# 2005 ATC Access Study Initiative Report

## Overview

ATC commenced its Access Initiative in 2004 to determine the potential value of expanding the transmission system to provide ATC's customers with 1) greater access to energy alternatives outside the ATC footprint and 2) improved ability to transfer energy within the ATC system where it is needed to serve retail customers. This Access Report provides a summary of the efforts undertaken to date and key findings from the analyses conducted.

The Access Initiative has resulted in the identification of a number of project alternatives that would provide significant economic and reliability benefits to ATC's customers. These measurable benefits of the Access Initiative projects are augmented by additional significant benefits that are less easily quantified or monetized. These factors are referred to as Other Factors and include geographic diversity, locational marginal price (LMP) comparability, enhanced backbone infrastructure, local economic development, improved access to renewable resources, benefits to neighboring systems, and increased operating flexibility.

The Access Initiative projects also have the potential to eliminate transmission constraints that presently cause the Wisconsin Upper Michigan System (WUMS) and Northern WUMS areas to be designated as Narrow Constrained Areas.[1]

The potential benefits of the Access Initiative project alternatives are explored and explained further in this Report.

*History of Access Initiative*

ATC held eight meetings at or near its Pewaukee office during 2004 to discuss the Access Initiative with customers and stakeholders. At the first two meetings, ATC introduced concepts to explore, discussed factors to consider and listed preliminary alternatives, and invited customer/stakeholder input. The computer software program PROMOD was chosen to perform runs of simulated market-based energy transactions in future years, to gauge how an LMP market would perform, and to evaluate the impact of various proposed Access Initiative projects.

Starting with the June 2, 2004 meeting and at subsequent meetings, ATC provided key results of analyses conducted, presented and refined a decision matrix developed to compare alternatives and solicited comments on what was presented.

[1] An NCA designation, as defined by the Midwest Independent System Operator (MISO) Independent Market Monitor (IMM), is an indication that Wisconsin and Upper Michigan cannot fully benefit from the competitive markets in the Midwest.

In the early stages of the Access Initiative, five representative projects were conceived to determine the relative merits of each. Those initial alternatives, listed below, were geographically diverse with the intention of determining which general direction(s) would likely provide the greatest economic and reliability benefits.

- **South:** a new Byron-North Monroe-West Middleton-North Madison 345 kV line
- **Southwest:** a new Salem-Spring Green-West Middleton-North Madison 345 kV line
- **West:** a new Adams-Genoa-Columbia 345 kV line
- **East:** a new 450 kV DC line from Ludington to a new substation on the western shore of Lake Michigan (Western Lakeshore) with AC/DC conversion stations at Ludington and Western Lakeshore, plus a 345 kV line from Western Lakeshore to Forest Junction
- **Northeast:** a new Sault Saint Marie-Arnold 345 kV with a virtual back-to-back DC tie at Sault Saint Marie

At the last two meetings held in 2004, ATC focused on determining which alternatives should be considered going forward. After conducting the initial round of comparative analyses, ATC proposed eliminating the Northeast and East alternatives from further consideration. The stakeholders agreed with these eliminations based on their poor performance relative to the other alternatives. After soliciting feedback from stakeholders and conducting comparative analyses, the list was refined to include the following alternatives:

- **Low voltage:** projects less than 345 kV
- **South:** a new Paddock-Rockdale 345 kV circuit
- **Southwest:** a new Salem-Spring Green-West Middleton-North Madison 345 kV line with an uprate of the Salem-Maquoketa 161 kV line
- **Southwest:** a new Salem-Spring Green-West Middleton-North Madison 345 kV line plus a new Hazelton-Salem 345 kV line
- **West:** a new Adams-Genoa-Columbia 345 kV line

*Summary of 2005 Efforts*

Similar to 2004, ATC held meetings with customers and stakeholders to provide updates on results and receive input into the Access Initiative process. In 2005, ATC has determined and communicated the topics to be explored, the factors to be taken into consideration, the alternatives to be evaluated, and results of the analyses conducted. Stakeholder/customer input has guided each of these areas.

The information presented in this Access Report covers the 2005 Access Initiative analysis through August 1st. All of the meeting materials, including presentations and meeting minutes, are posted on the atcllc.com web page at: http://www.atcllc.com/IT2c.shtml. The list of generators external to Wisconsin included in ATC's PowerBase cases are available at http://www.atcllc.com/oasis/Customer_Notices/External_Generation.pdf.

*PSCW Docket*

The Public Service Commission of Wisconsin (PSCW) opened a docket for the Access Initiative (Docket #137-EI-100) on February 14, 2005. On March 25, 2005, ATC filed an update to its Access Initiative that included a listing of the activities thus far and a summary of the analysis undertaken for the Access project alternatives.[2] The PSCW subsequently issued a Notice of Proceeding and Order Changing Filing Schedule directing ATC to file updated information with the Commission regarding the Access Initiative by August 15, 2005.

*2005 Access alternatives considered*

In 2005, the Access Initiative considered five representative projects for further analysis. These alternatives are listed below along with descriptions of the impacts on identified transmission grid problems:

- **South:** a new Byron (Illinois)-North Monroe-West Middleton-North Madison 345 kV line (approximately 56 miles of new right-of-way).
    - Potentially moderate improvement in Byron stability response
    - Directly improves one limitation on Alliant-West system (Hazelton-Dundee 161 kV line) and mitigates one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville-Nelson Dewey 161 kV path constraint)
    - Provides 345 kV infrastructure through the NW territory of the ComEd system

- **South:** a new (second) Paddock-Rockdale 345 kV circuit (approximately 8 miles).
    - Directly reduces one constraint on the Alliant-West system (Hazelton-Dundee 161kV line) and one chronic limitation on the Dairyland system (Cassville-Nelson Dewey 161kV path constraint) and mitigates one chronic limitation on the Alliant-West/Dairyland Power System (Lore-Turkey River-Cassville 161kV path constraint)

- **Southwest:** a new Salem (Iowa)-Spring Green-West Middleton-North Madison 345kV line with a rebuild of Salem-Maquoketa 161kV line (approximately 6 miles).
    - Potentially moderate improvement in Quad Cities (ComEd/MEC) and Cordova (MEC) stability response

[2] 137-EI-100-ATC Filing Letter:
http://www.atcllc.com/oasis/Customer_Notices/ATC_Filing_Letter032505.pdf
137-EI-100-ATC Status Report:
http://www.atcllc.com/oasis/Customer_Notices/Access_Initiative_Report032505.pdf

  - Directly reduces three constraints on the Alliant-West system (Hazelton-Dundee, Salem-Maquoketa and Davenport-East Calamus 161 kV lines) and one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville-Nelson Dewey 161 kV path constraint)
  - Provides 345 kV infrastructure through the ALTW and DPC systems

- **West:** a new Prairie Island (Minnesota)-Columbia 345 kV line (approximately 159 miles).
  - Directly reduces one chronic limitation on the Dairyland system (Cassville-Nelson Dewey 161 kV path constraint) and mitigates one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville 161 kV path constraint)
  - Provides 345 kV infrastructure through the Xcel Energy, RPU and DPC systems to support local needs in the Rochester (MN) and LaCrosse (WI) areas.

- **Lower-Voltage:** rebuilding the Lore-Turkey River-Cassville-Nelson Dewey 161 kV transmission line.
  - Directly reduces one chronic constraint (Lore-Turkey River-Cassville-Nelson Dewey 161 kV path constraint) on the Alliant-West/Dairyland Power System

ATC has retained Christensen Associates Energy Consulting (hereafter Christensen Associates), to assist in quantifying and analyzing Other Factors relevant to the issue of increased access. Please refer to the *Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans* Report included in this filing for more detailed information.

*MISO Planning and Transmission Cost Allocation Issues*

Please refer to Appendix 1 of the filing for additional relevant information, regarding the relationship of an Access Initiative project to the MISO regional planning process. Appendix 1 also includes a summary of current discussions associated with transmission cost allocation issues, currently being addressed by the MISO Regional Expansion Criteria and Benefits (RECB) task force.

*Narrow Constrained Area (NCA) and Implications*

The Access Initiative projects have the potential to help eliminate the need to designate the WUMS and Northern WUMS areas as NCAs. The congestion relief offered by the Access Initiative may remove pivotal suppliers or reduce the number of constrained annual hours.

*Planned 2005 Activities*

Subject to the direction of the Commission in the Access Initiative proceeding, ATC is planning to perform the following activities during the remainder of 2005:

- Coordinate technical studies with MISO and neighboring utilities.
- Compile relevant information on preferred packages to facilitate future pre-certification efforts.
- Participate in the MISO RECB efforts to determine the most appropriate means to allocate benefits and therefore costs of facilities deemed regional in nature.

## Study Assumptions

The power flow model used in this analysis was developed from the Summer 2013 base case drawn from the 2004 10-Year Assessment Update. For the first valid PROMOD constraint identified for each proxy project, an appropriate transmission solution was developed and the analysis was rerun with the solution implemented to determine the next limit. For each scenario, this process was repeated until it was apparent that resolving the limit was not cost-effective based on the PROMOD analysis (i.e.: additional low-voltage projects were only considered if sufficient additional production cost savings were obtained).

