2004 ATC Access Study Initiative

Access Value Case

In response to customer input, emerging regional energy markets, and customers' desires to access and participate in these markets, American Transmission Company (ATC) launched an Access Study Initiative in 2004. This initiative has been undertaken in conjunction with and in addition to regular ATC public planning process activities, presented in ATC's 10-Year Transmission System Assessment reports issued every six months. The purpose of this initiative, which will solicit and incorporate customer and stakeholder participation, is to

- assess the potential benefits and costs of improving the transfer capability of the ATC transmission system, and
- develop the value case for pursuit of future projects designed to increase transmission system access.

ATC is in the process of assessing and obtaining customer and stakeholder input on the potential benefits, costs, and impacts of improving access, and the elements that should be considered as part of the access "value case." In prior 10-Year Assessment reports, ATC has presented various discussions on the access/transfer capability topic, including most recently, examples of projects that might be considered to achieve various access objectives along with an estimated construction cost for those alternatives.

In it's current Access Initiative, ATC is evaluating five potential directions for potential interconnection projects conceived to improve access: south (Illinois), southwest (Iowa), west (Minnesota), north (Ontario) and east (Michigan). In addition, ATC is identifying transfer limitations with each of the projects to assess the feasibility of further improving access in each direction. As ATC's Access Initiative is an ongoing process in 2004, please refer to the following link in order to be apprised of the most current information:

http://atcllc.com/oasis/Customer_Notices/Access.html

Monthly meetings were scheduled throughout the summer to report on results of ongoing analyses and to solicit additional input. By the end of 2004, ATC intends to propose an access "target" that balances the costs and benefits of improved access on the ATC transmission network. A more detailed timetable is included at the end of this document.

Based on the results of analyses done to date, the following findings have been made:

- With projects already being planned by ATC completed by 2012, ATC estimates that its simultaneous import capability will increase from approximately 2,300 megawatts currently to approximately 3,050 megawatts by 2012, an increase of 650 megawatts.

- Interconnection projects to the south and southwest appear to yield the greatest improvement in access, the greatest level of energy production savings and have the lowest cost/benefit ratios.
- The interconnection projects to the south and southwest appear to provide the greatest reliability benefits as measured in 'expected unserved energy' (see discussion below).
- Based on the planned generation additions assumed for the Loss of Load Expectation analysis (see discussion below), ATC customers can meet their LOLE annual target of 0.1 day/year in 2012 with approximately 1,915 megawatts of import capability that is continuously available. The import capability required rises roughly by one megawatt for each megawatt of existing generation that is retired (see discussion below).
- Interconnection projects to the South and Southwest appear to yield the greatest reduction in system losses and the greatest projected loss cost savings (see discussion below).

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This section of the Assessment describes the components and status of ATC's Access initiative to date. Introductory materials regarding this initiative were presented to ATC customers and stakeholders in April 2004. All initiative materials are posted to the ATC node on the Midwest ISO OASIS as they are developed and released at the following link:

http://atcllc.com/oasis/Customer_Notices/Access.html

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". Additional analysis is needed to identify these limits so that potential impediments to achieving the 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 greater number and frequency of transactions from outside the ATC footprint, and allow more intra-ATC transactions to occur. ATC has identified historical chronic limits by data-mining the OASIS and NERC TLR (transmission loading relief incident) logs. ATC is in the process of identifying projected future chronic limits using power flow analysis and through Security Constrained Economic Dispatch (SCED) software simulations.

The chronic limits within the ATC footprint with the largest recent historic impact on transmission service are summarized in **Tables AC-1 and AC-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. Table findings are based on the information compiled for 2003 and the first half of 2004.

Table AC-1
2003 ATC Chronic Limiters (Jan 1 – Dec 31)

2003 Rank	Flowgate Name	Megawatt Hours Refused	Solution Proposed
1	Paddock Transformer for loss of Paddock-Rockdale	6,694,154	Second Paddock 345/138 kV transformer and second Paddock-Town Line Road 345 kV line[1]
2	Lore-Turkey River for loss of Wempletown-Paddock (Op Guide)	5,386,015	Second Wempletown–Paddock 345 kV line (2005)
3	Turkey River-Casville for loss of Wempletown-Paddock (Op Guide)	5,202,641	Second Wempletown–Paddock 345 kV line (2005)
4	Zion–Pleasant Prairie for loss of Wempletown – Paddock	5,155,125	Second Wempletown–Paddock 345 kV line (2005)
5	Turkey River–Cassville for loss of Wempletown– Paddock	5,057,806	Second Wempletown–Paddock 345 kV line (2005)
6	Albers–Paris for loss of Wempletown–Paddock	4,363,774	Second Wempletown–Paddock 345 kV line (2005)
7	Stiles–Pioneer for loss of N. Appleton–Lawn Rd	3,970,349	Rebuild Morgan–Falls–Pioneer –Stiles (2005)
8	Cassville–Nelson Dewey for loss of Wempletown– Paddock	3,521,114	Second Wempletown–Paddock 345 kV line (2005)
9	Zion–Pleasant Prairie for loss of Zion–Arcadian	3,373,179	A change in ARS TRM methodology will lead to increased capacity on this flowgate
10	Pleasant Prairie–Racine for loss of Wempletown– Paddock	3,310,364	Second Wempletown–Paddock 345 kV line (2005)
11	Wisconsin-Michigan Upper Peninsula interface (OTDF)	3,262,376	Plains–Stiles Projects (2005-06) Cranberry–Conover 138 kV line (2008)
12	Wisconsin-Michigan Upper Peninsula interface (PTDF)	3,020,095	Plains–Stiles Projects (2005-06) Cranberry-Conover 138 kV line (2008)
13	North Appleton–Lost Dauphin for loss of North Appleton–Mason St.	2,900,955	Forest Junction Substation (2003)
14	Lore–Turkey River for loss of Wempletown– Paddock	2,859,133	Second Wempletown-Paddock 345 kV line (2005)
15	Stiles–Amberg for loss of Morgan–Plains	2,232,681	Plains–Stiles Projects (2005-06) Cranberry–Conover 138 kV line (2008)
16	North Appleton-Lost Dauphin for loss of East Krok-Kewaunee	2,199,936	Forest Junction Substation (2003)
17	Eau Claire-Arpin (PTDF)	2,181,033	Arrowhead-Gardner Park 345 kV line (2008)
18	North Appleton-Lost Dauphin for loss of Kewaunee transformer	2,166,314	Forest Junction Substation (2003)
19	Amberg-Plains for loss of Morgan-Plains	2,150,880	Plains-Stiles Projects (2005-06) Cranberry-Conover 138 kV line (2008)
20	Pleasant Prairie-Arcadian for	2,132,856	Bain-Racine 345 kV line (2012)[2]

