section 2 Methodology And Assumptions

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This section of the Assessment describes the methods and techniques employed by ATC in developing this report. ATC conducted powerflow analyses to identify problems/constraints and to evaluate the merits of system alternatives. This analysis was supplemented by evaluations of transfer capability limitations and dynamic stability performance.

Power Flow Cases

ATC developed this updated Assessment based on power flow cases representing summer peak periods in 2004, 2008 and 2012. In addition, a 2008 shoulder peak case, reflecting load levels at 75% of peak and associated anticipated generation dispatch, was developed. For purposes of this Assessment, load includes transmission and distribution losses as well as load that could be interrupted for generation deficiencies.

The 2004 case was developed to evaluate near-term needs and to verify findings in the 2002 Assessment and Update. ATC has taken the approach of evaluating the subsequent summer peak season in each of its annual Assessments to determine the immediacy of needs identified, hence providing a means of prioritization.

The 2008 peak case was developed as an intermediate term case to evaluate emerging needs, to confirm that needs identified in 2004 will increase over time and to test the performance of reinforcements placed in service prior to 2008. The 2008 shoulder peak case was developed to identify needs and test the performance of reinforcements placed in service prior to 2008. Shoulder peak periods often result in as great or greater demand on the transmission system during peak periods. During these periods, since loads are not at their highest levels, local peaking generation is typically not operating and power transfers into and across the ATC system are often at maximum levels.

The 2012 case was developed to identify emerging needs in that timeframe, to confirm that needs identified in 2008 will increase over time and to test the performance of reinforcements to be placed in service prior to 2012 to resolve issues identified in 2008. It reflects a year sufficiently out in the future to assess the performance of larger scale projects (345 kV lines, for example) that could be expected to be in service in that timeframe.

Power Flow Model Revisions

Various revisions were made to the power flow models used in the 2002 Assessment due to new information available to ATC. The changes made to the power flow models used for the 2003 Assessment include:

2004 Summer Peak

- Utilized interconnection point load forecasts provided by various distribution companies in late 2002. Utilized EIA-411 reports for system-wide coincident peak loads. Projected peak load modeled within ATC is 13,453 megawatts.
- Revised line and equipment ratings based on field investigations and line surveys.
- Updated future generation to be included in the models. The specifics are outlined later in this section (see New Generation Assumptions).
- The model for the system external to ATC was taken from the NERC 2002 Series, 2004 summer model.
- Revised system topology based on projects that were placed in service in 2002 or early 2003, or are anticipated to be placed in service by June 2004. Those projects are listed in Tables IV-1 and IV-2 of this report.

2008 Summer Peak and Shoulder Peak

- Utilized interconnection point load forecasts provided by various distribution companies in late 2002. Utilized EIA-411 reports for system-wide coincident peak loads. Projected peak load modeled within ATC is 14,413 megawatts, a 960 megawatt increase from 2004, representing an average annual compounded growth rate of 1.74%)
- The model for the system external to ATC was taken from the NERC 2002 Series, 2008 summer model.
- In addition to the projects listed above for the 2004 case, the following projects were modeled in 2008 because they were assumed to be completed and placed in service prior to the summer of 2008:

