Planning Analysis of the Paddock-Rockdale Project

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American Transmission Company, LLC

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1. Executive Summary

The Paddock-Rockdale project (or simply Paddock-Rockdale) is a 345 kV transmission line from the Paddock Substation in Rock County to the Rockdale Substation in Dane County, as well as associated substation upgrades. The proposed route for this project is approximately 35 miles long and follows an existing high-voltage transmission line for its entire length. The total estimated direct cost for the proposed route, including construction, licensing, and congestion costs, is approximately $133 million for a 2010 in-service date. The alternate route follows existing high-voltage lines for most of its length, but would require approximately five miles of new right-of-way (ROW). The total estimated cost of the alternate route is approximately $211 million.

Paddock-Rockdale was one of five transmission projects analyzed during American Transmission Company's (ATC) 2004-2005 Access Initiative and the Public Service Commission of Wisconsin's (PSCW) 2005-2006 policy proceeding on transmission access. The purpose of these proceedings was to evaluate whether additional transmission lines into Wisconsin would reduce the delivered cost of energy to Wisconsin customers by reducing congestion on the system and improving access to additional energy sources. Following the issuance of the PSCW Staff Report on Transmission Access in March 2006, ATC selected Paddock-Rockdale for further review.

ATC has worked with a wide range of interested parties in developing its methods for evaluating Paddock-Rockdale. These parties include the PSCW Staff; the Midwest ISO (MISO); ATC's major customers (Alliant Energy, Madison Gas & Electric Company, We Energies, Wisconsin Public Service Corporation, and Wisconsin Public Power, Inc.); other transmission owners such as Dairyland Power Cooperative and Xcel; retail customer groups like the Citizens Utility Board and the Wisconsin Industrial Energy Group; and environmental organizations such as RENEW Wisconsin and Clean Wisconsin. ATC has also coordinated with the Midwest ISO for purposes of regional planning review, and is actively participating in various FERC proceedings on the issues of cost-sharing and pricing of transmission projects such as Paddock-Rockdale. Finally, ATC has followed closely the planning activities of adjoining transmission owners, especially the CapX2020 initiative in Minnesota. All of this input has provided valuable and useful feedback that ATC incorporated into its evaluation of Paddock-Rockdale.

The analytical approach chosen by ATC tested Paddock-Rockdale against seven plausible futures for the electric industry in 2011 and 2016, such as robust or slow economic growth, additional environmental regulation, and fuel supply volatility. The seven futures are based upon key drivers such as load growth, generation retirement and expansion, fossil-fuel costs, use of renewable energy, and increased environmental regulation. ATC assigned a range of plausible outcomes for each of these factors based upon available data and estimates and then built up a plausible future composed of these selected values. The purpose of these futures is to "bound" the range of plausible futures. During the 40-year life of the project, we would expect that actual events would fall somewhere between the defined futures most of the time and only occasionally be completely in a particular future. The premise of this approach, known as Strategic Flexibility, is that, if Paddock-Rockdale performs well in these futures, it is a robust project that will produce benefits for ratepayers.

ATC then analyzed the major economic and reliability impacts of Paddock-Rockdale and measured those impacts on an annual benefit basis for 2011 and 2016 and on a Net Present Value (NPV) basis. ATC measured the benefits using four different metrics as the basis of its measurement:

- Adjusted production costs (APC)[1]
- Load weighted locational marginal prices (LLMP)[2]
- 70% APC + 30% LLMP[3]
- ATC Customer Benefit[4].

Table 1 shows the Net Present Value (NPV) of the Paddock-Rockdale project using each of these metrics in each of the plausible futures The NPV is calculated over the 40-year life of the project using a 3% inflation factor and an 8.5% discount rate.

Table 1 Net Present Value of Net Benefits[5]

	$ MILLIONS						
Paddock - Rockdale	*Robust economy w/out NLAX-COL*	*Robust economy w/NLAX-COL*	*High plant retirements*	*High environ-mental*	*Slow growth*	*Fuel supply disruption*	*High growth WI*
APC	341	299	574	82	(62)	575	265
70%/30/%	529	455	950	132	(47)	956	544
LLMP	968	819	1,826	249	(12)	1,843	1,196
ATC Customer Benefit	409	356	710	104	(56)	710	365

[1] Adjusted Production Cost (APC) savings measure the actual production costs of the power plants used to generate energy for ATC's footprint adjusted for imports and exports. APC savings represent the bottom of a range of savings that retail customers would expect to see if the Paddock-Rockdale line is in service.

[2] Load-weighted Locational Marginal Price (LLMP) savings measure the difference in Load-weighted Locational Marginal Prices across the ATC footprint. LLMP savings are generally agreed to represent the high end of the range of savings that would occur if Paddock-Rockdale were in service.

[3] 70% Adjusted Production Costs + 30% Load-Weighted LMP is the measure that the Midwest ISO proposes to use for measuring the benefits of transmission projects built primarily for economic reasons. It is meant to approximate the amount retail ratepayers in the MISO footprint would save due to economic transmission projects.

[4] ATC Customer Benefit is a calculation of savings expected to be realized by retail customers within the ATC service territory, based upon the current mix of cost-of-service and market-based generation in that territory.

[5] All dollar figures in all tables in this report are nominal (year-of-occurrence) unless indicated otherwise. Also, all benefits are shown as positive dollars, unless indicated otherwise.

Table 1 shows the NPV for each of the futures using the total revenue requirement of the project for a 2010 in-service date on the proposed route. If the alternate route is chosen, the savings would be reduced.

The annual benefits that ATC estimated for Paddock-Rockdale are shown in tables 2 and 3 for each of the two years ATC modeled: 2011 and 2016. This summation is made up of a number of individual benefits ATC identified as resulting from additional transmission projects, including:

- energy-cost savings for customers
- reduced congestion costs and losses
- improved competitiveness
- system-failure insurance
- capacity savings due to reduced losses
- resource cost advantage
- reserve-margin impacts
- reliability effects

Energy cost savings for customers were initially estimated using the PROMOD model; these estimates were adjusted to reflect the correct impacts on congestion costs and losses. Other standard methods were used to quantify other economic benefits of Paddock-Rockdale such as increased competitiveness, system insurance value, and capacity benefits from reduced losses.

Paddock-Rockdale also produces other economic benefits such as Resource Cost Advantage (by improving access to lower cost sources of supply outside of ATC) and improved potential for increased regional reserve-sharing. However, ATC took a conservative approach and did not quantify these other benefits because it did not conclude that an appropriate method was available to measure them at this time. While Paddock-Rockdale is not driven by reliability benefits, it does produce somewhat reduced Loss of Load Expectation and Expected Unserved Energy, and ATC has calculated these reliability impacts as well.

The above list of positive impacts is not exhaustive. ATC will continue to evaluate and develop definitions and methodologies to measure the impacts of transmission projects like Paddock-Rockdale, in coordination with the Midwest ISO, PSCW Staff, its customers and stakeholders.

Tables 2 and 3 are high-level summaries of the results of ATC's evaluation of Paddock-Rockdale in terms of annual benefits in each of the futures for 2011 and 2016. Tables 4 and 5 show the ratepayer first-savings and break-ahead years for each of the futures.

Table 2 Aggregate Annual Benefits 2011 **($ Millions)**

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Production Cost	30	19	14	7	51	18
70% Adjusted Prod Costs + 30% Load Weighted LMP	33	19	17	7	76	21
Load Weighted LMP	39	20	23	9	133	27
ATC Customer Benefit	31	19	15	7	60	19

Table 3 Aggregate Annual Benefits 2016 **($ Millions)**

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Production Cost	49	44	80	23	7	72	43
70% Adjusted Prod Costs + 30% Load Weighted LMP	71	62	125	28	9	111	76
Load Weighted LMP	122	104	230	40	13	203	153
ATC Customer Benefit	57	51	96	25	8	86	55

Table 4 First Year of Annual Net Savings

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Production Cost	2011	2011	2011	2013	2027	2010	2012
70% Adjusted Prod Costs + 30% Load Weighted LMP	2011	2011	2011	2012	2024	2010	2011
Load Weighted LMP	2010	2010	2011	2011	2019	2010	2011
ATC Customer Benefit	2011	2011	2011	2013	2026	2010	2011

Table 5 First Year of Cumulative Net Savings (Break-Ahead) on a Present Value Basis

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Production Cost	2013	2013	2013	2022	After 2050	2011	2015
70% Adjusted Prod Costs + 30% Load Weighted LMP	2012	2012	2013	2018	After 2050	2011	2013
Load Weighted LMP	2012	2012	2012	2014	After 2050	2010	2012
ATC Customer Benefit	2012	2012	2013	2020	After 2050	2011	2014

ATC also compared Paddock-Rockdale to alternative transmission projects. It updated its construction-cost estimates of the other Extra High Voltage (EHV) projects and measured net benefits of Paddock-Rockdale against net benefits of the Low Voltage (LV) option in each of the futures. It concluded from this evaluation that Paddock-Rockdale provides higher and more consistent net benefits than the other EHV and LV options.

Paddock-Rockdale produces significant economic benefits for ATC customers in almost all scenarios and ATC is proposing this project based on those economic benefits. All transmission projects, however, have aspects of both economic value and reliability value and this is true of Paddock-Rockdale as well. This project will improve the reliability of the transmission system even though it is not being proposed in response to a reliability need.

Based upon all of these results, ATC has concluded that Paddock-Rockdale consistently produces benefits in excess of its costs and will reduce the delivered price of energy to customers without creating unreasonable risks for ratepayers. For this reason it is applying for PSCW approval to construct Paddock-Rockdale.

2. Description of Project

2.1 Physical Components of the Project

This proposed project consists of the following:

- A new 345 kV line, approximately 35 miles long, between the existing Paddock and Rockdale Substations along one of two existing transmission corridors.
- The expansion of the 345 kV bus at the Rockdale Substation to a modified breaker-and-a-half scheme to accommodate the proposed line, improve operating flexibility and prepare for future 345 kV line expansions both west and east out of the substation.
- The replacement of the existing 345/138 kV Rockdale Transformer T22 with a higher capacity unit.
- The replacement of five 138 kV circuit breakers at Rockdale Substation and five 138 kV circuit breakers at Christiana Substation due to increased fault current.

Refer to Appendix A for a one-line diagram showing major equipment specifications.

Implementing this project will require the expansion of the Rockdale Substation to accommodate the Paddock-Rockdale 345 kV line. The 345 kV bus will be reconfigured from a six-position ring bus to a modified breaker and a half configuration with transformers T22 and T23 located on the outside main buses. One of the new positions will be used for the Paddock - Rockdale 345 kV line. The remaining positions can be used for the proposed Rockdale - West Middleton 345 kV line and for possible future expansion. Some additional land acquisition will be needed to develop the Rockdale Substation to accommodate these changes.

The route of the proposed 345 kV line between the Paddock and Rockdale Substations will be determined through the regulatory approval process conducted by the PSCW. At the present time, it is anticipated that the proposed line will require supplementing the existing ROW to accommodate double and triple circuit construction if the proposed route (the Wempletown-Rockdale 345 kV line (W-4) corridor) is chosen. The alternate route (the existing 69 kV and 138 kV corridors near Janesville) would require the acquisition of new and the updating of existing right-of-way over a significant portion of the route to accommodate double and triple circuit construction.

The configuration of the existing Paddock Substation would not need to be altered to accommodate this new line. With the addition of a second circuit on the Wempletown to Paddock 345 kV line in 2005, one 345 kV terminal was made available for the proposed project.

2.2 Proposed Route

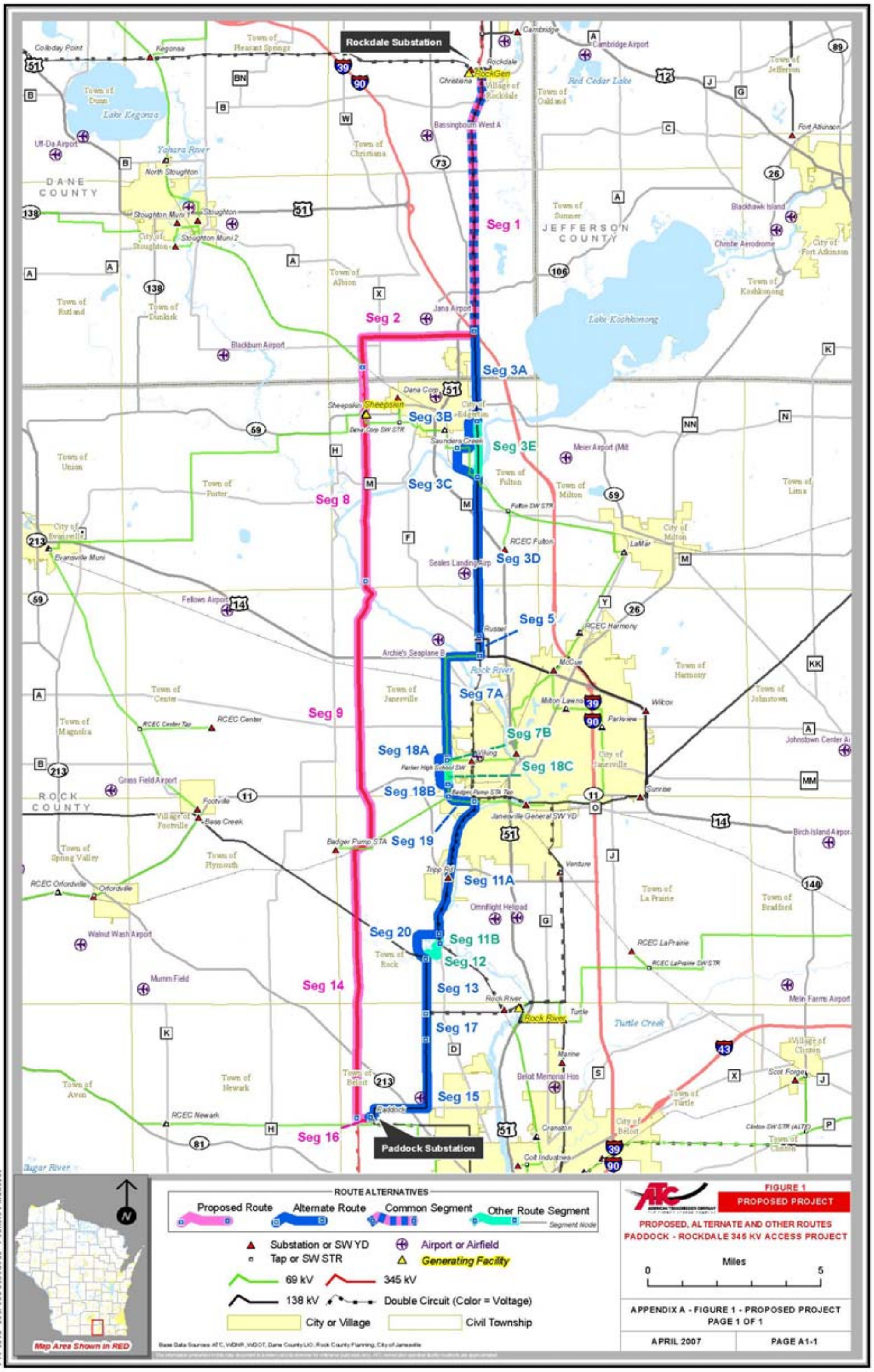
ATC's 34.7-mile Proposed Route (Segments 16, 14, 9, 8, 2 and 1) utilizes the 150-foot-wide ROW of an existing 345 kV transmission line (W4, also referred to as "Wempletown-Rockdale"). The existing single-circuit steel H-frame structures (Segments 2, 9 and 14) will be replaced with new double-circuit steel monopole structures, with the exception of the Jana Airport (Segment 2) where the double-circuit line will transition from a vertical to a horizontal configuration comprised of two adjacent single-circuit lines. The existing single-circuit steel H-frame structures (Segment 16) will remain intact. The existing double-circuit 345/138 kV steel lattice structures (Segment 8) will be reused for the new W4/W10 double-circuit 345 kV transmission line.

The existing 69 kV transmission line, Y-12 (1.5 miles of line north of Sheepskin Substation in Segment 8), will be relocated adjacent to the 345 kV double-circuit transmission line on expanded ROW (180 feet total width) single-circuit wood pole structures. The existing W4/X-31 (Segment 1) double-circuit transmission line (345/138 kV) steel monopole structures will be replaced with triple-circuit (345/345/138 kV) steel monopole structures. The 138 kV transmission circuit (X-31) will be relocated as underbuild.

2.3 Alternate Route

ATC's 36.2-mile Alternate Route (Segments 15, 17, 13, 20, 11A, 19, 18B, 18A, 7A, 5, 3D, 3C, 3B, 3A and 1) utilizes a combination of existing 345 kV transmission ROW (Segment 1), existing 138 kV transmission line ROW of varying widths (Segments 15, 17, 13, 11A, 5, 3D, and 3A) and existing 69 kV 80-foot-wide ROW (Segments 19, 18B and 7A), as well as approximately 5.3 miles of new ROW (Segments 20, 18A, 3C, 3B). The existing double-circuit 138 kV (supporting transmission lines X-7 and X-32) will be replaced with triple-circuit steel monopole structures. The existing single-circuit 138 kV (supporting transmission lines X-39, X-31, and X-12) lattice structures will be replaced with double-circuit steel monopole structures. The existing single-circuit 69 kV wood, steel and lattice structures will be replaced with steel double-circuit monopole structures. The existing W4/X-31 (Segment 1) double-circuit (345/138 kV) transmission line steel monopole structures will be replaced with triple-circuit (345/345/138 kV) steel monopole structures. The 138 kV transmission line (X-31) will be relocated as underbuild.

Figure 1 Map of Proposed Routes



2.4 Cost

ATC has prepared four separate cost estimates for Paddock-Rockdale: the proposed route and the alternate route with a 2010 in-service date, and the proposed route and the alternate route with a 2011 in-service date. Each estimate is the sum of the year-of-occurrence dollars and includes design, construction, licensing, and regulatory approval costs. The estimates also include estimated additional congestion costs during construction, and contingency costs. The costs are as follows:

	In-service Year	
	2010	2011
Preferred route	$132,706,210	$138,057,332
Alternative route	$210,804,062	$219,391,652

3. Introduction and Background

3.1 The ATC Access Initiative and the PSCW Transmission Access Proceeding

ATC commenced its Access Initiative in 2004. The purpose was to assess the value of expanding the ATC transmission system to reduce congestion costs and to improve access to generation sources outside the ATC system. As part of the Access Initiative, ATC performed a planning-level analysis of five access projects, including Paddock-Rockdale. In 2005 the PSCW initiated a policy proceeding to study the issue of improved transmission access. After receiving extensive comments and analyses regarding the issue and the five access projects, the PSCW Staff issued a Final Report on Transmission Access in March 2006. The Report provided guidance to ATC regarding the standards it should use in applying for a Certificate of Public Convenience and Necessity (CPCN) application for an access project.

3.2 The New Regional Market

In 2005 the Federal Energy Regulatory Commission (FERC) approved the MISO's Transmission and Energy Markets Tariff. This tariff included a system of security-constrained economic dispatch for generators in the MISO region, with pricing based upon Locational Marginal Price (LMP). The LMP is comprised of bid-based energy costs, marginal congestion costs, and marginal losses.

At the same time FERC recognized the Wisconsin Upper Michigan System (WUMS) and Northern WUMS load pockets as Narrow Constrained Areas (NCA). WUMS and Northern WUMS comprise the ATC service territory. As such, the ATC loads are subject to a higher risk of congestion costs and increased energy prices than loads in other MISO regions. For this reason FERC imposed bid caps on the ATC service territory. Load-Serving Entities (LSEs) within ATC also sought temporary special protection from congestion costs and indicated that they would use the additional time to build transmission facilities that would reduce congestion costs and more fully realize the benefits of the MISO market. In response FERC approved an Expanded Congestion Cost Hedge (ECCH) for ATC LSEs. With some restrictions, the ECCH frees ATC LSEs from having to pay for any shortfall in their congestion hedge (i.e. allocated Financial Transmission Rights (FTRs)) for existing network generating resources outside of ATC for the first 5 years of MISO market operation (i.e. through April 2010).

3.3 Summary of ATC Customer Concerns

ATC customers are concerned about the costs and risks to which they are exposed as a result of the limited import capability and frequent binding constraints into ATC's service area. They are not confident that they will be able to realize fully the promised benefits of the MISO market without increased transfer capacity and access to lower-cost generation outside of Wisconsin.

They are also concerned that, as load grows, so too will congestion and the differential in energy prices between ATC and the neighboring hubs (MISO Minnesota, MISO Illinois, and PJM Illinois). Therefore they support additional import capability (beyond that associated with projects scheduled to be in service by 2010) in order to reduce the financial risks of congestion and expiration of the ECCH. Because Paddock-Rockdale is the only EHV access project that does not require significant new ROW, it is the only project that can realistically be in-service by 2010.

3.4 Regional Activities

ATC has been working closely with MISO planners in developing and evaluating Paddock-Rockdale. It has submitted the project to the MISO for planning review pursuant to Appendix B of the Midwest ISO Agreement. ATC has also actively participated in the MISO process for cost-sharing of “economic” projects known as RECB II and in the FERC tariff proceeding on this subject.

ATC coordinates regularly with adjoining transmission owners (Commonwealth Edison, Alliant West, Dairyland Power Cooperative, and Xcel Energy) and has consulted with each of these transmission owners regarding Paddock-Rockdale. ATC also monitors the proceedings of the CapX2020 Initiative, the purpose of which is to expand the EHV transmission system in Minnesota and adjoining states. ATC has incorporated this information into its evaluation of Paddock-Rockdale (e.g. the proposed CapX2020 North La Crosse-Columbia 345 kV line is assumed to be built in one of ATC’s 2016 Robust Economy futures).

3.5 Wisconsin Stakeholder Activities

In conducting this evaluation, ATC sought input from many other interested parties and incorporated many of their suggestions into its analysis. It met several times with its major utility customers (Alliant Energy, Madison Gas & Electric Company, We Energies, Wisconsin Public Service Corporation, and Wisconsin Public Power, Inc.). It also consulted with retail customer groups (the Citizens Utility Board and the Wisconsin Industrial Energy Group), labor unions (the International Brotherhood of Electrical Workers), and environmental groups (RENEW Wisconsin and Clean Wisconsin).

3.6 Analysis Designed to Comply with PSCW Staff Suggestions

ATC also met with PSCW Electric Division Staff on several occasions regarding this evaluation, and incorporated their suggestions into its analysis. The March 2006 PSCW Staff Final Report on Transmission Access directed ATC to perform a rigorous and thorough quantitative and qualitative analysis of access projects. It stated that this analysis should include a detailed risk assessment and consider a number of different factors (such as fuel prices and generation retirements) over a wide variety of future scenarios. It also suggested a year-by-year revenue-requirement analysis, and quantification of both economic and reliability benefits. Finally, it emphasized the importance of regional coordination with MISO and other transmission owners. This ATC report is intended to comply with the PSCW Staff Report.

4. The Analytical Framework of this Report

4.1 The Strategic Flexibility Methodology

Strategic Flexibility is an analytical approach developed by Deloitte Consulting to assist organizations in making major investment decisions in an uncertain environment. The premise of Strategic Flexibility is that, because we cannot know the future, high-cost projects should be tested against a range of plausible futures. These plausible futures are to bound the range of plausible outcomes, and not to identify the most likely future. The project is tested against each of the futures and should be chosen only if it is successful in most of the futures. The objective is to identify projects that are robust across a range of plausible futures.

ATC developed seven scenarios that were designed to bound the range of plausible futures and coordinate with the MISO futures development that was occurring at the same time. ATC began with brief descriptions of fourteen futures from MISO and chose five futures that were sufficiently different from each other that they would capture a wide range of plausible outcomes. ATC built up the futures by identifying the variables or drivers that would most impact the results of the Paddock-Rockdale analysis and determining how those drivers would behave in each scenario. Futures were specified for 2011 and 2016. The "plausible futures" were designed to describe the possible market conditions that could exist in 2011 and 2016. ATC added a sixth future to represent what would happen if Wisconsin's economic development efforts were successful and Wisconsin grew faster than neighboring states. ATC also created a seventh future to test the impact on Paddock-Rockdale of adding an EHV transmission line from North La Crosse to Columbia in 2016.

4.2 Key Variables or Drivers

The drivers identified by ATC are:

- Load growth inside and outside ATC footprint
- Availability of low-cost generation in Wisconsin
- Amount and source of renewable energy consumed in Wisconsin
- Nearby EHV transmission projects
- Natural gas, coal and fuel oil prices
- Availability of coal and natural gas in Wisconsin
- Environmental regulations
- Availability of low cost-generation in MISO and the Commonwealth Edison service area.

Once the drivers were identified, the analysis team developed the range of plausible outcomes for each driver for 2011 and 2016. For some variables, including load growth and fuel prices, historical data was used to develop a range of future values while forecast data was used to develop the mid-level future value. For other variables, including nearby EHV transmission development and environmental regulations, a more qualitative approach was used, based on publicly available information. The proposed ranges of plausible outcomes for each driver were reviewed with many stakeholders. Much of the feedback received was incorporated into the ranges.

4.3 The Specific Futures

The approach to constructing futures was three-fold: 1) choose five MISO futures that represented a range of plausible futures plus the High Growth Wisconsin future (more specific to Wisconsin) and the Robust Economy with North La Crosse-Columbia EHV line, 2) anchor each future at an upper or lower bound of a particular driver, and 3) determine the behavior of the other drivers in that scenario consistent with the anchor and the MISO description. For example, the Robust Economy future is anchored in the load growth driver with that driver set at the upper bound (3%) to reflect robust economic growth. For each of the other drivers, the question was asked, “How will this driver behave in a future with high economic and energy growth?” The objective was to have an internally consistent future with logical connections between all the drivers in the scenario.

Each future was specified for 2011 and 2016. The combination of futures was then reviewed graphically to evaluate whether the futures reasonably bounded the range of plausible futures. Again, the futures were reviewed with a variety of stakeholders including ATC customers, PSCW staff, and representatives of intervener groups and their feedback was incorporated where appropriate. ATC believes the futures are sufficiently different and cover the range of plausible outcomes across the drivers.

ATC then analyzed the performance of the Paddock-Rockdale project in each future. The analytical results were reviewed to determine how well the project performed across the range of plausible futures. A project that performs well across most of the futures is a project that can be undertaken with a high degree of confidence that the project will produce positive effects. It is a robust option. Paddock-Rockdale performed well in the vast majority of the cases that were evaluated.

4.4 Descriptions of the Futures

- **Robust Economy** was run with and without the addition of a new North La Crosse to Columbia line.
  i. **Robust Economy With –** High load growth, high construction levels of low-cost generation in Wisconsin, Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) environmental regulations in place, mid-high fuel prices due to the high demand, North La Crosse to Columbia line is included in 2016 (but not in 2011), 6,000 MW mine-mouth coal campus is included in central Illinois in 2016 (1,500 MW in 2011).
  ii. **Robust Economy Without –** All drivers remained the same except that North La Crosse to Columbia line was not included.

- **High Generation Retirements –** Mid-level economic and energy growth, large number of small coal plant retirements, CAIR and CAMR environmental regulations in place, varying fuel prices with natural gas increasing due to more demand for gas-fired generation and reduced coal price increases due to less demand for coal-fired generation, mid-level amounts of generation built outside Wisconsin including 1,500 MW mine-mouth coal campus in central Illinois.
- **High Environmental Regulations –** Medium economic growth, low mid-level energy growth due to energy efficiency, coal retirements replaced by Nelson Dewey plant, CAIR and CAMR plus a CO2 tax at $44/ton, varying fuel prices, generation portfolio outside Wisconsin reflecting $44/ton CO2 tax with an emphasis on integrated gasification combined cycle (IGCC) plants.
- **Slow Growth –** Low economic growth driving low energy growth, some coal retirements, CAIR and CAMR environmental regulations in place, low-mid fuel prices, 0 MW of generation built outside Wisconsin**.**
- **Fuel Supply Disruption –** Natural gas supply disrupted, low mid-levels of economic and energy growth, high level of new coal generation, additional use of coal generation creates coal availability problems, high fuel prices result from disruption and additional demand, CAIR and CAMR environmental regulations in place, 3,750 MW mine-mouth coal campus built in central Illinois in 2016.
- **High Growth Wisconsin –** Economic development creates high economic and energy growth in Wisconsin while surrounding areas are mid-low economic and energy growth, some coal retirements and Nelson Dewey is built, and CAIR and CAMR environmental regulations in place, mid-level fuel prices, mid-low level generation built outside Wisconsin with a 1500 MW mine-mouth coal campus built in central Illinois.

Table 6 lists the various drivers and the associated futures that were examined for Paddock-Rockdale. More detailed information about the drivers and futures can be found in Appendix E.