	loss of Pleasant Prairie-Racine		

[1]"Strategic Project", not yet in Provisional category
[2]Provisional project

Table AC-2
2004 ATC Chronic Limiters (Jan 1 – Jun 30)

2004 Rank	Flowgate Name	Megawatt Hours Refused	Solution Proposed
1	Turkey River–Cassville for loss of Wempletown– Paddock	5,142,262	Second Wempletown–Paddock 345 kV line (2005)
2	Zion–Pleasant Prairie for loss of Wempletown– Paddock	3,652,457	Second Wempletown–Paddock 345 kV line (2005)
3	Lore–Turkey River for loss of Wempletown–Paddock	3,557,925	Second Wempletown–Paddock 345 kV line (2005)
4	Albers–Paris for loss of Wempletown–Paddock	3,521,604	Second Wempletown–Paddock 345 kV line (2005)
5	Paddock Transformer for loss of Paddock– Rockdale	3,273,499	Second Paddock 345/138 kV transformer and second Paddock-Town Line Road 345 kV line[1]
6	Zion–Pleasant Prairie for loss of Zion–Arcadian	3,048,749	A change in ARS TRM methodology will lead to increased capacity on this flowgate
7	Cassville–Nelson Dewey for loss of Wempletown– Paddock	2,906,576	Second Wempletown–Paddock 345 kV line (2005)
8	Center–Fiebrantz for loss of Zion–Arcadian (operating guide)	2,823,089	4.5 ohm reactor placed in series with Cornell-Fiebrantz-Center 138 kV line[1]
9	T Corners–Wien for loss of Eau Claire–Arpin (operating guide)	2,809,512	Arrowhead–Gardner Park 345 kV line (2008)
10	Eau Claire–Arpin PTDF	2,563,225	Arrowhead–Gardner Park 345 kV ine (2008)
11	Wisconsin-Michigan Upper Peninsula interface (PTDF)	2,353,673	Plains–Stiles Projects (2005-06) Cranberry-Conover 138 kV line (2008)
12	Wisconsin-Michigan Upper Peninsula interface (OTDF)	2,132,952	Plains–Stiles Projects (2005-06) Cranberry-Conover 138 kV line (2008)
13	Pleasant Prairie–Racine for loss of Wempletown– Paddock	1,876,689	Second Wempletown-Paddock 345 kV line (2005)
14	Lore–Turkey River for loss of Wempletown – Paddock (Op Guide)	1,686,229	Second Wempletown-Paddock 345 kV line (2005)
15	Center–Fiebrantz for loss of Wempletown – Paddock (operating guide)	1,479,585	Second Wempletown–Paddock 345 V line (2005) 4.5 ohm reactor placed in series with Cornell-Fiebrantz-Center 138 kV line[1]
16	Russell-Rockdale for loss of Paddock-Rockdale	1,413,852	Reconductor Russell-Rockdale 138 kV line (2004)
17	Turkey River-Casville for loss of Wempletown Paddock (Op Guide)	1,167,339	Second Wempletown-Paddock 345 kV Line
18	Amberg-Plains for loss of Morgan-Plains	1,132,060	Plains-Stiles Projects (2005-06) Cranberry-Conover 138 kV line (2008)
19	McGulpin-Straits circuit 1 for loss of McGulpin-Straits circuit 3	1,104,782	Third McGulpin-Straits 138 kV cable[1]
20	Zion-Arcadian for loss of Zion-Pleasant Prairie	1,077,275	A change in ARS TRM methodology will lead to increased capacity on this flowgate

[1]*"Strategic Project" not yet in Provisional category*

Economic benefits

Access to lower-cost power both outside and within the ATC footprint can lower the total cost of energy production. A utility can realize energy cost savings through traditional bilateral energy transactions or through participation in a Locational Marginal Price (LMP) energy market. In order to forecast the energy cost savings that could be expected if more transactions could be accommodated, a security-constrained economic dispatch (SCED) software package is required. ATC has acquired a SCED software package (PROMOD) that is being used to project energy cost savings associated with improving access. PROMOD is a simulation model that determines the lowest energy generation cost within the limitations of the transmission system for each hour of a given year.

The SCED analysis will be used to provide a present value of annual revenue requirements (PVRR) comparison of the Access projects based on the differences in generation production costs and transmission losses between the projects. Losses are inherently included in the hour-by-hour PROMOD simulation; they are handled similar to load, but are difficult to itemize.