*Key Assumptions*

The Base Case contains all planning projects needed to mitigate Summer 2013 overload and voltage violations except as noted below. The import capabilities identified in this analysis are dependent on the inclusion of these projects.

The Base Case was modified since ATC's Access Update report filed in March 2005. The modifications reflect updated information for load forecasts, control area interchange and major transmission projects. These changes include facilities required for confirmed transmission service requests. The following facilities were included in the 2013 Base Case:

Major future transmission facilities included:

- Weston-Central Wisconsin 345 kV line
- Morgan-Werner West 345 kV line
- Rockdale-Lannon Junction 345 kV line
- West Middleton-Rockdale 345 kV line

Significant future generation included in the current analysis, stated at summer rating:

- Riverside (2004) – 603 megawatts
- Butler Ridge (2006) – 10.8 megawatts

- Fox Energy (2006) – 603 megawatts[3]
- Lakefront No. 9 (2006) – 59 megawatts
- Point Beach uprate (2006) – 90 megawatts
- Blue Sky (2006) – 16 megawatts
- Green Field (2006) – 16 megawatts
- Forward Energy Center (2006) – 40 megawatts
- Port Washington (2008) – 545 megawatts
- Weston 4 (2008) – 519 megawatts
- Elm Road 1 (2009) – 615 megawatts
- Elm Road 2 (2010) – 615 megawatts

These units constitute an incremental capacity of 3,732 megawatts in total.

*Comments on Assumptions Associated with Modeling Generators*

Several of these units have gone in-service and are listed either because they differed from amounts in the 2004 analysis or because they did not go in-service until current analysis was already underway. Also, a total of 358 megawatts in generator retirements was included (103 megawatts in 2003, 15 megawatts in 2004, 240 megawatts in 2005, and no retirements after 2005). Wind power projects were only listed at twenty percent of capacity and their maximum plant output may be higher. Elm Road 3 (2013 – 600 megawatts) was included as a sensitivity in the 2005 analysis. For a list of significant external generation included in the model, please refer to ATC's website at http://www.atcllc.com/oasis/Customer_Notices/External_Generation.pdf.

During its analysis of alternatives, ATC noted a potential problem with generation reserves in the 2013 vendor model used for modeling the 2005 Access Initiative project alternatives. At a minimum, reserve margins should be high enough to meet reliability council standards, which for the MidAmerica Interconnected Network (MAIN) is 16 percent. It was not possible to calculate reserve margins with the data available. Instead, ATC used a proxy methodology by calculating the ratio of the maximum generator capacities to load for 2013 for the Eastern Interconnect. This ratio should be considerably higher than the reserve margin because it includes the maximum capacity for wind generation and hydro units and does not take into account summer derates, especially on units like combustion turbines, whose summer ratings can be 10 to 15 percent lower than their maximum ratings. For existing generation in 2004, this ratio is about 26 percent. For 2013 this ratio is about 22.5 percent, which means that the reserves modeled in 2013 are less than those for 2004.

Stakeholders have observed that there are a number of speculative generators in the model. For planning purposes, it is reasonable to presume that new generation will be built to meet reserve requirements, even though the specific size and location is not known at this time.

[3] Unit entered service in 2005 at lower amount.

*Description of Representative Projects*

The projects examined in this section correspond to three geographic directions ATC could reasonably pursue for a new extra-high voltage (EHV), typically 345 kV, transmission interconnection.

The three representative projects and one alternate are shown on the map in Figure 1. This map has been updated since March 25, 2005. The projects are:

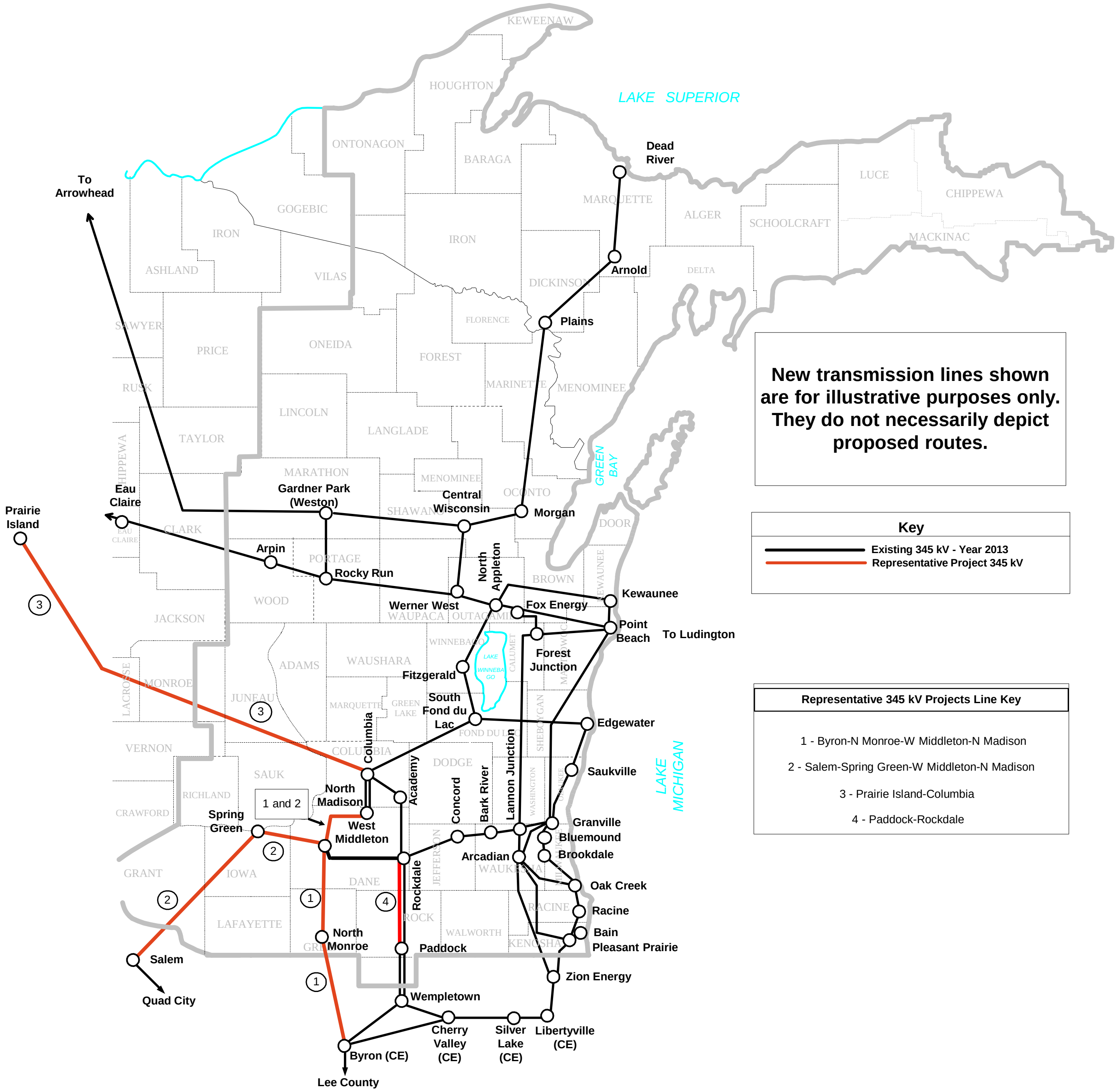
1. **South:** Byron–North Monroe–West Middleton–North Madison 345 kV.
2. **Southwest:** Salem–Spring Green–West Middleton–North Madison 345 kV with a rebuild of Salem-Maquoketa 161 kV line.
3. **West:** Prairie Island–Columbia 345 kV.
4. **South:** new (second) Paddock–Rockdale 345 kV.

One additional project was examined in the 2005 analysis but is not shown on the map to improve readability:

5. **Lower Voltage:** rebuild of Lore-Turkey River-Cassville-Nelson Dewey 161 kV path.

## *Figure 1*

*Representative Projects – Access Initiative*



## Status and Benefits

There are several readily identifiable benefits to improving transmission access, including mitigating chronic limits to power transfers, lowering overall energy costs for customers, reduction in system losses, improved reliability, improved operating flexibility and other strategic benefits. There are also readily identifiable costs and impacts associated with improving access, including construction costs and the societal impacts of new transmission facilities, including environmental impacts. These benefits and impacts are discussed below.

*Removing Chronic Limits*

Elimination of historical limits is an obvious first step towards increasing access. Many of the historically identified limits have either already been addressed or there are projects planned in the near future that address the limits. Additionally, experience shows that there are sometimes related limits "just around the corner" that appear just after the preceding limitation is addressed. Additional analysis is needed to identify these limits so that potential impediments to achieving an access target can be understood and mitigated, as appropriate.

Removing historical and projected chronic limits on the transmission system can reduce anticipated generation redispatch; permit a greater number and increased frequency of transactions from outside the ATC footprint; and allow more intra-ATC transactions to occur. ATC has identified historical chronic limits by reviewing the OASIS and NERC Transmission Loading Relief (TLR) incident logs. ATC is in the process of identifying projected future chronic limits using power flow analysis and through PROMOD.