Table 6 ATC Futures – Paddock-Rockdale

Drivers	Load Growth within ATC (MWs)		Load Growth within ATC (MWh)		Load Growth outside ATC (MWs)		Load Growth outside ATC (MWh)		New low-cost generation within ATC[1]		% of Energy in ATC from Renewables		% of Renewables inside/ outside Wis.[2]	
Bounds	2011	2016	2011	2016	2011	2016	2011	2016	2011	2016	2011	2016	2011	2016
Lower	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	Retirements: 300 MW coal	Retirements: 950 MW coal, 500 MW nuclear, No NED	6%	6%	Inside: 45% Out: 55%	Inside: 45% Out: 55%
Mid[3]	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	Retirements: 150 MW coal	Retirements: 475 MW coal, NED is built	8%	10%	Inside: 30% Outside: 70%	Inside: 25% Outside: 75%
Upper	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	Retirements: None, NED is built	Retirements: None, NED 280 MW plus 500 add'l MW	10%	15%	Inside: 25% Outside: 75%	Inside: 15% Outside: 85%

Drivers	Load Growth within ATC (MWs)	Load Growth within ATC (MWh)	Load Growth outside ATC (MWs)	Load Growth outside ATC (MWh)	New low-cost generation within ATC	% of Energy in ATC from Renewables	% of Renewables inside/ outside Wis.
2011 Futures Descriptions							
Robust Economy	3.0%	3.0%	3.0%	3.0%	Upper	Mid	Mid
High re-tirements	2.0%	2.0%	2.0%	2.0%	Lower	Mid	Mid
High Environ-mental	1.2%[4]	1.2%[4]	1.2%[4]	1.2%[4]	225 MW coal retirements plus NED 280 MW built	Upper	Upper
Slow Growth	0.5%	0.5%	0.5%	0.5%	Mid	Lower	Lower
Fuel Supply Disruption	1.7%	1.7%	1.7%	1.7%	Upper	9%	Mid
High Growth Wis.	2.7%	2.7%	1.2%	1.2%	Mid (not enough time to build anything)	Mid	Mid
2016 Futures Descriptions							
Robust Economy	3.0%	3.0%	3.0%	3.0%	Upper	Mid	Mid
High re-tirements	2.0%	2.0%	2.0%	2.0%	Lower	Mid	Mid
High Environ-Mental	1.2%[4]	1.2%[4]	1.2%[4]	1.2%[4]	950 MW coal retirements plus NED 280 MW built	Upper	Upper
Slow Growth	0.5%	0.5%	0.5%	0.5%	Mid	Lower	Lower
Fuel Supply Disruption	1.7%	1.7%	1.7%	1.7%	0 MW retirements, NED 280 MW	12%	Mid
High Growth Wis.	2.7%	2.7%	1.2%	1.2%	Mid	Mid	Mid

Table 6 ATC Futures – Paddock-Rockdale (cont.)

Drivers	CapX 2020 Transmission[5]		Natural Gas price forecast		Coal Price Forecast		Coal Availability in Wisconsin		Environmental Regulations		Generation Portfolios outside ATC	
Bounds	2011	2016	2011	2016	2011	2016	2011	2016	2011	2016	2011	2016
Lower	None	CapX Phase 1	-30%	-30%	-10%	-10%	Shortage reduces coal plant availability by 15%	Shortage reduces coal plant availability by 15%	Status Quo-CAIR & CAMR Regulations enforced	Status Quo-CAIR & CAMR Regulations enforced	Status Quo-CAIR & CAMR	Status Quo-CAIR & CAMR
Mid	None	CapX Phase 1	Nominal Henry Hub Price - $7.72	Nominal Henry Hub Price - $8.41	MISO MRO $1.38; MISO MAIN $1.63; MISO ECAR $2.05	MISO MRO $1.25; MISO MAIN $1.51; MISO ECAR $1.92	Normal Availability	Normal Availability	Status Quo-CAIR & CAMR Regulations enforced	Status Quo-CAIR & CAMR Regulations enforced	Status Quo-CAIR & CAMR	Central Illinois Coal Campus Case – 4,500 – 6,000 MWs
Upper	None	CapX Phase 1 + LaCrosse-Columbia 345 kV	40%	40%	10%	10%	Normal Availability	Normal Availability	Status Quo-CAIR & CAMR Regulations enforced & $44/ton for CO2	Status Quo-CAIR & CAMR Regulations enforced & $44/ton for CO2	Status Quo – CAIR & CAMR	Kyoto Generation Portfolio
2011 Futures Descriptions												
Robust Economy	None		Mid-Upper – 20%		Mid-Upper – 5%		Mid		Status Quo		26,133 MW (1,500 MW coal campus)	
High re-tirements	None		Mid-Upper		Lower		Mid		Status Quo		13,339 MW (1,500 MW coal campus)	
High Environ-mental	None		Upper		Lower		Mid		Kyoto - $44/ton CO2 Tax		1,330 MW (0 MW coal campus)	
Slow Growth	None		Lower		Mid		Mid		Status Quo		0 MW (0 MW coal campus)	
Fuel Supply Disruption	None		Upper		Upper		Lower		Status Quo		8,850 MW (1,500 MW coal campus)	
High Growth Wis.	None		Mid		Mid		Mid		Status Quo		1,700 MW (750 MW coal campus)	
2016 Futures Descriptions												
Robust Economy	Upper		Mid-Upper		Mid-Upper		Mid		Status Quo		46,063 MW (6,000 MW coal campus)	
High re-tirements	Mid		Mid-Upper		Lower		Lower –Mid - 7.5%		Status Quo		26,883 MW (1,500 MW coal campus)	
High Environ-mental	Mid		Upper		Lower		Mid		Kyoto - $44/ton CO2 Tax		14,227 MW (0 MW coal campus)	
Slow Growth	Mid		Lower		Mid		Mid		Status Quo		0 MW (0 MW coal campus)	
Fuel Supply Disruption	Mid		Upper		Upper		Lower		Status Quo		21,279 MW (3,750 MW coal campus)	
High Growth Wis.	Mid		Mid		Mid		Mid		Status Quo		12,689 (1,500 MW coal campus)	

Notes:

1) All scenarios include Weston 4 and Elm Road 1&2 for a total of 1,800 MWs
2) Approach: Determine # of MWh that could be produced from planned renewables in WI, all other comes from outside
3) Mid load growth was changed to reflect the draft Strategic Energy Assessment available at the time.
4) A lower load growth percentage was selected for the High Environmental future due to increased Demand Side Management and Energy Efficiency, not because of low economic growth.
5) Includes transmission upgrades from MTEP for 2011; Includes transmission upgrades from NERC in 2016

5. Summary Value Measures Used in this Report

ATC used different summary measures to calculate the benefits of Paddock-Rockdale. It measured benefits on a Net Present Value basis and also evaluated the impacts of the project for two years, 2011 and 2016. Each study year has a different generation and transmission topology.

When calculating the net present values, the following assumptions were made:

- A nominal discount rate of 8.5% was used to be consistent with the rate used by the PSCW staff in their Final Report on Transmission Access in Docket #137-EI-100.
- ATC's current tariff was used throughout the life of the projects
- The book and tax treatment of the assets was modeled to be consistent with the current methods.
- Inflation was assumed to be 3% per year.
- The economic benefits calculated for test years 2011 and 2016 were used in this analysis. The benefits assumed in years 2012 – 2015 were interpolated using a straight line method and for years beyond 2016 the benefits escalated with inflation. The benefits for 2010 were reduced from the 2011 result to account for inflation.

The analysis assumes mid-year 2010 in-service date for Paddock-Rockdale and therefore half a year of benefits in the year the project is placed in service. The costs follow ATC's tariff and therefore begin prior to the project in-service date.

Finally, ATC also calculated annual revenue requirements for the project, including ratepayer first-savings and break-ahead points.

6. Benefits of Paddock-Rockdale

6.1 Energy Cost Savings

6.1.1 Benefit Definition

Paddock-Rockdale produces energy-cost savings in the form of reductions in the cost of delivered energy for load-serving entities within ATC's service area. It will reduce congestion charges associated with moving energy from generation sources to load, increase the quantity of FTRs available to LSEs within ATC, and reduce electrical losses. The level of energy-cost savings depends upon several variables, including the extent to which Wisconsin LSEs are subject to cost-based versus market-based rates, and the degree to which this project increases transfer capacity and FTR coverage for Wisconsin LSEs. For this reason this benefit is presented in this section as a range of values. This range is bound on one end by the production cost of generators serving ATC load and on the other end by the Locational Marginal Price (LMP) paid by ATC load. The most probable actual energy-cost savings for Wisconsin customers lies somewhere in between these bookends. In this section ATC presents a detailed analysis and calculation of the full range of energy-cost savings as a result of Paddock-Rockdale.

6.1.2 Summary of Measurement Methods

Initial estimates of energy-cost savings were developed using PROMOD, an LMP computer market simulation model. The savings were calculated using four metrics. Three of these metrics have been proposed in MISO's Regional Expansion Criteria and Benefits (RECB) cost-sharing process, and one was developed to reflect estimated savings to ATC retail customers. The MISO metrics are:

- Adjusted Production Costs (adjusted for imports and exports)
- 70% of Adjusted Production Costs and 30% Load-Weighted LMP
- Load-Weighted LMP

The three metrics developed by MISO are consistent with ratepayer benefits under various simplified assumptions about market structure and the extent to which LSEs would be hedged against charges for transmission congestion. For example, the Load-Weighted LMP measure reflects fully market-based generation without any allocated FTRs that could hedge congestion charges. In contrast, the Adjusted Production Costs reflect: (1) only cost-based generation (as opposed to market-based generation) within the ATC service area; (2) no congestion costs incurred in transmitting energy from generation to load within ATC (i.e., ATC-internal transactions are fully hedged with allocated FTRs); and (3) imports are priced at the ATC-internal load LMP (i.e., no congestion on imports would be hedged with allocated FTRs). Finally, the measure based on 70% Adjusted Production Costs and 30% Load-Weighted LMPs is a hybrid measure representing a market structure under which retail rates reflect roughly 70% cost-based generation that is fully hedged against congestion charges and 30% market-based generation (plus imports) that are unhedged through FTR allocations.

In order to determine whether the 70%-30% hybrid measure was an appropriate metric, ATC retained The Brattle Group to undertake a more precise energy cost calculation that explicitly takes into account (1) the degree of cost-based versus market based generation in Wisconsin; (2) the level of FTR coverage for ATC-internal generation; (3) the level of FTR coverage for imports into the ATC service area; (4) the extent to which the Paddock-Rockdale project makes additional FTRs available toLSEs in the ATC service area; and (5) the difference between marginal losses, loss refunds, and the PROMOD modeling of energy losses. This ATC Customer Benefit, discussed in section 6.2 below, confirmed that the 70%-30% hybrid measure reasonably approximates ATC customer impacts of the Paddock-Rockdale project.

6.1.3 Energy-Cost Savings Results from PROMOD

Tables 7 and 8 show the energy cost difference for the ATC footprint without and with the Paddock-Rockdale project for the 2011 and 2016 futures. Note that the values are in year-of-occurrence dollars and that positive values denote benefits.

Table 7 Annual PROMOD Savings Attributable to Paddock-Rockdale for ATC Footprint for Various 2011 Futures **(Millions $)**

Metric	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Prod Costs	18	18	7	3	76	16
70% Prod Costs & 30% Load LMP	24	20	12	3	114	20
Load-Weighted LMP	37	26	23	5	201	31

In 2011 the two Robust Economy futures (one with North La Crosse-Columbia and one without) are identical as North La Crosse-Columbia would not be in service by 2011. Therefore, tables for 2011 in this report will only show one Robust Economy column.

Table 8 Annual PROMOD Savings Attributable to Paddock-Rockdale for the ATC Footprint for Various 2016 Futures **(Millions $)**

Metric	Robust Economy - No North La Crosse to Columbia Line	Robust Economy - With North La Crosse to Columbia Line	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Adjusted Prod Costs	25	20	98	8	0	91	41
70% Prod Costs & 30% Load LMP	52	40	154	16	2	146	83
Load-Weighted LMP	113	87	286	35	7	275	179

6.1.4 Refinements to PROMOD Results for Benefits from Congestion, FTR Allocations, and Marginal Losses

The MISO benefit measures do not specifically account for: 1) the extent to which LSEs are hedged against charges for transmission congestion through FTR allocations, and 2) the extent to which LSEs pay marginal loss charges and receive MISO loss refunds.

Because transmission expansion reduces congestion and losses and may increase the number of FTRs available for allocation to load-serving entities, these factors can be important in evaluating the benefits of a transmission project. To the extent that the MISO benefit measures do not accurately consider these factors, ATC's consultant, The Brattle Group, has developed adjustments that account for them. The methodologies used to arrive at these adjustments for congestion/FTR and losses are documented in more detail in sections 6.1.5 and 6.1.6 below.

6.1.5 Congestion Charges and FTR Revenues

Benefit Definition. In the Midwest ISO, utilities and other market participants pay congestion charges when transmitting energy from low-priced nodes to higher-priced nodes (unless the difference in nodal prices is only due to losses). Congestion charges can be hedged through offsetting revenues from FTRs that are allocated to or bought by load-serving entities, including the Wisconsin utilities. However, such FTR revenues do not exactly offset all congestion charges because allocated FTRs are often insufficient to cover peak flows but are often more than enough to cover non-peak flows.

If a new transmission project reduces congestion, congestion charges and FTR revenues both decrease, but often not in equal and offsetting amounts. Therefore, both changes in FTR revenues and changes in congestion charges are an important part of the benefit-cost analysis of new transmission projects.

The three MISO measures implicitly assume that none of the congestion charges on imports from outside the ATC footprint are offset by allocated FTRs. By pricing the imports at the ATC Load LMP, the MISO measures are equivalent to: (1) pricing the energy at the LMP of the external source from which these imports originate, and then (2) adding the full congestion and marginal loss charges given by the LMP differential between the source and sink.

Similarly, the Load LMP measure, which prices *all* transactions at the ATC Load LMP, assumes implicitly that none of the congestion charges associated with *ATC-internal* transactions would be hedged by allocated FTRs. In contrast, the Adjusted Production Cost measure of energy benefits does not consider any congestion charges on ATC-internal transactions, which is equivalent to assuming that ATC-internal transactions are fully hedged through allocated FTRs.

To more accurately consider the extent to which a transmission project affects the congestion charges and FTR values, the following adjustments can be made to the three MISO measures:

- The impact of the transmission project on the estimated volume and value of allocated FTRs available for *imports* needs to be added to all three MISO energy benefit measures;
- The impact of the transmission project on estimated congestion costs associated with *ATC-internal* transactions that are unhedged through allocated FTRs needs to be added to the Adjusted Production Cost measure; and
- A value corresponding to the extent to which the Wisconsin utilities' estimated exposure to *ATC-internal* congestion is already hedged through FTR allocations needs to be subtracted from the Load-weighed LMP measure.

Methodology. The congestion charges on internal transactions that are missing from the Adjusted Production Cost can be quantified by multiplying the hourly load served by internal generation by the difference between the marginal congestion component (MCC) of load and the MCC of internal generation.[6]

Based on discussions with our customers, ATC assumes that FTRs provide an 85% hedge against internal congestion costs, with annual FTR revenues equal to 85% of the calculated annual congestion cost. ATC also conservatively assumes that the Paddock-Rockdale project does not increase the quantity of ATC-internal FTRs available to the Wisconsin utilities.

FTR revenues on imports are given by the quantity of FTRs multiplied by the MCC differential between ATC Load and external hubs from which ATC imports will likely originate. The MCCs are taken from the PROMOD runs, but the quantity of FTRs must be estimated separately. Based on an analysis of existing FTR allocations, we found that there are currently approximately 800 MW of FTRs from Illinois to WUMS and 400 MW from Minnesota to WUMS. We assume this

[6] For each hour, PROMOD IV provides the load-weighted average MCC for all load buses and the generation-weighted average MCC for all generators in the ATC footprint.

distribution persists through 2011 (i.e., FTRs split 2/3 from Illinois and 1/3 from Minnesota) and that the total amount of FTRs from these outside markets is given by the projected simultaneous First Contingency Total Transfer Capability (FCTTC) for imports into the ATC service area under the various futures with and without Paddock-Rockdale.[7] On that basis, Paddock-Rockdale would make available an additional 220-444 MW of FTRs for imports from these markets in 2011, which would grow to 272-450 MW by 2016. Consistent with current FTR allocations, we assume that in both 2011 and 2016 two-thirds of the incremental FTRs would source in Illinois and sink in Wisconsin, and one third would source in Minnesota. However, we consider FTR allocations from Illinois and Minnesota only if the anticipated congestion revenues are positive. In some futures, the MCC is higher in Minnesota than in Wisconsin, in which case it is presumed that utilities would not nominate FTRs of negative value from Minnesota.

Results. Because new transmission reduces congestion and LMP differentials, congestion charges decrease, but so do congestion revenue credits on the existing volume of available FTRs. The incremental FTRs provided by the transmission upgrade, which MISO would likely be able to allocate to Wisconsin utilities if Paddock-Rockdale is built, provide incremental congestion revenues that would not otherwise be available to hedge imports.

Tables 9 and 10 present available and nominated FTRs due to Paddock-Rockdale for 2011 and 2016 and estimate the change in average FTR value due to Paddock-Rockdale (assuming that FTRs from Illinois equal 2/3, and FTRs from Minnesota equal 1/3 of the additional transfer capacity into ATC).

Table 11 documents the calculations used to measure these congestion and FTR-related benefits for the 2011 “Robust Economy” case. The calculation shows that these revenue increases for additional FTRs tend to be offset by revenue decreases on existing FTRs. Revenues on existing FTRs decrease because Paddock-Rockdale reduces congestion charges on imports and therefore reduces FTR revenues. For the Paddock-Rockdale transmission project, the value of additional import FTRs exceeds the reduced value of existing import FTRs in some futures, but falls short of that in other futures.

The results for all evaluated futures are presented in table 12 for the year 2011 and in table 13 for the year 2016.

[7] MISO’s methodology for allocating FTRs is related to transfer capability but not determined directly by FCTTC.

Table 9 FTRs Available and Nominated, 2011
(Assuming FTRs from Illinois equal 2/3 FCTTC, FTRs from Minnesota equal 1/3 FCTTC into WUMS)

		Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
FCTTC							
On Existing System (i.e., without PR2)	MW	2,732	2,884	2,732	2,884	2,732	2,884
On Modified System (with PR2)	MW	3,176	3,104	3,176	3,104	3,176	3,104
Physically Available FTRs (1 FCTTC = 1 FTR)							
Existing FTRs that have not been eliminated by PR2	MW	2,732	2,884	2,732	2,884	2,732	2,884
Additional FTRs due to PR2, if any	MW	444	220	444	220	444	220
MCC Differentials (WUMS MCC less Hub MCC; Positive indicates Valuable)							
Without PR2							
PJM NICA	$/MWh	$2.18	$2.12	$0.81	$0.47	$5.44	$1.61
IL HUB	$/MWh	$7.21	$2.84	$0.26	-$0.38	$6.87	$1.29
MN HUB	$/MWh	-$0.59	-$1.28	-$0.94	-$0.87	-$0.32	-$0.42
With PR2							
PJM NICA	$/MWh	$1.64	$1.63	$0.59	$0.43	$2.46	$1.25
IL HUB	$/MWh	$6.77	$2.38	$0.03	-$0.44	$3.92	$0.90
MN HUB	$/MWh	-$0.97	-$1.60	-$1.15	-$0.91	-$2.47	-$0.72
Valuable FTRs (Availability: 1/3 from PJM NICA, 1/3 from IL Hub and 1/3 from MN Hub; Each FTR is Valuable and Nominated if WUMS MCC > Hub MCC)							
Valuable FTRs into WUMS on Existing System	MW	1,821	1,923	1,821	961	1,821	1,923
PJM NICA	MW	911	961	911	961	911	961
IL HUB	MW	911	961	911	0	911	961
MN HUB	MW	0	0	0	0	0	0
Valuable FTRs into WUMS on Modified System (not eliminated by PR2)	MW	1,821	1,923	1,821	961	1,821	1,923
PJM NICA	MW	911	961	911	961	911	961
IL HUB	MW	911	961	911	0	911	961
MN HUB	MW	0	0	0	0	0	0
Additional Valuable FTRs into WUMS due to PR2, if any	MW	296	147	296	73	296	147
PJM NICA	MW	148	73	148	73	148	73
IL HUB	MW	148	73	148	0	148	73
MN HUB	MW	0	0	0	0	0	0
Total Valuable FTRs							
Without PR2	MW	1,821	1,923	1,821	961	1,821	1,923
With PR2	MW	2,117	2,069	2,117	1,035	2,117	2,069
Change in FTRs due to PR2	MW	296	147	296	73	296	147
Total FTR Value (= WUMS MCC - Outside Regions' MCC * Valuable FTRs)							
Without PR2	million $	$74.86	$41.80	$8.54	$3.99	$98.15	$24.39
With PR2	million $	$78.00	$36.35	$5.71	$3.88	$59.19	$19.49
Change in FTR Value due to PR2	million $	$3.14	-$5.45	-$2.83	-$0.11	-$38.96	-$4.90
Average FTR Value (= FTR Value / Valuable FTRs)							
Average FTR Value Without PR2	$/MWh	$4.69	$2.48	$0.54	$0.47	$6.15	$1.45
Average FTR Value With PR2	$/MWh	$4.21	$2.01	$0.31	$0.43	$3.19	$1.08
Change in Average FTR Value due to PR2 (= Avg. Value With PR2 - Avg. Value Without PR2)	$/MWh	-$0.49	-$0.48	-$0.23	-$0.05	-$2.96	-$0.37

Table 10 FTRs Available and Nominated, 2016
(Assuming FTRs from Illinois equal 2/3 FCTTC, FTRs from Minnesota equal 1/3 FCTTC into WUMS)

		Robust Economy- No North La Crosse Columbia	Robust Economy- With North La Crosse Columbia	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
FCTTC								
On Existing System (i.e., without PR2)	MW	2,174	2,526	2,031	2,174	2,174	2,174	2,174
On Modified System (with PR2)	MW	2,623	2,976	2,303	2,623	2,623	2,623	2,623
Physically Available FTRs (1 FCTTC = 1 FTR)								
Existing FTRs that have not been eliminated by PR2	MW	2,174	2,526	2,031	2,174	2,174	2,174	2,174
Additional FTRs due to PR2, if any	MW	449	450	272	449	449	449	449
MCC Differentials; WUMS less Hub								
Without PR2								
PJM NICA	$/MWh	$0.85	$0.47	$8.88	$0.75	-$0.10	$5.54	$5.22
IL HUB	$/MWh	$13.13	$12.86	$17.12	$3.41	-$0.17	$16.80	$7.18
MN HUB	$/MWh	$5.74	$5.09	$2.29	$0.19	-$0.85	$2.12	$2.95
With PR2								
PJM NICA	$/MWh	-$0.14	-$0.29	$5.69	$0.53	-$0.13	$1.98	$3.48
IL HUB	$/MWh	$12.46	$12.32	$14.08	$3.14	-$0.20	$13.53	$5.44
MN HUB	$/MWh	$5.11	$4.69	$0.04	$0.07	-$0.86	-$0.17	$1.83
Valuable FTRs (Availability: 1/3 from PJM NICA, 1/3 from IL Hub and 1/3 from MN Hub; Each FTR is Valuable and Nominated if WUMS MCC > Hub MCC)								
Valuable FTRs into WUMS on Existing System	MW	2,174	2,526	2,031	2,174	0	2,174	2,174
PJM NICA	MW	725	842	677	725	0	725	725
IL HUB	MW	725	842	677	725	0	725	725
MN HUB	MW	725	842	677	725	0	725	725
Valuable FTRs into WUMS on Modified System (not eliminated by PR2)	MW	1,449	1,684	2,031	2,174	0	1,449	2,174
PJM NICA	MW	0	0	677	725	0	725	725
IL HUB	MW	725	842	677	725	0	725	725
MN HUB	MW	725	842	677	725	0	0	725
Additional Valuable FTRs into WUMS due to PR2, if any	MW	299	300	272	449	0	299	449
PJM NICA	MW	0	0	91	150	0	150	150
IL HUB	MW	150	150	91	150	0	150	150
MN HUB	MW	150	150	91	150	0	0	150
Total Valuable FTRs								
Without PR2	MW	2,174	2,526	2,031	2,174	0	2,174	2,174
With PR2	MW	1,749	1,984	2,303	2,623	0	1,749	2,623
Change in FTRs due to PR2	MW	-425	-542	272	449	0	-425	449
Total FTR Value (= WUMS MCC - Outside Regions' MCC * Valuable FTRs)								
Without PR2	million $	$125.57	$136.24	$168.20	$27.64	$0.00	$155.77	$97.63
With PR2	million $	$134.94	$148.17	$133.61	$28.65	$0.00	$119.14	$82.61
Change in FTR Value due to PR2	million $	$9.37	$11.93	-$34.59	$1.01	$0.00	-$36.64	-$15.02
Average FTR Value (= FTR Value / Valuable FTRs)								
Average FTR Value Without PR2	$/MWh	$6.58	$6.14	$9.43	$1.45	$0.00	$8.16	$5.11
Average FTR Value With PR2	$/MWh	$8.79	$8.50	$6.60	$1.24	$0.00	$7.76	$3.59
Change in Average FTR Value due to PR2 (= Avg. Value With PR2 - Avg. Value With	$/MWh	$2.21	$2.36	-$2.82	-$0.20	$0.00	-$0.40	-$1.53

Table 11 Calculation of FTR and Congestion Adjustments to PROMOD Results ("Robust Economy", 2011) ($ millions)

			Without PR2	With PR2	Change
A. FTR and Congestion Adjustment to "Load x LoadLMP" Results					
FTR and Congestion Costs					
Into ATC					
+	Congestion Costs on Imports	already included in LoadLMP	-	-	-
	Existing Valuable FTRs into ATC	Existing FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable)	1,821	1,821	0
	Incremental FTRs into ATC due to PR2	Incremental FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable	0	296	296
+	Value of Existing FTRs	Existing FTRs * (MCCload - MCCcompositehub)	$74.86	$67.09	-$7.77
+	Value of Incremental FTRs	Incremental FTRs * (MCCload - MCCcompositehub)	$0.00	$10.90	$10.90
	Subtotal	*sum*	**$74.86**	**$78.00**	**$3.14**
Within ATC					
	Internal Congestion Costs	already included in LoadLMP	$72.76	$67.22	-$5.54
	Fraction of Internal Congestion Hedged	assumption based on customer responses	85%	85%	
+	Revenues on Internal FTRs	Hedged % * Internal Congestion Costs	$61.84	$57.14	-$4.71
	Subtotal	*sum*	**$61.84**	**$57.14**	**-$4.71**
FTR and Congestion Adjustment			**$136.70**	**$135.14**	**-$1.57**
B. FTR and Congestion Adjustment to "Adjusted Production Cost" Results					
FTR and Congestion Costs					
Into ATC					
+	Congestion Costs on Imports	already included in Adj. Prod. Cost	-	-	-
	Existing Valuable FTRs into ATC	Existing FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable)	1,821	1,821	0
	Incremental FTRs into ATC due to PR2	Incremental FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable	0	296	296
+	Value of Existing FTRs	Existing FTRs * (MCCload - MCCcompositehub)	$74.86	$67.09	-$7.77
+	Value of Incremental FTRs	Incremental FTRs * (MCCload - MCCcompositehub)	$0.00	$10.90	$10.90
	Subtotal	*sum*	**$74.86**	**$78.00**	**$3.14**
Within ATC					
+	Internal Congestion Costs	(Load - Imports) * (MCCload - MCCgen)	-$72.76	-$67.22	$5.54
	Fraction of Internal Congestion Hedged	assumption based on customer responses	85%	85%	
+	Revenues on Internal FTRs	Hedged % * Internal Congestion Costs	$61.84	$57.14	-$4.71
	Subtotal	*sum*	**-$10.91**	**-$10.08**	**$0.83**
FTR and Congestion Adjustment			**$63.95**	**$67.92**	**$3.97**
C. FTR and Congestion Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results					
FTR and Congestion Adjustment			**$85.77**	**$88.08**	**$2.31**

Table 12 FTR and Congestion Adjustments to PROMOD Results for 2011 ($ millions)

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. FTR and Congestion Adjustment to "Load x LoadLMP" Results						
Change in FTR and Congestion Costs						
Into ATC						
Existing Valuable FTRs into ATC, without PR2	1,821	1,923	1,821	961	1,821	1,923
Existing Valuable FTRs into ATC, with PR2	1,821	1,923	1,821	961	1,821	1,923
Incremental FTRs into ATC due to PR2	296	147	296	73	296	147
+ Value of Existing FTRs	-$7.77	-$8.02	-$3.63	-$0.38	-$47.23	-$6.28
+ Value of Incremental FTRs	$10.90	$2.58	$0.80	$0.28	$8.28	$1.38
Subtotal	**$3.14**	**-$5.45**	**-$2.83**	**-$0.11**	**-$38.96**	**-$4.90**
Within ATC						
Internal Congestion Costs	-$5.54	-$3.11	-$3.53	$0.92	-$34.13	-$3.65
Fraction of Internal Congestion Hedged						
+ Revenues on Internal FTRs	-$4.71	-$2.65	-$3.00	$0.78	-$29.01	-$3.11
Subtotal	**-$4.71**	**-$2.65**	**-$3.00**	**$0.78**	**-$29.01**	**-$3.11**
FTR and Congestion Adjustment	**-$1.57**	**-$8.09**	**-$5.83**	**$0.68**	**-$67.97**	**-$8.00**
B. FTR and Congestion Adjustment to "Adjusted Production Cost" Results						
Change in FTR and Congestion Costs						
Into ATC						
Existing Valuable FTRs into ATC, without PR2	1,821	1,923	1,821	961	1,821	1,923
Existing Valuable FTRs into ATC, with PR2	1,821	1,923	1,821	961	1,821	1,923
Incremental FTRs into ATC due to PR2	296	147	296	73	296	147
+ Value of Existing FTRs	-$7.77	-$8.02	-$3.63	-$0.38	-$47.23	-$6.28
+ Value of Incremental FTRs	$10.90	$2.58	$0.80	$0.28	$8.28	$1.38
Subtotal	**$3.14**	**-$5.45**	**-$2.83**	**-$0.11**	**-$38.96**	**-$4.90**
Within ATC						
+ Internal Congestion Costs	$5.54	$3.11	$3.53	-$0.92	$34.13	$3.65
+ Revenues on Internal FTRs	-$4.71	-$2.65	-$3.00	$0.78	-$29.01	-$3.11
Subtotal	**$0.83**	**$0.47**	**$0.53**	**-$0.14**	**$5.12**	**$0.55**
FTR and Congestion Adjustment	**$3.97**	**-$4.98**	**-$2.30**	**-$0.24**	**-$33.84**	**-$4.35**
C. FTR and Congestion Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results						
FTR and Congestion Adjustment	**$2.31**	**-$5.91**	**-$3.36**	**$0.03**	**-$44.08**	**-$5.45**