Things to keep in mind concerning this analysis:

- ❑ The results to date are based on only one year (2012) being modeled in PROMOD.
- ❑ We are calculating the difference in cost between alternatives. Hence, except for the model 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 results of the PROMOD analyses to date have led to the following findings:

- ❑ The “Base Case Plus 2 Fixes” alternative, an upgrade option that does not include a new 345 kV line, but rather fixes two lower-voltage constraints, has the best cost-benefit ratio.[1]
- ❑ Refinements are still being made to the PROMOD analyses and therefore the production cost savings are likely to change, at least to some degree. Similarly for the capital cost estimates for the alternatives.
- ❑ Energy imports into the ATC footprint range from 12.4 to 13.3 percent of the total annual energy requirement for the various alternatives, which is near historical levels of about 15 percent.

Table AC-3 lists the capital cost estimate for each project and the corresponding annual carrying cost. The annual carrying cost for each project can be compared

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[1] *The “Base Case Plus 2 Fixes” starts with the Base Case, but rather than adding a new 345 kV line instead fixes the next two most limiting constraints by (1) rebuilding the Lore-Turkey River-Cassville-Nelson Dewey 161 kV line and (2) installing a second Paddock 345/138 kV transformer (at a total estimated cost of $30 million).*

to its annual production cost savings to determine which project has the best cost/benefit ratio.   For example, the “Base Case Plus 2 Fixes” has an Annual Carrying Cost of $2.7 million and Annual Production Cost Savings of $8.1 million, resulting in a cost/benefit ratio of 0.33. The annual production cost savings for each project is calculated using PROMOD and is measured relative to the Base Case.[2]

The current results show that the “Base Case Plus 2 Fixes” has the best cost/benefit ratio. However, both the capital cost estimates and the PROMOD analyses are still being refined and these costs are just one component of a complex, multi-faceted decision-making process that is described later in this chapter.

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[2] *The Base Case includes the transmission facilities listed in the “Base Case Development/Assumptions” section, which is later in this chapter.*

Table AC-3

Costs for each Representative Project

Project	Total Capital Costs (2003 Dollars in Millions)	Approximate Annual Carrying Cost (2003 Dollars in Millions)	"Production Cost" Savings Relative to the Base Case (2003 Dollars in Millions)	Imports Relative to the Base Case (GWH)*
Base Case	$0	N/A	0	0
Base Case Plus 2 Fixes	$30	$2.7	$8.1	66
South: Byron–North Madison	$143	$12.9	$12.8	773
Southwest: Salem–North Madison	$223	$20.1	$14.5	694

* *Imports range from 12.4% to 13.3% of the total annual energy requirement.*

The baseline PROMOD analyses assumes 3,666 megawatts of net new generation through 2012, of which approximately 2,000 megawatts is new baseload capacity. Only announced retirements, totaling 358 megawatts (through 2005), were included in the analysis. The generation modeled in PROMOD for the ATC footprint works out to 108 percent of the net firm peak demand for 2012 — in other words to an 8 percent reserve margin (based on generation alone).

As more-efficient generation comes online, older less-efficient generation (some of whose output will be limited by emission standards) may be retired. **Table AC-4** compares the production cost savings of the baseline study relative to a scenario where some of the oldest, least-efficient generation is retired. In this "Low Internal Generation" scenario, the total generation was reduced to 100 percent of the net firm peak demand (i.e. reduced to a total of approximately 15,127 megawatts). This scenario required the "retirement" of approximately 1,100 megawatts of generation throughout the ATC footprint. In order to treat each control area consistently, generation was "retired" in proportion to each control areas' load-ratio share.

Table AC-4
Low Internal Generation - Costs for each Representative Project

Project	Baseline "108%" Internal Generation Scenario "Production Cost Savings Relative to the Base Case" (2003 Dollars in Millions)	Low "100%" Internal Generation Scenario "Production Cost Savings Relative to the Base Case" (2003 Dollars in Millions)
Base Case	0	0
Base Case Plus 2 Fixes	$8.1	$12.7
South: Byron–North Madison	$12.8	$12.6
Southwest: Salem–North Madison	$14.5	$10.8

The results of the “Low Internal Generation” scenario at first appear somewhat counter-intuitive because less internal generation would seem to favor those alternatives that should have the ability to import the most power, like Salem-North Madison. However, when the results of the analysis are examined closely, some of the generators that were retired were found to be particularly important for the Salem-North Madison alternative because they can “push back against”/relieve a key constraint. This ability to relieve a constraint by redispatching power plants is a key feature of SCED (and LMP). By relieving a key constraint via redispatch it may be possible to import more low-cost power, lowering overall costs. This appears to be the reason why the cost savings (relative to the Base Case) of Salem-North Madison declined from the “Baseline” study to the “Low Internal Generation” scenario.

If instead of comparing everything to the Base Case, you look at a particular alternative, like Byron to North Madison, and calculate the difference in production costs from PROMOD between the “Baseline” and “Low Internal Generation” scenarios you get approximately $84 million. This suggests that there would be a fairly significant production cost penalty of retiring 1,100 megawatts of generation. This production cost penalty would have to be compared against the operating and maintenance cost savings associated with the retirements.

Loss cost savings

As power from generators is transmitted over the transmission system to end-use customers, energy is lost continuously in the transmission system. This “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 and air emissions produced and require less generation to be installed. Transmission system loss analyses have been conducted to estimate the reduction in system losses and the resultant energy and capacity cost savings.

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

- ❑ System losses would increase with Base Case plus 2 fixes and Adams to Columbia options and as a result, life cycle costs would increase.
- ❑ System losses would decrease with South and Southwest projects and considerable loss cost savings are projected.