The chronic limits within the ATC footprint with the largest recent historic impact on transmission service are summarized in Tables 1 and 2. Limiters are ranked based on transmission service requests with a point of delivery in ATC that were refused due to a flowgate being either sold out or having TLR in effect at the time of the request. The information in these tables was compiled for 2004 and the first half of 2005. It should be noted that since the start of the "Day 2" energy market under the Midwest ISO, which began on April 1st, TLR activity is no longer a comprehensive indicator of system constraints. Therefore, ATC is now collecting market data, including binding constraint information, from the Midwest ISO.

**_Table 1_**

*2004 ATC Chronic Limiters (Jan 1 – Dec 31)*

| 2004 Rank | Flowgate Name | MWh Refused | Solution Proposed |
|---|---|---|---|
| 1 | Turkey River – Cassville flo Wempletown – Paddock | 9,437,992 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 2 | Paddock Transformer flo Paddock – Rockdale | 6,313,585 | 2nd Paddock 345/138kV transformer[1] |
| 3 | Lore – Turkey River flo Wempletown – Paddock | 6,254,762 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 4 | Eau Claire – Arpin PTDF | 6,074,557 | Arrowhead – Gardner Park 345kV line (2008) |
| 5 | T Corners – Wien flo Eau Claire – Arpin (OpGuide) | 5,305,590 | Arrowhead – Gardner Park 345kV line (2008) |
| 6 | Albers – Paris flo Wempletown – Paddock | 5,028,623 | Uprate Albers – Paris 138kV line (2005)<br>Wempletown – Paddock Circuit #2 345kV line (2005) |
| 7 | Zion – Pleasant Prairie flo Wempletown – Paddock | 4,571,658 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 8 | Zion – Pleasant Prairie flo Zion – Arcadian | 3,507,594 | A change in MISO methodology results in increased capacity on this flowgate |
| 9 | Cassville – Nelson Dewey flo Wempletown – Paddock | 3,383,504 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 10 | Flow South OTDF | 3,350,217 | Plains – Stiles Projects (2006)<br>Cranberry – Conover 138kV line (2008) |
| 11 | Center – Fiebrantz flo Zion – Arcadian (OpGuide) | 3,300,017 | 4.5 ohm reactor placed in series with the Cornell – Fiebrantz – Center 138kV line (2008) |
| 12 | Pleasant Prairie – Racine flo Wempletown – Paddock | 3,072,238 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 13 | Flow South PTDF | 2,993,957 | Plains – Stiles Projects (2006)<br>Cranberry – Conover 138kV line (2008) |
| 14 | Russell – Rockdale flo Paddock – Rockdale | 1,532,421 | Reconductor Russell – Rockdale 138kV line (2004) |
| 15 | Center – Fiebrantz flo Wempletown – Paddock (OpGuide) | 1,479,585 | Wempletown – Paddock Circuit #2 345kV line (2005)<br>4.5 ohm reactor placed in series with the Cornell – Fiebrantz – Center 138kV line (2008) |
| 16 | Pleasant Prairie – Arcadian flo Pleasant Prairie – Racine | 1,253,755 | None identified in Ten Year Assessment |
| 17 | McGulpin – Straits ckt 1 flo McGulpin – Straits ckt 3 | 1,239,883 | None identified in Ten Year Assessment |
| 18 | Rockdale Transformer flo | 1,215,187 | None identified, limit associated with |

| | | | |
|---|---|---|---|
| | Paddock Transformer | | construction outages. |
| 19 | Amberg – Plains flo Morgan – Plains | 1,207,162 | Plains – Stiles Projects (2006)<br>Cranberry – Conover 138kV line (2008) |
| 20 | Minnesota – Wisconsin Stability Interface | 1,193,555 | Arrowhead – Gardner Park 345kV line (2008) |

[1] Project listed in 2005 Ten Year Assessment as an Access Initiative project.

***Table 2***

*2005 ATC Chronic Limiters (Jan 1 – May 31)*[2]

| 2005 Rank | Flowgate Name | MWh Refused | Solution Proposed |
|---|---|---|---|
| 1 | Eau Claire – Arpin PTDF | 2,596,262 | Arrowhead – Gardner Park 345kV line (2008) |
| 2 | Minnesota – Wisconsin Stability Interface | 2,361,677 | Arrowhead – Gardner Park 345kV line (2008) |
| 3 | Lore – Turkey River flo Wempletown – Paddock | 1,998,112 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 4 | Turkey River – Cassville flo Wempletown – Paddock | 1,887,899 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 5 | Zion – Pleasant Prairie flo Wempletown – Paddock | 1,593,143 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 6 | Paddock Transformer flo Paddock – Rockdale | 1,210,980 | 2nd Paddock 345/138kV transformer [1] |
| 7 | Salem Transformer flo Wempletown – Paddock | 1,164,288 | Wempletown – Paddock Circuit #2 345kV line (2005) |
| 8 | T Corners – Wien flo Eau Claire – Arpin (OpGuide) | 1,077,932 | Arrowhead – Gardner Park 345kV line (2008) |
| 9 | Zion – Pleasant Prairie flo Zion – Arcadian | 1,038,222 | None identified in Ten Year Assessment; limit associated with rating in MISO AFC process. |
| 10 | Russell – Rockdale flo Paddock – Rockdale | 1,007,837 | None identified in Ten Year Assessment; limit associated with rating in MISO AFC process. |

[1] Project listed in 2005 Ten Year Assessment as an Access Initiative project.

[2] Only the ten flowgates that have refused at least 1,000,000 MWh are included in the 2005 ranking.

## Study Results

Given the number and complexity of issues that arise in the evaluation of interconnection projects to improve access, ATC has continued to present its study results in an integrated format to make the decision-making process more transparent.

*Factors considered*

ATC performed a *screening-level* evaluation of Access alternatives. ATC also utilized new analytical tools to further evaluate the relative economic and technical merits of Access alternatives. The factors considered and the methods by which they were considered are listed below.

*Construction Costs*

Building new transmission facilities requires significant investment. The price of materials, labor costs, right-of-way costs and regulatory approval costs must be considered in the cost of access. ATC's experience on a number of recent projects provides relevant costs for benchmarking.

The cost estimates for the Access projects and the associated "next fixes" represent screening level cost estimates. Cost estimates for new transmission lines assumed the use of single-circuit steel poles on new 120-foot rights-of-way where applicable, and the use of double-circuit steel poles on existing 120-foot rights-of-way where corridor sharing was possible. Cost estimates for facilities outside of the ATC footprint were calculated using the same assumptions or were based on preliminary conversations with the affected neighboring transmission owner. Detailed cost estimates for specific projects and routes may differ from these very preliminary figures. These cost estimates, though high level, reflect the latest information available to ATC based on recent construction projects.

Tables 3 and 4 list the estimated capital costs in 2005 dollars for five projects designed by ATC. Table 3 lists the major interconnection projects designed to improve transmission access from four different directions. Table 4 lists the "next fixes" designed to improve the performance of the major projects by relieving projected constraints observed in the PROMOD analysis.

***Table 3***

*Transmission Access Improvement Projects (2005 dollars)*

| Project Direction | Proxy Interconnection Project | Estimated Cost (Millions) |
|---|---|---|
| South | Byron-North Monroe-West Middleton-North Madison 345 kV line | $185.1 |
| South (Alt) | Paddock-Rockdale 345 kV line #2 | $66.4 |
| Southwest | Salem-Spring Green-West Middleton-North Madison 345 kV line with Salem-Maquoketa 161 kV rebuild | $351.3 |
| West | Prairie Island-Columbia 345 kV line | $620.6 |
| Lower Voltage | Rebuild of the Lore-Turkey River-Cassville-Nelson Dewey 161 kV path | $14.7 |

***Table 4***

*Additional Projects to Improve the Major Project (2005 dollars)*[1]

| | | Major Project | | | | |
|---|---|---|---|---|---|---|
| **Additional Project** | **Estimated Cost (Millions)** | **South** | **South (Paddock-Rockdale)** | **Southwest** | **West** | **Lower Voltage** |
| Potosi-Hillman 138 kV terminals | $0.03 | X | X | | X | X |
| 2nd Paddock 345/138 kV transformer and 2nd Paddock-Town Line Road 138 kV circuit | $17.3 | | | | X | X |
| Hazelton-Dundee 161 kV uprate | $1.0 | X | X | X | | X |
| Cassville-Nelson Dewey 161 kV rebuild | $1.8 | | X | | X | |
| Davenport-East Calamus 161 kV terminals | $0.02 | | | X | | |

1 – Additional projects are associated with those directions marked with an "X".

## *Economic Benefits*

Offsetting these costs to varying degrees were projected reductions in energy production and transaction costs achieved within the ATC footprint with each of the project alternatives. Access to lower-cost power both outside and within the ATC footprint can lower the total cost of energy production. To calculate the projected savings, a security constrained economic dispatch (SCED) tool was utilized. ATC uses the PROMOD software (developed by New Energy Associates) that models the transmission system and determines the lowest-cost hourly generation dispatch without violating transmission system planning criteria for known flowgates. The difference in energy production and transaction costs between the simulations with and without an Access alternative reflects the projected energy cost savings. ATC simulated projected system conditions in 2013 to evaluate potential energy cost savings associated with each alternative relative to the Base Case (i.e. a simulation without an Access alternative). The 2013 Base Case includes all transmission projects identified in ATC's Ten-Year Assessment through 2013, except for the access projects identified in the 2004 Access Initiative.