Table II-1 Projects Included in the 2008 Analysis

PROJECT	ZONE
Construct Skanawan-Highway 8 115 kV line	1
Construct the Arrowhead-Weston 345 kV line	1
Install a phase shifting transformer or reactor at Council Creek 69 kV	1
Install 4.1 MVAR capacitor banks at Berlin and Ripon	1
Increase emergency rating of Whitcomb 138/69 kV transformer	1
Rebuild one of the Hiawatha-Indian Lake 69 kV lines to double circuit 138 kV; operate at 69 kV initially	2
Install capacitor bank at Rio 69 kV	3
Replace the 138 kV breakers at Rock River	3
Reconfigure existing 69 kV and 138 kV circuits to form Rock River-Janesville and Rock River-Sunrise 138 kV circuits	3
Rebuild Turtle to West Darien Tap at 138 kV standards and operate at 69 kV	3
Construct a new 138 kV line from West Darien to Southwest Delavan to Delavan and operate at 69 kV	3
Remove 69 kV line from West Darien Tap to Bristol	3
Construct a 138 kV bus at Kegonsa	3
Construct a Femrite-Sprecher 138 kV line	3
Convert the Kegonsa-McFarland-Femrite 69 kV and Sycamore-Reiner-Sprecher 69 kV lines to 138 kV operation	3
Install a 138/69 kV transformer at Femrite	3
Install a 138/69 kV transformer at Reiner	3
Reconductor, reinsulate and convert the Columbia to North Madison 138 kV line to 345 kV	3
Construct a new North Madison 345/138 kV substation adjacent to the existing substation and replace the 345/138 kV transformers	3
Uprate terminal equipment at S Fond du Lac 69 kV	4
Replace current transformer at Sheboygan Falls 69 kV	4
Replace current transformer at S Fond du Lac 69 kV	4
Replace Edgewater 224 MVA 345/138kV transformers with a 500 MVA transformer	4
Install 2-16.3 MVAR capacitor banks at Canal 69 kV	4
Install 345 kV breaker for Edgewater 345/138 kV transformer (TR-22)	4
Construct a 138 kV line from Erdman to Howards Grove	4
Construct a 138 kV line from Waukesha through Duplainville to Sussex	5
Construct a 138 kV bus at Brookdale to accommodate third transformer	5
Rebuild Port Washington-Saukville 138 kV lines	5
Rebuild Port Washington – Rangeline 138 kV lines	5
Rebuild Cornell-Rangeline 138 kV underground line	5
Construct Oak Creek – Brookdale 345 kV line	5
Install Brookdale 345/138 kV, 500 MVA transformer	5
Construct a Brookdale –Granville 345 kV line	5
Construct a Oak Creek – St. Martins 138 kV line	5
Construct a Butler - Tamarack 138kV line	5
Convert Bluemound – Oak Creek 230 kV line (K873) to operation at 345 kV	5
Install a 345/138 kV transformer at Bluemound	5
Reconductor Oak Creek – Allerton 138 kV line	5
Reconductor Oak Creek – Ramsey 138 kV line	5
Reconductor Ramsey – Harbor 138 kV underground segment	5

- Assumed 318 megawatts of new generation and associated transmission reinforcements in Zone 1
- Assumed 528 megawatts of new generation and associated transmission reinforcements in Zone 3
- Assumed 75 megawatts of new generation in Zone 4
- Assumed 1,530 megawatts (net) of new generation and associated transmission reinforcements in Zone 5

The transmission reinforcements identified in generation interconnection and transmission service facility studies associated with the new generation above are described in Section V and listed in Section VI of this Assessment.

2012 Summer Peak

- Utilized interconnection point load forecasts provided by various distribution companies in late 2002. Utilized EIA-411 reports for system-wide coincident peak loads. Projected peak load within ATC is 15,755 megawatts (1342 megawatt increase from 2008, representing an average annual compounded growth rate of 2.25%).
- The model for the system external to ATC was taken from the NERC 2002 Series, 2008 summer model.
- In addition to the projects listed above for the 2008 case, the following projects were assumed to be completed and placed in service prior to 2012:

Table II-2 Projects Included in the 2012 Analysis

PROJECT	ZONE
Install a 10.0 MVAR capacitor bank at Hodag	1
Install a 13.6 MVAR capacitor bank at Antigo	1
Install a 16.4 MVAR capacitor bank at Council Creek	1
Uprate/rebuild of Weston-Kelly 115 kV line	1
Uprate Weston-Sherman St. 115 kV line	1
Uprate Weston-Morrison-Sherman St. 115 kV line	1
Reconductor Wien-McMillan 115 kV line	1
Construct double circuit 69 kV line from Femrite to AGA Gas to Nine Springs and reconfigure to loop in and out of Femrite	3
Construct South Beaver Dam-Prospect Street-North Beaver Dam 138 kV line	3
Convert Academy to South Beaver Dam 69 kV line to 138 kV	3
Construct a 138 kV bus and install a 138/69 kV transformer at South Beaver Dam	3
Rebuild Rock River to Turtle 69 kV line to 138 kV	3
Convert Rock River-Turtle-Bristol-Elkhorn 69 kV line to 138 kV	3
Install capacitor banks at South Monroe, Juneau, Lone Rock and Richland Center	3
Construct 138 kV line from Southeast Fitchburg to Verona	3
Construct 138 kV bus and install a 138/69 kV transformer at Verona	3
Convert South Lake Geneva-Katzenberg-Twin Lakes 69 kV line to 138 kV	3
Construct 138 kV line from North Lake Geneva to South Lake Geneva	3
Construct 138 kV line from Spring Valley to Twin Lakes	3
Construct 138 kV bus and install a 138/69 kV transformer at South Lake Geneva	3
Construct Rockdale-West Middleton 345 kV line	3
Construct 345 kV bus and install 345/138 kV transformer at West Middleton	3
Rebuild/convert West Middleton-Spring Green 69 kV line to 138 kV	3
Construct 138 kV bus and install 138/69 kV transformer at Stagecoach	3
Construct Spring Green-Prairie du Sac 69 kV line	3
Install second 138/69 kV line at Hillman	3
Convert Hillman to Eden 69 kV line to 138 kV	3
Uprate terminal equipment at N Fond du Lac 138 kV	4
Construct a 138 kV line from Lodestar to Sheboygan Falls and add a 138/69 kV transformer at Sheboygan Falls	4
Install a 28.8 MVAR capacitor bank at Butternut 138 kV	4
Rebuild Crivitz –High Falls 69 kV double circuit line	4
Loop in a 345/138 kV substation at a new location known as Werner West by splitting the Rocky Run-N Appleton 345 kV line and the White Lake-Werner 138 kV line and install a 345/138kV, 500 MVA transformer	4
Build a Morgan-Werner West 345 kV line	4
Reconductor a portion of the Sunset Pt-Pearl Ave 69 kV line	4
Construct a 138 kV line from Canal to Dunn Rd and add a 138/69 kV transformer Dunn Rd	4
Rebuild St. Lawrence- Pleasant Valley – Saukville 138 kV line	5
Uprate Oak Creek – Ramsey 138 kV line	5
Convert Oak Creek – Bluemound 230 kV line for operation at 345 kV	5
Install two 345/138kV, 500 MVA transformers at Bluemound	5
Loop Brookdale – Granville 345kV line into Bluemound	5

