on-line generation after firm interchange is taken into account, to model a 400 MW net ATC import. 400 MW level based on 200 MW as seen in the top 10 hours over the last 2 years plus a 200 MW adder.
- Dispatch: ATC-wide Merit order as of 12/26/2013.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW.
- Special additions:
  - Wind generation west of ATC dispatched to 50%.

**2014 10-Year Assessment**  
**www.atc10yearplan.com**

- Wind Generation south of ATC dispatched to 55% as drawn from Operations historical data.
- ATC western interface flow of 1,400 MW into ATC.
- Manitoba Hydro Exports set to 1,400 MW.
- Bias achieved by scaling load or generation as applicable based on the external model that was used for each study year.
- Generator QMax/Qmin reduced to 90%.

**1.2.2.b.7.b.3 High Load Scenario (2024)**

- ATC Load: 15,182 MW.
- 2013 load forecast utilized.
- Scalable loads were increased such that when non-scalable loads were reset to the LDC provided peak load levels, the overall ATC system load was modeled at a level determined by a probabilistic 90/10 forecast.
- Total ATC Generation: 14,182 MW.
- Includes all planned and proposed projects to be in-service by 6/15/2024.
- Interchange: Only firm interchange + internal ATC member transactions to cover load were included in the analyses.
- Dispatch: Merit order by control area as of 12/26/2013.
- Mackinac VSC set to the VSC bypass flow as long as it is within +/- 70 MW for the 2014+ model years.
- Special additions: Generator QMax/Qmin reduced 90%.

**1.2.2.b.8 Model years**

We started model development for this Assessment by building a system model that represented 2014 summer peak conditions. This 2014 model is referred to as an “as-planned” model because essentially everything in the model is certain to be in service by 2014 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 2014 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 2015 and 2019 were selected to meet the 1-5 year horizon. The years 2024 and 2029 meet the beyond 5 year horizon. The years 2015, 2019 and 2024 were chosen to coordinate with the most recently released MMWG models that were available.

The 2015, 2019, 2024 and 2029 models were developed to evaluate needs, verify findings of the 2013 Assessment, and confirm that previously identified needs will increase over time. The 2024 and 2029 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 assessment models***

The process for performing dynamic stability assessments includes three types of analyses: (1) the annual review of existing generator angular stability, (2) specific generator interconnection study reports, and (3) specific voltage stability assessments.

The base case for the annual review of existing generation angular stability for this compliance monitor period is a 2019 light load model based off a 2012 series MMWG 2018 model, modified to include the ATC project-deficient topology in the local area.

The base cases for specific generator interconnect study reports are described in detail in the associated study report.

The base cases for specific voltage stability assessments are described in detail within the associated study report. The voltage stability study for this compliance monitor period is the Rhinelander Area Voltage Stability Study.

### ***1.2.2.d Short-circuit assessment models***

The base case model for the annual short-circuit assessment was the CAPE application equivalent to the transmission planning 2013 ‘as built’ model with maximum generation dispatch. For our studies of new generation interconnections, the base model is modified to include the new facilities and any proposed transmission system modifications.

## **1.2.3 Preliminary needs and solution development**

### ***1.2.3.a Steady state project-deficient needs assessment***

#### ***1.2.3.a.1 System intact and single contingency simulations***

ATC performed system intact and single contingency simulations on the 2015, 2019, 2024 and 2029 models. Single contingency simulations included single element (line, transformer, generator, bus and switched shunt) and event-based breaker-to-breaker outages. We ran these simulations for all of the steady state models described above.

#### ***1.2.3.a.2 Comparison of results vs. Planning Criteria***

The models described above are analyzed and compared to the ATC Transmission System Planning Criteria. Limits that approach or exceed our criteria are then listed in a limitations table.