Table 13 FTR and Congestion Adjustments to PROMOD Results for 2016 ($ millions)

	Robust Economy- No North La Crosse Columbia	Robust Economy- With North La Crosse Columbia	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. FTR and Congestion Adjustment to "Load x LoadLMP" Results							
Change in FTR and Congestion Costs							
Into ATC							
Existing Valuable FTRs into ATC, without PR2	2,174	2,526	2,031	2,174	0	2,174	2,174
Existing Valuable FTRs into ATC, with PR2	1,449	1,684	2,031	2,174	0	1,449	2,174
Incremental FTRs into ATC due to PR2	299	300	272	449	0	299	449
+ Value of Existing FTRs	-$13.73	-$10.47	-$50.37	-$3.89	$0.00	-$57.03	-$29.16
+ Value of Incremental FTRs	$23.10	$22.41	$15.78	$4.90	$0.00	$20.39	$14.14
Subtotal	**$9.37**	**$11.93**	**-$34.59**	**$1.01**	**$0.00**	**-$36.64**	**-$15.02**
Within ATC							
Internal Congestion Costs	-$4.62	$1.84	-$17.01	-$1.98	$0.90	-$35.32	-$14.18
Fraction of Internal Congestion Hedged							
+ Revenues on Internal FTRs	-$3.93	$1.57	-$14.46	-$1.69	$0.77	-$30.02	-$12.06
Subtotal	**-$3.93**	**$1.57**	**-$14.46**	**-$1.69**	**$0.77**	**-$30.02**	**-$12.06**
FTR and Congestion Adjustment	**$5.44**	**$13.50**	**-$49.05**	**-$0.68**	**$0.77**	**-$66.66**	**-$27.07**
B. FTR and Congestion Adjustment to "Adjusted Production Cost" Results							
Change in FTR and Congestion Costs							
Into ATC							
Existing Valuable FTRs into ATC, without PR2	2,174	2,526	2,031	2,174	0	2,174	2,174
Existing Valuable FTRs into ATC, with PR2	1,449	1,684	2,031	2,174	0	1,449	2,174
Incremental FTRs into ATC due to PR2	299	300	272	449	0	299	449
+ Value of Existing FTRs	-$13.73	-$10.47	-$50.37	-$3.89	$0.00	-$57.03	-$29.16
+ Value of Incremental FTRs	$23.10	$22.41	$15.78	$4.90	$0.00	$20.39	$14.14
Subtotal	**$9.37**	**$11.93**	**-$34.59**	**$1.01**	**$0.00**	**-$36.64**	**-$15.02**
Within ATC							
+ Internal Congestion Costs	$4.62	-$1.84	$17.01	$1.98	-$0.90	$35.32	$14.18
+ Revenues on Internal FTRs	-$3.93	$1.57	-$14.46	-$1.69	$0.77	-$30.02	-$12.06
Subtotal	**$0.69**	**-$0.28**	**$2.55**	**$0.30**	**-$0.14**	**$5.30**	**$2.13**
FTR and Congestion Adjustment	**$10.07**	**$11.66**	**-$32.04**	**$1.31**	**-$0.14**	**-$31.34**	**-$12.89**
C. FTR and Congestion Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results							
FTR and Congestion Adjustment	**$8.68**	**$12.21**	**-$37.14**	**$0.71**	**$0.14**	**-$41.93**	**-$17.14**

6.1.6 Marginal Losses and Loss Refunds

Benefit Definition. As energy is transmitted, some energy is lost in the form of heat. Losses must be replaced, increasing the total amount of generation required to serve load. Under MISO Day 2 operation, the marginal cost of incremental generation needed to replace losses is reflected in the marginal loss component (MLC) of the LMP at each node. The difference in MLCs between two nodes determines the marginal loss charges imposed on transactions between those two points. However, because marginal losses are twice average losses, MISO's collection of marginal loss provides MISO with twice the funds it needs to compensate generators for the incremental generation replacing losses. MISO returns the surplus to LSEs as a refund that is equal, on average, to half of the marginal loss charges collected. Hence, it is important to estimate changes in marginal loss charges and loss refunds as part of the analysis of project benefits and costs.

Methodology. The PROMOD simulations include losses only by applying a static loss factor, which does not vary across cases, to increase forecasted loads. As a result, estimated production costs incorporate only a static estimate of the average cost of losses. Thus, the loss-adjusted load forecast and the three MISO benefits measures do not fully capture how a transmission project changes marginal loss payments made and loss refunds received by the Wisconsin utilities.

Changes in marginal loss charges and loss refunds can be estimated using the MLCs from PROMOD as follows: marginal loss charges for transmitting internal generation to load are given by the MLC differential between load and generation; and the loss refund returns half of that amount. Similarly, marginal loss charges on imports into ATC are given by the MLC differential between ATC load and external sources. The change in total marginal loss charges and loss refunds due to Paddock-Rockdale can thus be calculated from the MLCs in the PROMOD simulations with Paddock-Rockdale versus without Paddock-Rockdale.

The Adjusted Production Cost measure does not consider changes in *ATC-internal* marginal loss charges nor the associated refunds. These values consequently need to be incorporated for a more complete description of transmission project benefits. Marginal loss charges on imports are already included implicitly in the Adjusted Production Cost measure because imports are valued at the ATC-internal Load LMP. However, the associated loss refund, given by half of the MLC differential, is not reflected in the Adjusted Production Cost, and it must be applied as a credit in order to produce a more comprehensive measure of changes in customer costs.

The Load LMP measure of energy benefits does reflect marginal loss charges because it prices all energy needed to supply load at the Load LMP, which includes the full effect of marginal losses as reflected in the MLC component of LMPs. However, it does not reflect the associated refunds, which must be applied as a credit to the Load LMP measure to more fully reflect the change in a LSE's cost of service.

Results. The net loss adjustments that must be made to the Adjusted Production Cost measure are very different from those made to the Load LMP measure. Table 14 documents the calculations used to measure loss-related benefits for the 2011 "Robust Economy" case. The calculation shows that a $2.5 million benefit (i.e., cost reduction) must be added to the benefits quantified by the Adjusted Production Cost measure (which does not otherwise account for reductions in net loss charges resulting from Paddock-Rockdale). In contrast, $2.1 million must be deducted from the Load LMP measure of benefits (which did not account for the loss refund that Paddock-Rockdale reduces). The results for all evaluated futures are presented in table 15 for the year 2011 and in table 16 for the year 2016.

Table 14 Calculation of Marginal Loss and Loss Refund Adjustments to PROMOD Results ("Robust Economy", 2011) ($ millions)

		Without PR2	With PR2	Change
A. Marginal Loss and Loss Refund Adjustment to "Load x LoadLMP" Results				
Losses				
+ Marginal Loss Charges on Imports	already included in LoadLMP	-	-	-
+ Marginal Loss Charges on Internal Gen	already included in LoadLMP	-	-	-
+ Loss Refund Internal: Utility & Merchant Gen to Load	1/2 of Utility Loss Charges on Internal Transactions	$101.44	$99.15	-$2.29
+ Loss Refund on Imports: External Sources to Load	1/2 of Utility Loss Charges on Imports	$9.50	$10.43	$0.93
Subtotal	*sum*	**$110.94**	**$109.58**	**-$1.36**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count				
Adjusted Production Cost	provided by ATC	-$2,357.20	-$2,339.18	$18.02
Static Loss % Included in Load Forecast	From case w/o PR2: Avg. Loss from MLC / Prod. Cost	4.3%	4.3%	0.0%
Cost of Losses Already Captured	Adj. Prod. Cost * Static Loss %	**$101.44**	**$100.67**	**-$0.78**
Marginal Loss and Loss Refund Adjustment		**$212.38**	**$210.25**	**-$2.14**
B. Marginal Loss and Loss Refund Adjustment to "Adjusted Production Cost" Results				
Losses				
+ Marginal Loss Charges on Imports	already included in Adj. Prod. Cost	-	-	-
+ Marginal Loss Charges on Internal Gen	(Load-Imports) * (MLCload - MLCgen)	-$202.89	-$198.30	$4.59
+ Loss Refund Internal: Utility & Merchant Gen to Load	1/2 of Utility Loss Charges on Internal Transactions	$101.44	$99.15	-$2.29
+ Loss Refund on Imports: External Sources to Load	1/2 of Utility Loss Charges on Imports	$9.50	$10.43	$0.93
Subtotal		**-$91.95**	**-$88.72**	**$3.23**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count				
Adjusted Production Cost	provided by ATC	-$2,357.20	-$2,339.18	$18.02
Static Loss % Included in Load Forecast	From case w/o PR2: Avg. Loss from MLC / Prod. Cost	4.3%	4.3%	0.0%
Cost of Losses Already Captured	Adj. Prod. Cost * Static Loss %	**$101.44**	**$100.67**	**-$0.78**
Marginal Loss and Loss Refund Adjustment		**$9.50**	**$11.95**	**$2.45**
C. Marginal Loss and Loss Refund Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results				
Marginal Loss and Loss Refund Adjustment		**$70.36**	**$71.44**	**$1.08**

Table 15 Marginal Loss and Loss Refund Adjustments to PROMOD Results for 2011 (nominal, $ millions)

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. Marginal Loss and Loss Refund Adjustment to "Load x LoadLMP" Results						
Losses						
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$2.29	-$1.84	-$1.95	-$0.71	-$4.72	-$1.85
+ Loss Refund on Imports: External Sources to Load	$0.93	$0.95	$0.65	$0.17	$0.94	$0.79
Subtotal	**-$1.36**	**-$0.90**	**-$1.30**	**-$0.54**	**-$3.78**	**-$1.06**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count						
Adjusted Production Cost	$18.02	$18.03	$6.95	$2.58	$76.45	$15.56
Static Loss % Included in Load Forecast	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cost of Losses Already Captured	**-$0.78**	**-$0.75**	**-$0.21**	**-$0.08**	**-$3.03**	**-$0.57**
Marginal Loss and Loss Refund Adjustment	**-$2.14**	**-$1.65**	**-$1.51**	**-$0.62**	**-$6.81**	**-$1.63**
B. Marginal Loss and Loss Refund Adjustment to "Adjusted Production Cost" Results						
Losses						
+ Marginal Loss Charges on Internal Gen	$4.59	$3.69	$3.90	$1.42	$9.44	$3.70
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$2.29	-$1.84	-$1.95	-$0.71	-$4.72	-$1.85
+ Loss Refund on Imports: External Sources to Load	$0.93	$0.95	$0.65	$0.17	$0.94	$0.79
Subtotal	**$3.23**	**$2.79**	**$2.61**	**$0.88**	**$5.66**	**$2.64**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count						
Adjusted Production Cost	$18.02	$18.03	$6.95	$2.58	$76.45	$15.56
Static Loss % Included in Load Forecast	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cost of Losses Already Captured	**-$0.78**	**-$0.75**	**-$0.21**	**-$0.08**	**-$3.03**	**-$0.57**
Marginal Loss and Loss Refund Adjustment	**$2.45**	**$2.04**	**$2.40**	**$0.80**	**$2.63**	**$2.07**
C. Marginal Loss and Loss Refund Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results						
Marginal Loss and Loss Refund Adjustment	**$1.08**	**$0.93**	**$1.23**	**$0.38**	**-$0.20**	**$0.96**

Table 16 Marginal Loss and Loss Refund Adjustments to PROMOD Results for 2016 (nominal, $ millions)

	Robust Economy- No North La Crosse Columbia	Robust Economy- With North La Crosse Columbia	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. Marginal Loss and Loss Refund Adjustment to "Load x LoadLMP" Results							
Losses							
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$5.34	-$4.51	-$10.76	-$3.81	-$0.89	-$8.90	-$7.03
+ Loss Refund on Imports: External Sources to Load	$0.83	$0.73	$1.04	$0.84	$0.04	-$0.70	$1.03
Subtotal	**-$4.51**	**-$3.78**	**-$9.72**	**-$2.97**	**-$0.85**	**-$9.60**	**-$5.99**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count							
Adjusted Production Cost	$25.22	$20.00	$98.03	$7.79	$0.46	$91.32	$41.37
Static Loss % Included in Load Forecast	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cost of Losses Already Captured	**-$1.22**	**-$0.96**	**-$4.80**	**-$0.29**	**-$0.02**	**-$4.38**	**-$1.95**
Marginal Loss and Loss Refund Adjustment	**-$5.72**	**-$4.74**	**-$14.52**	**-$3.26**	**-$0.87**	**-$13.98**	**-$7.94**
B. Marginal Loss and Loss Refund Adjustment to "Adjusted Production Cost" Results							
Losses							
+ Marginal Loss Charges on Internal Gen	$10.68	$9.02	$21.52	$7.63	$1.78	$17.79	$14.05
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$5.34	-$4.51	-$10.76	-$3.81	-$0.89	-$8.90	-$7.03
+ Loss Refund on Imports: External Sources to Load	$0.83	$0.73	$1.04	$0.84	$0.04	-$0.70	$1.03
Subtotal	**$6.17**	**$5.24**	**$11.80**	**$4.66**	**$0.93**	**$8.20**	**$8.06**
+ "Credit" for Losses Already Captured in Production Cost (and then again through MLCs) to avoid double-count							
Adjusted Production Cost	$25.22	$20.00	$98.03	$7.79	$0.46	$91.32	$41.37
Static Loss % Included in Load Forecast	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cost of Losses Already Captured	**-$1.22**	**-$0.96**	**-$4.80**	**-$0.29**	**-$0.02**	**-$4.38**	**-$1.95**
Marginal Loss and Loss Refund Adjustment	**$4.96**	**$4.28**	**$6.99**	**$4.37**	**$0.91**	**$3.82**	**$6.11**
C. Marginal Loss and Loss Refund Adjustment to "70% Adjusted Prod. Costs Plus 30% Load-Weighted LMP" Results							
Marginal Loss and Loss Refund Adjustment	**$1.75**	**$1.58**	**$0.54**	**$2.08**	**$0.38**	**-$1.52**	**$1.90**

6.1.7 ATC Customer Benefit

Benefit Definition. The previous section quantified congestion, FTR, and loss-related costs and benefits to LSEs in Wisconsin that are not fully reflected in the three MISO energy benefits measures. However, even with these adjustments, the three benefit measures do not capture how a transmission project affects the total energy and congestion-related cost of service of Wisconsin utilities. This is because none of the three MISO measures fully reflects the existing structure of the market and regulatory environment in Wisconsin. Rather, the three adjusted MISO metrics quantify a transmission project's benefits to LSEs only under various simplified assumptions about market structure and the extent to which LSEs are subjected to cost-based versus market-based rates.

Methodology. Paddock-Rockdale's estimated impact on the energy and congestion-related costs of Wisconsin utilities explicitly takes into account the estimated degree of cost-based versus market-based generation in Wisconsin; the estimated level of FTR coverage for ATC-internal generation; the estimated level of FTR coverage of imports into the ATC service area; the extent to which the Paddock-Rockdale project is estimated to make additional FTRs available to LSEs in the ATC service area; and the difference between marginal losses, loss refunds, and the PROMOD modeling of energy losses.

Table 17 documents the methodology used to measure the transmission project's impact on the energy and congestion-related cost of service of Wisconsin utilities by calculating these benefits for the 2011 "Robust Economy" case. This "energy formula," based on a variety of PROMOD simulation results and additional data, assembles a bottom-up estimate of the total energy and congestion-related cost of serving Wisconsin load as the sum of (1) total cost of generation supply; (2) congestion charges *net of* FTR revenues; and (3) marginal loss charges *net of* loss refunds.

As shown in table 17, the total *cost of generation supply* is determined as the sum of total utility production costs, market-based purchases from merchant generators, and the cost of imports (priced at the LMP of the source of the imported energy, outside of ATC) less any revenues from exports. The costs and benefits associated with congestion, FTRs and losses are determined as discussed in section 4.6 above. Total *congestion charges* imposed on Wisconsin utilities are determined based on the quantity of imports and internally-supplied generation times the MCC differences between source locations (external hubs and ATC-internal generation) and ATC-internal load. These congestion charges are partially offset by *FTR revenues*, which are estimated based on the quantity of allocated FTRs available to hedge both imports and internal transactions. Marginal *loss charges* are determined based on the quantity of imports and internally-supplied load multiplied by the MLC differences between sources and load. Credits associated with *loss refunds* are estimated as half of the marginal loss charges. Finally, to avoid double counting, the production costs associated with the static losses that are embedded in the PROMOD load forecast must, again, be removed.

Results. Table 17 shows for the 2011 "Robust Economy" future that the Paddock-Rockdale transmission project decreases the total cost of generation supply of the Wisconsin utilities by

$17.3 million per year. The Wisconsin utilities total annual congestion charges are estimated to drop by approximately $9.2 million, but that reduction is offset by a $1.6 million reduction in FTR revenues (note, however, that the $1.6 million decrease in FTR revenues results from the combination of a $4.7 million decrease of FTR revenues associated with ATC-internal transactions, which is offset by a $3.1 million increase in import-related FTR revenues). The table also shows that $2.7 million in reduced marginal loss charges are offset by $1.4 million in reduced loss refunds. Finally, $775,000 of changes in costs associated with static losses reflected in the PROMOD estimate of production costs need to be added back to avoid double counting of loss-related benefits. The sum total of all of these cost impacts is a $25.6 million annual benefit in 2011 for a "Robust Economy" under today's market structure.

The energy and congestion-related reductions to the Wisconsin utilities' cost of service for each of the evaluated futures are presented in table 18 for the year 2011 and in table 19 for the year 2016.

Table 17 Calculation of Estimated Energy and Congestion Cost Impact on Wisconsin LSEs ("Robust Economy", 2011) ($ millions)

		Without PR2	With PR2	Change
Energy Formula				
Cost of Generation Supply				
+ Production Cost of ATC Utility Generation	(1-Merchant %) * (Variable Prod. Cost)	-$1,917.47	-$1,872.23	$45.25
Merchant % of Internal Production	assumption based on SEA report	10%	10%	
+ Cost to Utilities of Purchasing Merchant Gen (at Gen bus)	Merchant % * (Load - Imports) * LMPgen	-$418.71	-$412.80	$5.92
+ Cost of Imports (market price at external hubs)	Imports * (LMPil + LMPnica + LMPmn)/3	-$229.94	-$260.91	-$30.98
+ Revenues from Exports	Exports * LMPgen	$39.90	$37.02	-$2.88
Subtotal	*sum*	**-$2,526.22**	**-$2,508.91**	**$17.31**
Congestion Charges				
+ Utility Congestion Charges on Internal Transactions	(Load-Imports) * (MCCload - MCCgen)	-$72.76	-$67.22	$5.54
+ Utility Congestion Charges on Imports: External Hubs to Load	Imports * (MCCload - [MCCil + MCCnica + MCCmn]/3)	-$15.91	-$12.21	$3.70
Subtotal	*sum*	**-$88.67**	**-$79.43**	**$9.23**
FTR Revenues				
Into ATC				
Existing Valuable FTRs into ATC, without PR2	Existing FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable)	1,821	1,821	1,821
Existing Valuable FTRs into ATC, with PR2		-	1,821	1,821
Incremental FTRs into ATC due to PR2	Incremental FCTTC * (1/3 from each Ilhub, NICAhub, MN hub; if valuable	-	296	296
Value of FTRs ($/MWh)	MCCload - MCCcompositehub	$4.69	$4.21	-$0.49
+ Value of Existing FTRs	Existing FTRs * (MCCload - MCCcompositehub)	$74.86	$67.09	-$7.77
+ Value of Incremental FTRs	Incremental FTRs * (MCCload - MCCcompositehub)	$0.00	$10.90	$10.90
Subtotal	*sum*	**$74.86**	**$78.00**	**$3.14**
Within ATC				
Fraction of Internal Congestion Hedged	assumption based on customer responses	85%	85%	
+ Revenues on Internal FTRs	Hedged % * Internal Congestion Costs	$61.84	$57.14	-$4.71
Subtotal	*sum*	**$61.84**	**$57.14**	**-$4.71**
Loss Charges				
+ Utility Loss Charges on Internal Transactions	(Load-Imports) * (MLCload - MLCgen)	-$202.89	-$198.30	$4.59
+ Utility Loss Charges on Imports: External Hubs to Load	Imports * (MLCload - [MLCil + MLCnica + MLCmn]/3)	-$18.99	-$20.86	-$1.87
Subtotal	*sum*	**-$221.88**	**-$219.16**	**$2.72**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)				
+ Loss Refund Internal: Utility & Merchant Gen to Load	1/2 of Utility Loss Charges on Internal Transactions	$101.44	$99.15	-$2.29
+ Loss Refund on Imports: External Sources to Load	1/2 of Utility Loss Charges on Imports	$9.50	$10.43	$0.93
+ Loss Refund on Internal and Imports	*sum*	**$110.94**	**$109.58**	**-$1.36**
Adjusted Production Cost	provided by ATC	-$2,357.20	-$2,339.18	$18.02
Static Loss % Included in Load Forecast	From case w/o PR2: Avg. Loss from MLC / Prod. Cost	4.3%	4.3%	0%
+ Cost of Losses Already Captured	Adj. Prod. Cost * Static Loss %	**$101.44**	**$100.67**	**-$0.78**
= Total Customer Cost	*sum of subtotals*	**-$2,487.68**	**-$2,462.12**	**$25.56**

Table 18 Estimated Energy and Congestion Cost Impact on Wisconsin LSEs for 2011 ($ millions)

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Energy Formula						
Cost of Generation Supply						
+ Production Cost of ATC Utility Generation	$45.25	$43.60	$37.05	$11.41	$69.43	$36.88
+ Cost to Utilities of Purchasing Merchant Gen (at Gen bus)	$5.92	$4.93	$5.00	$1.48	$15.86	$4.94
+ Cost of Imports (market price at external hubs)	-$30.98	-$30.33	-$28.16	-$7.47	-$43.86	-$26.07
+ Revenues from Exports	-$2.88	-$2.08	-$6.08	-$2.55	-$1.16	-$1.59
Subtotal	**$17.31**	**$16.13**	**$7.81**	**$2.88**	**$40.27**	**$14.15**
Congestion Charges						
+ Utility Congestion Charges on Internal Transactions	$5.54	$3.11	$3.53	-$0.92	$34.13	$3.65
+ Utility Congestion Charges on Imports: External Hubs to Load	$3.70	$4.11	$1.54	$0.32	$46.53	$4.02
Subtotal	**$9.23**	**$7.22**	**$5.07**	**-$0.60**	**$80.66**	**$7.68**
FTR Revenues						
Into ATC						
Existing Valuable FTRs into ATC, without PR2	1,821	1,923	1,821	961	1,821	1,923
Existing Valuable FTRs into ATC, with PR2	1,821	1,923	1,821	961	1,821	1,923
Incremental FTRs into ATC due to PR2	296	147	296	73	296	147
Value of FTRs ($/MWh)	-$0.49	-$0.48	-$0.23	-$0.05	-$2.96	-$0.37
+ Value of Existing FTRs	-$7.77	-$8.02	-$3.63	-$0.38	-$47.23	-$6.28
+ Value of Incremental FTRs	$10.90	$2.58	$0.80	$0.28	$8.28	$1.38
Subtotal	**$3.14**	**-$5.45**	**-$2.83**	**-$0.11**	**-$38.96**	**-$4.90**
Within ATC						
Fraction of Internal Congestion Hedged						
+ Revenues on Internal FTRs	-$4.71	-$2.65	-$3.00	$0.78	-$29.01	-$3.11
Subtotal	**-$4.71**	**-$2.65**	**-$3.00**	**$0.78**	**-$29.01**	**-$3.11**
Loss Charges						
+ Utility Loss Charges on Internal Transactions	$4.59	$3.69	$3.90	$1.42	$9.44	$3.70
+ Utility Loss Charges on Imports: External Hubs to Load	-$1.87	-$1.89	-$1.31	-$0.35	-$1.89	-$1.58
Subtotal	**$2.72**	**$1.80**	**$2.59**	**$1.08**	**$7.55**	**$2.12**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)						
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$2.29	-$1.84	-$1.95	-$0.71	-$4.72	-$1.85
+ Loss Refund on Imports: External Sources to Load	$0.93	$0.95	$0.65	$0.17	$0.94	$0.79
+ Loss Refund on Internal and Imports	**-$1.36**	**-$0.90**	**-$1.30**	**-$0.54**	**-$3.78**	**-$1.06**
Adjusted Production Cost	$18.02	$18.03	$6.95	$2.58	$76.45	$15.56
Static Loss % Included in Load Forecast	0%	0%	0%	0%	0%	0%
+ Cost of Losses Already Captured	**-$0.78**	**-$0.75**	**-$0.21**	**-$0.08**	**-$3.03**	**-$0.57**
= Customer Benefit	**$25.56**	**$15.40**	**$8.13**	**$3.41**	**$53.70**	**$14.31**

Table 19 Estimated Energy and Congestion Cost Impact on Wisconsin LSEs for 2016 ($ millions)

	Robust Economy- No North La Crosse Columbia	Robust Economy- With North La Crosse Columbia	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Energy Formula							
Cost of Generation Supply							
+ Production Cost of ATC Utility Generation	$53.88	$43.72	$111.74	$40.37	$4.52	$83.20	$65.35
+ Cost to Utilities of Purchasing Merchant Gen (at Gen bus)	$13.26	$10.85	$27.37	$6.25	$1.05	$22.33	$18.18
+ Cost of Imports (market price at external hubs)	-$37.05	-$30.36	-$71.53	-$34.57	-$3.01	-$51.68	-$47.81
+ Revenues from Exports	-$0.66	-$0.38	$0.00	-$1.61	-$1.57	-$1.50	-$0.33
Subtotal	**$29.43**	**$23.82**	**$67.58**	**$10.45**	**$0.99**	**$52.35**	**$35.40**
Congestion Charges							
+ Utility Congestion Charges on Internal Transactions	$4.62	-$1.84	$17.01	$1.98	-$0.90	$35.32	$14.18
+ Utility Congestion Charges on Imports: External Hubs to Load	$5.42	$4.18	$48.65	$1.38	$0.14	$51.49	$19.75
Subtotal	**$10.04**	**$2.34**	**$65.66**	**$3.36**	**-$0.77**	**$86.80**	**$33.94**
FTR Revenues							
Into ATC							
Existing Valuable FTRs into ATC, without PR2	2,174	2,526	2,031	2,174	-	2,174	2,174
Existing Valuable FTRs into ATC, with PR2	1,449	1,684	2,031	2,174	-	1,449	2,174
Incremental FTRs into ATC due to PR2	299	300	272	449	-	299	449
Value of FTRs ($/MWh)	$2.21	$2.36	-$2.82	-$0.20	$0.00	-$0.40	-$1.53
+ Value of Existing FTRs	-$13.73	-$10.47	-$50.37	-$3.89	$0.00	-$57.03	-$29.16
+ Value of Incremental FTRs	$23.10	$22.41	$15.78	$4.90	$0.00	$20.39	$14.14
Subtotal	**$9.37**	**$11.93**	**-$34.59**	**$1.01**	**$0.00**	**-$36.64**	**-$15.02**
Within ATC							
Fraction of Internal Congestion Hedged							
+ Revenues on Internal FTRs	-$3.93	$1.57	-$14.46	-$1.69	$0.77	-$30.02	-$12.06
Subtotal	**-$3.93**	**$1.57**	**-$14.46**	**-$1.69**	**$0.77**	**-$30.02**	**-$12.06**
Loss Charges							
+ Utility Loss Charges on Internal Transactions	$10.68	$9.02	$21.52	$7.63	$1.78	$17.79	$14.05
+ Utility Loss Charges on Imports: External Hubs to Load	-$1.67	-$1.46	-$2.08	-$1.69	-$0.08	$1.40	-$2.07
Subtotal	**$9.02**	**$7.56**	**$19.44**	**$5.94**	**$1.71**	**$19.19**	**$11.99**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)							
+ Loss Refund Internal: Utility & Merchant Gen to Load	-$5.34	-$4.51	-$10.76	-$3.81	-$0.89	-$8.90	-$7.03
+ Loss Refund on Imports: External Sources to Load	$0.83	$0.73	$1.04	$0.84	$0.04	-$0.70	$1.03
+ Loss Refund on Internal and Imports	**-$4.51**	**-$3.78**	**-$9.72**	**-$2.97**	**-$0.85**	**-$9.60**	**-$5.99**
Adjusted Production Cost	$25.22	$20.00	$98.03	$7.79	$0.46	$91.32	$41.37
Static Loss % Included in Load Forecast	0%	0%	0%	0%	0%	0%	0%
+ Cost of Losses Already Captured	**-$1.22**	**-$0.96**	**-$4.80**	**-$0.29**	**-$0.02**	**-$4.38**	**-$1.95**
= Customer Benefit	**$48.21**	**$42.48**	**$89.10**	**$15.81**	**$1.83**	**$77.71**	**$46.31**

6.2 Improved Competitiveness

Benefit Defined. The WUMS and Northern WUMS regions have been designated as NCAs within MISO.[8] The Independent Market Monitor for MISO has deemed WUMS the least competitive market area within MISO.[9] As an NCA, WUMS is subjected to special scrutiny in the form of bid caps and other measures.