The analysis results, which are based on the differences in generation production costs and transmission losses, are used as a component in the economic comparison of the Access projects. Losses are inherently included as a component of the total energy required to serve the system in the hour-by-hour PROMOD simulation.

Important points and observations regarding the PROMOD analysis and modeling:

- The results to date are based on modeling only one year (2013) in PROMOD. The savings from 2013 are assumed to be the same over the life of the project.
- Only the difference in cost between alternatives is calculated. Hence, except for the modeling of the Access projects, all of the input data is identical. Using the difference between alternatives tends to reduce the impact of any inaccuracies in forecasts and input data.
- Given the volume of input data used in PROMOD and the complexity of the program, the generation production cost and/or transmission model data used in PROMOD may require additional refinements.

The PROMOD production cost savings are conservative. Based on customer and stakeholder feedback, the capacity factors (i.e., the intensity of use of generation capacity) on some of the large low-cost coal-fired units within ATC are unrealistically high (e.g., as high as 96 percent), based on historical capacity factors which are considerably lower (typically in the range of 80 percent to 85 percent). This over-generation of lower-cost coal units tends to depress imports and reduce the cost savings associated with more imported power. In aggregate, the excess energy from the coal-fired units is roughly equivalent to an additional 450 MW coal-fired unit within ATC, or equivalent to about 50 percent of net imports. In addition, the input data is based on production cost of units and may not reflect actual supply offers in a "Day 2" market where supply offers from generators are market-based rather than cost-based. Both of these factors have the effect of reducing production cost savings.

The following observations are also pertinent:

- The analyses performed for the Access Report were made with the information available at the time of the analysis along with input from customers and stakeholders. Refinements to the input assumptions and to the model will continue to be made in the future, which will result in changes to projected production cost savings. This is also true for the capital cost estimates, which are updated as new information becomes available.

- Net energy imports into the ATC footprint range from 8.5 to 9.5 percent of the total annual energy requirement for the various alternatives, which is considerably lower than historical levels of about 15 percent.

Table 5 lists the capital cost estimate for each project and the corresponding annual carrying cost. The annual carrying cost for each project was compared to its annual production cost savings to determine which project has the best cost/benefit ratio. For example, the Lower Voltage Reinforcement has an Annual Carrying Cost of $2.6 million and Annual Production Cost Savings of $8.5 million. The annual production cost savings for each project is calculated using PROMOD and is measured relative to the Base Case.[4]

ATC developed an "Annual Carrying Cost" for the capital costs of the Access projects. The "Approximate Annual Carrying Cost" in Table 5 is calculated by multiplying the "Total Capital Costs" by a real levelized fixed charge rate of 7.93 percent. This charge rate accounts for the annual carrying costs of the equity and debt components for capital expenditures including the tax and depreciation effects. The real levelized fixed charge rate was updated to 7.93 percent to account for the tax changes in the Federal Energy Bill that was recently passed and for ATC's latest revenue requirement calculation.

Because of their complexity, power plants are periodically forced out of service at various times. To simulate these breakdowns, PROMOD develops a random outage pattern for each generator. Different outage patterns (known as "draws") result in somewhat different production costs from PROMOD. ATC determined that average production costs from three PROMOD runs with different draws was sufficient to yield a statistically consistent result within a small tolerance (sometimes referred to in statistics as the "expected value"). In Table 5 below, average savings from PROMOD were based on three draws. Also, imports ranged from 8.5 percent to 9.5 percent of the total annual energy requirement.

[4] *The Base Case includes the transmission facilities listed in the "Study Assumptions" section.*

***Table 5***

*Costs for each Representative Project*

| Project | Total Capital Costs (2005 Dollars in Millions) | Approximate Annual Carrying Cost (2005 Dollars in Millions) | "Production Cost" Savings Relative to the Base Case (2005 Dollars in Millions) | Imports Relative to the Base Case (GWH) |
|---|---|---|---|---|
| Base Case | $0 | N/A | 0 | 0 |
| Lower Voltage | $33 | $2.6 | $8.5 | 524 |
| South: Byron–North Madison | $186.1 | $14.8 | $10.6 | 802 |
| Southwest: Salem–North Madison | $352.3 | $27.9 | $9.2 | 648 |
| West: Prairie Island–Columbia | $639.7 | $50.7 | $9.0 | 781 |
| South: Paddock–Rockdale #2 | $69.1 | $5.5 | $9.0 | 606 |

The baseline PROMOD analyses assume 3,732 megawatts (not including retirements) of net new generation through 2013, of which approximately 1,800 megawatts is new baseload capacity (not including Elm Road unit 3). Only announced retirements, totaling 358 megawatts (through 2005), were included in the analysis. Using the information available, the generation modeled in PROMOD for the ATC footprint is 111 percent of the net firm peak demand for 2013, which results in an 11 percent reserve margin.

*Scenario/Sensitivity Analyses*

A variety of scenarios and sensitivities were considered to evaluate the Access project alternatives, as discussed below. Stakeholders were provided a list of sensitivities and bounds and asked to rank them to help direct ATC's analytical efforts. The sensitivities offered included:

- High Gas Prices (20% increase in fuel cost) for all gas and oil units
- $50 Adder to offer prices by Combustion Turbines in ATC footprint
- Three Nuclear units out of service in ATC footprint
- Elm Road Phase III in-service
- Supply offers in ATC footprint increased to 150% of variable production costs

*Additional Comments on Sensitivity Analysis considered*

ATC's stakeholders and customers asked for a sensitivity case to gauge the potential impact of strategic bidding behavior by generators when transmission congestion is present. The suggested sensitivity was to set generation supply offers (bids) within the ATC footprint in PROMOD equal to the offer cap set by MISO's Independent Market Monitor (IMM) for Broadly Constrained Areas (BCAs) whenever there is congestion into or within ATC.[5] Due to software limitations in PROMOD it is not possible to apply a bid adder to simulate "strategic" bidding behavior only during congested periods. As a proxy, an alternate approach was suggested. The alternate approach adds $50/MWh to the bid price for combustion turbines within the ATC footprint in PROMOD. This was done based on the theory that congestion (and strategic bidding behavior) is likely to be present when combustion turbines are on the margin, thereby applying higher bids inside ATC when the transmission system is constrained. However, based on the analysis, this may not have been the best approach to test the sensitivity sought by stakeholders and customers, as there appears to be significant congestion when power plants with costs lower than combustion turbines are on the margin.

The sensitivity where supply offers in the ATC footprint were increased to account for 150% of variable production costs is discussed further in the transfer capability section in this Access Report. This sensitivity was used to stress the imports into the ATC system by creating a significant cost difference between units inside and outside of the ATC footprint. Generator bid prices (offers) for all units in the ATC footprint were increased regardless of fuel type.

The results of the sensitivity analysis are presented in Table 6.

***Table 6***

*Sensitivity Results (2005 dollars)*

| | **Production Cost Savings Relative to Base Case of each Sensitivity (2005 Dollars in Millions)** | | | | |
|---|---|---|---|---|---|
| **Sensitivity** | **South** | **South (Paddock-Rockdale)** | **Southwest** | **West** | **Lower Voltage** |
| High Gas Prices | $12.2 | $10.9 | $10.1 | $10.6 | $10.0 |
| $50 Bid Adder to CTs in ATC | $13.2 | $10.6 | $12.2 | $10.4 | $9.9 |
| Three Nuclear Units Out of Service | $30.8 | $26.4 | $29.0 | $29.1 | $22.5 |
| Elm Road Phase III | $6.3 | $5.1 | $5.8 | $10.6 | $4.8 |
| Bids at 150% of Production Cost | $17.9 | $16.1 | $16.2 | $13.4 | $14.8 |

[5] The offer cap for a Broadly Constrained Area was used as a starting point for the sensitivity because it uses a static bid adder ($100/MWh above operating costs for combustion turbines). In contrast, the offer cap and adder for a Narrowly Constrained Area (NCA) varies based on a running average of generator offers and, at least at this time, cannot be calculated or modeled by PROMOD. Based on subsequent customer feedback, a $50/MWh bid adder was used instead of a $100/MWh adder in PROMOD.

*Other factors considered*

In addition to the economic factors described above, various technical and other factors were considered. These included:

- *fuel and technology risk mitigation*
- *operating flexibility*
- *reduced Expected Unserved Energy*
- *improved system performance*
- *benefits to neighboring systems*
- *enhancing the value of other planned projects*
- *increased transfer capability*
- *societal impacts*
- *environmental impacts*
- *access to renewable resources*
- *accessibility to high voltage network*
- *geographic diversity of 345 kV infrastructure*
- *LMP comparability*

Further detail on ranking these factors can be found in the Other Factors Report prepared by Christensen Associates.