Table AC-5
Present Value of Total 20-Year Energy and Capacity Loss Cost Savings

Project	Load Level	Losses (Megawatts)			Savings		
		Base Case	New	Change	Energy Savings (1000s)	Capacity Saving (1000s)	Total Savings (1000s)
Base Case Plus 2 Fixes	100% Load	389	390	1	$(6,241)	$(611)	$(6,852)
	80% Load	306	309	3			
	60% Load	231	233	2			
West: Adams-Columbia	100% Load	389	389	0	$(3,684)	NA	$(3,684)
	80% Load	306	308	2			
	60% Load	231	231	0			
Southwest: Salem-North Madison	100% Load	389	364	-25	$38,681	$15,285	$53,966
	80% Load	306	289	-17			
	60% Load	231	218	-13			
South: Byron-North Madison	100% Load	389	363	-26	$36,418	$15,896	$52,314
	80% Load	306	290	-16			
	60% Load	231	220	-11			

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 have and are being 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 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 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 1,915 megawatts of import capability by 2012 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 4,024 megawatts of additions for a net of 3,666 megawatts). Additional retirements would increase the 1,915-megawatt import capability requirement on roughly a one-for-one basis.
- ❑ The additional import capability provided by projects like Salem-North Madison could potentially defer the need to build additional generation and/or increase the import capability to meet the LOLE criterion by several years, depending on load growth.

As an additional benefit of increased access, it may be possible to reduce reserve margins required to meet the LOLE criterion of 0.1 days/year. LOLE analysis will be run iteratively to determine the reserve margin required to maintain the LOLE criteria of 0.1 days per year for the access alternatives. These results will be provided in the 2004 Assessment Update to be issued early in 2005.

Table AC-6 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 1,915 megawatts. The third column shows the estimated Base Case Total Simultaneous Import Capability of 3,049 megawatts, which exceeds the amount necessary to meet the LOLE criterion and results in an LOLE of 0.007 days/year.

Table AC-6

LOLE for WUMS (the ATC Footprint) for 2012

	Base Case with the Import Capability Needed to Meet 0.1 Days/Year	Base Case with Total Simultaneous Import Capability	Base Case Plus Fixes with Total Simultaneous Import Capability	Byron-NMA with Total Simultaneous Import Capability	Salem-NMA with Total Simultaneous Import Capability
Total Generation	16,314	16,314	16,314	16,314	16,314
Net Peak Demand	15,127	15,127	15,127	15,127	15,127
Reserve Margin not Including Import Capability	7.8%	7.8%	7.8%	7.8%	7.8%
Needed/Estimated Import Capability	1,915	3,049	3,974	4,783	4,802
Hypothetical "Reserves" Including Full Import Cap.	20.5%	28.0%	34.1%	39.5%	39.6%
LOLE (Days/Year)	0.1	0.007	0.0005	0.00003	0.00003

A**Table AC-7** shows for the Base Case, with a total simultaneous import capability of 3,049 megawatts and a minimum requirement of 1,915 megawatts, the import capability exceeds the minimum amount needed by 1,134 megawatts. Taking this value and dividing by the average increase in demand (332 megawatts/year) equates to 3.4 years, which is an estimate of the number of years before additional generation and/or import capability would be needed to continue to meet 0.1 day/year LOLE criterion. Projects like Byron-North Madison and Salem-North Madison could delay the need by nearly nine years based on this calculation.

Table AC-7

Years Before Additional Generation and/or Import Capability is Needed[1]

	Base Case	Base Case Plus Fixes	Byron-NMA	Salem-NMA
Total Simultaneous Import Capability	3,049	3,974	4,783	4,802
Import Capability Needed To Meet the LOLE Criterion	1,915	1,915	1,915	1,915
Difference	**1,134**	**2,059**	**2,868**	**2,887**
Average Annual Increase in the Projected Peak Demand	332	332	332	332
Years Before Additional Generation and/or Import Capability is Needed[1]	**3.4**	**6.2**	**8.6**	**8.7**

[1]*Strictly from an LOLE perspective*.

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, it 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

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. In this way, the likelihood of each contingency can be considered and it can be quantified as a single summary measure EUE which 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 2012, 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 from 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.

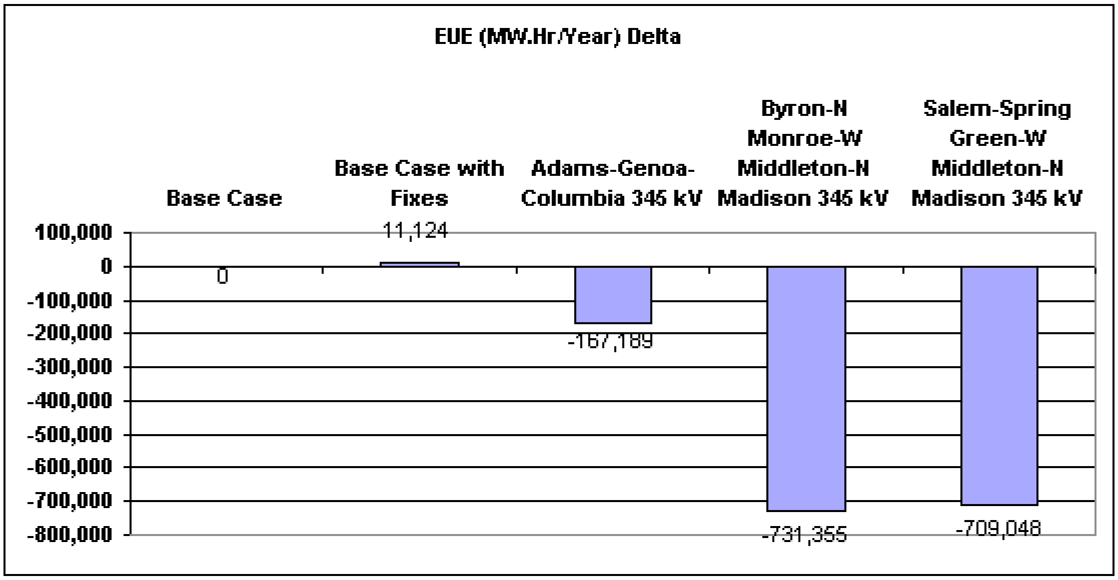
Based on the analysis to date, the following findings have been made:

- Unserved megawatt loads for intact and N-1 (first contingency) conditions were computed for each access model and tabulated as shown in **Table AC-8**. The unserved megawatt load for intact condition shown in the table represents the amount of loads curtailed to meet the planning criteria under intact condition. The unserved megawatt load for N-1 condition represents the sum of all the amount of loads curtailed to meet the transmission planning criteria for each contingency condition. No probabilistic data were considered for the computation of the unserved megawatt load.
- EUEs were computed for each access model and tabulated as shown in the table below. 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. The EUE indicates the relative system performance of system reinforcement.
- As shown i**Table AC-8 and Figure AC-1**, the performance of the Byron-North Madison 345 kV line would result in significant reduction in EUE. Salem-North Madison 345 kV line can be considered as a second best alternative because of the significant EUE reduction that is comparable to the Byron-North Madison 345 kV line. The impact of Adams-Columbia 345 kV line on EUE is insignificant.

Table AC-8
Unserved Megawatt Load and EUE for Each Alternative

Model	Unserved MW load (Megawatts)		EUE (Megawatt Hours/Year)			
	Intact	N-1	Intact	N-1	Total	EUE Relative To Base Case
Base Case	575	3,229	1,193,765	28,259	1,222,024	0
Base Case with two fixes	583	3,318	1,204,884	28,265	1,233,149	11,124
Adams-Columbia 345 kV	501	2,946	1,034,290	20,545	1,054,836	-167,189
Byron-N Madison 345 kV	229	1,930	471,489	19,181	490,670	-731,355
Salem-N Madison 345 kV	238	2,132	493,278	19,698	512,976	-709,048

Figure AC-1


EUE (MW.Hr/Year) Delta
Base Case
Base Case with Fixes
Adams-Genoa-Columbia 345 kV
Byron-N Monroe-W Middleton-N Madison 345 kV
Salem-Spring Green-W Middleton-N Madison 345 kV
100,000
0
-100,000
-200,000
-300,000
-400,000
-500,000
-600,000
-700,000
-800,000
0
11,124
-167,189
-731,355
-709,048

In addition, depending on how a new Access project is configured, it can provide reliability benefits to the system in the form of voltage support and line loading mitigation to lower voltage systems. These potential benefits will be identified for specific interconnection projects in ATC's 2004 10-Year Assessment Update to be issued in early 2005.

Strategic

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. 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.
- A new interconnection to the northeast (Ontario) would necessitate constructing additional 345 kV facilities in the Upper Peninsula of Michigan, which could significantly improve reliability in the region. Such an interconnection would provide excellent geographic diversity to existing 345 kV interconnections to neighboring areas but may introduce complexity to the current Lake Erie loop flow and Manitoba-Ontario interconnection situations.
- A new interconnection to the east (Michigan) would necessitate a DC interconnection in Wisconsin or Michigan and submarine cable across Lake

Michigan. Such an interconnection would provide excellent geographical diversity to the existing 345 kV interconnections to neighboring regions. This would also relieve chronic limitations on the system across the upper peninsula of Michigan, but has the potential aggravate stability limitations in northeast Wisconsin.

- Depending on the level of wind generation development in Iowa and Minnesota and the transmission facilities constructed to transmit the output, proxy interconnection projects to the south, southwest or west could improve access to a new source of renewable energy.

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 is being assessed. These potential benefits will be identified for specific interconnection projects in ATC's 2004 10-Year Assessment Update to be issued in early 2005.

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 will provide relevant costs for benchmarking.

The cost estimates for these projects and the associated "next fixes" represent general screening level cost estimates. Cost estimates for new transmission lines assumed the use of single-circuit steel poles on new 150-foot rights-of-way. 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.

Tables AC-9 and AC-10 list the estimated capital costs in today's dollars for ten projects designed by ATC. **Table AC-9** lists proxy interconnection projects designed to improve transmission access from five different directions. **Table AC-10** lists projects that have been designed to relieve the chronic historic limits observed in the ATC footprint.

Based on the cost information summarized in **Tables AC-9 and AC-10**, the following findings have been made:

- The proxy interconnection project to the south appears to have the lowest capital cost. This is due largely to the low overall mileage of the project.
- The proxy project to the east appears to have the highest capital cost. This is due primarily to the complexity of a project that includes a submarine cable across Lake Michigan.

Table AC-9
Transmission Access Improvement Projects

Project Direction	Proxy Interconnection Project	Estimated Cost (Millions)
South	Byron-North Monroe-West Middleton-North Madison 345 kV line	$ 142
Southwest	Salem-Spring Green-West Middleton-North Madison 345 kV line	$ 223
West	Adams-Genoa-Columbia 345 kV line	$ 244
Northeast	Sault Ste. Marie-Arnold 345 kV line	$ 262
East	Ludington-Forest Junction combined DC / 345 kV AC line	$ 332

Table AC-10
Chronic Limit Relief Projects

Limit Relieved	Proposed Solution	Estimated Cost (Millions)
Lore-Turkey River 161 kV (and multiple other limits)	Second Wempletown – Paddock 345 kV line (2005)	$4.5
Stiles-Pioneer 138 kV	Rebuild Morgan–Falls–Pioneer–Stiles (2005)	$6.3
Flow South (and multiple other limits)	Plains–Stiles Projects (2006)	$45.0
Flow South (and multiple other limits)	Cranberry–Conover 138 kV line (2007)	$7.0
T-Corners-Wien 115 kV and Eau Claire-Arpin 345 kV	Arrowhead–Gardner Park 345 kV line (2008)	$420.3