#### ***1.2.3.a.3 Reconciliation of significant changes to power flow results***

To reconcile changes in power flow results between Assessments, zone planners ran data comparisons to determine if limitations identified in prior Assessments have become more



severe, less severe, or have been mitigated. Steps were taken to verify topology and other model changes to ensure that the results are consistent with all of the available information.

### ***1.2.3.b Preliminary Solution Development***

#### ***1.2.3.b.1 New Limitation***

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

Cost estimates are developed for one or more solution options that effectively address the identified limitations. After cost information has been obtained, the zone planner initiates the project development process by completing the project request to create a provisional project. Finally, the project request is processed through ATC's project approval process.

#### ***1.2.3.b.2 Repeat Limitation***

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

#### ***1.2.3.b.3 Network Unspecified Project Process***

Unspecified projects are defined as those projects which may shift into the 10-year timeframe. Unspecified projects can be the result of the following reasons.

- Changing load forecast.
- Changes in generation and distribution interconnection projects.
- Changes in public policy requirements.
- Additional projects that are driven by economic benefits or multiple outage impacts.

A significant amount of dollars were set aside in ATC's capital forecast in order to address Network Unspecified Projects. ATC begins to identify Network Unspecified Projects with internal discussions to determine how to best serve our customers local and regional needs. In these discussions, we collaboratively determine which potential projects are more likely to be built within the 10-year Assessment period. The cost and potential benefits of the project are discussed, vetted and approved by our executives. After consensus is reached, the ATC capital forecast is updated to include these Network Unspecified Project 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 2015, 2019, 2024 and 2029 study years. These models may be appropriate for internal planning studies performed throughout the year.

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

This All Projects Assessment provides a list of reinforcements that are beginning to optimize our reinforcement plan. The following are three important questions regarding this plan.

- 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?

We attempt to address the first two questions, in our 10-Year Assessment. Models for years 2015, 2019, 2024 and 2029 were built 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.

### **1.2.4 Other Studies**

#### **1.2.4.a Multiple Outage Review and Analysis**

ATC performs a comprehensive evaluation of each applicable NERC Category C and Category D type outage on either an annual schedule, a rolling periodic schedule, or interconnection study specific schedule.

#### Category C Outages



ATC performs a comprehensive screening of each applicable NERC Category C type outage on at least a five year rolling schedule.

ATC performs an assessment of all of the Category C1 through C9 events, except the Category C4 events. Category C4 contingency events do not apply to ATC because there are no applicable HVDC facilities in the ATC system.

#### Category D Outages

ATC performs a sufficient assessment for each category of Category D extreme events analyses.

#### **1.2.4.b System Stability Review and Analysis**

ATC generally investigates three type of system stability: steady state voltage stability, dynamic voltage stability and dynamic angular (e.g. generator) stability.

The specific system performance criteria that are used to assess each type of system stability are given in the ATC Transmission System Planning Criteria.

#### Steady State Voltage Stability

The steady state voltage stability analysis (e.g. P-V Curve simulation) is performed on a specific area of the ATC system when general steady state analysis indicates areas of very low voltage or voltage collapse (non-convergent simulations) for NERC TPL-002 or TPL-003 reliability standard requirement contingencies in the near or longer term planning horizons. Additionally, each dynamic study performed by ATC screens for voltage stability issues through the application of the ATC voltage recovery criteria described in the ATC Transmission System Planning Criteria. If general steady state or dynamic analyses identifies areas of weakness indicative of voltage instability, further examination of system characteristics and, possibly, more detailed analysis will be performed.

#### Dynamic Voltage Stability

The dynamic voltage stability analysis is performed on a specific area of the ATC system when general steady state analysis indicates areas of very low voltage or voltage collapse (non-convergent simulations) for NERC TPL-002 or TPL-003 reliability standard requirement contingencies in the near or longer term planning horizons. Dynamic voltage stability analysis can reveal results where the voltage at some buses will collapse and not recover to acceptable values found by steady state analysis, which assumes that system “rides through” the dynamic recovery period.