*System Performance - Transfer Capability*

Transfer capability refers to the maximum level of power that can be imported into the ATC service territory under various market and system conditions. It is measured as the maximum megawatts of simultaneous import capability from neighboring systems. In general, the simultaneous import capability is greater at relatively low load levels than at high load levels, and is specific to the distribution of flows across ATC's inter-ties.

Traditionally, transfer capability has been quoted as a single value calculated for anticipated peak load conditions (e.g., 2K/2K/3K).[6] However, this approach is an oversimplification of transfer capability, as it does not account for the remaining 8,759 hours in the year nor does it take into account the ability of the Day 2 market to redispatch generation in the most efficient manner possible at any moment to optimize production costs. Additionally, this approach typically ignores system voltage and, therefore, it does not examine whether or not the transfer could result in low system voltages or voltage instability. Finally, if supply offers in the Day 2 market in the ATC footprint are above unit production

[6] The 2K/2K/3K is the target transfer capability from the Wisconsin Reliability Assessment Organization (WRAO) – 2,000 MW from the West, 2,000 MW from the South, and a simultaneous total of 3,000 MW into WUMS. Each of the values is individually calculated.

costs, then greater import levels may be achieved due to the lower cost of generation outside of the ATC footprint.  However, increasing offers within the ATC footprint to achieve a higher import capability has an associated LMP penalty, as shown in Table 7.  Several values related to transfer capability are:

- Traditional peak condition maximum transfer capability (First Contingency Total Transfer Capability).
- Peak condition maximum transfer capability – voltage security constraints only (voltage transfer capability, as estimated with the Voltage Security Assessment Tool (VSAT).
- Highest import level utilized by PROMOD simulation using production costs (Highest PROMOD import level).
- Maximum import level utilized by PROMOD simulation using supply offers in the ATC footprint increased to account for 150% of variable production costs (Maximum Imports).

The simultaneous import capability into the ATC system (aka Total Transfer Capability or TTC) of the 2013 Access model built in 2005 showed a significant decrease (~1600 MW) as compared to the 2012 Access model built in 2004.  The changes to the transmission system topology and generation mix external to the ATC system account for approximately half of the decrease.  The remaining decrease in TTC is primarily due to the increased load and generation mix applied to the ATC system and ATC transmission topology differences between the two models.

The 2012 Access model started with a 2008 Multiregional Modeling Working Group (MMWG) model and was updated to represent the ATC system as it is expected to exist for the summer of 2012.[7]  The 2013 Access model was originally a 2009 MMWG model updated to represent the ATC system as it is expected to exist for the summer of 2013.  Loads, transmission topology and generation mix were all updated in each of the models to represent the expected ATC system.

[7] The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are for use by the Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems.

***Table 7***

*Average LMP Penalty to Obtain Maximum Import Levels Using Supply Offers at 150% of Production Costs*

| Major Project | LMP Penalty (2005 dollars) |
|---|---|
| South | $3.15 |
| South (Paddock-Rockdale) | $3.41 |
| Southwest | $3.35 |
| West | $3.37 |
| Lower Voltage | $3.43 |

Increasing transfer capability is one of the expected primary benefits of an access project. The projects chosen to optimize the energy-saving benefits of the alternatives using PROMOD did not necessarily optimize the transfer capability into the ATC transmission system. PROMOD analyzes the system for every projected hour of the year, whereas traditional transfer capability analysis evaluates conditions only for the projected peak hour of the year. Transfer capability remains a useful value, however, because it is a single value that can represent the "strength" of the ties. Additional analysis was performed to determine which projects are required to obtain increased transfer capability.

The transfer capability of the alternatives, along with their supporting projects optimized for economic energy savings only, did not meet expectations of a system with a major reinforcement. In order to differentiate further between alternatives, each of the alternatives was "built out" to determine what projects would be required to support up to 5,000 MW of import capability. Some of these projects are common to all of the alternatives and some are common to those identified previously, but many are not.

The Lower Voltage Project consists of a rebuild of the 161 kV line from Lore to Turkey River to Cassville to Nelson Dewey. The Alternative Lower Voltage Project would negate the need for the 161 kV rebuild by installing instead a 161 kV Phase Shifting Transformer (PST) at Nelson Dewey. This alternative project was reviewed as a means to reduce flow on the 161 kV line without necessitating rebuild. Also, the Alternative Lower Voltage Project is approximately $6 Million lower in cost when compared to the Lower Voltage Project.

Figure 2 represents the simultaneous import capability into the ATC transmission system in 2013, at peak load, for each of the Access projects with various other projects added.

## *Figure 2*

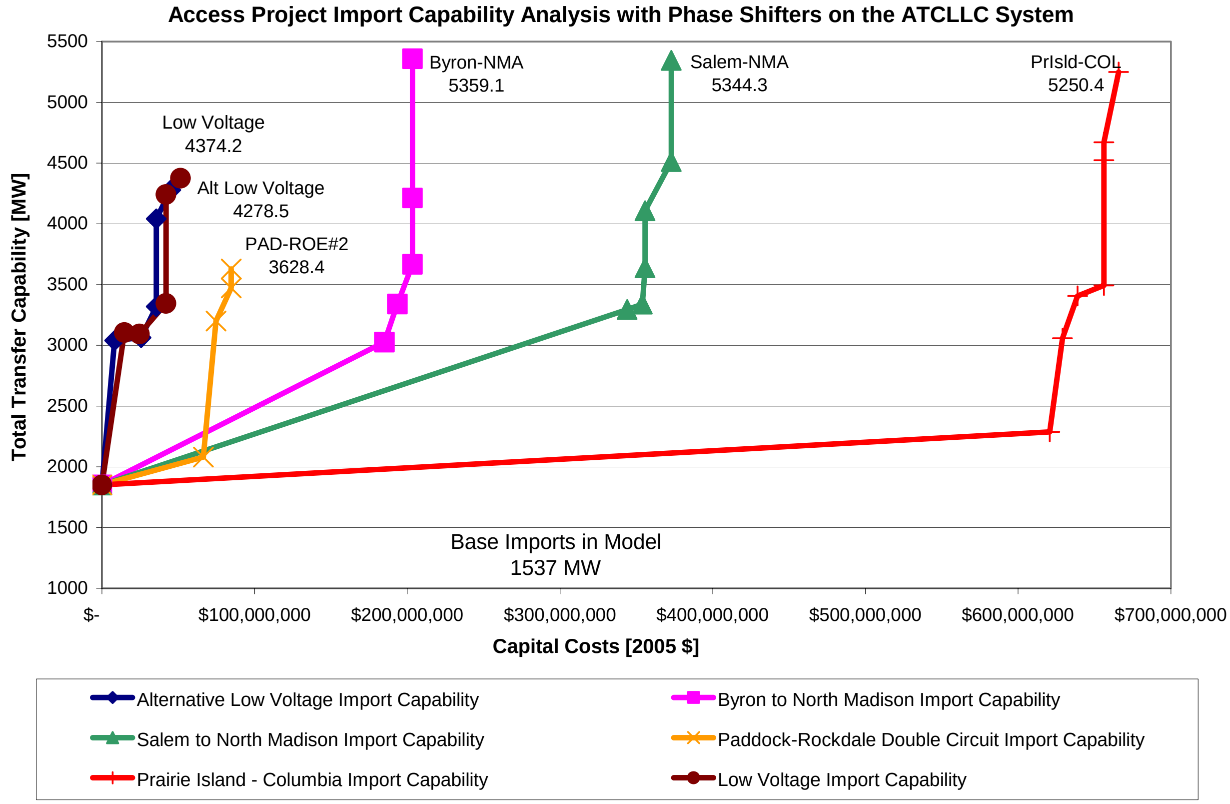



Table 8 lists the supporting projects required for each alternative, along with maximum transfer capability attained.

### *Table 8*

*Alternative Low Voltage Import Capability*

| **Alternative Lower Voltage Import Capability** | **TTC** |
|---|---|
| Base Imports | 1537 |
| Base Case | 1851.4 |
| #1 with Nelson Dewey PST | 3039.9 |
| #2 with Paddock Transformer #2 and PAD-TLR #2 | 3063.7 |
| #3 with Straits PST | 3319.5 |
| #4 with ComEd Reconfiguration #1 | 4041.7 |
| #5 with Bryon-Wempletown #2 | 4278.5 |
| | |
| **Byron to North Madison Import Capability** | **TTC** |
| Base Case FCTTC | 1851.4 |
| Byron to North Madison | 3026.5 |
| #1 with Nelson Dewey PST | 3339.2 |
| #2 with Straits PST | 3666.1 |