New transmission can improve the market structure and competitiveness if it enables external suppliers to offer additional generation into the WUMS market. In turn, increased competition can reduce market prices that may be elevated above competitive levels during tight market conditions. To the extent that loads are exposed to such market prices through short-term purchases and the turnover of longer-term contracts, these reductions in market prices will also reduce customer costs. Such cost reductions can be significant and should be considered as a benefit to additional EHV transmission into the ATC footprint.[10]

*Methodology***.** Structural measures of competitiveness, including the Herfindahl-Hirschman Index (HHI) and the Residual Supplier Index (RSI), are commonly used to evaluate the extent of competition in power markets.[11] These measures can also be calculated for expected market conditions with and without new transmission, such as Paddock-Rockdale. These measures are provided in table 20 for 2011 and table 21 for 2016. As the tables show, the RSI and HHI both decrease slightly with Paddock-Rockdale because import capability from non-local suppliers has

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[8] *Midwest Independent System Operator*, 108 FERC par. 61, 163 (8/6/04), pp. 77, 85. A third NCA was recently designated covering Northern Iowa, southwestern Wisconsin, and southeast Minnesota.
was recently designated as a third NCA.

[9] See 2005 State of the Market Report, Midwest ISO, July 2006, p. 75.

[10] For a discussion of competitive benefits of transmission projects, see, for example, *Managing Unilateral Market Power in Electricity*, presentation by Frank A. Wolak, Chairman, Market Surveillance Committee California ISO. Presentation can be found at http://www.stanford.edu/~wolak.

[11] The Herfindahl-Hirschman Index is calculated by summing the square of each supplier's market shares. This means, the HHI is equal to 10,000 in a fully monopolistic market (one supplier with a 100% market share) and equal to zero in a "fully competitive" market with infinitely many suppliers. In a market with 5 suppliers with a 20% market share each, the HHI is equal to 2,000 (i.e., 5 times 20 squared, which is 5 times 400). Markets with HHIs of less than 1,000 are generally considered competitive, markets with an HHI between 1,000 and 1,800 are considered moderately concentrated, while markets with HHI above 1,800 are considered highly concentrated. *See* U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, issued April 2, 1992, revised April 8, 1997 (DOJ/FTC Merger Guidelines).

The Residual Supplier Index (RSI) is calculated as the ratio of residual supply (i.e., total supply minus the capacity of the largest supplier in the market) to the total demand. If the RSI is less than 1.0 or 100%, it means the largest supplier is "pivotal", meaning that a load cannot be served without the largest supplier making available at least some of its capacity. With inelastic demand, a pivotal supplier theoretically would be able to set the market price at any desired level above the competitive price. *See* von der Fehr, Nils-Henrik and David Harbord, (1993), "Spot Market Competition in the UK Electricity Industry," *Economic Journal*, 103, 531-46. Furthermore, Wolfram, Catherine, (1999), "Measuring Duopoly Power in the British Electricity Spot Market," *American Economic Review*, 89(4), pp. 805-826; and Wolak, Frank, (1997), "Market Design and Price Behavior in Restructured Electricity Markets: An International Comparison," Working Paper PWP-051, University of California Energy Institute, Berkeley, California, show how tight supply conditions in the electricity markets in England and California, respectively, put sellers in a position to exercise market power, raising prices above the level at which a competitive market would clear.

increased.[12] These results are based on the assumption that average import capability increases only with the amount of the First Contingency Total Transfer Capability as determined by ATC's analysis using the PSS/E model: +220 to 444 MW in 2011 and +272 to 450 MW in 2016.

However, while structural measures such as HHIs or RSIs are frequently calculated to determine the "concentration" of power markets, there is no standard approach for translating changes to such structural measures into changes to bid markups, market prices, and the resulting impacts on customer costs. ATC has attempted to estimate the economic value of increased competitiveness using three independent approaches, called the *Modified MISO IMM Approach*, the *Modified California ISO Approach*, and the *Modified TCA Study Approach*.

The *Modified MISO IMM Approach* assumes that without any pivotal suppliers, market participants in WUMS will bid their marginal costs, and whenever a supplier becomes pivotal, its bids will exceed its marginal costs by up to $36/MWh, which is the cap that the MISO imposes on markups in NCAs. Studies elsewhere found that the likelihood of competitive outcomes decreases quickly as RSIs fall below 1.2 (i.e., the suppliers other than the largest firm in the market have enough capacity to meet 1.2 times the level of demand of the market). For example, using summer 2000 peak hourly data from the California Power Exchange, Sheffrin (2002) shows that there is negative correlation between the price-cost mark-up and the RSI values for California. She finds that when RSI is about 1.2, the average price-cost markup is zero.[13] We use this "1.2 threshold" to calculate price markups over marginal costs for each hour such that: (1) prices are equal to marginal-cost-based dispatch for RSIs above 1.2; (2) the price markup above marginal costs would average $18/MWh (i.e., half of the $36/MWh NCA threshold) for RSIs equal to less than 1.0; and (3) the price markup linearly increases from zero to $18/MWh as RSIs decline from 1.2 to 1.0. Hence, if new transmission increases the RSI from below 1.2 to above 1.2 in a given hour, the markups are eliminated and prices decrease accordingly, reducing the cost to serve the estimated fraction of load that is exposed to market prices.

We estimated the effects of potential price markups on customer costs by constructing two cases: (1) a "Limited Market-Based Pricing Case" (or *Limited Case*) that approximately reflects the current market structure in WUMS; and (2) an "Increased Market-Based Pricing Case" (or *Increased Case*) that could be consistent with possible future market structure under which more of the WUMS load is served through market-based supplies (e.g., from merchant plants or market-based utility-owned plants). In the "Limited Market-Based Pricing Case," we assume 20% of load is exposed to market prices through short-term purchases and the turnover of longer-term contracts, approximately reflecting current supply arrangements in Wisconsin.[14] In addition, the RSI is calculated on a "Net RSI" basis by netting suppliers' (cost-of-service or fixed-priced) load obligations from their supply portfolios before testing for pivotality based on withholding the residual supply. This reflects the fact that even very large suppliers would have limited (or no) incentives to withhold generation capacity if much (or all) of their capacity is

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[12] Our analysis assumes that import capacity is symmetrically allocated to six non-incumbent generation suppliers.

[13] Sheffrin, A., (2002), "Predicting Market Power Using the Residual Supply Index," Mimeo, Department of Market Analysis, California ISO.

[14] Note that 20% reflects the approximate level of purchases from merchant suppliers within ATC, other utilities within ATC, and suppliers outside of ATC. See Docket Nos. ER04-375-002 et al., *Prepared Direct and Answering Testimony of Johannes P. Pfeifenberger and Samuel A. Newell on behalf of the Michigan and Wisconsin Utilities*, September 15, 2004, at Exhibit MW-12.

needed to satisfy their own load obligations at cost-of-service based on long-term fixed-priced rates. In the "Increased Market-Based Pricing Case," we assume that 50% of load is directly exposed to market prices and calculate the RSI on a "Gross RSI" basis without considering suppliers' load obligations.

The *Modified California-ISO Approach* is based on a statistical analysis that the California ISO (CAISO) developed for its benefit-cost analyses of new transmission projects in California.[15] The CAISO estimated price impacts of new transmission by using regression analysis to find the relationship between historical market structure and price-bid markups. In the regression equation, the explanatory or independent variables are RSI and the fraction of load that is unhedged, and the dependent variable is the price-cost markup. We have adapted CAISO's analysis to derive an estimate for average price-cost markups in WUMS with and without Paddock-Rockdale by applying the CAISO-determined regression coefficients to the hourly RSIs and unhedged load (i.e., fraction of load exposed to market prices) projected for WUMS in 2011 and 2016. The RSIs and assumed fraction of load unhedged are the same as those used in the *Modified MISO IMM Approach*.

The *Modified TCA Study Approach* is based on an analysis that Tabors Caramanis and Associates (TCA or "Tabors") performed for the PSCW in 2000 to evaluate the competitiveness of the Wisconsin market in the event of restructuring.[16] In that study, TCA developed a market simulation model that optimizes bidding behavior from a supplier perspective given each supplier's supply portfolio and load obligations. The TCA study estimated market prices for several future years as load, generation supply, and import capability changed. It found that prices would decrease between 2003 and 2004, when it was assumed that the combination of new import capability and growth in generation supply would outpace load growth by 1700 MW. We adapted their findings by scaling the price effect by the ratio of the increased import capability due to Paddock-Rockdale (i.e., 220 - 444 MW in 2011 and 272 - 450 MW in 2016) to 1700 MW. In addition, we estimate the price effect at 20% and 50% load unhedged by interpolating the price effects that TCA calculated for 100% and 30% load unhedged.

*Results***.** Table 20 shows the effect of Paddock-Rockdale on structural measures of competitiveness (HHI and RSI) and on customer costs in 2011 based on the three approaches described above. Table 21 shows the competitive benefits of Paddock-Rockdale for the 2016 market simulations.

As tables 20 and 21 show, the benefit varies strongly with the assumed fraction of load exposed to market prices. The fraction of load exposed matters partly because suppliers have more incentive to bid above cost when they are selling more of their supplies at market prices. In the Limited Market-Based Pricing case, price effects are calculated based on Net RSI, which assumes that suppliers must serve their own load at cost-of-service or fixed-priced rates before considering physically or economically withholding generation. In the Increased Market-Based

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[15] *See* Transmission Economic Assessment Methodology (TEAM) Report published in June 2004. Available at http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf.
[16] *See* Tabors Caramanis & Associates, (2000), "Horizontal Market Power in Wisconsin Electricity Markets: A Report to the Public Service Commission of Wisconsin," published November 2, 2000 (revised November 14, 2000); available at http://www.utilityregulation.com/content/reports/WImktstudy.pdf.

Pricing case, price effects are calculated based on the Gross RSI, which does not consider suppliers' cost-based or fixed-priced load serving obligations. In addition, changes in prices have a larger impact on customer costs when a larger fraction of load is exposed to market prices.

Table 20 Competitiveness Benefits of Paddock-Rockdale in 2011

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. Annual Competitiveness Benefits under Limited Market-Based Pricing of Generation (20% Load Unhedged, Net RSI)						
Total Load ('000 MWh)	83,691	79,707	76,630	74,016	78,542	82,480
Total Load Unhedged ('000 MWh)	16,738	15,941	15,326	14,803	15,708	16,496
Change in % of Hours with At Least One Pivotal Supplier	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Without PR2	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
With PR2	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Change in HHI Value as a result of PR2	**-57**	**-30**	**-64**	**-34**	**-63**	**-30**
HHI Value Without PR2	1,135	1,158	1,216	1,264	1,205	1,152
HHI Value With PR2	1,078	1,128	1,152	1,230	1,142	1,122
Decrease in WUMS LMP Due to PR2 (Load-Weighted Average $/MWh)						
Modified California ISO Approach	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Modified MISO IMM Approach	$0.01	$0.00	$0.00	$0.00	$0.00	$0.01
Modified TCA Study Approach	$0.46	$0.21	$0.73	$0.15	$0.51	$0.36
Benefit of Increased Competitiveness (nominal $, millions)						
Modified California ISO Approach	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Modified MISO IMM Approach	**$0.16**	**$0.03**	**$0.00**	**$0.00**	**$0.00**	**$0.10**
Modified TCA Study Approach	**$7.73**	**$3.34**	**$11.23**	**$2.21**	**$7.99**	**$5.99**
B. Annual Competitiveness Benefits under Increased Market-Based Pricing of Generation (50% Load Unhedged, Gross RSI)						
Total Load ('000 MWh)	83,691	79,707	76,630	74,016	78,542	82,480
Total Load Unhedged ('000 MWh)	41,845	39,854	38,315	37,008	39,271	41,240
Change in % of Hours with At Least One Pivotal Supplier	**-3.61%**	**-1.51%**	**-1.30%**	**-0.62%**	**-1.63%**	**-2.33%**
Without PR2	9.91%	7.11%	3.81%	2.96%	4.69%	10.45%
With PR2	6.30%	5.61%	2.51%	2.34%	3.06%	8.12%
Change in HHI Value as a result of PR2	**-80**	**-40**	**-80**	**-40**	**-80**	**-40**
HHI Value Without PR2	2,034	2,006	2,026	2,026	2,034	2,026
HHI Value With PR2	1,954	1,966	1,946	1,986	1,954	1,986
Decrease in WUMS LMP Due to PR2 (Load-Weighted Average $/MWh)						
Modified California ISO Approach	$0.77	$0.36	$0.88	$0.15	$0.74	$0.34
Modified MISO IMM Approach	$1.55	$0.74	$1.02	$0.46	$1.15	$0.80
Modified TCA Study Approach	$1.77	$0.80	$2.80	$0.46	$1.94	$0.74
Benefit of Increased Competitiveness (nominal $, millions)						
Modified California ISO Approach	**$32.39**	**$14.26**	**$33.56**	**$5.66**	**$29.03**	**$14.05**
Modified MISO IMM Approach	**$64.75**	**$29.48**	**$39.11**	**$17.05**	**$45.29**	**$32.98**
Modified TCA Study Approach	**$73.89**	**$31.87**	**$107.32**	**$16.90**	**$76.36**	**$30.66**

Table 21 Competitiveness Benefits of Paddock-Rockdale in 2016 (nominal $)

	Robust Economy-No North La Crosse Columbia	Robust Economy-With North La Crosse Columbia	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
A. Annual Competitiveness Benefits under Limited Market-Based Pricing of Generation (20% Load Unhedged, Net RSI)							
Total Load ('000 MWh)	97,021	97,021	88,003	81,339	75,884	85,448	94,232
Total Load Unhedged ('000 MWh)	19,404	19,404	17,601	16,268	15,177	17,090	18,846
Change in % of Hours with At Least One Pivotal Supplier	**-0.07%**	**-0.05%**	**-0.19%**	**0.00%**	**0.00%**	**0.00%**	**-0.17%**
Without PR2	0.09%	0.05%	0.49%	0.00%	0.00%	0.00%	0.27%
With PR2	0.02%	0.00%	0.30%	0.00%	0.00%	0.00%	0.10%
Change in HHI Value as a result of PR2	**-61**	**-47**	**-82**	**-94**	**-88**	**-77**	**-74**
HHI Value Without PR2	1,050	1,000	1,520	1,338	1,342	1,207	1,156
HHI Value With PR2	988	953	1,437	1,245	1,254	1,130	1,082
Decrease in WUMS LMP Due to PR2 (Load-Weighted Average $/MWh)							
Modified California ISO Approach	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Modified MISO IMM Approach	$0.15	$0.11	$0.17	$0.06	$0.00	$0.04	$0.20
Modified TCA Study Approach	$0.59	$0.59	$0.39	$0.83	$0.33	$0.65	$0.51
Benefit of Increased Competitiveness (nominal $, millions)							
Modified California ISO Approach	**$0.00**	**$0.00**	**$0.06**	**$0.00**	**$0.00**	**$0.00**	**$0.03**
Modified MISO IMM Approach	**$2.85**	**$2.19**	**$3.00**	**$1.00**	**$0.03**	**$0.71**	**$3.85**
Modified TCA Study Approach	**$11.50**	**$11.44**	**$6.87**	**$13.54**	**$5.07**	**$11.12**	**$9.64**
B. Annual Competitiveness Benefits under Increased Market-Based Pricing of Generation (50% Load Unhedged, Gross RSI)							
Total Load ('000 MWh)	97,021	97,021	88,003	81,339	75,884	85,448	94,232
Total Load Unhedged ('000 MWh)	48,510	48,510	44,001	40,670	37,942	42,724	47,116
Change in % of Hours with At Least One Pivotal Supplier	**-8.69%**	**-8.41%**	**-4.55%**	**-8.67%**	**-2.86%**	**-7.98%**	**-7.68%**
Without PR2	40.33%	33.31%	58.52%	29.19%	7.48%	22.14%	47.85%
With PR2	31.65%	24.90%	53.96%	20.51%	4.62%	14.16%	40.16%
Change in HHI Value as a result of PR2	**-87**	**-81**	**-41**	**-97**	**-92**	**-90**	**-92**
HHI Value Without PR2	2,115	2,046	2,026	2,190	2,146	2,145	2,146
HHI Value With PR2	2,028	1,965	1,985	2,093	2,054	2,055	2,054
Decrease in WUMS LMP Due to PR2 (Load-Weighted Average $/MWh)							
Modified California ISO Approach	$1.55	$1.43	$1.34	$1.87	$0.55	$1.38	$1.46
Modified MISO IMM Approach	$1.24	$1.30	$0.76	$1.60	$1.48	$1.58	$1.08
Modified TCA Study Approach	$2.27	$2.25	$1.49	$3.18	$1.28	$2.49	$1.96
Benefit of Increased Competitiveness (nominal $, millions)							
Modified California ISO Approach	**$75.35**	**$69.20**	**$59.04**	**$76.01**	**$20.75**	**$58.98**	**$69.02**
Modified MISO IMM Approach	**$60.04**	**$63.23**	**$33.39**	**$65.19**	**$56.18**	**$67.51**	**$50.79**
Modified TCA Study Approach	**$109.90**	**$109.32**	**$65.59**	**$129.33**	**$48.41**	**$106.23**	**$92.12**

6.3 Reliability and Insurance Benefits

Benefit Definition. The most important job of the transmission system is to maintain system reliability so that load can be served. Transmission enhancements reduce the likelihood and extent of loss of load by improving the stability of the system and/or increasing access to additional resources. Such enhancements improve the ability of the transmission system to respond to emergencies. Projects whose primary objective is "economic" also tend to improve system reliability by reducing the likelihood or magnitude of load-shedding events under certain contingencies or system conditions. Indeed, due to system growth, such economically-justified projects could ultimately be necessary to satisfy reliability criteria. The economic value of such reliability benefits can be quantified based on the avoidance of load-shedding events and the economic harm caused by such events.

The reliability benefit of a project is the impact it has on reducing the probability of a loss-of-load event within ATC due to insufficient generation to serve load. This reduced likelihood of a loss-of-load event as a result of a project can be measured, and the resulting reduction in the expected unserved energy can be calculated, using Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE) analyses, as described below.

The insurance benefit of a project is the positive result it produces in mitigating the energy-cost impacts of more severe generation or transmission outages. The PROMOD runs used to evaluate energy-cost savings are consistent with the North American Electric Reliability Council (NERC) standards which require the continued stable operation of the system and continuity of service to all load and generation in the event of a forced outage of *single* system elements and generation units. Given past actual system events, it is also reasonable to consider the performance of the system with and without the project when confronted with more severe *multiple* outages to generation units and transmission elements. Such outages may occur from time to time over the forty year evaluation period of the project. Several scenarios of multiple outages are listed in the NERC Transmission Planning Standards and are referred to as "Category C" for loss of two or more Bulk Electric System (BES) elements and "Category D" for extreme Bulk Electric System events.

The NERC standards state that "depending on system design and expected system impacts, the controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary" to maintain ongoing operation of the transmission system. Therefore the value of this benefit is defined as:

1) The difference in the value of energy and congestion with and without the proposed project, and
2) The difference in the value of unserved energy with and without the proposed project when evaluating the performance of the BES under these multiple or extreme system failure events.

New transmission can improve the performance of the Bulk Electric System and provide an insurance benefit against the loss of load, generation or transmission service under these multiple element or extreme events.

Methodology. To determine reliability benefit, an LOLE analysis was conducted for 2011 and 2016. The analysis also yields a value for EUE.

LOLE is a probabilistic measure of the possibility that there might not be enough generation to meet the load in a particular area. It is important to note, however, that an LOLE calculation does not yield a probability, but an expected value. A generally accepted industry standard reliability criterion is to meet an LOLE of one day in 10 years, or 0.1 days per year. To determine the expected number of days of failure, the LOLE calculation sums the probabilities that the generation would fail to meet the load. However, the calculation is performed using the peak hour of each day rather than every hour and therefore 0.1 days per year cannot be equated to 2.4 hours per day.

The EUE, for each hour calculated, would be the number of MW that would be expected to not be served should a Loss of Load event occur. These values are summed for each hour that has been calculated to provide a figure in MWh.

The key drivers for a LOLE analysis are the MW load at the peak hour of each day, the maximum capacity of the generation at a given time, and the forced outage rates of the generating units. The maximum capacity of the generation takes into account unit de-rates and scheduled maintenance. The data used to perform this analysis was taken from the economic models that were used for the Paddock-Rockdale PROMOD studies.

The purpose here is to provide a comparison of the LOLE for the ATC footprint between the studied scenarios. As such, the FCTTC values calculated for the various scenarios were used to represent the import capability of the ATC transmission system. For the LOLE analysis, import capability was modeled as a perfectly available generator. Economic factors that impact the cost of operating the units were not considered. Of particular note, for the Fuel Supply Disruption case, the limit applied to the supply of coal did not have an impact on the case because it was assumed that, in an emergency situation, the generation would be operated without regard to fuel reserves. Also, the unit de-rates that were applied to coal units in all scenarios to more accurately model their economic capacity were removed for the LOLE analysis. This is because the emergency capacity of units, rather than their economic capacity, is appropriate for this kind of analysis.

Reliability benefits could be monetized by multiplying expected unserved energy or LOLP by the value of lost load. The value of lost load varies by customer class, duration of the outage, weather and region. Numerous studies have quantified the economic value of lost load by customer class in specific regions. A survey of the literature finds a reasonably consistent set of estimates of the value of lost load. The Midwest ISO's May 2006 value of lost load study is applicable. Applying Wisconsin's customer class percentages of 40 percent industrial, 31 percent residential, and 28 percent commercial[17] to the minimum end of the range of values presented for each customer class

[17] Based on 2004 retail sales in Wisconsin from FERC Form 1's.

results in an average value of lost load of approximately $13,000 per MWh of unserved energy (or lost load) in 2011 dollars.

To determine the insurance benefit of a project in the event of more severe outages, the appropriate methodology to use is the standard insurance valuation tools of probability of occurrence and impact of occurrence for several generation scenarios and several transmission scenarios. Impact is defined as: (1) the energy and congestion cost impacts on the load served as evaluated when each of the major contingencies was run through the PROMOD model plus (2) the value of load not served. However, the PROMOD simulations generally do not estimate the magnitude of unserved energy. For this reason ATC did not calculate the $/MWh value of lost load with and without the project for these more severe scenarios. As noted above, this value is significant, on the order of $13,000/MWh (2011$), based on the Midwest ISO's May 2006 value of lost load study.

Probabilities were derived from historical experience events in Wisconsin and their impact on the performance of the BES in Wisconsin and a review of the relevant similar regions nationally. The prominent drivers found were weather (wind such as the St Nazienz tornado in 2000, flood such as the Presque Isle Power Plant switchyard in 2002, and ice such as the ice storm of March 1976 which interfered with power plant water intakes), regulatory mandate (1996 – 1998 nuclear plant unavailability for regulatory concerns) and sabotage (such as the 2003 tower collapse near Oak Creek and incidents involving Robert Konopka). The duration of these outages was also derived from historical events, with the most severe durations based on the time to order long lead-time equipment replacements.

Transmission scenarios were based on locations where multiple circuits share the same ROW, structure or substation. Three risk levels were evaluated based on two circuits (one high voltage and one EHV), two circuits (both EHV) and a complete substation outage.

Generation scenarios were based on generation risks derived from a common campus with shared facilities or common design basis which might result in a common regulatory mandate (requiring the shutdown of multiple plants until the regulatory deficiencies are resolved). Two risk levels were evaluated based on a common system failure at a 1200MW coal generation campus and a regulatory mandate across three common design basis nuclear units. A third level of generation risk is already embedded in the PROMOD software protocol which removes single units on the basis of their forced outage characteristics.

Results. The reliability benefit of Paddock-Rockdale for the year 2016 can be found in table 22. The results for 2011 are not presented because the LOLE for all scenarios were practically zero. Table 23 shows the insurance benefit of Paddock-Rockdale in the event of extreme multiple-element system-outage events.

Table 22 LOLE and EUE Results, 2016

Scenario	LOLE (Days per Year)		EUE (MWh)		
	Without Paddock-Rockdale	With Paddock-Rockdale	Without Paddock-Rockdale	With Paddock-Rockdale	Difference
Robust Economy	0.04925	0.01338	16.47	4.06	-12.41
High Retirements	0.43256	0.22769	169.50	82.70	-86.82
High Environmental	0.00041	0.00006	0.10	0.01	-0.09
Slow Growth	0.00000	0.00000	0.00	0.00	0.00
Fuel Supply Disruption	0.00029	0.00004	0.07	0.01	-0.06
High Growth Wisconsin	0.28859	0.09544	112.10	33.00	-79.10

Table 23 Insurance Benefit Results

Generation Events Event Description and Duration	Frequency of Occurrence (Probability)	Severity: Energy and Congestion (Cost per Occurrence)	Severity: Energy and Congestion (Annual Cost $2006)	NPV
2 - 600 MW Coal-fired Units 3 Weeks	20 Years (5%)	$5,326,152	$266,308	$3,652,870
3 - 500 MW Nuclear Units 1 Year	40 Years (2.5%)	$33,711,923	$842,798	$11,560,435
Transmission Events Event Description and Duration				
1 - 138kV and 1 - 345kV Line 2 weeks	10 Years (10%)	($481,295)	($48,130)	($660,179)
3 - 345kV Lines 4 - Weeks	20 Years (5%)	$5,050,212	$252,511	$3,463,620
345 kV Substation 6 Months	40 Years (2.5%)	$27,787,589	$694,690	$9,528,873
	Total		**$2,008,177**	**$27,545,619**

The annual benefit of $2.0M in 2006 is escalated at an assumed 3% inflation rate resulting in benefits of $2.3M in 2011 and $2.7M in 2016. ATC included these 2011 and 2016 energy-cost reductions and their NPV in its calculation of project benefits. It did not monetize or include in its calculation benefit values for reduced EUE as a result of this project.

6.4 Long Term Resource Cost Advantage

Benefit Definition. Wisconsin utilities are required to secure enough capacity to be able to meet their forecast peak load plus an 18% planning reserve margin. They do so by building or contracting for generation that can be physically delivered to their load. Their resource planning process typically involves selecting the most economic technology, fuel, size, and location for new capacity that minimizes their overall cost of service.

New transmission has the potential to reduce the overall cost of service by increasing the physical deliverability of energy from locations with access to lower-cost fuel or other economic advantages. For example, Paddock-Rockdale could enable Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin. Sites in Illinois potentially offer significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) but would require higher congestion and loss charges in order to transmit the energy into the ATC service area. Similarly, increased import capability may provide Wisconsin utilities with improved access to lower-cost renewable resources, such as generation from more wind-rich Midwestern locations. If the total cost advantage of building and operating generation in neighboring states plus the additional congestion and loss-related costs associated with physically importing that power into Wisconsin is less than the corresponding costs for a Wisconsin plant, the outside location would have a “resource cost advantage.” A transmission upgrade that increases the ability to physically import power from such outside resources could consequently make that resource cost advantage accessible to Wisconsin utilities.

Methodology. The installed generating capacity in the PROMOD simulations in this study was the same with Paddock-Rockdale as without. Hence the economic benefit of having the option to locate more physical capacity outside of Wisconsin as a result of the transmission upgrade is not captured in the model results.

However, information from the PROMOD results can be used to estimate whether there could be any benefit from shifting a small amount of capacity to low-cost locations in Illinois. It is assumed that the amount of additional generating capacity that could be located outside the ATC service area as a result of Paddock-Rockdale is given by the increase in the minimum FCTTC occurring as a result of the project, depending on the future (i.e. 220-444 MW in 2011, increasing to 272-450 MW in 2016), and two-thirds of which could be located in Illinois. We evaluated the potential for a resource cost advantage in the case of a mine-mouth coal plant with a significant fuel cost advantage in central Illinois. The fuel cost savings per MW can be estimated based on the difference in fuel costs (and environmental allowance costs) multiplied by the number of hours per year and an expected availability factor of 90%. The incremental congestion and loss charges are given by the difference in MCCs and MLCs between Wisconsin and the external site, such as at the Prairie State Energy Facility in Illinois. Incremental loss refunds reduce the incremental loss charges by 50%. Incremental FTR revenues would be available to hedge some of the congestion costs, but such incremental FTR benefits have already been quantified above and their availability depends on where Wisconsin utilities buy energy, not on where Wisconsin utilities build their physical generating capacity.