Societal impacts (including environmental)

Although difficult or impossible to quantify in dollars, the societal and environmental impacts of new transmission facilities are being identified and assessed as well. Based on the investigations done to date, the following findings have been made:

- Each of the proxy interconnection projects conceived would involve significant societal 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: New right-of-way will likely be required.
  - Southwest: Mississippi River and potentially Wisconsin River crossings. New right-of-way will likely be required.
  - West: Mississippi River and potentially Wisconsin River crossings. New right-of-way will likely be required.
  - Northeast: Underwater cable likely to be required. Power flow controlling device/mechanism, and coordination with other similar devices in the region, may be required. Significant transmission reinforcements in the upper peninsula of Michigan likely to be required.
  - East: Lake Michigan crossing with underwater cable required. Power flow controlling device/mechanism likely to be needed.

Decision matrix

Given the number and complexity of issues that arise in the evaluation of interconnection projects to improve access, ATC has begun developing a decision matrix to make the decision-making process more transparent. The matrix developed to date is shown in **Table AC-11**. Given the number of unknowns at this point in time, no definitive conclusions can be drawn regarding the interconnection projects. This process will be reported on in ATC's Assessment Update, to be issued early in 2005.

Table AC-11
Preliminary Draft
American Transmission Company Access Initiative Decision Matrix

Category	*Measure*	*Weighting %*	*out of state terminal* / *in-state terminal* / *connects to*	**Access Alternatives** Base Case + two fixes	Byron N. Madison (Illinois)	Salem N. Madison (Iowa)	Adams Columbia (Minnesota)	Ludington Forest Junction (Michigan)	Sault Ste. Marie Arnold (Canada)
Transfer capability				*rank of alternatives, with 1 indicating the best for each category*					
base case, with two fixes	Megawatts								
high coal scenario, committed internal generation	Megawatts								
high wind scenario, committed internal generation	Megawatts								
high internal generation scenario	Megawatts								
low internal generation scenario	Megawatts								
Chronic limits mitigated	list facilities								
Market energy savings									
base case, with two fixes	$$								
high coal scenario, committed internal generation	$$								
high wind scenario, committed internal generation	$$								
high internal generation scenario	$$								
low internal generation scenario	$$								
Control area FCITC (base case w/two fixes)									
Alliant	Megawatts								
MG&E	Megawatts								
WE Energies	Megawatts								
WPS	Megawatts								
UPPCo	Megawatts								
Loss reduction									
peak	Megawatts								
80% of peak	Megawatts								
60% of peak	Megawatts								
annual loss cost reduction	$$								
Reliability measurements									
LOLE	probability, days/year								
reserve margin required to achieve 0.1 day/year LOLE	%								
EUE	Megawatt Hours								
Strategic benefits									
provides transmission infrastructure	subjective, +/-								
economic development potential	subjective, +/-								
access to out-of-state renewable resources	subjective, +/-								
benefits to neighboring systems	subjective, +/-								
enhances value of other TYA projects	subjective, +/-								
System Performance									
angular stability limits	Megawatts								
voltage stability limits	Megawatts								
Operating flexibility	list anticipated benefits								
Capital costs	$$								
Societal impacts									
corridor sharing potential	% of route								
new right-of-way required	Miles								
public/private lands traversed	% of route								
Environmental impacts									
river crossings	#								
wetlands	Miles								
endangered species	List								
State natural areas	miles								
State parks	miles								
Federal lands (national forests and parks)	miles								
tribal lands	miles								
special water areas	#								
		0%							
			Overall Ranking	0.00	0.00	0.00	0.00	0.00	0.00
			the lower the ranking, the better						

Base Case Development/Assumptions
The analysis presented in this section describes the process used to identify and model the five strategic proxy projects representing five potential directions for system expansion:

- ❑ South (Illinois)
- ❑ Southwest (Iowa)
- ❑ West (Minnesota)
- ❑ Northeast (Ontario)
- ❑ East (Michigan)

The proxy projects were developed based on various analyses performed since the release of the 2003 10-Year Assessment.

The analysis was performed using a linear analysis tool in the Power Technologies, Inc. Managing and Utilizing System Transmission software. This software used industry-wide for transfer capability simulations. In this analysis, a transfer distribution factor was used to determine whether facility overloads are affected by increased power transfers from one of the directions above into the ATC service territory.

The transfer distribution factor impact cutoffs used in this analysis were:

- ❑ 3 percent for all facilities in the network analysis
- ❑ 3 percent for MISO-monitored single outage flowgates
- ❑ 5 percent for MISO-monitored no outage flowgates

A list of relevant impacts on MISO-monitored flowgates is supplied for each proxy project and the base case scenario (i.e. no strategic project added). Transfers were not examined on a control area to control area basis; therefore, the results obtained for specific source-sink pairs may be different.

The power flow model used in this analysis was developed from the Summer 2012 base case from the 2003 10-Year Assessment. For the first valid limit 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, the first two valid limits were identified and solutions were developed to mitigate these limits. The final run for each scenario included the two transmission solutions, and the subsequent new valid limit was identified.