New Generation Assumptions

There have been numerous generation projects proposed within ATC's service territory. Many of these proposed projects have interconnection studies completed and a few have had transmission service facility studies completed. A few have proceeded to or through the licensing phase, and two are under construction. However, there are numerous proposed generation projects that have dropped out of the generation queue (see Section VIII), adding considerable uncertainty to the transmission planning process. To address this planning uncertainty, ATC adopted a criterion, for purposes of this and prior Assessments, to establish which proposed generation projects would be included in the 2003 Assessment models, which is:

Those generation projects for which, at the time the models were developed, (i) ATC has ***completed*** *a generation interconnection impact study, a generation interconnection facility study, a transmission service impact study and a transmission service facility study,* ***and*** *(ii) the generation developer or a customer of the developer has* ***accepted*** *the transmission service approved by ATC.*

For purposes of this Assessment, the models were developed during the month of March. Only those generation projects with approved transmission service as of March 15 of this year were included in the Assessment models. The criterion above result in the following proposed generation projects being included in the applicable powerflow models:

Plant Name/IC No.	Zone	Capacity	Assumed In-service
Petenwell (IC047)	1	18 MW	2003
Pulliam (IC035)	4	75 MW	2003
Escanaba #3	2	18 MW	2003
Kaukauna retirements	4	- 7 MW	2003
Kaukauna (IC225)	4	60 MW	2004
Riverside (IC004)	3	453 MW	2004
West Campus (IC029)	3	105 MW	2004
West Campus (IC049)	3	45 MW	2004
Sherry Mill (IC014)	1	300 MW	2005
Port Washington (IC002)	5	500 MW	2005
Port Washington (IC027)	5	100 MW	2005
Port Washington retirements	5	- 320 MW	2005
Port Washington (IC002)	5	500 MW	2008
Port Washington (IC027)	5	100 MW	2008
Elm Road (IC012)	5	650 MW	2007
Elm Road (IC012)	5	650 MW	2009
Elm Road (IC012)	5	650 MW	2011
Net Increase by 2004:		767 MW	
Net Increase by 2008:		2,597 MW	
Net Increase by 2012:		3,897 MW	

A more comprehensive discussion of proposed generation is provided in Section VIII, including map showing all of the generation interconnection requests that ATC has received.

Dynamic Stability/Short Circuit Assessments

ATC conducts transient analyses to evaluate dynamic stability of generators as part of its study of new generation interconnections and voltage stability analysis on portions of the system where severe low voltages are identified. In instances where ATC's stability criteria were not met, remedying projects were devised and included in this Assessment (see Section V). ATC also conducts short circuit analyses as part of its 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.

Transfer Capability Assessments

The amount of transfer capability within and between the ATC system and neighboring systems is becoming an increasingly important issue. This topic will be expanded significantly in future reports. For this Assessment, ATC has conducted transfer capability analyses in two ways. Summary graphs showing simultaneous import capability into the ATC service territory from the west and south, based on the Assessment power flow cases and the planned/proposed projects that would be in service in the applicable summer peak peak simulation (2004 and 2008), are provided in Section V. In addition, examples of the scope of projects that would be needed to achieve 1,000 megawatts, 2,000 megawatts or 3,000 megawatts of additional transfer capability into the ATC system are described and listed in the last subsection of Section V.