Results. In this case ATC found that the fuel cost advantage of a mine-mouth plant in central Illinois in 2011 is greater than the higher congestion and net loss charges in most scenarios. We also found, however, that this resource cost benefit could be short-lived if congestion outside of the ATC footprint increases.

For example, the PROMOD results for the 2016 futures suggest that, by 2016, the Illinois mine-mouth fuel cost advantage would be more than offset by high congestion on local transmission constraints within Illinois. However, these results are highly dependent upon the assumptions made about transmission constraints in central Illinois in 2016. If these constraints are addressed by the transmission and resource planning efforts of MISO and the local Illinois utilities, the central Illinois generation and transmission system configurations would be different from those in the 2016 PROMOD assumptions.

In order to be conservative and avoid premature conclusions, this study consequently does not quantify the long-term resource cost advantage that may be provided by Paddock-Rockdale.

6.5 Capacity Savings from Reduced Losses

Benefit Definition. The PSCW currently requires that all utilities own or contract for sufficient installed generation capacity to cover 118% of their projected non-interruptible peak load, including projected losses in transmission and distribution during the peak load period. To the extent that new transmission changes dispatch and flow patterns, transmission losses will also change. If transmission losses decrease, utilities will not have to install as much generation capacity in order to meet their resource adequacy requirements.

Methodology. The PSS/E load flow program was used to assess the impact of Paddock-Rockdale on losses within ATC during peak load periods. Loads were set to the peak forecast for 2011 and 2016 and sufficient generation was dispatched in merit order to meet the load. Transmission losses are an output of the PSS/E program. The difference in losses between the with- and without-Paddock-Rockdale cases was applied to all futures.

For each 1 MW reduction in peak losses, 1.18 fewer MW of capacity are needed. The cost savings can be estimated based on the annualized cost of a nearly pure capacity product, a gas-fired combustion turbine. We have assumed a cost of $58.4/kW-yr (in 2006 dollars), based on PJM's Capacity Deficiency Rate, which is currently set at $160/MW-day and which reflects PJM's estimate of the all-in levelized cost of a combustion turbine.[18]

Results. Using PSS/E, a 7.9 to 11.1 MW decrease in peak losses in 2011 and a 12.1 to 16.8 MW decrease in peak losses in 2016 was calculated. Multiplying by 1.18 MW reserves per MW of peak demand, by $58.4/kW-yr, and by an inflation factor, yields a $631,000 to $887,000 benefit in 2011 and a $1,120,000 to $1,560,000 benefit in 2016.

[18] See the *2005 State of the Market Report* by PJM's Market Monitoring Unit, March 8, 2006, at p. 415 footnote 9.

6.6 Reserve Requirements

Transmission projects that increase import capability, like Paddock-Rockdale, have a positive impact on our ability to reduce reserve-margin requirements while still meeting reliability requirements.

ATC performed a generic cost analysis for its 2005 ATC Access Study Initiative Report to determine annual cost savings that could be attributed to reducing the required reserve margin. The analysis showed an approximate annual cost savings of $8.1 million dollars (2005$) per percentage point decrease in the required reserve margin. Based on that estimate, lowering the 18% requirement for Wisconsin by three percentage points to the regional requirement of 15% would save about $24.3 million dollars (2005$) per year. Reserve margin requirements are based on an LOLE[19] analysis. ATC did not repeat its reserve-margin analysis for Paddock-Rockdale in this Report because the PSCW Staff stated in its Report that the reserve margin issue should be reviewed separately and in conjunction with MISO's Resource Adequacy process. However, transmission projects like Paddock-Rockdale could provide significant savings if required planning reserve margins were to be lowered as a result of increased import capability.

[19] Reserve margin requirements are based on a Loss of Load Expectation (LOLE) analysis. 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 analyses are complex and 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.

7. Summaries of Total Impacts of this Project (Annual Benefits and NPV)

In this section ATC presents its summaries of the total impacts of Paddock-Rockdale. Costs and individual benefits are presented in an annual-benefit basis for 2011 and 2016 and on an NPV basis.

Tables 24 through 35 set forth the annual benefits of the project for 2011 and 2016 on an NPV basis for each of the futures, based upon APC, LLMP, the 70%-30% weighted measure, and the ATC Customer Benefit metric.

Table 24 Annual Benefits 2011 – Adjusted Production Costs

MILLIONS $

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
PROMOD Adjusted Production Costs	18	18	7	3	76	16
FTR and Congestion	4	(5)	(2)	(0)	(34)	(4)
Losses	2	2	2	1	3	2
Competitiveness Limited Market-Based Pricing (avg.)	3	1	4	1	3	2
Insurance Benefit During System Failure Events	2	2	2	2	2	2
Capacity Savings From Reduced Losses	1	1	1	1	1	1
Total Annual Benefit	**30**	**19**	**14**	**7**	**51**	**18**

Table 25 Annual Benefits 2011 – 70% Adjusted Production Costs and 30% Load Weighted LMP

$ MILLIONS

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
PROMOD 70% Adjusted Production Costs and 30% Load Weighted LMP	24	20	12	3	114	20
FTR and Congestion	2	(6)	(3)	0	(44)	(5)
Losses	1	1	1	0	(0)	1
Competitiveness Limited Market-Based Pricing (avg.)	3	1	4	1	3	2
Insurance Benefit During System Failure Events	2	2	2	2	2	2
Capacity Savings From Reduced Losses	1	1	1	1	1	1
Total Annual Benefit	**$33**	**$19**	**$17**	**$7**	**$76**	**$21**

Table 26 Annual Benefits 2011 – Load Weighted LMP

$ MILLIONS

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
PROMOD Load Weighted LMP	37	26	23	5	201	31
FTR and Congestion	(2)	(8)	(6)	1	(68)	(8)
Losses	(2)	(2)	(2)	(1)	(7)	(2)
Competitiveness Limited Market-Based Pricing (avg.)	3	1	4	1	3	2
Insurance Benefit During System Failure Events	2	2	2	2	2	2
Capacity Savings From Reduced Losses	1	1	1	1	1	1
Total Annual Benefit	**39**	**20**	**23**	**9**	**133**	**27**

Table 27 Annual Benefits 2011 – ATC Customer Benefit

$ MILLIONS

	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Customer Benefit Including FTR, Congestion and Losses	26	15	8	3	54	14
Competitiveness Limited Market-Based Pricing (avg.)	3	1	4	1	3	2
Insurance Benefit During System Failure Events	2	2	2	2	2	2
Capacity Savings From Reduced Losses	1	1	1	1	1	1
Total Annual Benefit	**31**	**19**	**15**	**7**	**60**	**19**

Table 28 Annual Benefits 2016 – Adjusted Production Costs

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wis.
PROMOD Adjusted Production Costs	25	20	98	8	0	91	41
FTR and Congestion	10	12	(32)	1	(0)	(31)	(13)
Losses	5	4	7	4	1	4	6
Competitiveness Limited Market-Based Pricing (avg.)	5	5	3	5	2	4	5
Insurance Benefit During System Failure Events	3	3	3	3	3	3	3
Capacity Savings From Reduced Losses	2	1	1	2	2	2	2
Total Annual Benefit	**49**	**44**	**80**	**23**	**7**	**72**	**43**

Table 29 Annual Benefits 2016 – 70% Adjusted Production Costs and 30% Load Weighted LMP

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
PROMOD 70% Adjusted Production Costs and 30% Load Weighted LMP	52	40	154	16	2	146	83
FTR and Congestion	9	12	(37)	1	0	(42)	(17)
Losses	2	2	1	2	0	(2)	2
Competitiveness Limited Market-Based Pricing (avg.)	5	5	3	5	2	4	5
Insurance Benefit During System Failure Events	3	3	3	3	3	3	3
Capacity Savings From Reduced Losses	2	1	1	2	2	2	2
Total Annual Benefit	**71**	**62**	**125**	**28**	**9**	**111**	**76**

Table 30 Annual Benefits 2016 – Load Weighted LMP ($ millions)

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
PROMOD Load Weighted LMP	113	87	286	35	7	275	179
FTR and Congestion	5	14	(49)	(1)	1	(67)	(27)
Losses	(6)	(5)	(15)	(3)	(1)	(14)	(8)
Competitiveness Limited Market-Based Pricing (avg.)	5	5	3	5	2	4	5
Insurance Benefit During System Failure Events	3	3	3	3	3	3	3
Capacity Savings From Reduced Losses	2	1	1	2	2	2	2
Total Annual Benefit	**122**	**104**	**230**	**40**	**13**	**203**	**153**

Table 31 Annual Benefits 2016 – ATC Customer Benefit

MILLIONS $

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Customer Benefit Including FTR, Congestion and Losses	48	42	89	16	2	78	46
Competitiveness Limited Market-Based Pricing (avg.)	5	5	3	5	2	4	5
Insurance Benefit During System Failure Events	3	3	3	3	3	3	3
Capacity Savings From Reduced Losses	2	1	1	2	2	2	2
Total Annual Benefit	**57**	**51**	**96**	**25**	**8**	**86**	**55**

Table 32 NPV of Net Benefits – Adjusted Production Costs

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Revenue Requirement	(136)	(136)	(136)	(136)	(136)	(136)	(136)
Construction Congestion Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)
PROMOD Adjusted Production Costs	250	206	858	80	9	927	379
FTR and Congestion	93	106	(278)	6	(2)	(335)	(117)
Losses	47	41	63	42	9	38	56
Competitiveness Limited Market-Based Pricing (avg.)	46	44	30	49	16	39	42
Insurance Benefit During System Failure Events	28	28	28	28	28	28	28
Capacity Savings From Reduced Losses	15	12	11	15	14	15	14
Total NPV of Net Benefits	**341**	**299**	**574**	**82**	**(62)**	**575**	**265**

*Note to Tables 32 through 35: $136M is the present value of the annual revenue requirements of the project, comprised of return of and on investment, precertification expenses, project O&M, and ongoing O&M from 2006 to 2050. The figure of $133M used in the Executive Summary and Section 2 of this Report is ATC's direct cost for the project in nominal dollars, including capital, project O&M and precertification expenses, assuming a 2010 in-service date and construction on the proposed route.

Table 33 NPV of Net Benefits – 70% Adjusted Production Costs and 30% Load Weighted LMP

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Revenue Requirement	(136)	(136)	(136)	(136)	(136)	(136)	(136)
Construction Congestion Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)
PROMOD 70% Adjusted Production Costs and 30% Load Weighted LMP	483	386	1,335	159	27	1,469	734
FTR and Congestion	77	107	(323)	(1)	1	(445)	(155)
Losses	17	15	7	20	4	(13)	18
Competitiveness Limited Market-Based Pricing (avg.)	46	44	30	49	16	39	42
Insurance Benefit During System Failure Events	28	28	28	28	28	28	28
Capacity Savings From Reduced Losses	15	12	11	15	14	15	14
Total NPV of Net Benefits	**529**	**455**	**950**	**132**	**(47)**	**956**	**544**

Table 34 NPV of Net Benefits – Load Weighted LMP

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Revenue Requirement	(136)	(136)	(136)	(136)	(136)	(136)	(136)
Construction Congestion Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)
PROMOD Load Weighted LMP	1,026	807	2,447	343	68	2,733	1,562
FTR and Congestion	42	109	(427)	(18)	8	(703)	(243)
Losses	(52)	(44)	(125)	(30)	(9)	(131)	(70)
Competitiveness Limited Market-Based Pricing (avg.)	46	44	30	49	16	39	42
Insurance Benefit During System Failure Events	28	28	28	28	28	28	28
Capacity Savings From Reduced Losses	15	12	11	15	14	15	14
Total NPV of Net Benefits	**968**	**819**	**1,826**	**249**	**(12)**	**1,843**	**1,196**

Table 35 NPV of Net Benefits – ATC Customer Benefit

$ MILLIONS

	Robust Economy No NLAX - COL	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
ATC Revenue Requirement	(136)	(136)	(136)	(136)	(136)	(136)	(136)
Construction Congestion Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)
ATC Customer Benefit Including FTR, Congestion and Losses	458	410	778	150	23	765	418
Competitiveness Limited Market-Based Pricing (avg.)	46	44	30	49	16	39	42
Insurance Benefit During System Failure Events	28	28	28	28	28	28	28
Capacity Savings From Reduced Losses	15	12	11	15	14	15	14
Total NPV of Net Benefits	**409**	**356**	**710**	**104**	**(56)**	**710**	**365**

8. Transmission Alternatives to this Project

8.1 Summary of Alternatives

The system alternatives considered in the 2005 Access Initiative are listed below. More information about the process that identified these alternatives, the planning results for these alternatives, and the stakeholder discussions regarding these alternatives can be found in the filings in PSCW in Docket 137-EI-000.

The system alternatives evaluated were:

- **Alternative #1 - South:** a new Paddock-Rockdale 345 kV circuit.
- **Alternative #2 - Low voltage:** projects less than 345 kV.
- **Alternative #3 - West:** a new Prairie Island-North La Crosse-Columbia 345 kV line.
- **Alternative #4 - South:** a new Byron-North Monroe-West Middleton-North Madison 345 kV line.
- **Alternative #5 - Southwest:** a new Salem-Spring Green-West Middleton-North Madison 345 kV line with an uprate of the Salem-Maquoketa 161 kV line.

The PSCW Staff Report stated that "…preference should be given to the EHV access projects that provide the greatest net ratepayer economic benefit, all else being equal." This determination, along with consideration of the performance of the alternatives evaluated, provided ATC with guidance to pursue Alternative #1, the Paddock-Rockdale project.

8.2 Updated Construction Costs

ATC has revised its estimated construction costs to reflect recent increased labor and materials costs for transmission lines. To provide an apples-to-apples comparison of costs, estimates were also adjusted to reflect a 2010 in-service date. Table 36 compares the 2005 estimate to the revised estimates for the various alternatives.

Table 36 Revised Construction Cost of Alternative Projects ($ Millions)

Alternative	Filed with Access Docket	Revised to 2010 ISD	Mileage	Cost per Mile	Difference	% Increase
#1 - Paddock- Rockdale	$69	$131	34	$3.9	$62	90%
#2 – Low-Voltage	$33	$66			$33	99%
#3 - Prairie Island - North La Crosse – Columbia	$639	$847	251	$3.4	$208	32%
#3a - Prairie Island - North La Crosse		$455	133	$3.4		
#3b - North La Crosse - Columbia		$392	118	$3.3		
#4 - Byron - North Monroe - West Middleton - North Madison	$186	$323	97	$3.3	$137	74%
#5 - Salem – Spring Green - West Middleton - North Madison	$352	$631	149	$4.2	$279	79%

Notes:
1. Inflation is 5%.
2. Estimates include pre-certification, environmental impact fees as appropriate by state and environmental monitoring costs in addition to complete line and substation construction costs.
3. The 2010 date is for cost comparison and does not imply that in-service date is possible for any but the Paddock-Rockdale alternative.
4. Items 3a and 3b are segment breakdowns of Alternative #3, and not meant to be in addition to Alternative #3.

The revised construction cost estimates were not used to update the summary tables provided in the 2005 report (shown in table 1), because the relative rank of all projects remains the same with respect to the Paddock-Rockdale 345 kV project.

8.3 Comparing the Performance of Alternatives

Alternative #1 – Paddock-Rockdale. Paddock-Rockdale takes advantage of the recently added second 345 kV circuit to the Wempletown-Paddock line, making it a double circuit 345 kV project, and extends it into eastern Dane County. As the shortest project in length, almost entirely along existing ROW, it has certain cost and impact advantages. In addition, Paddock-Rockdale is the only option that could be constructed by June 2010 when the ECCH will expire for market participants in the ATC footprint. The projected savings due to the project exceed the estimated capital cost of the project.

For Alternative #1 studies indicate that during periods of higher probability of a double circuit outage (e.g., a severe storm warning), an import or corridor flow limit will be needed pre-contingency to mitigate post-contingency loadings. However, the risk of the loss of two circuits on a common tower is much lower than the loss of a single circuit. Therefore, from a reliability perspective, Alternative #1 is an improvement over Alternative #2, but not as much of an improvement as Alternatives #3 through #5.

Alternative #2 - Low Voltage Projects. In the 2005 analysis, Alternative #2, the "Low Voltage Package," consisted of the following transmission upgrades:

1. Rebuild of the 161-kV circuit between Lore and Nelson Dewey Substations via the Turkey River and Cassville Substations.
2. Installation of a second 345/138-kV transformer at the Paddock Substation and construction of a second 138-kV circuit between the Paddock and Town Line Road Substations.
3. Replacement of terminal equipment at the Hillman Substation to improve the rating of the Potosi-Hillman segment of the Nelson Dewey-Hillman 138-kV line.
4. Improve the rating of the 161-kV circuit between Hazelton and Dundee Substations.

In the Access Docket, the Low Voltage option provided the best benefit-cost ratio. For this reason, ATC undertook additional analysis of this option for comparison to Paddock-Rockdale. Since this option was initially specified, Alliant Energy has proposed building additional generation at the Nelson Dewey generating station and, as part of that effort, performing some of the transmission upgrades described above. ATC re-specified the alternative to reflect this development.

In ATC's analysis in 2006, the alternative consisted of the following transmission upgrades:

1. Build-out of the 345-kV and 138-kV GIS substation at Paddock with the addition of a second 345/138-kV 500/720 MVA rated transformer.
2. Rebuild of the existing X-39 138-kV circuit between Paddock and Town Line Road Substations to double circuit 138-kV. The modeling of the new line was based on the existing circuit with respect to ratings, impedances and line charging.
3. New construction of a 161-kV circuit between the Nelson Dewey (WI) and Liberty (IA) Substations. .

One weakness of this alternative is that it does not add any new EHV transmission lines to the system. In addition, the import capability of this study alternative is limited by the inability of the system to maintain adequate post-contingency voltage at higher transfer levels, i.e., the voltage limitations are reached before the thermal limitations in the first contingency total transfer capability analysis. This is an indication of the weakness of this alternative. Therefore, from a reliability perspective, Alternative #2 does not perform as well as the other alternatives.

There are other factors to consider for Alternative #2. A complicating factor for Alternative #2 is that the transmission lines need to be upgraded across the Mississippi River and the Dubuque, Iowa area. These lines are not owned by ATC. Therefore, arrangements for approvals, permitting, construction, ownership and compensation would need to be determined between ATC, Dairyland Power Cooperative and Alliant Energy – Interstate Power & Light.

An improvement to this area may also be needed in any event in 2011 due to Alliant Energy – Wisconsin Power & Light's announcement that they are seeking to construct a new coal-fired generating unit at the Nelson Dewey Substation. The required MISO generator interconnection planning studies for this proposed unit have been completed and are posted on the MISO website. Interconnection of the proposed unit at the Nelson Dewey site would require the construction of a new 161-kV circuit from Nelson Dewey into the 161-kV network near Lore. Therefore, the addition of this generator, along with its required transmission, essentially implements the core component of the low voltage alternative, which is the improvement of the Lore to Nelson Dewey

161-kV circuit. Given this possibility, the 2016 economics analysis included as a base assumption the construction of the proposed Nelson Dewey plant and its required transmission.

Finally, in the 20-Year Assessment studies, ATC also found that the southwestern portion of the ATC territory will likely need substantial EHV improvements within the next 15 years. In addition, the MISO has identified that an EHV extension to the Dubuque, Iowa area will be needed for reliability purposes within the next ten years. Since Alternative #2 involves a rebuild of the link between these two systems within the next five years but does not consider these longer term reliability needs, it would not be prudent to consider construction of Alternative #2.

ATC also calculated the net benefits of Paddock-Rockdale versus the Low-Voltage Option for all of the futures using the 70% APC/30% LLMP metric and the ATC Customer Benefit metric. As table 37 shows, Paddock-Rockdale outperforms the Low Voltage alternative in the great majority of the cases.

Table 37 Analysis of Paddock-Rockdale vs. Low Voltage Option – NPV of Net Savings

Paddock-Rockdale	$ MILLIONS						
	Robust Economy (No NLAX - COL)	**Robust Economy (NLAX - COL)**	**High Retirements**	**High Environ-mental**	**Slow Growth**	**Fuel Supply Disruption**	**High Growth Wisconsin**
Total benefits based on APC	313	272	547	55	(89)	547	238
Total benefits based on 70%/30%	501	428	922	105	(74)	928	517
Total benefits based on LLMP	940	791	1,799	222	(39)	1,816	1,168
Total benefits based on ATC Customer Benefit	382	329	682	77	(84)	682	338
Low Voltage	$ MILLIONS						
Total benefits based on APC	(227)	114	725	(109)	(61)	80	(93)
Total benefits based on 70%/30%	(195)	217	981	(132)	(67)	362	64
Total benefits based on LLMP	(119)	458	1,579	(184)	(82)	1,021	430
Total benefits based on ATC Customer Benefit	(211)	153	820	(112)	(62)	181	(33)

Note: ATC calculated the system-insurance value results for Paddock-Rockdale, but did not do so for the Low-Voltage option, because it would have required extensive additional time and resources. Instead, ATC concluded that it was highly likely that the Low-Voltage option would yield lower results for this benefit than an EHV option like Paddock-Rockdale. A brief analysis confirmed the accuracy of this assumption. To preserve the validity of the comparison between these two alternatives, ATC has excluded the system-insurance value results from this Table for both Paddock-Rockdale and the Low-Voltage Option.

Alternative #3 - Prairie Island-North La Crosse-Columbia. Alternative #3 does not measure up well when all of the various costs and benefits are considered. The principal disadvantage of this alternative is its very high cost in relationship to all the other projects. For these reasons, ATC does not consider Alternative #3 to be a viable project since it cannot be justified by its economic performance.

Alternative #4 – Byron-North Monroe-West Middleton-North Madison. Alternative #4 is not as cost-effective as Paddock-Rockdale. While Alternative #4 does provide system benefits, these do not compare favorably with Paddock-Rockdale when capital cost of the project and a longer completion time are taken into account. For these reasons, ATC does not consider Alternative #4 to be an appropriate selection.

Alternative #5 – Salem-Spring Green-West Middleton-North Madison. Alternative #5 is not as cost-effective as Paddock-Rockdale. While Alternative #5 does provide system benefits, these do not compare favorably with Paddock-Rockdale when the project's capital cost and longer completion time are taken into account. For these reasons, ATC does not consider Alternative #5 to be an appropriate selection.

9. Conclusions and Recommendations

Based on the above analysis, ATC concludes that the Paddock-Rockdale provides substantial economic, usage, service, and other benefits to Wisconsin customers.

ATC therefore seeks PSCW approval to place the Paddock-Rockdale project in-service by June 1, 2010.