| | |
|---|---|
| #3 with ComEd Reconfiguration #1 | 4211.9 |
| #3 with ComEd Reconfiguration #2 | 5359.1 |
| | |
| **Salem to North Madison Import Capability** | **TTC** |
| Base Case FCTTC | 1851.4 |
| Salem to North Madison | 3295 |
| #1 with Straits PST | 3339.2 |
| #2 with Cassville - Nelson Dewey RBLD | 3638.5 |
| #3 with ComEd Reconfiguration #1 | 4108.8 |
| #4 with Paddock Transformer #2 and PAD-TLR #2 | 4512.6 |
| #5 with ComEd Reconfiguration #2 | 5344.3 |
| | |
| **Paddock-Rockdale Double Circuit Import Capability** | **TTC** |
| Base Case FCTTC | 1851.4 |
| Wempletown-PAD-ROE Double Circuit | 2080.8 |
| #1 with Nelson Dewey PST | 3199 |
| #2 with Straits PST | 3471.5 |
| #3 with ComEd Reconfiguration #1 | 3628.4 |
| #4 with Bryon-Wempletown #2 | 3473.6 |
| | |
| **Prairie Island - Columbia Import Capability** | **TTC** |
| Base Case FCTTC | 1851.4 |
| Prairie Island to Columbia | 2287.6 |
| #1 with Nelson Dewey PST | 3057.2 |
| #2 with Straits PST | 3407 |
| #3 with Paddock Transformer #2 and PAD-TLR #2 | 3492.3 |
| #4 with ComEd Reconfiguration #1 | 4523.8 |
| #4 with ComEd Reconfiguration #2 | 4672.1 |
| #6 with Bryon-Wempletown #2 | 5250.4 |
| | |
| **Lower Voltage Import Capability** | **TTC** |
| Base Case FCTTC | 1851.4 |
| Lore - Turkey River - Cassville - Nelson Dewey | 3105.1 |
| #1 with Straits PST | 3094.1 |
| #2 with Paddock Transformer #2 and PAD-TLR #2 | 3345.9 |
| #3 with ComEd Reconfiguration #1 | 4240.5 |
| #4 with Bryon-Wempletown #2 | 4374.2 |

*System Performance - System Losses*

As power from generators is transmitted over the transmission system to end-use customers, energy is lost continuously in the transmission system. To make up for this lost energy, “extra” energy must be produced by generators, resulting in additional costs to customers and added air emissions released from some of those generators. Transmission system losses that occur during peak load periods also add to the amount of generating capacity that utilities must install to meet peak demand. Thus, reducing transmission losses is desirable due to the economic and environmental benefits. Access projects being evaluated by ATC would lower transmission system losses and thus result in less energy production, lower air emissions produced, and require less generation to be installed. Transmission system loss analyses have been conducted to estimate the reduction in system losses. The results are listed in Table 9.

***Table 9***

*System Losses*

| Major Project | ATC System Losses (MW) |
|---|---|
| Base Case | 425 |
| Paddock-Rockdale (South) | 412 |
| Salem-North Madison (Southwest) | 409 |
| Lower Voltage | 427 |
| Byron-North Madison (South) | 406 |
| Prairie Island-Columbia (West) | 427 |

*System Performance - Tower Outage*

ATC plans the transmission system in compliance with the North American Electric Reliability Council’s (NERC’s) Reliability Standards. The Access projects may include the use of double circuit structures and NERC requires that the loss of these circuits will not result in uncontrolled, cascading outages on the transmission system. NERC permits the use of load shedding and special protection schemes to mitigate cascading outages. Alternatives to these solutions would include import limits or additional projects to reinforce the parallel facilities.

ATC reviewed the performance of the Access projects under high import scenarios with the loss of a double circuit tower. Transmission loadings and voltages under contingency were monitored in the ATC system and in the surrounding control areas.

The results of the tower outage analyses to date have led to the following findings:

- The critical contingency for each scenario examined was the loss of a double circuit 345 kV tower between Wempletown and Paddock substations.

- For a 3,600 MW import scenario with the 2013 Base Case, the Nelson Dewey-Cassville 161 kV line may experience loadings greater than 130% of summer emergency rating. Loadings greater than 130% are indications of potential cascading situations.
- For a 4,500 MW import scenario with any of the Prairie Island-Columbia or Lower Voltage alternatives in the model, the power flow simulations would not converge under the critical contingency. Non-convergence is an indication of voltage instability and/or cascading outages.
- For a 4,500 MW import scenario with the Paddock-Rockdale alternative in the model, the power flow simulations would not converge under the critical contingency. In addition, the power flow simulations would not converge for the loss of a double circuit 345 kV tower between Paddock and Rockdale substations. Non-convergence is an indication of voltage instability and/or cascading outages.
- For a 4,500 MW import scenario with either the Salem-North Madison or the Byron-North Madison alternative, there was no indication of voltage instability, cascading outages or significant overloads.

*LMP Comparability*

LMP comparability refers to the level of variation among the average locational marginal prices (LMP) of different utility service territories within ATC's footprint. The increased transfer capability of the alternatives also reduces ATC customers' LMP as well as LMP variation and thus improves LMP comparability.

*Reliability*

Improved access can increase reliability by providing additional import capability for the ATC system during emergencies and by improving the ability of the transmission system to respond to emergencies. Two different reliability analyses were conducted to assess the reliability merits of improving access. System adequacy is assessed using a Loss of Load Expectation (LOLE) analysis to determine how much import capability is needed from a reliability perspective. System security is assessed using an Expected Unserved Energy (EUE) analysis to determine the expected amount of load that would have to be interrupted for various emergencies and under various scenarios.

*Loss of Load Expectation*

LOLE is a probabilistic measure that is used to help determine if there is enough power to meet demand such that a shortage of power (forcing the use of rolling blackouts) should occur no more than one day in ten years. From this measure, guidelines for an adequate capacity reserve margin can be developed. LOLE determinations include consideration of future power needs of the study area, resources already available (existing generation and import capability), power that is relatively certain to become available either through new generation or improved import capability, demand-side measures such as interruptible loads and other factors, such as power plant forced outage rates and maintenance outages. If the calculations show that the area will not meet a LOLE of 0.1 days/year (i.e., one day in ten years), then demand must be reduced and/or capacity (generation or transmission) must be increased to meet the LOLE criterion.

Based on the analysis to date, the following findings have been made:

- The ATC system is projected to require approximately 1,450 megawatts of import capability by 2013 to meet the LOLE criterion, assuming all planned generation is in-service, no existing generation is retired and the import capability modeled is assumed to be available 100% of the time.
- Relatively few generator retirements are assumed in the baseline studies (358 megawatts of retirements versus 3,629 megawatts of additions for a net of 3,987 megawatts dating back to 2003). Additional retirements would increase the 1,450-megawatt import capability requirement on roughly a one-for-one basis.
- It may be possible to reduce reserve margins required to meet the LOLE criterion of 0.1 days/year. LOLE analysis was run iteratively to determine the reserve margin required to maintain the LOLE criteria of 0.1 days per year for the access alternatives.

The LOLE results in this section were calculated using the MARELI software package, which is also used by the Midwest ISO.[8] LOLE analyses presented in previous Ten Year Assessment reports used an LOLE program developed by MAIN. ATC benchmarked the results from the new software package against previous results. The results, although similar, were not identical. Therefore, to maintain consistency with the previous results and MAIN's LOLE standard, a scaling factor was applied in MARELI to account for the small difference in results.

Table 10 shows the results of the LOLE analysis for the ATC footprint. The second column shows that to achieve the LOLE criterion of 0.1 days/year, the import capability has to be at least 1,450 megawatts. The third column shows the estimated Base Case Total Simultaneous Import Capability of 1,913 megawatts, which exceeds the amount necessary to meet the LOLE criterion.

[8] LOLE determines the minimum generation reserves that a load-serving entity must maintain to meet a given reliability standard. LOLE is defined as the fraction of time that electricity demand is likely to exceed available sources of power for a given system. The LOLE criterion set by the Mid-America Interconnected Network (MAIN) reliability region is loss of load no more than 0.1 days per year or one day in ten years.

**Table 10**

*LOLE for WUMS for 2013*

| | Base Case with the Import Capability Needed to Meet 0.1 Days/Year | Base Case with Total Simultaneous Import Capability | Low Voltage Alternative with Total Simultaneous Import Capability | Paddock-Rockdale with Total Simultaneous Import Capability | Byron-NMA with Total Simultaneous Import Capability | Salem-NMA with Total Simultaneous Import Capability | Prairie Island-Columbia with Total Simultaneous Import Capability |
|---|---|---|---|---|---|---|---|
| Total Generation | 17,780 | 17,780 | 17,780 | 17,780 | 17,780 | 17,780 | 17,780 |
| Net Peak Demand | 16,005 | 16,005 | 16,005 | 16,005 | 16,005 | 16,005 | 16,005 |
| Reserve Margin not Including Import Capability | 11.1% | 11.1% | 11.1% | 11.1% | 11.1% | 11.1% | 11.1% |
| Estimated Import Capability | 1,450 | 1,913 | 3,166 | 2,789 | 3,094 | 3,342 | 3,118 |
| Hypothetical "Reserves" Including Full Import Cap. | 20.1% | 23% | 30.9% | 28.5% | 30.4% | 32% | 30.6% |
| Internal Generation in Excess of the Min. Needed to Meet the LOLE[9] | | 530 | 1,929 | 1,529 | 1,849 | 2,119 | 1,874 |
| Potential Reduction in Total Internal Generation (%)[10] | | 3.0% | 10.8% | 8.6% | 10.4% | 11.9% | 10.5% |
| Theoretical Annual Cost Savings (2005$/Year)[11] | | $28,634,840 | $104,220,012 | $82,608,812 | $99,897,772 | $114,485,332 | $101,248,472 |

The current required planning reserve margin of 18% in Wisconsin was set by the PSCW based on historical availability and usage of the transmission import capability as well as generator availability. With the potential increased import capability associated with an Access Initiative project, it may be possible to reduce this required reserve margin. ATC performed a generic cost analysis to

[9] When comparing "importing" reserves versus using internal generation to meet the LOLE criterion, less import capability is needed than generation because the forced outage rate on transmission lines is lower than that for power plants.
[10] Theoretical reduction in total internal generation to maintain an LOLE of 0.1 days/year given the increase in access presented in the table.
[11] Based on the estimated avoided capital, operating and maintenance (O&M) and transmission interconnection costs for a combustion turbine (CT) of $54,028/MW/Year.

determine annual cost savings that could be attributed to reducing the required reserve margin. The analysis showed an approximate annual cost savings of $8.1 million dollars per percentage point decrease in the required reserve margin.