Key Assumptions
The base case contains all planning projects needed to mitigate Summer 2012 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 to reflect updated information for load forecasts, control area interchange and major transmission projects. One major project was eliminated from the model to avoid unduly biasing certain directions, and nine major projects were added to the base case power flow model. These changes include facilities required for confirmed transmission service requests included in the model. The following facilities were either excluded from or added to the 2012 base case from the 2003 10-Year Assessment:

Transmission facilities excluded:

- West Middleton-Rockdale 345 kV line with a 345/138 kV transformer at West Middleton
- Duplicate Blount-Ruskin 69 kV circuit

Transmission facilities added:

- Second Wempletown-Paddock 345 kV circuit
- Weston-Central Wisconsin 345 kV line
- Rockdale-Lannon Junction 345 kV line
- Fox Energy Generation interconnected to the Point Beach-N. Appleton 345 kV line and Fox Energy-Forest Junction 345 kV line
- West Marinette-White Rapids 69 kV line conversion to 138 kV and White Rapids-Amberg 138 kV line rebuild
- Plains-Stiles 138 kV line rebuild
- Cranberry-Conover 138 kV line with a 138/115kV transformer at Cranberry
- Conover-Twin Lake-Iron River-Plains 69 kV line conversion to 138 kV and a 138/69 kV transformer at Conover
- Morgan-White Clay 138 kV line

Planned generation added: Total: 3,816 megawatts

- Kaukauna (2004) – 53 megawatts
- Riverside (2004) – 528 megawatts
- Port Washington (2005) – 600 megawatts
- Fox Energy (2005) – 235 megawatts
- Port Washington (2008) – 600 megawatts
- Weston 4 (2008) – 500 megawatts
- Elm Road 1 (2009) – 650 megawatts
- Elm Road 2 (2010) – 650 megawatts

Description of Representative Proxy Projects

The five projects examined in this section correspond to five geographic directions ATC could reasonably pursue for a new extra-high voltage (typically 345 kV) transmission interconnection. Only extra-high voltage projects were considered for the major projects in this analysis. However, ATC recognizes that extra-high voltage facilities are not the only alternatives available to meet future import requirements. Relevant alternatives to extra-high voltage facilities will be examined in the analysis performed for the 2004 10-Year Assessment Update.

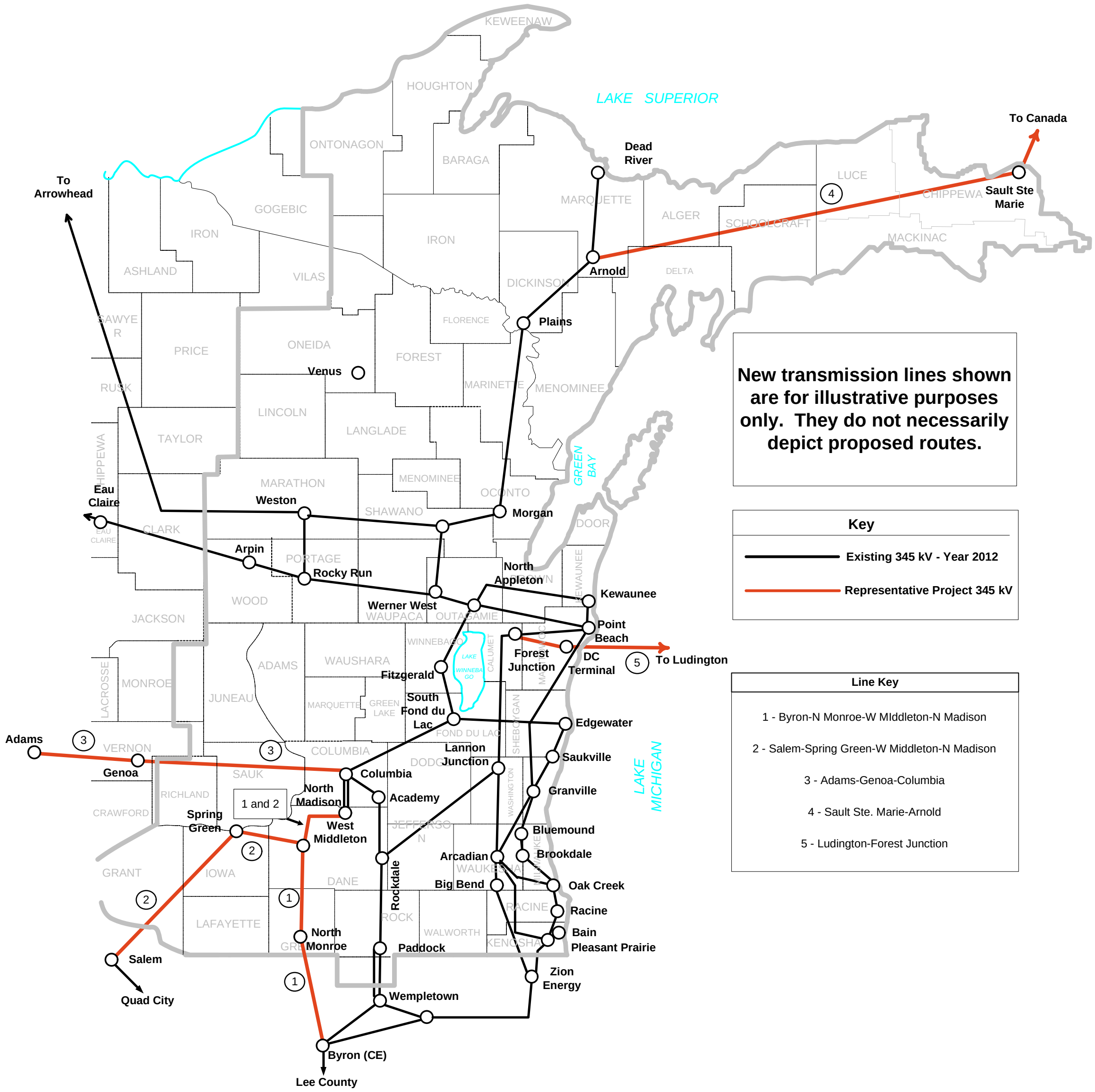
The five representative proxy projects, as shown on the map in **Figure AC-2** are:

1. **South:** Byron–North Monroe–West Middleton–North Madison 345 kV
2. **Southwest:** Salem–Spring Green–West Middleton–North Madison 345 kV

3. **West:** Adams–Genoa–Columbia 345 kV
4. **Northeast:** Sault Ste. Marie–Arnold 345 kV
5. **East:** Ludington–Forest Junction combined DC and 345 kV AC project

Project number 4 above would include either a DC tie or a phase shifting transformer at or near Sault Ste. Marie. However, for this analysis, the system in Ontario was not included in the model and the Sault Ste. Marie bus was modeled as an injection point for the transfers. For project number 5, a special source subsystem was created to mimic the DC sink and DC source points in the interconnected system.