Appendix A: Electrical one-line of substations and 345-kV line

Figure 2: Rockdale 345-kV Substation

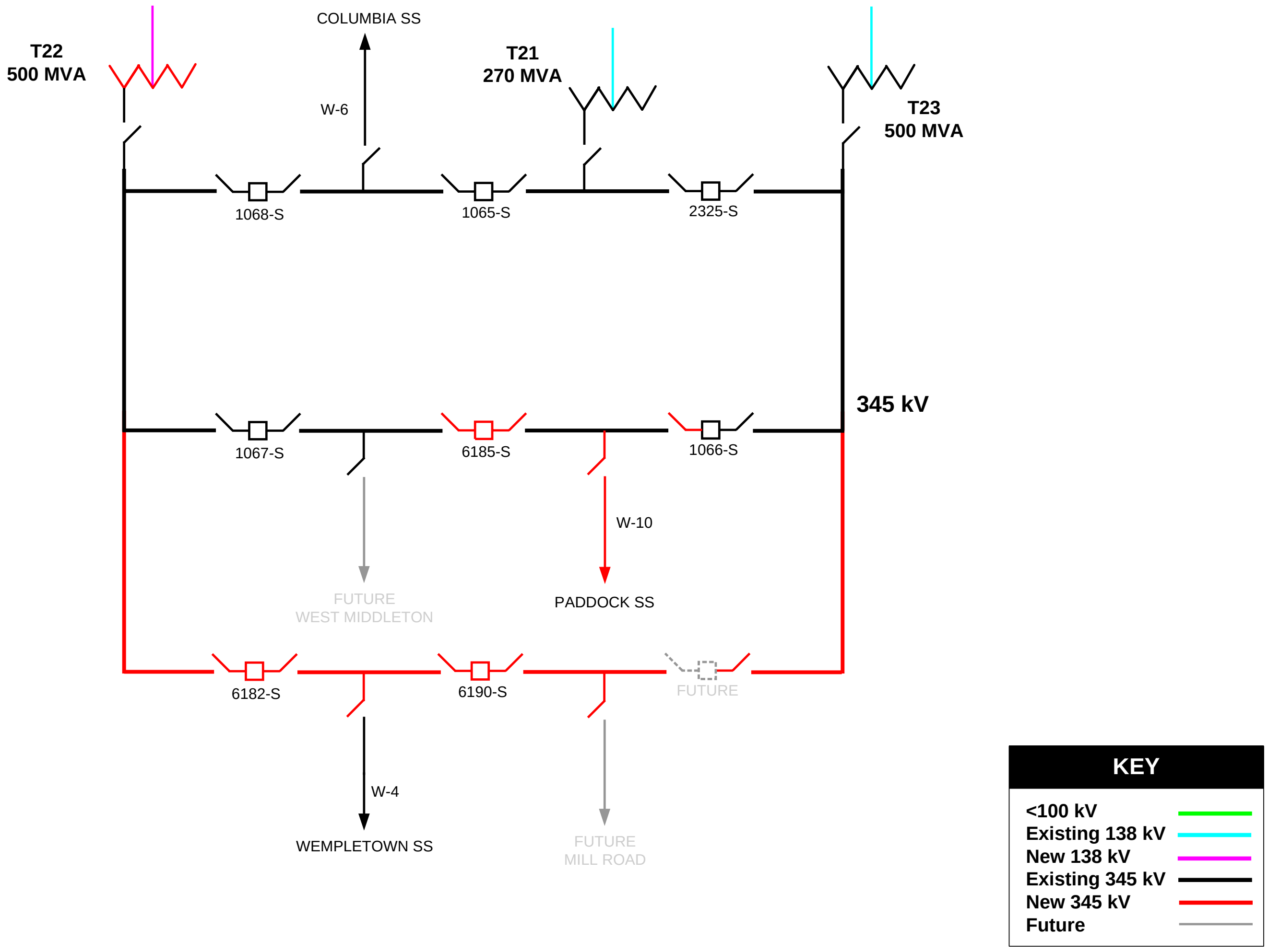


Figure 3: Christiana and Rockdale 138-kV Substations

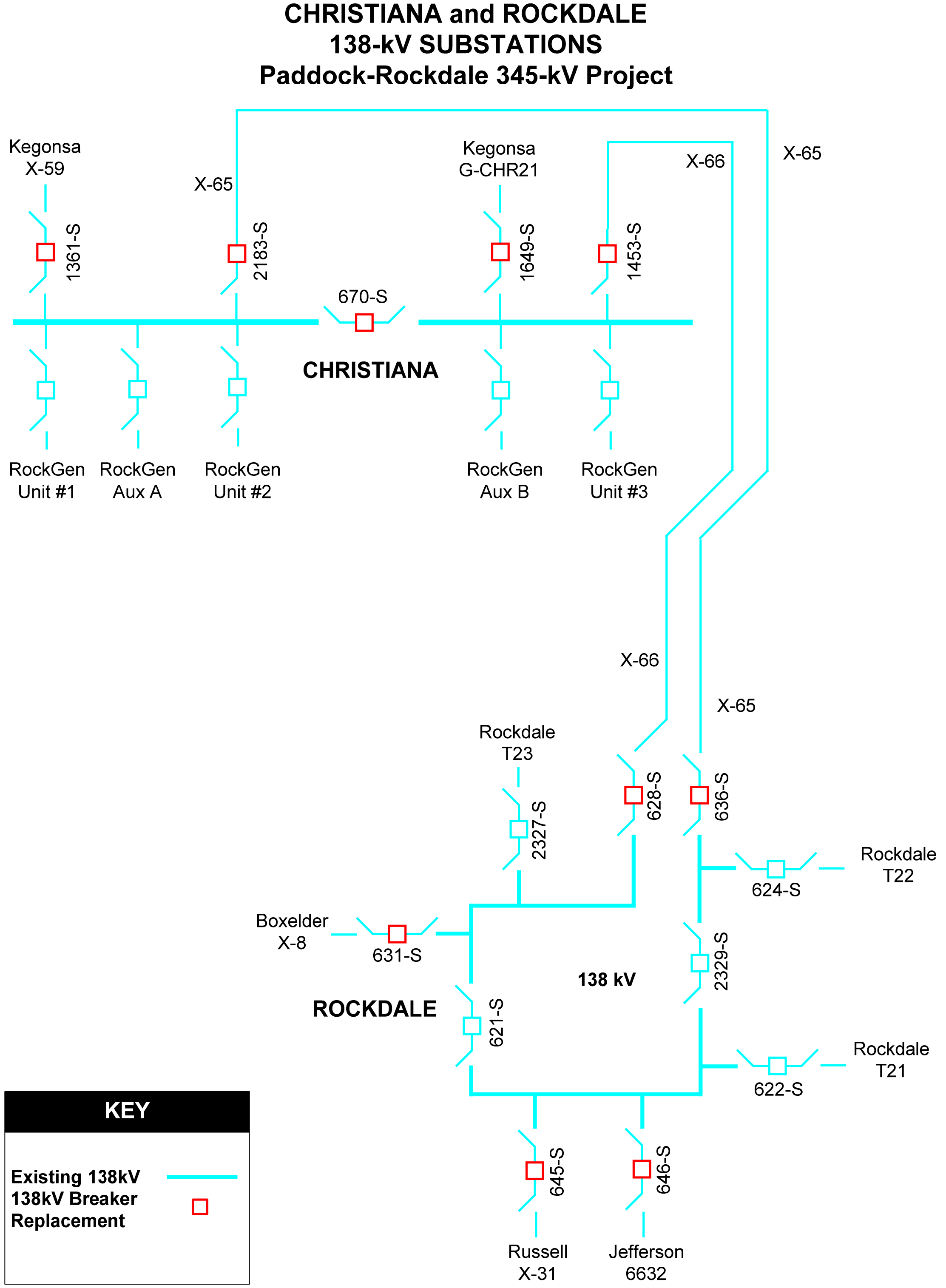


Figure 4: Paddock Substation

PADDOCK 345/138/69 KV
SUBSTATION
Paddock-Rockdale 345-kV Project

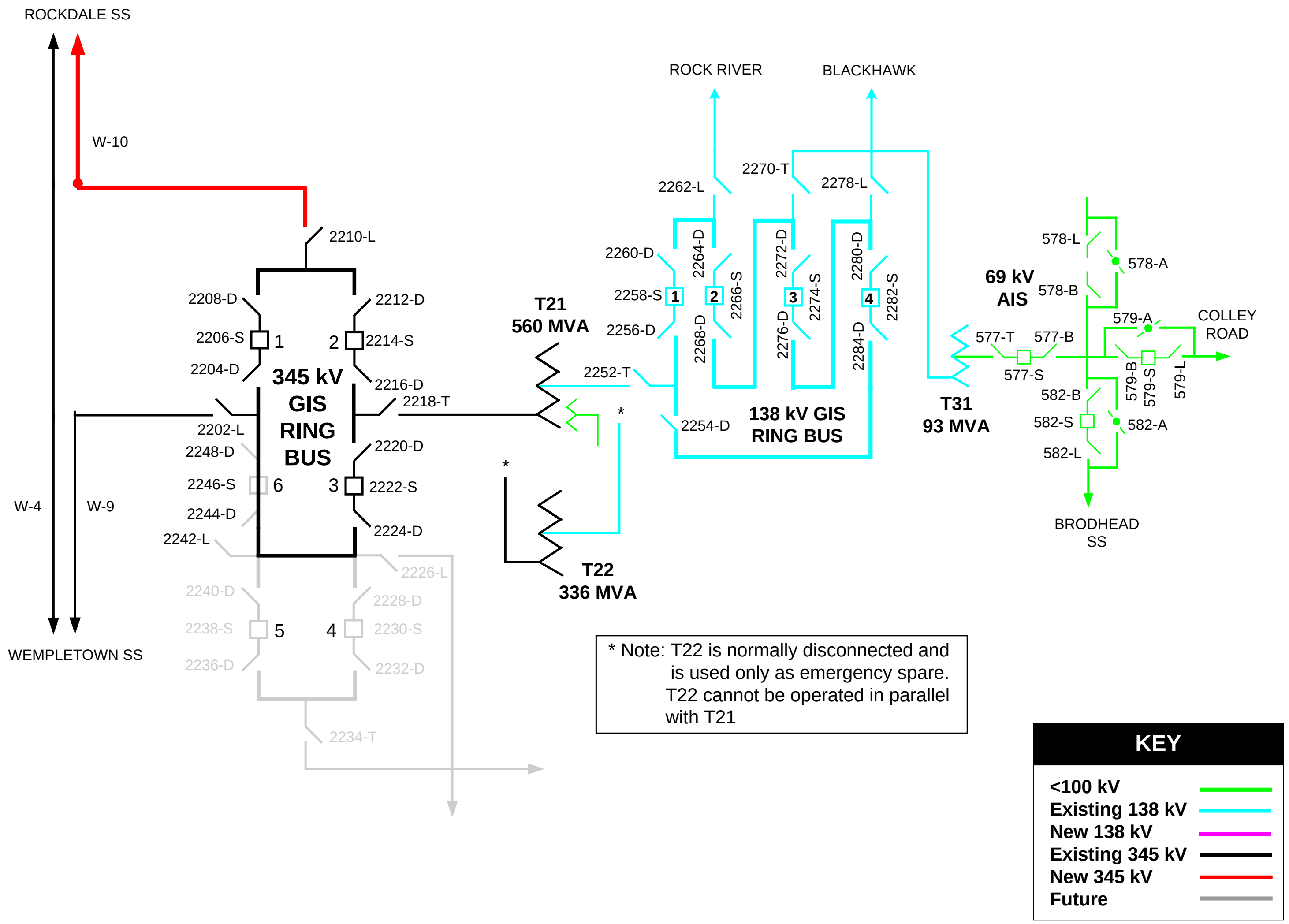
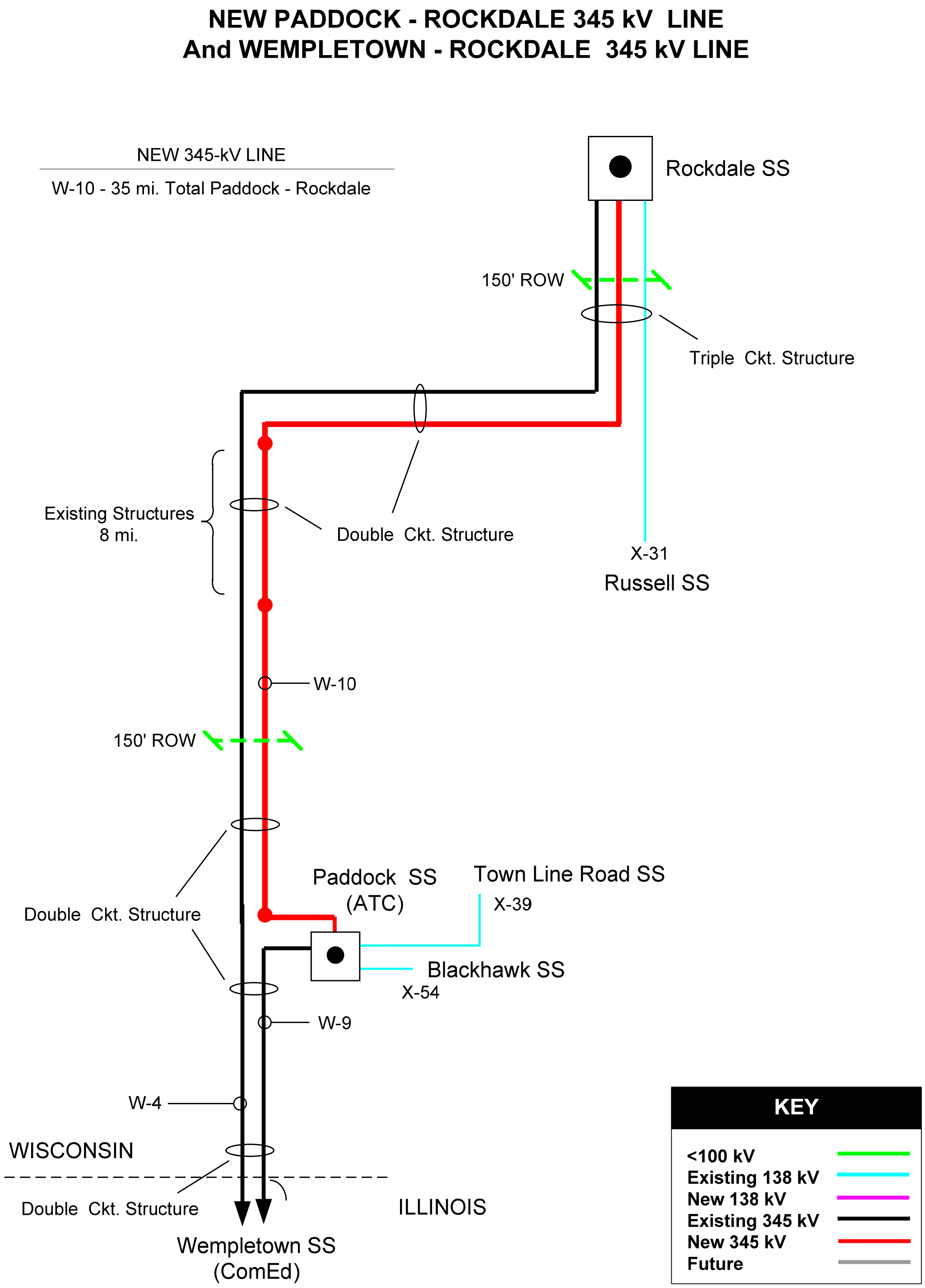


Figure 5: Paddock-Rockdale Transmission Line
Proposed Route Shown



Appendix B: Line Flows for EMF Calculations, along with Assumptions

Table 38 Line Flows for EMF-Calculations, along with Assumptions

Current Flow Under System Intact Condition

	2010 summer peak		2010 80% peak		2020 summer peak		2020 80% peak		2011 summer peak		2016 summer peak		PSS/E Bus
	Direction	Amps	Direction	Amps	Direction	Amps	Direction	Amps	Direction	Amps	Direction	Amps	Measured at
W-4 Wempletown-Rockdale	" + "	652	" + "	522	" + "	1042	" + "	834	" + "	669	" + "	944	36406
W-10 Paddock-Rockdale	" + "	620	" + "	496	" + "	1003	" + "	803	" + "	636	" + "	909	39058
X-12 Town Line Road-North Monroe													
X-12 Town Line Road-Albany	" + "	384	" + "	307	" + "	407	" + "	326	" + "	394	" + "	369	39141
X-31 Russell-Rockdale	" + "	306	" + "	245	" + "	439	" + "	351	" + "	314	" + "	398	39090
X-32 Town Line Road - Russell													
X-32 Town Line Road - Tripp Rd	" + "	484	" + "	387	" + "	618	" + "	495	" + "	496	" + "	560	39141
X-32 Tripp Rd - Viking	" + "	437	" + "	349	" + "	554	" + "	443	" + "	448	" + "	502	39213
X-32 Viking - Russell	" + "	362	" + "	289	" + "	461	" + "	369	" + "	371	" + "	418	39092
X-7 Town Line Road-Janesville General	" + "	365	" + "	292	" + "	471	" + "	377	" + "	374	" + "	427	39141
X-39 Paddock-Town Line Road	" ? "	165	" ? "	132	" ? "	295	" ? "	236	" ? "	169	" ? "	267	39059
Y-151 Russell-McCue													
Y-151 Russell-Parker Sw Str	" + "	318	" + "	254	" + "	421	" + "	336	" + "	326	" + "	381	39926
Y-38 Badger-Janesville General													
Y-38 Parker Sw Str-Badger Tap	" + "	0	" + "	0	" + "	0	" + "	0	" + "	0	" + "	0	39999
Y-38 Badger Tap-Janesville General	" ? "	9	" ? "	9	" ? "	9	" ? "	9	" ? "	9	" ? "	9	38101

NOTE:
1. For the 2011 summer peak base case (7-11-06_MTEP06_2011 Summer Peak PAD-ROE+Fix2c.sav), ATC imports are 1528 MW.
2. For the 2016 summer peak base case (8-2-2006_MISO_2016 Summer Peak PAD-ROE Package.sav), ATC imports are 1696 MW.
3. " + " means the current flow direction is from the first node listed to the second node listed in the description of the line segment.
4. " - " means the current flow direction is reversed from the description of the line segment.
5. Assumptions:

(1) Line current flow data for 80% peak models are calculated as 80% of the line current flow in the 100% summer peak model in the same year.

(2) Line current flow data for 2010 and 2020 years is based on an extrapolation from the 2011 and 2016 cases with a 2.5% increase in flow per year. That is, assume load growth of 2.5% in WUMS is served by increased imports. Note, this also assumes loop flows grow by

Appendix C: PROMOD Study Assumptions

Footprint Reduction

The purpose of creating a reduced footprint PROMOD case is to reduce the run times to reasonable levels. As PROMOD adds additional features, the run times can increase relative to hardware advances. Initial work with the MISO PROMOD cases indicated that runs would be at least 50-60 hours each. Reducing the footprint was found to bring the run time down to a range of 12-18 hours.

Footprint reduction is a practice that was recommended by NEA to improve run time and has been used regularly by MISO. NEA experience with footprint reduction indicates it is an acceptable practice. The process does not require any changes to the power flow (RAW) file. The footprint is set in the Powerbase data for use in PROMOD. Areas outside the PROMOD footprint will not have load or generation detail translated. For those areas, PROMOD assumes a static external system that is uniformly ramped to meet any interaction with the areas in the footprint. The external footprint retains the transmission topology translated from the power flow (RAW) file. Therefore, the reduced PROMOD footprint should not be referred to as an equivalized run.

The external footprint areas still interact with the internal footprint by means of defined transactions which are locked down based on the full footprint model. The full footprint model and a sample outage library are used for this evaluation. In order to measure the interaction in the full footprint model, interface events are created to represent the tie lines to the various external footprint areas. From the completed full footprint run, the tie line flows are converted into transactions used in the WTHC table. Import and export systems are defined to implement each transaction.

The external footprint is not dispatched to relieve transmission constraints (“events”). Thus, events in or very close to the external footprint may be difficult to regulate using the remaining internal footprint units. For that reason, events in or very close to the external footprint need to be removed from the tested events file. Review of the events to be excluded may take several passes to determine if significant internal footprint generation can be dispatched to mitigate their flows.

For the Paddock-Rockdale studies, we chose to reduce the footprint in 3 groupings: a northeast group (NY, NEPOOL, HQ), a southern group (Carolinas, FL, TVA, South, Entergy), and a third group for Southwest Power Pool (SPP), acting as a separate pool. The MISO case typically reduces the northeast (as NEPOOL and HQ) and FL. An alternate way of modeling is to include pricing files for determining the transaction between these areas. The MISO case was in this original format but NEA recommended the use of defined transactions for our study purposes, and MISO has also been moving in that direction.

When areas are outside the footprint, their power flow interchanges can contribute to a bias between external systems. NEA recommends performing a typical analysis of northern tie interfaces to determine values to zero out interaction between the Northeast and Florida. A similar review and adjustment were performed by NEA on the PAD-ROE reference cases.

Sample Results. Listed below are some LMP comparison results of the full footprint versus the reduced footprint. This data was from an earlier version of the PROMOD data that more closely represented the starting MISO case data.

Table 39 LMP Comparison Results

	FULL Footprint					REDUCED Footprint					DIFFERENCE (Reduced-Full)			
	MGE	WPL	WPPI	WPS		MGE	WPL	WPPI	WPS		MGE	WPL	WPPI	WPS
Average LMP (equal weight for each hr)	$35.27	$34.69	$34.34	$35.21		$36.10	$35.51	$35.02	$36.02		-$0.83	-$0.82	-$0.68	-$0.81
											MGE	WPL	WPPI	WPS
Hour 15 Average Difference in LMPs											-$1.21	-$1.29	-$1.24	-$1.11

The reduced footprint average LMPs are just over 2% higher than the full footprint LMPs.

Listed below are plots of the selected LMPs for the entire year and specifically hour 15 of each day during the year.

Figure 6

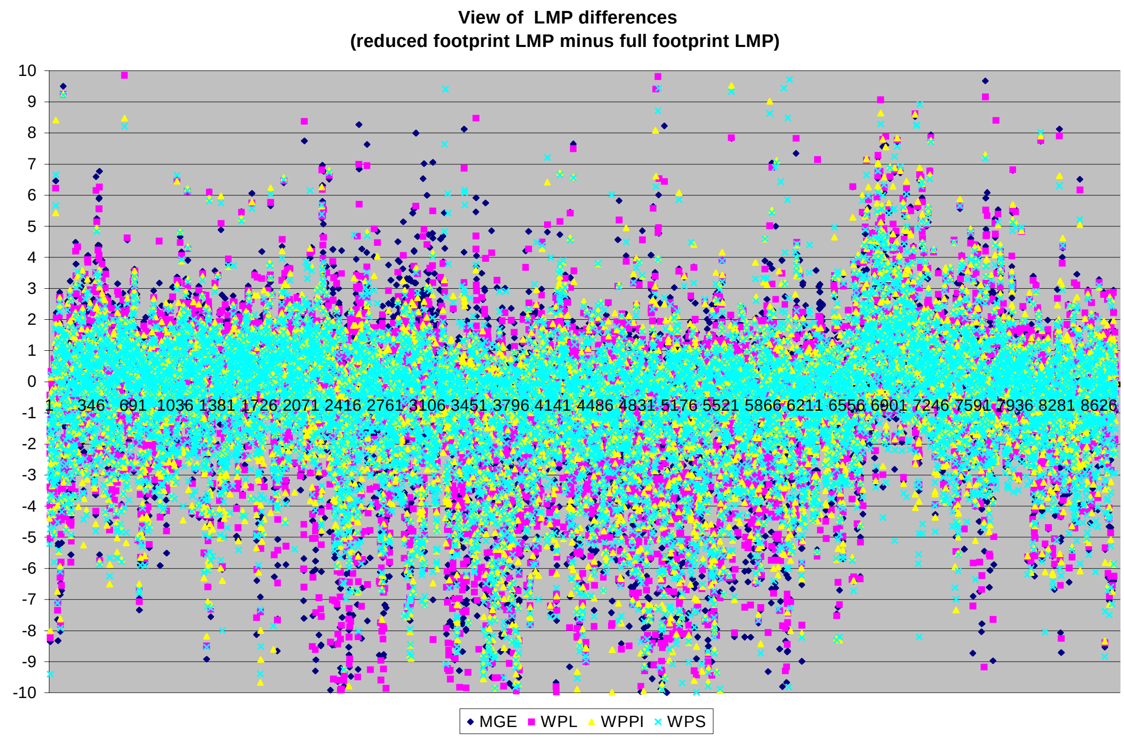
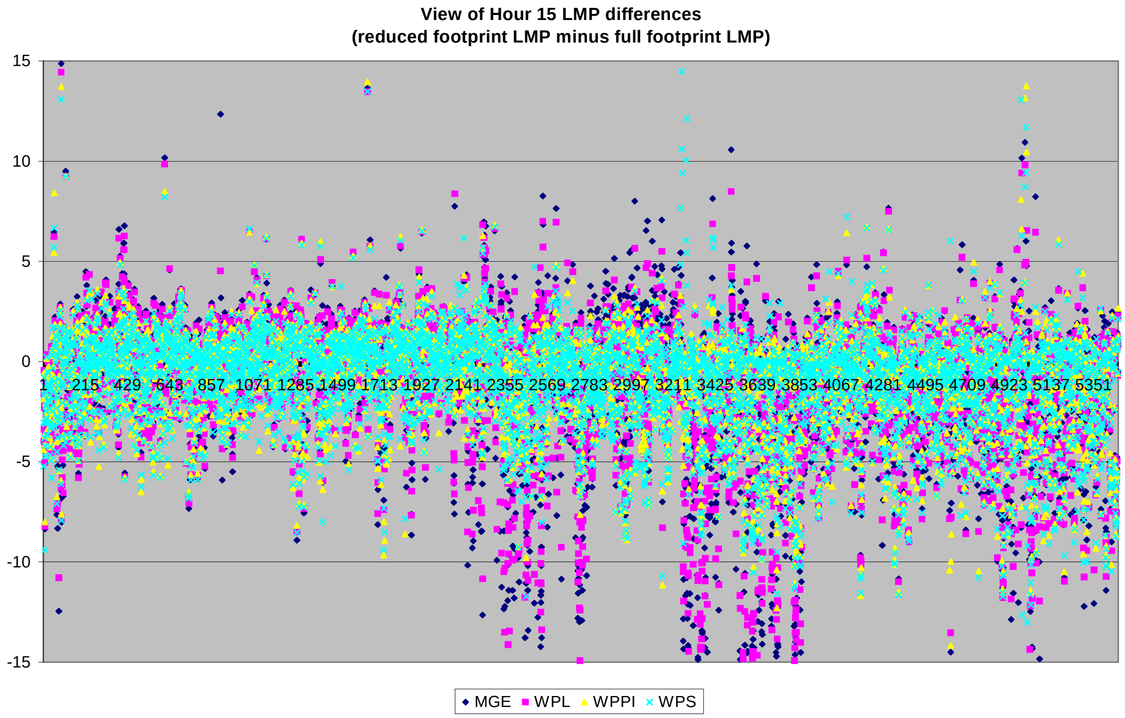


Figure 7



A review of the binding constraint shows that the results are comparable. There may be a slight increase in west to east bias.

Table 40 Annual Shadow Price Total ($K)

Constraint Name				Near / Far	Range	FULL	REDUCED
17DUNACR	28027	17MCHCTY	28053	NEAR	$128.49	$738	$609
MAREN;RT	36953	P VAL; R	37119	NEAR	$114.64	$168	$282
18MCGULP	28411	STRAITS	39753	NEAR	$30.22	$77	$107
NELSO; R	37039	NELSO;RT	37037	NEAR	$20.68	$15	$36
17BUROAK	28002	17BUROAK	28023	NEAR	$19.46	$34	$53
CORDO; B	36284	NELSO; B	36362	NEAR	$14.77	$9	$24
18FARRDJ	28313	18TIPPA	28532	NEAR	$10.79	$65	$76
REASNOR5	34191	DMOINES5	64062	NEAR	$10.76	$0	$11
PLS PR2	38849	ZION ; R	36421	NEAR	$7.20	$24	$32
KENOSH45	39345	LAKEVIEW	39362	NEAR	$5.86	$32	$38
NELSO; B	37038	DIXON;7B	36680	NEAR	$5.85	$7	$13
SLINE; R	37263	17WOLFLK	28087	NEAR	$5.47	$11	$6
GENOA 5	69523	LAC TAP5	69535	NEAR	$5.32	$7	$2
CRETE;BP	37646	17STJOHN	28013	NEAR	$3.87	$5	$1
OK CRK	39367	OC CRK8	38857	NEAR	$3.84	$6	$10
BUTLER	39268	GRANVL 5	39327	NEAR	$3.35	$3	$6
02LEMOYN	21706	19MON34	28806	NEAR	$1.72	$2	$1
LIME CK5	34015	EMERY 5	34016	NEAR	$1.39	$4	$2
SQBUTTE4	66756	ARROWHD4	61615	NEAR	$1.39	$5	$4
ZION ; R	36421	PLS PR2	38849	NEAR	$1.09	$8	$9
RACINE2	38853	OK CRK	39367	NEAR	$1.08	$17	$18
18ATLNTJ	28539	19ATLAN	28898	NEAR	$0.84	$1	$0
TRK RIV5	34033	CASVILL5	69503	NEAR	$0.59	$3	$2
ROE 345	39119	ROE 138	39120	NEAR	$0.58	$0	$1
NELSO; B	36362	ELECT; B	36310	NEAR	$0.56	$0	$1
GENOA 5	69523	COULEE 5	60302	NEAR	$0.50	$23	$23
17LESBRG	28046	17NRTHES	28062	NEAR	$0.32	$0	$0
BYRON 5	61948	MAPLE LF	61906	NEAR	$0.28	$3	$4
AIRTECH7	62865	W FARIB7	60107	NEAR	$0.26	$1	$0
17MUNSTR	28010	BURNH;0R	36279	NEAR	$0.26	$0	$0
HAZL S 5	34020	DUNDEE 5	34135	NEAR	$0.19	$0	$0
DYSART 5	34087	WASHBRN5	64269	NEAR	$0.15	$0	$0
LAKEFLD3	34006	LKFLDXL3	60331	NEAR	$0.11	$1	$1
CASVILL5	69503	NED 161	39010	NEAR	$0.11	$0	$0
SALEM 3	34029	SALEM N5	34030	NEAR	$0.09	$0	$0
PAD 345	39058	PAD 138	39059	NEAR	$0.06	$0	$0
LORE 5	34028	TRK RIV5	34033	NEAR	$0.06	$0	$0
PONTI; B	36344	WILTO; B	36414	NEAR	$0.05	$1	$1
18WHIT W	28563	18WHTNGA	28559	NEAR	$0.03	$1	$1
PAD 138	39059	TOWNLINE	39141	NEAR	$0.02	$0	$0

Load, Interruptibles, and Direct Control Load Management Forecasts

Load Forecasts

The peak load and energy usage forecasts used in the analysis for the ATC Footprint were developed based on the 2005 Energy Information Administration (EIA) Form 411 data for the control areas within the ATC footprint. The EIA Form 411 data is provided by the control areas and includes the projected summer peaks and the projected annual energies needed to develop the Forecasts. The 2005 EIA Form 411 includes data on the following control areas: Alliant Energy East (ALTE), Madison Gas and Electric (MGE), Upper Peninsula Power Company (UPPC), We-Energies (WEC), and Wisconsin Public Service Corporation (WPS).

Only the 2006 energy and peak load data was used from the 2005 EIA Form 411. To these starting values, various annual growth rates were applied (as specified for each Future in Table 6) to come up with the loads for 2011 and 2016. Due to the area setup in PROMOD and its supporting database, it was necessary to adjust the data for use in the analyses. UPPCo is not explicitly modeled as its own area in PROMOD. Its information is accounted for in the WEP control area. The 2005 EIA Form 411 data does not include information for WPPI, which is modeled as a separate area in PROMOD. As a result, various pieces of public information for WPPI were used to calculate appropriate peak and energy information, and were divided proportionally between the WEP and ALTE control areas. The corresponding values were subtracted from the WEP and ALTE control areas and used for the WPPI area in the analyses.

The control areas within ATC are predicting somewhat different annual load growth rates. To capture these differences, the percentages for each control area of ATC’s total load (based on the 2011 load forecast from the 2004 EIA Form 411) were used to develop different growth rates for each control area within ATC, but still provide the overall desired load growth rate for the entire ATC footprint. The 2004 EIA Form 411 was used for this task because it included specific information for WPPI while the 2005 EIA Form 411 did not. The peak load and energy usage forecasts used in the analyses can be found in tables 41 through 46.

Table 41 0.5% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2006 Energy (GWh)	Company Percentage of ATC 2011 Peak %	2011 Energy %	Forecast 2011 Peak (MW)	2011 Energy (GWh)	Forecast 2016 Peak (MW)	2016 Energy (GWh)	Growth Rates Peak %	Energy %
MGE	807	3588	5.85	4.98	830	3688	851	3781	0.53	0.53
WEP	6434	32233	45.78	44.93	6501	33257	6666	34097	0.35	0.56
ALTE	2817	14679	22.02	20.59	3128	15237	3207	15621	1.31	0.62
WPS	2912	17019	20.16	22.37	2863	16554	2935	16972	0.08	-0.03
WPPI	883	4674	6.20	7.13	880	5280	902	5413	0.22	1.48
ATC	13853	72193	100.00	100.00	14203	74016	14561	75885	0.50	0.50

Table 42 1.2% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2006 Energy (GWh)	Company Percentage of ATC 2011 Peak %	2011 Energy %	Forecast 2011 Peak (MW)	2011 Energy (GWh)	Forecast 2016 Peak (MW)	2016 Energy (GWh)	Growth Rates Peak %	Energy %
MGE	807	3588	5.85	4.98	860	3819	912	4053	1.23	1.23
WEP	6434	32233	45.78	44.93	6731	34432	7145	36548	1.05	1.26
ALTE	2817	14679	22.02	20.59	3239	15775	3438	16744	2.01	1.32
WPS	2912	17019	20.16	22.37	2964	17138	3146	18192	0.78	0.67
WPPI	883	4674	6.20	7.13	911	5466	967	5802	0.91	2.19
ATC	13853	72193	100.00	100.00	14704	76630	15608	81339	1.20	1.20

Table 43 1.7% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2006 Energy (GWh)	Company Percentage of ATC 2011 Peak %	2011 Energy %	Forecast 2011 Peak (MW)	2011 Energy (GWh)	Forecast 2016 Peak (MW)	2016 Energy (GWh)	Growth Rates Peak %	Energy %
MGE	807	3588	5.85	4.98	881	3914	958	4258	1.73	1.73
WEP	6434	32233	45.78	44.93	6899	35291	7506	38394	1.55	1.76
ALTE	2817	14679	22.02	20.59	3319	16168	3611	17590	2.51	1.83
WPS	2912	17019	20.16	22.37	3038	17566	3305	19111	1.27	1.17
WPPI	883	4674	6.20	7.13	934	5603	1016	6095	1.41	2.69
ATC	13853	72193	100.00	100.00	15071	78541	16396	85448	1.70	1.70

Table 44 2% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2005 EIA 411 Adjusted for PROMOD 2006 Energy (GWh)	Company Percentage of ATC 2011 Peak %	Company Percentage of ATC 2011 Energy %	Forecast 2011 Peak (MW)	Forecast 2011 Energy (GWh)	Forecast 2016 Peak (MW)	Forecast 2016 Energy (GWh)	Growth Rates Peak %	Growth Rates Energy %
MGE	807	3588	5.85	4.98	894	3972	987	4385	2.04	2.03
WEP	6434	32233	45.78	44.93	7001	35814	7730	39542	1.85	2.06
ALTE	2817	14679	22.02	20.59	3369	16408	3719	18116	2.82	2.13
WPS	2912	17019	20.16	22.37	3083	17827	3404	19682	1.57	1.46
WPPI	883	4674	6.20	7.13	948	5686	1046	6278	1.71	2.99
ATC	13853	72193	100.00	100.00	15295	79707	16887	88003	2.00	2.00

Table 45 2.7% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2005 EIA 411 Adjusted for PROMOD 2006 Energy (GWh)	Company Percentage of ATC 2011 Peak	Company Percentage of ATC 2011 Energy	Forecast 2011 Peak (MW)	Forecast 2011 Energy (GWh)	Forecast 2016 Peak (MW)	Forecast 2016 Energy (GWh)	Growth Rates Peak	Growth Rates Energy
MGE	807	3588	5.85%	4.98%	925	4110	1057	4696	2.74%	2.73%
WEP	6434	32233	45.78%	44.93%	7245	37060	8277	42341	2.55%	2.77%
ALTE	2817	14679	22.02%	20.59%	3486	16979	3982	19398	3.52%	2.83%
WPS	2912	17019	20.16%	22.37%	3190	18447	3645	21075	2.27%	2.16%
WPPI	883	4674	6.20%	7.13%	981	5884	1120	6722	2.41%	3.70%
ATC	13853	72193	100.00%	100.00%	15827	82480	18082	94232	2.70%	2.70%

Table 46 3% Load Growth Forecasts for 2011 & 2016

Company	2005 EIA 411 Adjusted for PROMOD 2006 Peak (MW)	2005 EIA 411 Adjusted for PROMOD 2006 Energy (GWh)	Company Percentage of ATC 2011 Peak	Company Percentage of ATC 2011 Energy	Forecast 2011 Peak (MW)	Forecast 2011 Energy (GWh)	Forecast 2016 Peak (MW)	Forecast 2016 Energy (GWh)	Growth Rates Peak	Growth Rates Energy
MGE	807	3588	5.85%	4.98%	939	4170	1088	4835	3.04%	3.03%
WEP	6434	32233	45.78%	44.93%	7351	37605	8522	43594	2.85%	3.07%
ALTE	2817	14679	22.02%	20.59%	3537	17228	4100	19972	3.83%	3.13%
WPS	2912	17019	20.16%	22.37%	3237	18718	3753	21699	2.57%	2.46%
WPPI	883	4674	6.20%	7.13%	995	5970	1154	6921	2.71%	4.00%
ATC	13853	72193	100.00%	100.00%	16059	83691	18617	97021	3.00%	3.00%

Interruptible Load and Direct Control Load Management

Interruptible Load and Direct Control Load Management were modeled together in PROMOD as Interruptible Loads. The 2011 forecast data for these items was taken from the 2005 EIA Form 411. The data for Interruptible Load and Direct Control Load Management was summed to represent the total load management available for each area. This value was then divided and distributed over several locations in each control area. The locations were chosen based on engineering judgment, as actual locations are unavailable. The information used in the analyses is shown in table 47.