Dynamic voltage stability analysis is assessed for any new or revised generation interconnection facilities before they are placed in service.

When dynamic analysis is performed and there is not a large stability margin, then normal load modeling is replaced with more specific, and generally conservative, dynamic load

modeling. Very large loads may be modeled with specific dynamic models and the remaining loads are modeled with using lumped dynamic load models that depend on the percentage of industrial, commercial, agricultural and residential load at each distribution load interconnection point.

#### Dynamic Angular (Generator) Stability

The dynamic angular stability of all major generation facilities in the ATC system is assessed on a five year rotation. Generation facilities may be assessed in less than five years, if there are significant changes to the generator exciter, the generator governor, a power system stabilizer, the generator step up transformer, or nearby system topology. In addition, dynamic angular stability is assessed for any new generation facility before it is placed in service.

Generation facilities with a total net output above 100 MW and associated transmission lines operating usually above 100 kV are normally selected for system angular stability assessment. The methodology used in assessing the major generator stations includes:

1. A review to determine that no significant system topological changes have occurred near the generator stations other than local load growth.
2. A review of the parameter values and the model types used in representing the dynamic response of units at the generator stations in system angular stability simulations to determine that no significant changes have occurred.
3. A review of the date of the last stability study conducted for each of the major generator stations to determine that the elapsed time does not exceed 5 years.

The assessments take into account applicable simulation requirements and performance requirements in the NERC TPL-002, TPL-003 and TPL-004 reliability standards, as well as the ATC dynamic performance criteria, which cover compliance with the TPL-503-MRO-1 reliability standard requirements.

ATC observes a ½ cycle margin required for tested generator data and a 1 cycle margin required for planned generator data. These margins are observed between the Maximum Expected Clearing Time (MECT) and Critical Clearing Times (CCT) that lead to unacceptable system instability.

#### Small Signal Stability

Since no previous studies have found any small signal instability situations in the ATC system and the MRO recently retired its small signal stability standard, no small signal stability assessment was performed this year. However, the ATC transient stability damping criteria will continue to be used as screening tool to determine whether any new small signal stability studies should be performed.



## **1.2.5 Documentation**

### **1.2.5.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 text, figures and tables are compiled for peer review.
- A summary presentation of Assessment information is reviewed and approved by ATC management.

Once the information has been approved by all parties, the hard copy Summary Report is printed and distributed. The Summary Report and additional details are posted at [www.atc10yearplan.com](http://www.atc10yearplan.com).

**Table PF-1***Projects included in the 2015 10-Year Assessment Model*

<b>System additions</b>	<b>Planning zone</b>
T-20 asset management uprate	1
G-7 asset management rerate	1
Y-80 asset management uprate	1
I-9 asset management rerate	1
Petenwell transformer replacement	1
Council Creek-Petenwell line uprate	1
Construct Monroe County-Council Creek 161-kV line and Timberwolf 69-kV switching station	1
Y-93 asset management uprate	1
T-Corners bus reconfiguration	1
Hoerner line retirement	2
Pine River - Straits line rebuild	2
6730 asset management rerate	2
Chandler - Old Mead Road project	2
Straits flow control project	2
FREG11 asset management rerate	2
ESE_6902 asset management rerate	2
ESE_6901 asset management rerate	2
Plains 138/69-kV transformer replacements	2
Barnum T-D interconnection	2
Arnold 345/138 kV transformer	2
Boscobel capacitor bank	3
Hillman capacitor bank expansion	3
Cross Plains, West Middleton, and Tokay distribution capacitor bank retirements	3
Sun Prairie T-D interconnection	3
Y-158 asset management rerate	3
X-23 asset management uprate	3
Montello mobile cap bank	3
X-39 and X-95 asset management rebuilds	3
Paddock - Shaw 69-kV line rebuild	3
X-103 asset management rerate	3
Horicon bus rebuild	3
Glacier Hills G-T increase in capacity	3
Manrap - Custer 69-kV line uprate	4
Thunder distribution transformer replacement	4
Potts Ave T-D interconnection	4
X-64 asset management uprate	4
Construct ring bus at 96th St. Substation	5
Racine-St. Rita 138-kV line re-conductor	5
Lakeview-Zion 138-kV line re-conductor	5
Branch - Kansas 138-kV line uprate	5
Lincoln transformer tap change	5
Paris-Albers asset management rebuild	5
Milwaukee County T-D interconnection	5
Oak Creek - Kansas 138-kV line uprate	5
Granville - Tamarack 138-kV line rebuild	5