Figure AC-2
Representative Proxy Projects – Access Initiative



Identification of flowgates associated with "local" constraints

In order to ensure that the PROMOD analysis properly accounts for all constraining flowgates, we need to identify new flowgates based on planned enhancements to the transmission system, as well as to identify local flowgates associated with delivery of power to all control areas within the ATC footprint.

Linear transfer analysis modules of the Managing and Utilizing System Transmission (MUST) program from Power Technologies, Inc (PTI) will be used to detect the limiting flowgates for each given solution and scenario. The transfer analysis will be performed from the following source and sink control areas and zones:

Source Control Areas

1. ALTE – Alliant East
2. MGE – Madison Gas and Electric
3. UPPC – Upper Peninsula Power Company
4. WE – We Energies
5. WPS – Wisconsin Public Service Corp.
6. CE – Commonwealth Edison (Exelon)
7. NSP – Northern States Power (Xcel Energy)
8. ALTW – Alliant West
9. MECS – Michigan Electric Coordinated System
10. DPC – Dairyland Power Cooperative

Sink Control Area

1. ALTE – Alliant East
2. MGE – Madison Gas and Electric
3. UPPC – Upper Peninsula Power Company
4. WE – We Energies
5. WPS – Wisconsin Public Service Corp.

Sink Zones

1. MPU – Manitowoc Public Utilities
2. ESE – Edison Sault Electric
3. WPPI – Wisconsin Public Power Inc.

Participating Generators

Coal or nuclear generating sites that have a single generating unit larger than 250 megawatts will be excluded from the sink subsystem for the purpose of detecting new flowgates. The following list of generators will be excluded from the sink subsystems:

1. Columbia – ALTE, MGE and WPS
2. Pleasant Prairie Unit #1 and #2 – WE
3. Kewaunee – ALTE and WPS
4. Point Beach Unit #1 and #2– WE
5. Weston Unit #3 and #4 – WPS

6. Oak Creek Unit #5, #6, #7 and #8 – WE
7. Edgewater Unit #4 – ALTE and WPS
8. Edgewater Unit #5 – ATLE and WE
9. Oak Creek Unit #1 – Phase One - WE

Offline units will be available for use in the source subsystem modeling.

Models

In order to capture as many potential new constraining flowgates as possible, models have been constructed to represent the expected topology, load levels and anticipated imports of the ATC transmission system in the year 2012. Load levels were varied to represent different transmission flows for each of the selected scenarios. The load levels evaluated are:

1. Summer peak
2. 80% of summer peak
3. 60% of summer peak

The selected scenarios that will be analyzed are as follows:

1. Base case + Fix 1 + Fix 2
   a. Fix 1: Rebuild of Lore–Turkey River–Cassville–Nelson Dewey 161 kV line
   b. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV transformer at Town Line Road
2. Byron–North Monroe–West Middleton–North Madison 345 kV line + Fix 1 + Fix 2
   a. 345/138 kV transformer at North Monroe
   b. 345/138 kV transformer at Weston Middleton
   c. Fix 1: Des Plaines – Lombard 345 kV line uprate
   d. Fix 2: Monroe–Council Creek 161 kV to relieve Eau Claire–Arpin voltage stability limit
3. Salem–Spring Green–West Middleton–North Madison 345 kV line + Fix 1 + Fix 2
   a. 345/138 kV transformer at Spring Green
   b. 345/138 kV transformer at West Middleton
   c. Fix 1: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV transformer at Town Line Road
   d. Fix 2: Des Plaines – Lombard 345 kV line uprate

The following scenarios will give consideration to including the Rockdale – West Middleton 345 kV line in the models and will be analyzed in the future:

1. Adams–Genoa–Columbia 345 kV + Fix 1 + Fix 2
   a. 345/161 kV transformer at Genoa
   b. Fix 1: Rebuild of Lore–Turkey River–Cassville–Nelson Dewey 161 kV line
   c. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV transformer at Town Line Road
2. Ludington – Forest Junction DC line + Fix 1 + Fix 2
   a. A DC line across Lake Michigan from Ludington Pump Storage Facility to the Forest Junction Substation
   b. Fix 1: Rebuild of Lore–Turkey River–Cassville–Nelson Dewey 161 kV line

   c. Fix 2: Installation of a third 345/138 kV transformer at Forest Junction
3. Canadian – Upper Peninsula DC Tie with a 345 kV terminal at Arnold Substation
   a. A DC tie across at Sault Saint Marie connecting with Canada
   b. Sault Saint Marie–Arnold 345 kV line
   c. 345/138 kV transformer at Arnold
   d. Fix 1: Rebuild of Lore–Turkey River–Cassville–Nelson Dewey 161 kV line
   e. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV transformer at Town Line Road
4. Prairie Island–North LaCrosse–Columbia 345 kV + Fix 1 + Fix 2
   a. 345/161 kV transformer at North LaCrosse
   b. Fix 1: Unknown at this time
   c. Fix 2: Unknown at this time