***Table 11***

*Savings to Retail Consumers Due to Reduced Reserve Requirements*

| Reserve Margin Reduction | Approximate Annual Cost Savings (2005$) |
|---|---|
| 1% | $8,104,259 |
| 2% | $16,208,518 |
| 3% | $24,312,777 |
| 4% | $32,417,036 |

This analysis was performed by determining the annual carrying costs associated with the construction and operation of a new conventional combustion turbine. It was based on information taken from the Energy Information Administration's Annual Energy Outlook 2005 report. The annual carrying cost figure also includes an adder for transmission system upgrades necessary to interconnect a new generator. This adder was based on an analysis of transmission costs for generation interconnections on the ATC system over the past few years.

*Expected Unserved Energy*

Planning is a forward looking process and, as such, evaluates a transmission system with uncertain parameters including uncertain load level and uncertain operating status of generators, transmission lines and other transmission system components. A common method for managing uncertainty is to develop alternative scenarios, evaluate each scenario independently and then resolve the multiple scenario results into a single representative measure. However, this requires an extensive study of specified scenarios or so-called 'credible' events. One way to simplify the extensive study of multiple scenarios, to assess system-wide bulk power transmission reliability and to measure the reliability merit of transmission system additions, is to calculate a single aggregated index such as Expected Unserved Energy (EUE).

EUE is a measure of transmission system capability to continuously serve all loads at all delivery points while satisfying all reliability criteria. To compute EUE of a system, the following information is required:

- frequency of each contingency
- duration of each contingency
- unserved megawatt load for each contingency and for the intact system

The unserved megawatt load is determined by reducing load, in amounts and locations around the system, in such a way that all system violations are resolved with the minimum total load reduction. The total load remaining, after this load reduction, represents the capability of the system. The computed unserved megawatt load for each contingency is multiplied by the duration and frequency of each contingency, and the computed unserved megawatt load for the intact system is multiplied by the probability of no contingency occurring. In this way, the likelihood of each contingency can be considered and it can be quantified as a single summary EUE that is the sum of all the probabilistic weighted unserved megawatts for each contingency. That single quantified EUE index indicates the relative system performance of system reinforcement. Thus, ranking or comparing the qualities among alternatives can be analyzed.

ATC is utilizing Physical Operation Margin and Optimal Mitigation Measure (POM & OPM) software from V&R Energy for this analysis. The analysis utilizes the historic probability of transmission facility outages along with the expected load, generation and topology of the transmission system (in 2013, in this case) to determine how much load would need to be interrupted and for how long.

Line outage probabilities are derived from actual statistics for years 1997-2003. Actual line outages per hundred mile-years were calculated separately for each voltage class. Total reactance and total miles were calculated for each voltage class to convert outages per hundred mile years to outages per ohm-years. Outages per year, or outage frequency, were calculated for each model branch as the product of that branch's reactance and outages per ohm-years. Actual line outage durations were calculated separately for each voltage class. Each branch's outage probability is based on the product of its outage frequency and outage duration.

To better quantify the results for actual yearly conditions, ATC studied three load levels for each project. The three levels are summer peak load, 80% of summer peak load, and 60% of summer peak load. The EUE of each level is multiplied by the probability of being at that load level. The total EUE is then calculated by summing the EUE at each load level. The probability of being at the defined load levels is determined by using available data from 2001 through 2003, as seen in Table 12. For the purpose of this study, the summer peak EUE will be multiplied by 0.037, the average occurrence of load greater than 80% of the summer peak over the selected timeframe.

***Table 12***

*Load Level Probabilities*

| Load Level (% of summer peak) | % of Hours in Year | | | |
|---|---|---|---|---|
| | 2001 | 2002 | 2003 | Average |
| Load > 80% | 3.5 | 4.6 | 2.9 | 3.7 |
| 60% < Load < 80% | 44.5 | 48.2 | 45.7 | 46.1 |
| Load < 60% | 52.0 | 47.2 | 51.4 | 50.2 |

EUEs were computed for each access model and tabulated as shown in Table 13. The unserved megawatt load and probabilistic data such as frequency and duration of each contingency were utilized to compute the EUE which is the sum of all the unserved megawatt loads weighted for the probability that each contingency will occur and the probability of each load level. The EUE indicates the relative system performance of the system reinforcement.

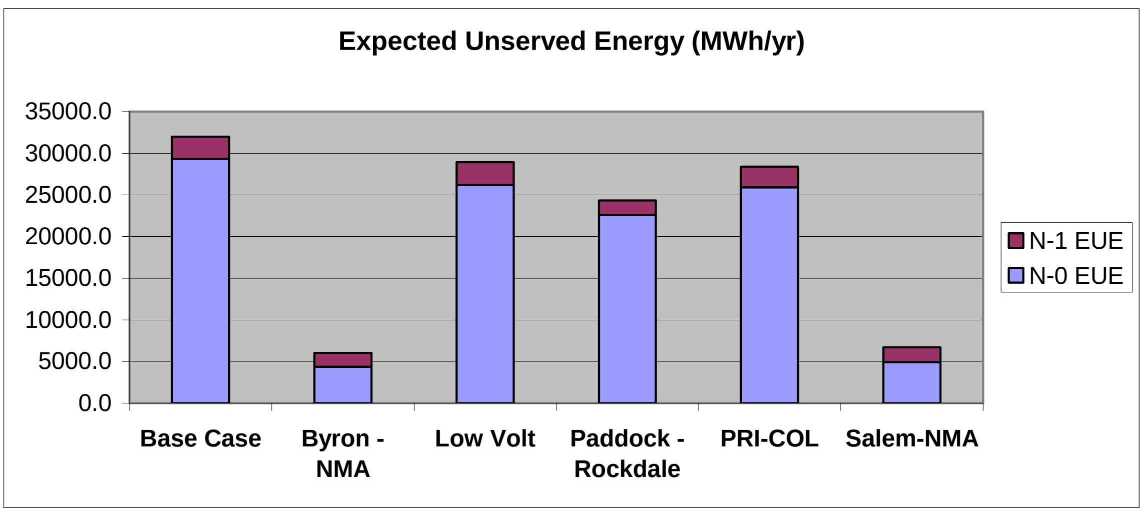
***Table 13***

*EUE for Each Alternative*

| Model | Expected Unserved Energy (MWh/yr) | | | | | |
|---|---|---|---|---|---|---|
| | Summer Peak Intact (N-0) | SP N-1 | 80% SP N-1 | 60% SP N-1 | Total EUE | EUE Relative to Base Case |
| Base Case | 29,310.5 | 765.2 | 1,692.6 | 206.0 | 31,974.3 | 0.0 |
| Low Voltage Fixes | 26,166.2 | 804.2 | 903.1 | 152.7 | 28,026.2 | -3,948.1 |
| Byron – N Madison 345 kV | 4,357.1 | 625.2 | 1,782.4 | 191.4 | 6,956.1 | -25,018.2 |
| Paddock – Rockdale 345 kV | 22,564.5 | 585.8 | 1,025.5 | 154.9 | 24,330.7 | -7,643.6 |
| Prairie Island – Columbia 345 kV | 25,913.8 | 756.9 | 1,532.0 | 188.5 | 28,391.2 | -3,583.1 |
| Salem – N Madison 345 kV | 4,915.5 | 607.6 | 1,066.2 | 135.7 | 6,725.0 | -25,249.3 |

*N-0 EUE = 0 for all non-Summer Peak load levels

***Figure 3***




EUE might also possibly be reduced with less costly measures. For instance, EUE reduction might be accomplished with smaller scale projects not yet identified rather than the proposed Access Initiative projects. However, at this time no studies exist to make a definitive statement on the impact on EUE of smaller-scale projects.

*Strategic Benefits*

There are various strategic advantages associated with improving transmission access. Depending on the size and location of the new facilities added to improve access, the ability to serve new customers and access new markets, including renewable resources, may be created. The backbone transmission infrastructure an access project provides may be necessary to support load growth and economic development. These and other strategic attributes of access projects are being identified, explored, and assessed for each alternative access scenario.