**Table PF-1***Projects included in the 2015 10-Year Assessment Model*

<b>System additions</b>	<b>Planning zone</b>
Granville - Butler 138-kV line uprate	5
Port Washington-Saukville 138-kV line re-conductors	5

**Table PF-2***Projects included in the 2019 10-Year Assessment Model\**

<b>System additions</b>	<b>Planning zone</b>
Cedar Creek T-D interconnection	1
Y-17 asset management rebuild	1
Knowlton T-D interconnection	1
X-4 and X-77 reroute transmission lines	1
S-45 asset management uprate	1
Y-19 asset management uprate	1
Z-52 asset management uprate	1
Y-27 asset management uprate	1
J061 G-T interconnection	2
Empire - Presque Isle 138-kV line uprate	2
Twin Falls rebuild project	2
Aspen - Crystal Falls 69-kV line uprate	2
Escanaba units 1 and 2 retirements	2
Keel Ridge T-D interconnection	2
Nelson Dewey units 1 and 2 retirements	3
Sun Valley tap - Oregon 69-kV line rebuild	3
Kirkwood - Artesian 138-kV line uprate	3
Colley Road mobile cap bank removal	3
Y-8 reroute transmission line	3
Portage - Columbia 69-kV line uprate	3
Y-16 asset management rebuild	3
Williams Bay T-D interconnection	3
Portage - Trienda 138-kV line uprate	3
Colley Road - Brick Church 69-kV line rebuild	3
South Sheboygan Falls capacitor banks	4
Edgewater unit 3 retirement	4
Brillion Iron Works T-D interconnection	4
Pulliam - Glory Rd voltage conversion	4
Danz Ave - University 69-kV line uprate	4
Creekview T-D interconnection	4
Pleasant Prairie - Racine 345-kV line uprate	5
Kenosha - Lakeview 138-kV line re-conductor	5
Ramsey - Barland 138-kV line uprate	5
Norwich - Barland 138-kV uprate	5
Bain-Albers 138-kV line rebuild	5
Oak Creek-St. Rita 138-kV line re-conductor	5
Concord-Cooney asset management rebuild	5
Racine-Oak Creek 138-kV line re-conductor	5
Kenosha - Albers 138-kV line uprate	5
Waukesha - Merrill Hills asset management rebuild	5
Hartford-Butler Ridge asset management rebuild	5
Rubicon-Butler Ridge asset management rebuild	5
Rubicon-Concord asset management rebuild	5
St. Lawrence-Hartford asset management rebuild	5
Merrill Hills - Summit asset management rebuild	5
Center third transformer T-D interconnection	5

**Table PF-2**

*Projects included in the 2019 10-Year Assessment Model\**

<b>System additions</b>	<b>Planning zone</b>
Berryville T-D interconnection	5

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

**Table PF-3***Projects included in the 2024 10-Year Assessment Model\**

<b>System additions</b>	<b>Planning zone</b>
Hawk T-D interconnection	3
Schofield T-D interconnection	3

*\*Projects included in addition to those listed in Table PF-2*

**Table PF-4**

*Projects included in the 2029 10-Year Assessment Model\**

System additions	Planning zone
None	

*\*Projects included in addition to those listed in Table PF-3*