As data for WPPI was unavailable in the 2005 EIA Form 411, the default data provided by New Energy Associates was used.

The data for the WEP and WPL areas is incorrectly overstated. Fortunately, this error did not have a significant effect on the analyses, because very little load management was dispatched due to its high cost.

Table 47 Interruptible Loads Assumed for the Analyses

Name	Area	Maximum Capacity (MW)	Location
MGE Interruptible:1	Madison Gas & Electric Co.	23	Blount 138 kV Bus
MGE Interruptible:2	Madison Gas & Electric Co.	22	Huiskamp 138 kV Bus
MGE Interruptible:3	Madison Gas & Electric Co.	22	Fitchburg 138 kV Bus
WEP Interruptible:1	We Energies	170[1]	Bluemound 138 kV Bus
WEP Interruptible:2	We Energies	170[2]	Saukville 138 kV Bus
WEP Interruptible:3	We Energies	170[3]	Empire 138 kV Bus
WPL Interruptible:1	Wisconsin Power & Light Co.	74[4]	Huebner 138 kV Bus
WPL Interruptible:2	Wisconsin Power & Light Co.	74[4]	Janesville 138 kV Bus
WPL Interruptible:3	Wisconsin Power & Light Co.	74[4]	North Fond du Lac 138 kV Bus
WPPI Interruptible:1	Wisconsin Public Power, Inc. System	24	Appleton Papers 138 kV Bus
WPS Interruptible:1	Wisconsin Public Service Corp.	101	Eastman 138 kV Bus
WPS Interruptible:2	Wisconsin Public Service Corp.	101	Rocky Run 138 kV Bus
WPS Interruptible:3	Wisconsin Public Service Corp.	101	Butte des Morts 138 kV Bus
WPS Interruptible:4	Wisconsin Public Service Corp.	25	Cranberry 115 kV Bus

[1]*Intended to be 81 MW*
[2]*Intended to be 80 MW*
[3]*Intended to be 212 MW*
[4]*Intended to be 48 MW*

Generation

Generation within the ATC Footprint

Table 48 contains a list of currently existing generation inside the ATC footprint that were included in all models for the analyses. The maximum capacity listed is the emergency maximum capacity for the units, and is only achievable under specific conditions for short periods of time.

Table 48 Existing Generation within the ATC Footprint included in the models for all analyses

Name	Category	Area	Maximum Capacity (MW)
Alexander (WPS):HYOP3	Hydro Storage	Wisconsin Public Service Corp.	6.6
Autrain:HYOP2	Hydro Run-of-River	We Energies	1.1
BHP Copper White Pine Ref. Inc .:GEN1	ST Coal	We Energies	20.0
BHP Copper White Pine Ref. Inc .:GEN2	ST Coal	We Energies	20.0
BIG POND:New CT	CT Gas	Wisconsin Power & Light Co.	17.9
Big Quinnesec 61:HYOP2	Hydro Run-of-River	We Energies	8.0
Big Quinnesec 92:HYOP2	Hydro Run-of-River	We Energies	9.1
Biron:HYOP4	Hydro Run-of-River	Wisconsin Public Service Corp.	5.6
Blackhawk:3	ST Gas	Wisconsin Power & Light Co.	27.0
Blackhawk:4	ST Gas	Wisconsin Power & Light Co.	27.0
Blount:3	ST Gas	Madison Gas & Electric Co.	41.7
Blount:4	ST Coal	Madison Gas & Electric Co.	23.8
Blount:5	ST Gas	Madison Gas & Electric Co.	30.3
Blount:6	ST Gas	Madison Gas & Electric Co.	53.0
Blount:7	ST Gas	Madison Gas & Electric Co.	50.8
Brule:HYOP3	Hydro Run-of-River	We Energies	5.7
Caldron Falls:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	6.9
Castle Rock:HYOP5	Hydro Run-of-River	Wisconsin Power & Light Co.	17.5
Cataract (UPP):HYOP1	Hydro Run-of-River	We Energies	1.5
Chalk Hill:HYOP3	Hydro Run-of-River	We Energies	6.0
Columbia (WPL):1	ST Coal	Wisconsin Power & Light Co.	559.0
Columbia (WPL):2	ST Coal	Wisconsin Power & Light Co.	588.0
Combined Locks Energy Center:WPS Power Development Inc	CT Gas	We Energies	48.0
Combined Locks:HYOP2	Hydro Run-of-River	Wisconsin Public Power, Inc. System	6.0
Concord:1	CT Gas	We Energies	100.0
Concord:2	CT Gas	We Energies	100.0
Concord:3	CT Gas	We Energies	100.0
Concord:4	CT Gas	We Energies	100.0
Custer Energy Center:1	CT Gas	Wisconsin Public Service Corp.	17.0
Dafter:GTOL5	CT Oil	We Energies	7.7
De Pere Energy Center:GT	CT Gas	Wisconsin Public Service Corp.	191.6

Name	Category	Area	Maximum Capacity (MW)
Detour:GTOL2	CT Oil	We Energies	5.0
Dewey:1	ST Coal	Wisconsin Power & Light Co.	113.0
Dewey:2	ST Coal	Wisconsin Power & Light Co.	114.0
Du Bay:HYOP4	Hydro Run-of-River	Wisconsin Public Service Corp.	7.2
Eagle River:GTOL2	CT Oil	Wisconsin Public Service Corp.	4.0
Edgewater (WPL):3	ST Coal	Wisconsin Power & Light Co.	74.0
Edgewater (WPL):4	ST Coal	Wisconsin Power & Light Co.	342.0
Edgewater (WPL):5	ST Coal	Wisconsin Power & Light Co.	402.0
Edison Sault:HYOP73	Hydro Run-of-River	We Energies	41.5
ESC STM:New CT	CT Gas	Wisconsin Public Service Corp.	17.9
Escanaba:STCL2	ST Coal	We Energies	26.3
Fitchburg (MGE):1	CT Gas	Madison Gas & Electric Co.	24.3
Fitchburg (MGE):2	CT Gas	Madison Gas & Electric Co.	23.1
Fox Energy Center (Kaukauna):CC	Combined Cycle (existing)	Wisconsin Public Service Corp.	540.0
Germantown:1	CT Oil	We Energies	77.3
Germantown:2	CT Oil	We Energies	77.3
Germantown:3	CT Oil	We Energies	77.3
Germantown:4	CT Oil	We Energies	77.3
Germantown:5	CT Gas	We Energies	135.0
Gladstone - UPP:1	CT Oil	We Energies	25.4
Grand Rapids (WPS):HYOP5	Hydro Run-of-River	Wisconsin Public Service Corp.	11.4
Grandfather Falls:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	17.6
Hemlock Falls:HYOP1	Hydro Run-of-River	We Energies	1.8
High Falls (WPS):HYOP5	Hydro Run-of-River	Wisconsin Public Service Corp.	7.0
Hoist:HYOP3	Hydro Run-of-River	We Energies	4.3
Johnson Falls:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	4.0
Kaukauna (WPPI):GT	CT Gas	Wisconsin Public Power, Inc. System	52.0
Kaukauna Hy:HYOP2	Hydro Run-of-River	Wisconsin Public Power, Inc. System	4.8
Kaukauna:GT1	CT Gas	Wisconsin Public Power, Inc. System	19.1
Kewaunee:1	Nuclear (existing)	Wisconsin Public Service Corp.	578.0
Kilbourn:HYOP4	Hydro Run-of-River	Wisconsin Power & Light Co.	9.5
Kimberly-Clark Corporation-Mun:M387	ST Coal	We Energies	6.3
Kingsford:HYOP3	Hydro Run-of-River	We Energies	6.0
Main Street Plant:STCL2	ST Coal	We Energies	45.0
Manistique:GTOL2	CT Oil	We Energies	4.8
Manitowoc:5	ST Coal	Wisconsin Public Service Corp.	22.0
Manitowoc:GTGS2	CT Gas	Wisconsin Public Service Corp.	10.5
Manitowoc:ST	Steam Turbine (existing)	Wisconsin Public Service Corp.	58.0
McClure (UPP):HYOP2	Hydro Run-of-River	We Energies	8.7
Merrill:HYOP3	Hydro Run-of-River	Wisconsin Public Service Corp.	3.8
Michigamme Falls:HYOP2	Hydro Run-of-River	We Energies	8.8
Milwaukee County:1	ST Coal	We Energies	12.0
Montfort Wind Farm:WIOP1	Wind	We Energies	30.6

Name	Category	Area	Maximum Capacity (MW)
Neenah:GT1	CT Gas	Wisconsin Power & Light Co.	150.0
Neenah:GT2	CT Gas	Wisconsin Power & Light Co.	150.0
New_BLUESKYWIND	Wind	We Energies	80.0
New_GRNFLDWIND	Wind	We Energies	80.0
Nine Springs:GT1	CT Gas	Madison Gas & Electric Co.	21.3
Oak Creek South:5	ST Coal	We Energies	262.1
Oak Creek South:6	ST Coal	We Energies	265.1
Oak Creek South:7	ST Coal	We Energies	298.0
Oak Creek South:8	ST Coal	We Energies	314.0
Oak Creek South:9	CT Gas	We Energies	22.5
Paris (WEP):1	CT Gas	We Energies	100.0
Paris (WEP):2	CT Gas	We Energies	100.0
Paris (WEP):3	CT Gas	We Energies	100.0
Paris (WEP):4	CT Gas	We Energies	100.0
Peavy Falls:HYOP2	Hydro Run-of-River	We Energies	15.0
Petenwell:HYOP4	Hydro Run-of-River	Wisconsin Public Service Corp.	20.0
Pine:HYOP2	Hydro Run-of-River	We Energies	4.0
Plant Four:GT1	CT Oil	We Energies	23.0
Plant Two:HYOP2	Hydro Run-of-River	We Energies	2.0
Pleasant Prairie:1	ST Coal	We Energies	616.9
Pleasant Prairie:2	ST Coal	We Energies	592.3
Point Beach:1	Nuclear (existing)	We Energies	517.0
Point Beach:2	Nuclear (existing)	We Energies	519.0
Point Beach:5	CT Oil	We Energies	24.0
Port Washington (Wep):CC	Combined Cycle (existing)	We Energies	545.0
Portage - UPP:1	CT Oil	We Energies	25.4
Prairie Du Sac:HYOP8	Hydro Run-of-River	Wisconsin Power & Light Co.	30.0
Presque Isle:1	ST Coal	We Energies	25.0
Presque Isle:2	ST Coal	We Energies	37.0
Presque Isle:3	ST Coal	We Energies	58.0
Presque Isle:4	ST Coal	We Energies	58.0
Presque Isle:5	ST Coal	We Energies	87.0
Presque Isle:6	ST Coal	We Energies	90.0
Presque Isle:7	ST Coal	We Energies	85.0
Presque Isle:8	ST Coal	We Energies	85.0
Presque Isle:9	ST Coal	We Energies	88.0
Prickett:HYOP2	Hydro Run-of-River	We Energies	2.2
Pulliam:3	ST Coal	Wisconsin Public Service Corp.	28.2
Pulliam:4	ST Coal	Wisconsin Public Service Corp.	31.0
Pulliam:5	ST Coal	Wisconsin Public Service Corp.	50.2
Pulliam:6	ST Coal	Wisconsin Public Service Corp.	65.0
Pulliam:7	ST Coal	Wisconsin Public Service Corp.	82.0
Pulliam:8	ST Coal	Wisconsin Public Service Corp.	132.0
Pulliam:GT	CT Gas	Wisconsin Public Service Corp.	85.0
Riverside Energy Center:CC	Combined Cycle (existing)	Wisconsin Power & Light Co.	655.0

Name	Category	Area	Maximum Capacity (MW)
Rock River:1	ST Gas	Wisconsin Power & Light Co.	74.9
Rock River:2	ST Gas	Wisconsin Power & Light Co.	76.9
Rock River:3	CT Oil	Wisconsin Power & Light Co.	20.8
Rock River:4	CT Oil	Wisconsin Power & Light Co.	17.2
Rock River:5	CT Oil	Wisconsin Power & Light Co.	50.2
Rock River:6	CT Oil	Wisconsin Power & Light Co.	58.3
Rockgen Energy Center:1	CT Gas	Wisconsin Power & Light Co.	175.0
Rockgen Energy Center:2	CT Gas	Wisconsin Power & Light Co.	175.0
Rockgen Energy Center:3	CT Gas	Wisconsin Power & Light Co.	175.0
Rosiere (MGE):WIOP1	Wind	Madison Gas & Electric Co.	11.2
Saint Marys Falls:HYOP5	Hydro Run-of-River	We Energies	20.0
Sandstone Rapids:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	4.0
Sheboygan Falls:CT 1	CT Gas	Wisconsin Power & Light Co.	150.0
Sheboygan Falls:CT 2	CT Gas	Wisconsin Power & Light Co.	150.0
Sheepskin:1	CT Oil	Wisconsin Power & Light Co.	43.9
Shiras:2	ST Coal	We Energies	21.0
Shiras:3	ST Coal	We Energies	43.7
South Fond Du Lac:GT1	CT Gas	Wisconsin Power & Light Co.	88.0
South Fond Du Lac:GT2	CT Gas	Wisconsin Power & Light Co.	88.0
South Fond Du Lac:GT3	CT Gas	Wisconsin Power & Light Co.	88.0
South Fond Du Lac:GT4	CT Gas	Wisconsin Power & Light Co.	85.0
Stevens Point:HYOP6	Hydro Run-of-River	Wisconsin Public Service Corp.	4.8
Sycamore (MGE):1	CT Gas	Madison Gas & Electric Co.	15.8
Sycamore (MGE):2	CT Gas	Madison Gas & Electric Co.	23.4
Tomahawk:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	2.2
Twin Falls (WEP):HYOP5	Hydro Run-of-River	We Energies	6.0
Valley (WEP):1	ST Coal	We Energies	140.0
Valley (WEP):2	ST Coal	We Energies	134.0
Victoria (UPP):HYOP2	Hydro Run-of-River	We Energies	12.3
Wausau:HYOP3	Hydro Run-of-River	Wisconsin Public Service Corp.	9.7
Way:HYOP1	Hydro Run-of-River	We Energies	1.4
West Campus Cogeneration Facility:CC	Combined Cycle (existing)	Madison Gas & Electric Co.	150.0
West Marinette (Mge):34	CT Gas	Madison Gas & Electric Co.	93.2
West Marinette:31	CT Gas	Wisconsin Public Service Corp.	50.2
West Marinette:32	CT Gas	Wisconsin Public Service Corp.	46.0
West Marinette:33	CT Gas	Wisconsin Public Service Corp.	105.5
Weston (WPS):1	ST Coal	Wisconsin Public Service Corp.	68.1
Weston (WPS):2	ST Coal	Wisconsin Public Service Corp.	90.7
Weston (WPS):3	ST Coal	Wisconsin Public Service Corp.	341.1
Weston (WPS):31	CT Gas	Wisconsin Public Service Corp.	24.0
Weston (WPS):32	CT Gas	Wisconsin Public Service Corp.	61.4
White Rapids:HYOP3	Hydro Run-of-River	We Energies	7.8
Whitewater Cogeneration Facility:CC	Combined Cycle (existing)	We Energies	251.3
Wisconsin Rapids Division:HYOP3	Hydro Run-of-River	Wisconsin Public Service Corp.	9.3

Name	Category	Area	Maximum Capacity (MW)
Wisconsin Rapids Pulp Mill:BIRON PM	ST Coal	Wisconsin Public Service Corp.	29.1
Wisconsin Rapids Pulp Mill:HOT POND	ST Coal	Wisconsin Public Service Corp.	20.8
Wisconsin Rapids Pulp Mill:KRAFT	ST Coal	Wisconsin Public Service Corp.	42.6
Wisconsin River Div:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	5.5

Tables 49 and 50 contain lists of planned and possible future units which were added for the 2011 and 2016 analyses respectively.

Table 49 Planned Units added for all 2011 Analyses

Unit Name	Category	Area	Maximum Capacity (MW)
Butler Ridge Wind Farm	Renewable	We Energies	54
Elm Road Generating Station [Oak Creek North]:ST1	Steam Turbine	We Energies	615
Elm Road Generating Station [Oak Creek North]:ST2	Steam Turbine	We Energies	615
Forward Energy Center Wind Farm (Butternut)	Renewable	We Energies	200
Port Washington:CC2	Combined Cycle	We Energies	545
Weston:4	Steam Turbine	Wisconsin Public Service Corp.	515

Table 50 Planned and Possible Future Units added for all 2016 Analyses

Unit Name	Category	Area	Maximum Capacity (MW)
Butler Ridge Wind Farm	Renewable	We Energies	54
Elm Road Generating Station [Oak Creek North]:ST1	Steam Turbine	We Energies	615
Elm Road Generating Station [Oak Creek North]:ST2	Steam Turbine	We Energies	615
Forward Energy Center Wind Farm (Butternut)	Renewable	We Energies	200
New_Darlington	Renewable	Wisconsin Power & Light Co.	99
New_Green Lake	Renewable	Wisconsin Power & Light Co.	160
New_Lake Breeze	Renewable	We Energies	98
New_Randolph Wind	Renewable	Wisconsin Power & Light Co.	80
New_Twin Creeks	Renewable	Wisconsin Public Service Corp.	99
New_Whistling Wind	Renewable	Wisconsin Power & Light Co.	50
Port Washington:CC2	Combined Cycle	We Energies	545
Weston:4	Steam Turbine	Wisconsin Public Service Corp.	515

Tables 51 and 52 contain generators that were added within the ATC Footprint for particular 2011 and 2016 analyses respectively. The proposed new Nelson Dewey unit was modeled based on a similar unit from the 2005 ATC Access Initiative PowerBase Database, specifically the Seward:PB1 unit. Please note that the Seward:PB1 unit from the 2005 ATC Access Initiative PowerBase database is not the same as the Seward:PB1 unit from the database used for these analyses. The operating characteristics and costs for a future Weston 5 unit are the same as for the Weston 4 unit (both units are coal fired).

Table 51 Generating Unit Additions within ATC for the Various Analyses for 2011

Unit Name	Maximum Capacity (MW)	Estimated Commission Date	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Nelson Dewey	280.0	2012	X		X		X	
Total Additions (MW)	**280**		**280**	**0**	**280**	**0**	**280**	**0**

Table 52 Generating Unit Additions within ATC for the Various Analyses for 2016

Unit Name	Maximum Capacity (MW)	Estimated Commission Date	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Nelson Dewey	280.0	2012	X		X	X	X	X
Weston 5	515.0	2016	X					
Total Additions (MW)	**795**		**795**	**0**	**280**	**0**	**280**	**0**

Generation additions outside ATC – description of the need to meet planning reserves

For future study years, like 2011 and 2016, sufficient generation must be included in PROMOD to meet the minimum planning reserve requirements set by the regional North American Electric Reliability Council (NERC) Reliability Councils. These planning reserve requirements are normally set based on a Loss of Load Expectation (LOLE) analysis. The LOLE is defined as the fraction of time that electricity demand is likely to exceed available sources of power (including internal generation, load control measures and imported power) for a given system. The LOLE criterion is typically loss of load no more than 0.1 days per year or one day in ten years. The LOLE only considers electricity shortfalls on the bulk, high-voltage power system.

Two methods can be used for meeting the minimum planning reserve requirements in PROMOD. One method is to add generators for future study years. This was done for MISO and the Commonwealth Edison (CE) portion of PJM based on an analysis done by the consulting firm, E3. Alternatively, forecasted load for a future study year can be reduced in the model so that the generation available in PROMOD meets the requirements. This was done for PJM, except as noted for CE.

Generation additions outside ATC – MISO & Commonwealth Edison

Generation additions were made to the model in an effort to simulate enough generation to meet the load demands of the region in both 2011 and 2016. Consultants from E3 Consulting and NewEnergy Associates were assigned different portions of this task.

E3 worked to determine how many megawatts of generation were necessary throughout the MISO and Commonwealth Edison regions along with the optimal mix of generation types needed to attain the generation levels described below. E3 used two different sets of growth assumptions:

1. 2% demand and energy growth over the period and middle of the road assumptions on all other pertinent variables (e.g. environmental regulations, renewable portfolio standards, etc.); this was referred to as "status quo"
2. 1.2% demand and energy growth in a Kyoto world with $44/ton CO2 tax and a heavy reliance on IGCC plants

E3 also worked to ascertain what specific grid points throughout the region would be best suited to locate new generation.[20] Upon completion of their study E3 provided lists of reasonable generation types and locations for addition to the PROMOD models. In addition, NewEnergy Associates also provided lists of generating units which could be used as realistic additions to the future year PROMOD models.

The generation capacity needs as provided by E3 were based on a flat load profile throughout the study region. However, the load growth rates and corresponding levels vary across the futures. As such, calculations were done to adjust the necessary megawatt levels of generation both by type and regional location to meet the reserve margin requirements of the regions (based on the different forecasted load levels assumed in each future). From this point, generating units were placed into the model to match what the calculations indicated was needed for adequate generation in both MISO and Commonwealth Edison. One additional piece to the mix of generation chosen within the MISO footprint is the inclusion of a potential mine-mouth coal campus located in south central Illinois. This plant was added in response to a request from PSCW staff to calculate the "Resource Cost Advantage" of the project. Please also see the "Generation Portfolios Outside ATC" column in table 6.

The generators that were added to the model for the 2011 study year included a mix of combustion turbines, coal-fired units and renewable generation. The following tables show details of the total megawatts of generation along with the area where that generation was sited for the 2011 PROMOD model:

[20] Power Technology, Inc (PTI), under the direction of E3, conducted a bus injection study to help determine from a transmission perspective where new generation could be added most easily, i.e. locations on the transmission system where fewer transmission upgrades would likely be needed to support new generation.

Table 53 2011 Combustion Turbine Additions

	Total MWs					
PowerBase Area	Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
AmerenUE	2070	920	230	---	460	---
Central Illinois Light Co.	230	---	---	---	---	---
Cincinnati Gas & Electric Co.	690	230	---	---	230	---
Commonwealth Edison Co.	5290	2530	---	---	1610	---
Consumers Energy Co.	460	460	---	---	230	---
FirstEnergy Corp.	460	---	---	---	---	---
Great River Energy	230	230	---	---	230	---
Hoosier Energy Rural Electric Coop, Inc.	230	---	---	---	---	---
Manitoba Hydro	460	460	---	---	---	---
Northern Indiana Public Service Co.	920	690	---	---	460	---
Northern States Power Co.	2530	460	---	---	230	---
Ontario Hydro	230	230	---	---	---	---
PSI Energy, Inc.	690	460	---	---	460	---
Southern Indiana Gas & Electric Co.	230	230	---	---	---	---
Wolverine Power Supply Coop, Inc.	690	460	---	---	230	---
Total	**15410**	**7360**	**230**	**0**	**4140**	**0**

Table 54 2011 Coal-fired Additions

PowerBase Area	Total MWs Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
AmerenCIPS	4145	2304	---	---	2034	---
Springfield Water, Light & Power	200	200	---	---	200	---
Commonwealth Edison Co.	600	600	---	---	600	---
FirstEnergy Corp.	2800	1000	---	---	---	---
Montana Dakota Utilities Co.	675	675	500	---	675	500
Northern States Power Co.	1203	600	---	---	600	600
Otter Tail Power Co.	600	600	600	---	600	600
PSI Energy, Inc.	500	---	---	---	---	---
Total	**10723**	**5979**	**1100**	**0**	**4709**	**1700**

The generators that were added to the model for the 2016 study year included a mix of combustion turbines, coal-fired units, combined cycle generators and renewable generation. The following tables show details of the total megawatts of generation along with the area where that generation was sited for the 2016 PROMOD model.

Table 55 2016 Combustion Turbine Additions

PowerBase Area	Total MWs Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
Alliant West	230	230	230	---	---	---
AmerenUE	3680	2530	2530	---	2530	1610
Central Illinois Light Co.	460	230	230	---	230	230
Cincinnati Gas & Electric Co.	920	460	460	---	230	230
Commonwealth Edison Co.	7360	4370	3910	---	3450	2070
Consumers Energy Co.	690	460	230	---	---	---
Detroit Edison Co.	460	460	---	---	---	---
FirstEnergy Corp.	690	460	460	---	460	460
Great River Energy	230	230	230	---	230	230
Hoosier Energy Rural Electric Coop, Inc.	690	460	230	---	230	230
Indianapolis Power & Light Co.	690	690	690	---	690	230
Manitoba Hydro	460	460	460	---	460	---
Northern Indiana Public Service Co.	920	460	460	---	460	230
Northern States Power Co.	2530	460	460	---	460	230
Ontario Hydro	230	230	230	---	230	---
PSI Energy, Inc.	1380	690	690	---	460	230
Southern Indiana Gas & Electric Co.	230	---	---	---	---	---
Wolverine Power Supply Coop, Inc.	690	230	230	---	230	230
Total	**22540**	**13110**	**11730**	**0**	**10350**	**6210**

Table 56 2016 Coal-fired Additions

PowerBase Area	Total MWs: Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
AmerenUE	550	---	---	---	---	---
AmerenCIPS	8645	4695	1297	---	5851	2304
Cincinnati Gas & Electric Co.	550	550	---	---	---	---
Springfield Water, Light & Power	200	200	---	---	200	200
Commonwealth Edison Co.	3500	2400	---	---	600	600
FirstEnergy Corp.	1800	1800	---	---	1800	1000
Illinois Power Co.	550	550	---	---	---	---
Detroit Edison Co.	200	---	---	---	---	---
Manitoba Hydro	600	600	---	---	---	---
Minnesota Power, Inc.	1100	---	---	---	---	---
Montana Dakota Utilities Co.	675	675	---	---	675	675
Northern States Power Co.	2903	1203	600	---	1203	600
Otter Tail Power Co.	600	600	600	---	600	600
PSI Energy, Inc.	500	500	---	---	---	500
Wolverine Power Supply Coop, Inc.	1150	---	---	---	---	---
Total	**23523**	**13773**	**2497**	**0**	**10929**	**6479**

Table 57 2016 Combined Cycle Additions

PowerBase Area	Total MWs: Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
AmerenCIPS	---	---	800	---	---	---
Detroit Edison Co.	---	---	2000	---	---	---
Montana Dakota Utilities Co.	---	---	200	---	---	---
Northern States Power Co.	---	---	515	---	---	---
Total	**0**	**0**	**3515**	**0**	**0**	**0**

Generation additions outside MISO and CE

For PJM, not including CE, NEA adjusted the load forecasts of each control area to meet the minimum planning reserve requirements based on the appropriate Reliability Council requirements. These requirements are consistent with those used by E3 for its analysis and were all provided by NEA.

Retirements inside ATC

Tables 58 and 59 contain existing generating units that were retired for the 2011 and 2016 futures respectively.