Environmental Considerations

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

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

Assessment Development

This 2003 Assessment was developed in a chronological fashion. Planned transmission additions expected to be in service by June 2004 were included in the 2004 model, as listed in Tables IV-1 and IV-2. Projects for which ATC has completed its analysis and is either constructing, has filed an application to construct, or is in the process of preparing an application were included in the 2008 and/or 2012 models, based on projected in service dates.

The needs identified in this Assessment were determined by identifying facilities whose normal or emergency ratings or tolerances are exceeded. The criteria ATC uses to determine what these ratings and tolerances should be based on was developed over the course of 2001 and 2002. This planning criteria is provided in Appendix C. Among these criteria, the system performance criteria used by the ATC in identifying needs, limitations and problems included the following:

- Any transmission facility that experienced loading in excess of its normal rating under normal system conditions
- Any transmission facility that experienced loading in excess of its emergency ratings under single contingency conditions
- Any load bus that experiences a voltage more than 5% greater or less than the nominal bus voltage under normal system conditions,
- Any load bus that experiences a voltage more than 10% greater or less than the nominal bus voltage under single contingency conditions, and
- Any facility that routinely shows up as a limiter to granting firm transmission service.
- Generator transient stability will be maintained for a sustained three phase fault cleared from any line or transformer in primary time with a single existing line or transformer contingency
- Generator transient stability will be maintained for a three-phase fault cleared in breaker failure backup time with no pre-existing line or transformer contingency
- Unacceptable transient stability performance includes the following conditions:
  - a) Generating unit is out of step, unless deliberately islanded
  - b) Cascading tripping of transmission line or uncontrolled loss of load
  - c) Voltage excursions outside of 20% of nominal voltage for more than 30 cycles
  - d) Voltage instability at any time after a disturbance
  - e) Voltage recovery of less than 70% of nominal after a disturbance
  - f) Poorly damped oscillations

- With a generating plant at full output, all units will remain steady-state stable with the non-fault opening of any of the transmission circuits interconnected with that plant.
- With a generating plant at full output, all units will remain steady-state stable with the non-fault opening of any two transmission circuits on a common structure that are interconnected with that plant.

Generator Redispatch

Redispatch refers to the need for certain generators to operate out of normal economic dispatch order during certain periods of time in response to certain system conditions. The purpose of redispatch is to avoid interrupting power purchases for which the buyer has reserved firm transmission service and/or to ensure that system security is maintained. Within the ATC system, redispatch is done only for network resources – power plants and power purchases that are dedicated to load served within the ATC system. Since the redispatched generators are operated out of economic dispatch order, ATC customers incur additional costs for each redispatch incident. ATC monitors redispatch incidents to determine whether transmission system reinforcements to eliminate the need for such incidents may be justified. As shown in the summary of dispatch cost table below, the costs incurred for redispatch incidents during 2002 increased significantly from 2001. Part of this is due to scheduled outages of various transmission facilities required to connect new projects ATC placed in service during 2002. However, redispatch due to scheduled outages alone does not make up the entire difference in redispatch costs between 2001 and 2002. The increase in redispatch is an indication that the existing system, though being enhanced during 2002, is being utilized to its capacity.

ATC has already taken steps to reduce the number and duration of redispatch events. In particular, ATC has taken steps to significantly reduce the number, duration and costs of redispatch associated with the constraints to transferring power from Wisconsin to the Upper Peninsula of Michigan, which accounted for more than $5 million of the roughly $8 million in redispatch costs in 2002.

Summary of ATC Redispatch Charges

	2002	2001
January	$100,082	$192,867
February	$190,901	$190,922
March	$104,050	$603,596
April	$209,553	$106,818
May	$334,642	$31,269
June	$730,981	$7,128
July	$420,966	$22,570
August	$512,726	$42,257
September	$775,725	$457,199
October	$246,434	$933,298
November	$2,943,957	$267,050
December	$1,458,483	$55,968
Total Costs	$8,028,500	$2,910,942

Lost Opportunity Costs

ATC is currently attempting to compile information on lost opportunity costs. Lost opportunity costs are costs incurred when economic wholesale power transaction between entities cannot be approved due to transmission constraints. Developing reliable estimates of lost opportunity costs can aid in the economic valuation of transmission projects designed to address transmission service constraints and enhance transfer capability. ATC has investigated ways of developing estimates of lost opportunity costs and has requested that its customers help in the compilation of data. ATC intends to report on developments in this area in its Update to the 2003 Assessment, to be issued in early 2004.