Based on the investigations done to date, the following findings have been made:

- A new interconnection to the south (Illinois) would provide infrastructure to support the 138 kV system in south central Wisconsin. A 345/138 kV transformer installed at North Monroe, for example, would provide a new source for the 138 kV network in the area. Such an interconnection would provide some geographical diversity to existing 345 kV interconnections to neighboring areas. Providing a new 345 kV source in the Madison area would improve access to a historically constrained area. Another 345 kV tie to North Madison may also provide stability benefits for the Columbia generators.
- A new interconnection to the southwest (Iowa) would provide infrastructure to support and relieve loading on the 161 kV, 138 kV and 69 kV facilities in southwest Wisconsin and northeast Iowa.[12] Installing 345/138 kV transformers along the existing 138 kV network from Nelson Dewey to West Middleton would provide an additional source for the area. Such an interconnection would provide excellent geographical diversity to the existing 345 kV interconnections to neighboring areas. Providing a new 345 kV source in the Madison area would improve access to a historically constrained area. Another 345 kV tie to North Madison may also provide stability benefits for the Columbia generators.
- A new interconnection to the west (Minnesota) could provide new interconnections with DPC and relieve loading on 161 kV, 138 kV and 69 kV facilities in western Wisconsin. Such an interconnection would provide additional geographical diversity to existing 345 kV interconnections to neighboring areas. If connected at Columbia, it could improve the stability response of the existing Columbia units.
- Depending on the level of wind generation development in Iowa and Minnesota and the transmission facilities constructed to transmit the output, interconnection projects to the south, southwest or west could improve access to new sources of renewable energy.

[12] A preliminary ATC study of system reliability in southwest Wisconsin for 2019 indicates that additional projects will be required to maintain system voltage even if the LV project is constructed.

In addition to the benefits listed above, the Access projects have the potential to eliminate or defer reliability projects identified in the Ten Year Assessment. Based on ATC's assessment, only the southwest (Salem-North Madison) project could result in the elimination or deferral of reliability projects. Table 14 lists the Ten Year Assessment projects that may be deferred along with the original need date, the new need date and the present value savings of the capital costs based on the number of years deferred.

***Table 14***
Potential Savings Due to Deferral of Reliability Projects
Salem-North Madison Alternative

| Project in 2005 TYA | Year Originally Needed | Capital Cost of Project (2005 $) | Deferred To | Present Value Savings of Deferral[1] (2005 $) |
|---|---|---|---|---|
| Uprate Portage-Trienda 138 kV circuits to 383 MVA | 2012 | $1,062,160 | 2017 | $380,080 |
| New 138 kV line from Columbia to Portage | 2014 | $5,394,761 | 2016 | $888,713 |
| Replace two Columbia 345/138 kV transformers | 2014 | $6,626,795 | 2019 | $2,371,309 |
| | | | Total | $3,640,102 |

1 – Using a 5.5% real discount rate over 40 years.

*Operating Flexibility*

A robust transmission system provides additional flexibility to perform both transmission and generation maintenance outages and maintain reliable service under multiple contingency scenarios. Operating flexibility enhancements enabled by alternative access scenarios are being assessed in 2005.

*Societal and Environmental Impacts*

Although difficult or impossible to quantify in dollars, the societal and environmental impacts of new transmission facilities are being identified and assessed as well. Additional analysis regarding some of these impacts is provided in the Other Factors Report. Based on the investigations done to date, the following findings have been made:

- Each of the projects under consideration would involve societal effects that, depending upon the specific physical attributes of each project, vary from virtually non-existent to potentially sizeable impacts.

- There are opportunities for corridor sharing with existing transmission lines for the proxy interconnection projects to the south, southwest and west.
  - Key considerations for each of the proxy interconnection projects include:
  - South (Byron – North Madison):
    - Estimated corridor sharing 42% of route
    - Estimated new miles of right away required: 56
  - South (Paddock – Rockdale #2)
    - Estimated corridor sharing 70% of route
    - Estimated new miles of right away required: 7.6
  - Southwest: Mississippi River and potentially Wisconsin River crossings. New right-of-way will likely be required.
    - Estimated corridor sharing 96% of route
    - Estimated new miles of right away required: 6
  - West: Mississippi River and Wisconsin River crossings. New right-of-way will likely be required.
    - Estimated corridor sharing 42% of route
    - Estimated new miles of right away required: 159

## Summary Table

Table 15 is a Summary Table. It shows the economic factors, sensitivities, system performance, LMP comparability, reliability, and project mileage for the five Access Alternatives.

***Table 15***
*Summary Table*

| Scenario/Category | Measure | Economic Component | Access Alternatives: Base Case | Paddock - Rockdale | Salem - North Madison | Lower Voltage | Byron - North Madison | Prairie Island - Columbia |
|---|---|---|---|---|---|---|---|---|
| **Economics** | | | | | | | | |
| **Capital Costs** | $Millions (2005$) | Estimated Cost of Package | | 69.1 | 352.3 | 33.0 | 186.1 | 639.7 |
| | $Millions per year (2005$) | Annual Capital Carrying Cost | | 5.5 | 27.9 | 2.6 | 14.8 | 50.7 |
| **PROMOD Analysis - Base Models[1]** | $Millions per year (2005$) | Market Savings - Draw 1 | | 9.4 | 9.8 | 8.8 | 10.8 | 8.7 |
| | | Market Savings - Draw 2 | | 8.7 | 8.8 | 7.9 | 10.3 | 9.1 |
| | | Market Savings - Draw 3 | | 8.9 | 8.8 | 8.6 | 10.5 | 9.1 |
| | | Average Market Savings | | 9.0 | 9.2 | 8.5 | 10.6 | 9.0 |
| | | Standard Deviation | | 0.4 | 0.6 | 0.5 | 0.2 | 0.2 |
| | | **Annual Net Savings** | | **3.5** | **-18.8** | **5.8** | **-4.2** | **-41.8** |
| **Annual Capital Carrying Charge** | **7.93%** | | | | | | | |
| **Sensitivities** | | | | | | | | |
| **Sensitivity #1: High Gas Prices** | $Millions per year (2005$) | Market Savings | | 10.9 | 10.1 | 10.0 | 12.2 | 10.6 |
| | | **Annual Net Savings** | | 5.4 | -17.8 | 7.4 | -2.6 | -40.1 |
| **Sensitivity #2: CT Bid Up $50** | | Market Savings | | 10.6 | 12.2 | 9.9 | 13.2 | 10.4 |
| | | **Annual Net Savings** | | 5.1 | -15.7 | 7.3 | -1.6 | -40.3 |
| **Sensitivity #3: Three WI Nukes Out** | | Market Savings | | 26.4 | 29.0 | 22.5 | 30.8 | 29.1 |
| | | **Annual Net Savings** | | 20.9 | 1.0 | 19.9 | 16.1 | -21.7 |
| **Sensitivity #4: Elm Road 3** | | Market Savings | | 5.1 | 5.8 | 4.8 | 6.3 | 10.6 |
| | | **Annual Net Savings** | | -0.4 | -22.1 | 2.1 | -8.4 | -40.1 |
| **Sensitivity #5: Bid 150% of Production Cost (for generators within ATC)** | $Millions per year (2005$) | Market Savings | | 16.1 | 16.2 | 14.8 | 17.9 | 13.4 |
| | | **Annual Net Savings** | | 10.6 | -11.7 | 12.2 | 3.1 | -37.4 |
| | $ (2005$) | Average LMP Penalty | | 3.41 | 3.35 | 3.43 | 3.15 | 3.37 |
| **System Performance** | | | | | | | | |
| First Contingency Total Transfer Capability | MW | | 1913 | 2789 | 3342 | 3166 | 3094 | 3118 |
| VSAT Transfer Capability Results | Transfer Level (MW) | | 2465 | 3715 | 3862 | 2493 | 3834 | 3056 |
| Type of VSAT Limit | Due to Voltage Collapse | | LV | VC | VC | LV | VC | LV |
| Highest PROMOD Import Level | MW | | 3339 | 3871 | 3609 | 3740 | 3907 | 3916 |
| Maximum Imports (PROMOD) | MW | | 4424 | 4996 | 4960 | 4747 | 5101 | 5189 |
| ATC System Losses | MW | | 425 | 412 | 409 | 427 | 406 | 427 |
| **LMP Comparability** | | | | | | | | |
| Average Std Deviation of LMPs | $ (2005 $) | | 1.667 | 1.518 | 1.494 | 1.528 | 1.485 | 1.567 |
| **Reliability** | | | | | | | | |
| LOLE | probability, days/year | | 0.03423 | 0.00319 | 0.00055 | 0.00099 | 0.00124 | 0.00116 |
| Total EUE | MW Hr/yr | | 31974 | 24330 | 6726 | 28026 | 6956 | 28391 |
| **Project Mileage** | | | | | | | | |
| 345 kV Miles | miles | | 0.0 | 34.8 | 149.0 | 0.0 | 97.0 | 275.5 |
| 161 kV and Lower Voltage Miles | miles | | 0.0 | 24.5 | 188.6 | 52.6 | 62.0 | 125.7 |
| Total miles | miles | | 0.0 | 59.3 | 337.6 | 52.6 | 159.0 | 401.2 |

*Summary Table*