Table 58 Existing Generation Retirements within ATC for the Various Futures for 2011

Unit Name	**Maximum Capacity (MW)**	**Commission Date**	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Blount:4	23.8	1/1/1938		X	X	X		X
Blount:5[1]	30.3	11/1/1948		X	X	X		X
Blount:3[1]	41.7	9/1/1953		X	X	X		X
Presque Isle:1	25.0	9/1/1955		X	X	X		X

Presque Isle:2	37.0	7/1/1962		X	X	X		X
Presque Isle:3	58.0	1/1/1964		X	X			
Pulliam:3	28.2	1/1/1943		X				
Presque Isle:4	58.0	12/1/1966		X				
Total Retirements (MW)	**302**		**0**	**302**	**216**	**158**	**0**	**158**

[1]*Blount Units 3,5,6 and 7 were coal fired steam turbine units in the database obtained from MISO, but were modified to be natural gas fired steam turbine units based on newer information.*

Table 59 Existing Generation Retirements within ATC for the Various Futures for 2016

Unit Name	Max. Capacity (MW)	Commission Date	Robust Economy	High Retirements	High Environmental	Slow Growth	Fuel Supply Disruption	High Growth Wisconsin
Blount:4	23.8	1/1/1938		X	X	X		X
Blount:5[1]	30.3	11/1/1948		X	X	X		X
Blount:3[1]	41.7	9/1/1953		X	X	X		X
Presque Isle:1	25.0	9/1/1955		X	X	X		X
Presque Isle:2	37.0	7/1/1962		X	X	X		X
Presque Isle:3	58.0	1/1/1964		X	X			
Pulliam:3	28.2	1/1/1943		X				
Presque Isle:4	58.0	12/1/1966		X				
Pulliam: 4	31.0	8/1/1947		X	X	X		X
Pulliam: 5	50.2	9/1/2979		X	X	X		X
Manitowoc: 5	22.0	1/1/1956		X	X	X		X
Blount:: 6[1]	53.0	6/1/1957		X	X	X		X
Escanaba STCL2	26.3	5/1/1958		X	X	X		X
Main Street Plant: STCL2	45.0	1/1/1968		X	X			
Shiras: 2[2]	21.0	1/1/1972		X	X			
Shiras: 3[2]	43.7	4/1/1983		X	X			
Milwaukee County: 1	12.0	3/1/1996		X	X			
Pulliam: 6	65.0	11/1/1951		X	X			
Weston (WPS): 3	68.1	11/1/1954		X	X			
Edgewater (WPL): 3	74.0	7/1/1951		X	X			
Presque Isle: 5	87.0	12/1/1974		X	X			
Pulliam: &	82.0	11/1/1958		X	X			
Kewaunee Nuclear Plant	578.0	6/1/1974		X				
Total Retirements (MW)	**1,560**		**0**	**1,560**	**982**	**484**	**0**	**484**

[1]Blount Units 3,5,6 and 7 were coal fired steam turbine units in the database obtained from MISO, but were modified to be natural gas fired steam turbine units based on newer information.
[2]Shiras 2 and 3 are owned by the City of Marquette, which is surrounded by ATC, but technically not part of ATC. These units fall into a gray area because they are quite important to the Upper Peninsula of Michigan.

Fuel Costs

Table 60 Energy Price Forecasts

Year	Natural Gas	Coal	No. 2 Fuel Oil
	$ per mmBtu	$ per ton	$ per mmBtu
2007	9.78	51.13	15.53
2008	9.64	51.92	15.45
2009	9.01	52.07	15.09
2010	8.32	53.49	14.85
2011	7.72	53.64	15.20
2012	7.88	54.60	15.80
2013	8.27	55.57	15.65
2014	8.35	56.32	16.28
2015	8.24	57.39	16.77
2016	8.41	58.52	17.59

The natural gas prices from 2007 to 2011 are the annual averages of the monthly NYMEX future prices as of May 23, 2006. The prices from 2012 to 2016 use the 2011 natural gas price and escalate the price at the nominal natural gas price change assumed in the Energy Information Administration *Annual Energy Outlook 2006* as shown in table 61.

The distillate oil price for 2007 is the annual averages of the monthly NYMEX future prices as of June 2, 2006. The prices from 2008 to 2016 use the 2007 oil price and escalate the price at the nominal oil price change assumed in the Energy Information Administration *Annual Energy Outlook 2006* as shown in table 61.

The coal costs in PROMOD are plant specific and are provided by NewEnergy Associates.

Table 61 US Energy Price and Inflation Escalation Prices

		Natural Gas Prices (1)			Coal Prices (1)			Distillate Fuel Oil Prices (1)		
	Inflation (2)	Real	Nominal	% Change	Real	Nominal	% Change	Real	Nominal	% Change
2003	0.974	5.66	5.52		1.33	1.29		6.65	6.48	
2004	1.000	5.92	5.92		1.36	1.36		9.23	9.23	
2005	1.026	8.09	8.30		1.50	1.53		9.71	9.96	
2006	1.046	7.24	7.57		1.53	1.60		10.61	11.09	
2007	1.064	6.54	6.96		1.51	1.61		10.06	10.70	
2008	1.086	6.22	6.75		1.50	1.63		9.80	10.64	-0.6%
2009	1.109	5.77	6.40		1.47	1.63	0.3%	9.38	10.40	-2.3%
2010	1.132	5.46	6.18		1.48	1.68	2.7%	9.04	10.23	-1.6%
2011	1.159	5.26	6.09		1.45	1.68	0.3%	9.04	10.47	2.4%
2012	1.188	5.24	6.23	2.2%	1.44	1.71	1.8%	9.16	10.88	3.9%
2013	1.219	5.36	6.53	4.9%	1.43	1.74	1.8%	8.85	10.79	-0.9%
2014	1.249	5.28	6.60	1.0%	1.41	1.77	1.4%	8.98	11.22	4.0%
2015	1.281	5.08	6.51	-1.4%	1.40	1.80	1.9%	9.02	11.55	3.0%
2016	1.313	5.06	6.64	2.1%	1.40	1.83	2.0%	9.23	12.12	4.9%

Source: Energy prices are from US Energy Information Administration *Annual Energy Outlook 2006* Table 3, while inflation estimates are from Table 19

Note 1: The natural gas, coal, and oil prices represent prices paid to produce electricity and are expressed in dollars per mmBtu.
Note 2: Inflation is measured by the GDP Chain-Type Price Index.

Forced Outages

NEA provides generator Forced Outage Rates (FORs) for use in PROMOD based on national averages for various plant sizes and types. These averages come from the NERC's Generator Availability Data System (GADS) database. Forced Outage Rate data are "Equivalent FORs" (EFORs) to account for partial (derates) as well as full generator outages.

Maintenance

PROMOD automatically schedules generator maintenance outages to maximize reliability (which is done by minimizing the LOLE). The only exception to this is that NEA hard wires nuclear plant maintenance outages in PROMOD. A maintenance outage "blackout" period is defined from Mid-June through August.

Generation additions – Renewable Energy and Renewable Portfolio Standards

Additional generation in the form of wind energy was added to the PROMOD models in an effort to represent renewable portfolio standards in Wisconsin and surrounding states. E3 Consulting calculated the necessary amounts of energy required to meet the future year renewable standards for the states of Illinois, Iowa, Minnesota, and Wisconsin. Wind generators and locations were provided by E3 for inclusion in the PROMOD model. These units were then added to the PROMOD models based on the required amounts of renewable energy for both 2011 and 2016.

The wind generators added to the 2011 PROMOD model had a 33% capacity factor. Some of the wind units external to ATC were scaled to help meet Wisconsin's renewable portfolio standard and to account for external renewable energy which could be available for import into Wisconsin. Since the required amount of renewable generation for the Wisconsin renewable portfolio standard differed along with the futures, the factor by which these units were scaled also changed. These factors made up the basis of the added wind generation in the 2011 PROMOD model as detailed in the following table:

Table 62 2011 Wind Additions

Power Base Area	Total MWs (33% Capacity Factor)					
	Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
Alliant West	567.03	528.54	567.03	490.04	547.79	528.54
American Electric Power Co., Inc. EAST	200	200	200	200	200	200
Central Illinois Light Co.	100	100	100	100	100	100
Commonwealth Edison Co.	2419.18	2226.7	3919.18	2034.22	2322.94	22267
Consumers Energy Co.	579.33	518.7	1579.33	458.06	549.01	518.7
Great River Energy	825.3	738.71	825.33	652.09	782.02	738.71
Illinois Power Co.	910	910	910	910	910	910
Montana Dakota Utilities	337.03	298.54	337.03	260.04	317.79	298.54
Northern States Power Co.	17	17	17	17	17	17
Otter Tail Power co.	--	--	300	--	--	--
PSI Energy Co.	1109.62	974.89	1109.62	840.15	1042.26	974.89
WAPA Billing East (UM-East) NEBRASKA & IOWA	670	670	670	670	670	670
Total	7734.52	7183.08	10534.52	6631.6	7458.81	7183.08

The wind generators which were added to the 2016 PROMOD model also utilized a 33% capacity factor. Calculations were run to help determine approximately how much generation was necessary to meet the renewable portfolio standards for Illinois, Iowa, Minnesota, and Wisconsin. These calculations were compared against available wind additions as provided by E3. Wind generation was added to help meet the calculated renewable standards for 2016, as detailed in the following table:

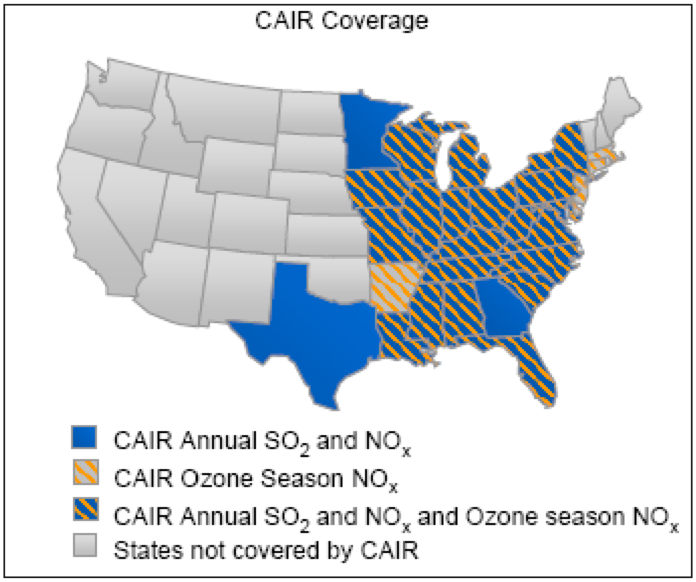
Table 63 2016 Wind Additions

PowerBase Area	Total MWs (33% Capacity Factor) Robust Economy Case	High Retirements Case	High Environmental Case	Slow Growth Case	Fuel Supply Disruption Case	High Growth Wisconsin Case
Alliant West	528.54	528.54	567.03	490.04	547.79	528.54
Central Illinois Light Co.	100	100	100	100	100	100
Commonwealth Edison Co.	3226.7	3026.7	3919.18	2034.22	2622.94	2726.7
Consumers Energy Co.	1518.7	518.7	1579.33	458.06	549.01	1518.7
Great River Energy	738.71	738.71	825.33	652.09	782.02	738.71
Illinois Power Co.	910	910	910	910	910	910
Montana Dakota Utilities Co.	298.54	298.54	337.03	260.04	317.79	298.54
Northern States Power Co.	17	17	17	17	17	17
Otter Tail Power Co.	300	300	300	---	300	---
PSI Energy, Inc.	974.89	974.89	1109.62	840.15	1042.26	974.89
WAPA Billings East (UM-East_ NEBRASKA & IOWA	420	420	420	420	420	420
Total	9033.08	7833.08	10084.52	6181.6	7608.81	8233.08

Environmental Regulations: CAIR and CAMR

The MISO 2011 PowerBase database, as modified by ATC, which served as the Base Case for the Paddock-Rockdale transmission line analysis (PAD-ROE) initially, did not include any representation of the Clean Air Interstate Rule (CAIR) or the Clean Air Mercury Rule (CAMR). CAIR and CAMR represent major, new environmental regulations that become applicable in the United States beginning in 2009. Thus, for the Paddock-Rockdale analysis which utilized two representative years, 2011 and 2016, it was critical to include a representation of CAIR/CAMR programs in the production simulation model in order to simulate a proper commitment and dispatch with respect to the future environmental regulations.

The CAIR program provides a basic framework for states in the CAIR region (see below) to achieve large reductions in SO_2 and NOx emissions utilizing a cap and trade approach beginning in 2009. For the PAD-ROE study, the state of Wisconsin and many of the surrounding states are included in the CAIR region, and the revised SO_2 and NOx restrictions were modeled for this study. For a detailed overview of the CAIR program, please refer to the EPA's website at http://www.epa.gov/air/interstateairquality/index.html.



The CAMR program was the first of its kind to permanently cap and reduce mercury emissions from coal-fired boilers. Unlike CAIR, which is in place for certain states, the CAMR program affects all states in the U.S. The CAMR program is effective beginning in 2010. For a detailed overview of the CAMR program, please refer to the EPA's website at http://www.epa.gov/oar/mercuryrule/.

NewEnergy Associates (NEA) has developed a set of data assumptions that models the provisions of CAIR/CAMR for use in PROMOD. The following paragraphs describe the process by which NEA incorporated the CAIR/CAMR provisions into our data:

The EPA has published two sets of rules based on legislation passed: CAIR and CAMR. The EPA provides a snapshot of CAIR for 2010, 2015 and 2020, and a snapshot for CAMR for 2010 and 2020. These snapshots call for unit retrofits over these periods in order to meet the regulations outlined by the EPA.

In order to achieve these mandates, the retrofits on units are staggered prior to these dates in order to meet the prescribed regulations. The 2010 retrofits are placed in 2008 and 2009, the 2015 retrofits are placed in 2013 and 2014, and the 2020 retrofits are placed in 2016 and 2017. This allows the emissions control technology to be phased in, as opposed to having a dramatic effect at a single point in time.

Some units in the EPA studies have multiple emissions control technologies. For example, some units may get an SCR in 2010 and a scrubber in 2015. The emissions release rates will reflect this change through time. The emissions data through time will reflect the combined emission rate with all technology in service. In addition to all of the emission control technology added, the heat rate and maximum capacities are adjusted to account for the emissions changes, as well as the variable and fixed operating and maintenance cost.

The PAD-ROE analysis initially utilized a MISO-developed 2011 PowerBase case as the starting point. Because the MISO had yet to incorporate the CAIR/CAMR provisions into their data (as of the commencement of this study in June 2006), NEA was asked to modify the MISO 2011 case in order to include all of the CAIR/CAMR provisions. Because the origins of the MISO 2011 case were from a 2004 version of NEA's data, and the available CAIR/CAMR data was based on NEA's current 2006 version of data, the incorporation of the data into the PAD-ROE was done by manually re-creating the steps necessary to model CAIR/CAMR rather than direct usage of these new datasets from NEA. The following steps were completed by Michelle Tisdale of NEA in order to reflect the modeling of CAIR/CAMR in the Base Case PAD-ROE analysis:

1. Add the following new effluents to the database (CAIR Annual NOx, CAIR Seasonal NOx, CAIR SO2, and Mercury).
2. Update all allowance prices consistent with NEA's June 2006 data release (consistent with E3's allowance price assumptions for the generation portfolio expansion to meet future reserve requirements analysis).
3. Incorporate all planned unit retrofits occurring during the time period 2009 through 2020 for all existing units. This step would include a change to emission release rates and potential changes to Fixed and Variable O&M charges depending on the planned retrofit (according to the EPA models).
4. Perform step 3 for all new and planned units developed during the E3 expansion process, such that all units falling in the CAIR and CAMR regulation contain consistent assumptions for emission rates and O&M rates.
5. Provide PowerBase cases to ATC reflecting the incorporation of CAIR/CAMR, such that they can be added to the PAD-ROE 2011 and 2016 Base Cases.

Transmission

Transmission Models for 2011 and 2016

The transmission model used for this analysis was obtained from the Midwest ISO (MISO). The 2011 model is based on the 2011 MISO Transmission Expansion Plan model created for use in the transmission system analysis performed by MISO in 2006. The 2016 model is based on the MISO 2016 model used for MISO PROMOD analysis. Updates to these models consisted of applying the latest available 10-Year Assessment (TYA) project list (i.e. March 2006 TYA update) to each model and adding in generation or transmission as described in the various scenarios and sensitivities. The major transmission projects in the 2011 and 2016 models are described below. Generation was dispatched according to control area merit order dispatch and load levels were set based on LSE forecasts.

Major Changes in 2011 Power Flow Case:

- Columbia to North Madison 138kV line rebuilt to 345 kV.
- New Cranberry to Conover 138 kV line.
- Conover to Plains 69 kV line rebuilt to 138 kV.
- Indian Lake to Hiawatha 69 kV line converted to double circuit 138 kV.
- Hiawatha to Pine River 69 kV line converted to 138 kV.
- Pine River to Straits to 69 kV line converted to 138 kV.
- Columbia 1 & 2, 345/138 kV transformers upgraded.

- Second Kilbourn 138/69 kV transformer.
- New Port Edwards 138/69 kV transformer.
- New Plains 345/138 kV transformer.
- New Menominee 138/69 kV transformer.
- Additional Hillman 138/69 kV transformer.
- Additional Oak Creek 345/138 transformer.
- New Gardner Park 345 and 115 kV Substation.
- New HWY V series reactor.
- New Stone Lake – Gardner Park 345 kV line and Stone Lake 345/161 kV transformer.
- New Werner West 345 kV and 138 kV Substation, Werner West 345/138 kV transformer.
- New Gardner Park to Hilltop 115 kV Line.
- New Venus – Metonga 115 kV line.
- Kegonsa to Femrite to Reiner to Sycamore lines converted from 69 kV to 138 kV.
- New 138/69 kV transformer at Femrite and Reiner Substations.
- New Cornell to Fiebrantz reactor.
- New Arrowhead – Stone Lake 345 kV line
- New Arrowhead 230 kV phase shift transformer
- New Arrowhead 345/230 kV transformer.
- New Stoneybrook – Jefferson 138 kV line (348/481/552)
- North Madison – Huiskamp 138 kV line, new 138/69 kV transformer at Huiskamp Substation.
- Rockriver – Elkhorn 138 conversion project
- New Rubicon – Hustisford 138 kV line
- New Hustisford – Hubbard 138 kV line.
- New Hubbard 138/69 kV transformer.
- New Oakridge to Verona 138 kV line.
- New Verona 138/69 KV transformer.
- New Ramsey to Norwich 138 kV line
- New Kansas to Harbor 138 kV line.
- New Werner West and Highway 22 (formerly known as Central Wisconsin) 345 kV substations
- New Highway 22 to Morgan 345 kV line
- New Werner West to Highway 22 345 kV line.
- New Gardner Park to Highway 22 345 kV line.
- New Werner West to Clintonville 138 kV line.
- New Monroe County to Council Creek 161 kV line
- New Council Creek 161/138 kV transformer.
- Blount – Ruskin overhead double circuit converted to single underground circuit.
- Concord generation facility maximum output increased to 400 MW net.
- Forward 200 MW wind farm (G368) located on the SFL – Butternut 138 kV line.
- Green County 50 MW wind farm (G483) located on the Black Smith – Spring Grove 69 kV line.
- Darlington 99 MW wind farm (G282) located on the Hillman – Darlington 69 kV line.

- Randolph 80 MW wind farm (G366) located on the North Randolph – Portage 138 kV line.
- Twin Creeks 99 MW wind farm (G384) located at the Mischicot 138 kV substation.
- Butler Ridge 54 MW wind farm (G338) located on the Rubicon – Hartford 138 kV line.
- Cypress Wind farm (G353/G354/G427) located on the Forest Junction to Arcadian 345 kV line.
- Weston 550 MW generator (G144).
- White Pine generation facility maximum output increased to 35 MW net.
- Port Washington 2nd block of generation (610 MW)
- New Oak Creek Generation facility (1300 MW).

Major Changes in 2016 Power Flow Case inside ATC

- New Rockdale - West Middleton 345 kV line.
- New West Middleton - North Madison 345 kV line.
- New Huiskamp to Blount 138 kV and 69 kV lines.
- Spring Green to West Middleton 69 kV conversion to 138 kV.
- New Nelson Dewey generation (G527) (Out of Service).
- New Nelson Dewey - Liberty 161 kV line (Out of Service).
- New Nelson Dewey 161/138 kV Transformer.

Major Changes in 2016 Power Flow Case outside ATC

- New Rising-Sidney 345 kV line.
- New Coffeen-Kincaid 345 kV line.
- New Albion-Norris City 345 kV line.
- New Newton-Merom 345 kV line.
- New Mt Vernon-Albion 345 kV line.
- Two new Mt Vernon-Coffeen 345 kV lines.

System topology used in this study reflects projects identified at that point in time. Since this study's inception, some projects have changed status.

PROMOD Proxy Transmission outage Simulation

Some N-2 system conditions were included in the PROMOD results by adding proxy simulations of scheduled transmission outages. Since scheduled outages are not known in the 2011 and 2016 time frames, proxy transmission outages were used. To limit the scope of the sensitivities, it was proposed to simulate typical maintenance outages for 17 selected 345kV lines that can impact Wisconsin import capability. These outages were further reviewed for coordination with the unit maintenance list to make sure the outages are reasonable.[21] Typically, 5 days of line maintenance are required for each 345kV line within a 2 year period. For simulation purposes, this equated to

[21] Transmission outages may require that the output of nearby power plants be reduced. To minimize this possibility transmission maintenance outages are normally coordinated to coincide with associated generator maintenance outages.

setting random 3-working day continuous outages set in the spring or fall and coordinated with related unit maintenance outages.

Listed below are the 2011 and 2016 preferences for coordination with generator maintenance outages.

Table 64 Generator Maintenance Outage Coordination Preferences

Description	Coordnate with Gen Maint Outage
Eau Claire to Arpin with 69 kV lines open but the 115 kV line in-service	Prefer Weston 4 available
Arrowhead to Stone Lake	Prefer Weston 4 available
Stone Lake to Gardner Park	Prefer Weston 4 available
Pleasant Prairie to Arcadian	prefer with one PleasantPr unit off
Pleasant Prairie to Racine	prefer with one PleasantPr unit off (no restiction on OkCr and ElmRd)
Pleasant Prairie to Zion	prefer with one PleasantPr unit off
Arcadian to Granville	no restrictions
Arcadian to Zion	no restrictions
Columbia to South Fond Du Lac	coordinate with single Columbia off
Wempletown to Rockdale	coordinate with single Byron off
Wempletown to Paddock	coordinate with single Byron off
Cherry Valley to Silver Lake	coordinate with single Byron off
Nelson to Electric Junction	coordinate with single Byron off
North Appleton to Werner West	no restrictions
Kewanee to North Appleton	prefer Kewaunee off
Point Beach to Forest Junction	prefer single PtBeach off
Prairie Island to Byron	no requirement on PrIsl outage

The resulting proxy transmission outages were used for both the 2011 and 2016 studies. They are not coordinated with unit forced outages, and they are the same for all studies. The chosen proxy dates were reviewed by Forward Operations for reasonableness. The transmission outage data is placed in the PROMOD PDTR table.

Table 65 2011 Proxy Transmission Outages

Appendix

Power Flow Branch Description	Transmission BranchID	StartDt	StartHr	EndDt	EndHr	Description
39244 60304 1 ! ARP 345 345-EAU CL 3 345 1 (ALTE-XEL)	039244060304 1	3/15/2011	8	3/17/2011	17	Eau Claire to Arpin with 69 kV lines open but the 115 kV line in-service
38333 68821 1 ! HLT 69 69-MAUSTON 69 1 (ALTE-DPC)	038333068821 1	3/15/2011	8	3/17/2011	17	
38342 39901 1 ! COC 69 69-COC DPC 69 1 (ALTE-ALTE)	038342039901 1	3/15/2011	8	3/17/2011	17	
39449 39450 1 ! ARROWHD 345-ST LAKE 345 1 (WPS-WPS)	039449039450 1	11/8/2011	8	11/10/2011	17	Arrowhead to Stone Lake
39450 39676 1 ! ST LAKE 345-GARDR PK 345(WPS-WPS)	039450039676 1	11/29/2011	8	12/1/2011	17	Stone Lake to Gardner Park
39432 39253 1 ! PLS PR1 345-ARCADN1 345 1 (WE-WE)	039253039432 1	4/26/2011	8	4/28/2011	17	Pleasant Prairie to Arcadian
38850 39471 1 ! PLS PR3 345-RACINE1 345 1 (WE-WE)	038850039471 1	5/3/2011	8	5/5/2011	17	Pleasant Prairie to Racine
38849 36421 1 ! PLS PR2 345-ZION ; R 345 1 (WE-NI)	036421038849 1	5/10/2011	8	5/12/2011	17	Pleasant Prairie to Zion
39253 39329 1 ! ARCADN1 345-GRANVL1 345 1 (WE-WE)	039253039329 1	11/15/2011	8	11/17/2011	17	Arcadian to Granville
36420 39247 1 ! ZION ; B 345-ARCADN3 345 1 (NI-WE)	036420039247 1	10/11/2011	8	10/13/2011	17	Arcadian to Zion
39157 39176 1 ! COL 345 345-SFL 345 345 1 (MGE-ALTE)	039157039176 1	11/1/2011	8	11/3/2011	17	Columbia to South Fond Du Lac
36406 39119 1 ! WEMPL; B 345-ROE 345 345 1 (NI-ALTE)	036406039119 1	9/13/2011	8	9/15/2011	17	Wempletown to Rockdale
36407 39058 1 ! WEMPL; R 345-PAD 345 345 1 (NI-ALTE)	036407039058 1	9/20/2011	8	9/22/2011	17	Wempletown to Paddock
36289 36389 1 ! CHERR; R 345-SILVE; R 345 1 (NI-NI)	036289036389 1	9/27/2011	8	9/29/2011	17	Cherry Valley to Silver Lake
36362 36310 1 ! NELSO; B 345-ELECT; B 345 1 (NI-NI)	036310036362 1	10/4/2011	8	10/6/2011	17	Nelson to Electric Junction
38894 38928 1 ! N APP 3 345-WERNER W 345 1 (WE-WE)	038894038928 1	3/29/2011	8	3/31/2011	17	North Appleton to Werner West
39359 39630 1 ! N APP 1 345-KEWAUNEE 345 1 (WE-WPS)	039359039630 1	1/18/2011	8	1/20/2011	17	Kewanee to North Appleton
38898 39304 1 [PT BCH2 345]-[FORST JT 345] (365-365)	038898039304 1	10/25/2011	8	10/27/2011	17	Point Beach to Forest Junction
61950 63032 1 BYRON 3 345 PL VLLY3 345 (600-600) NSP	061950063032 1	3/8/2011	8	3/10/2011	17	Prairie Island to Byron

Table 66 2016 Proxy Transmission Outages

Power Flow Branch Description	Transmission BranchID	StartDt	StartHr	EndDt	EndHr	Description
39244 60304 1 ! ARP 345 345-EAU CL 3 345 1 (ALTE-XEL)	039244060304 1	3/15/2016	8	3/17/2016	17	Eau Claire to Arpin with 69 kV lines open but the 115 kV line in-service
38333 68821 1 ! HLT 69 69-MAUSTON 69 1 (ALTE-DPC)	038333068821 1	3/15/2016	8	3/17/2016	17	
38342 39901 1 ! COC 69 69-COC DPC 69 1 (ALTE-ALTE)	038342039901 1	3/15/2016	8	3/17/2016	17	
39449 39450 1 ! ARROWHD 345-ST LAKE 345 1 (WPS-WPS)	039449039450 1	9/6/2016	8	9/8/2016	17	Arrowhead to Stone Lake
39450 39676 1 ! ST LAKE 345-GARDR PK 345(WPS-WPS)	039450039676 1	11/1/2016	8	11/3/2016	17	Stone Lake to Gardner Park
39432 39253 1 ! PLS PR1 345-ARCADN1 345 1 (WE-WE)	039253039432 1	4/26/2016	8	4/28/2016	17	Pleasant Prairie to Arcadian
38850 39471 1 ! PLS PR3 345-RACINE1 345 1 (WE-WE)	038850039471 1	5/3/2016	8	5/5/2016	17	Pleasant Prairie to Racine
38849 36421 1 ! PLS PR2 345-ZION ; R 345 1 (WE-NI)	036421038849 1	5/10/2016	8	5/12/2016	17	Pleasant Prairie to Zion
39253 39329 1 ! ARCADN1 345-GRANVL1 345 1 (WE-WE)	039253039329 1	11/15/2016	8	11/17/2016	17	Arcadian to Granville
36420 39247 1 ! ZION ; B 345-ARCADN3 345 1 (NI-WE)	036420039247 1	11/8/2016	8	11/10/2016	17	Arcadian to Zion
39157 39176 1 ! COL 345 345-SFL 345 345 1 (MGE-ALTE)	039157039176 1	10/11/2016	8	10/13/2016	17	Columbia to South Fond Du Lac
36406 39119 1 ! WEMPL; B 345-ROE 345 345 1 (NI-ALTE)	036406039119 1	9/13/2016	8	9/15/2016	17	Wempletown to Rockdale
36407 39058 1 ! WEMPL; R 345-PAD 345 345 1 (NI-ALTE)	036407039058 1	9/20/2016	8	9/22/2016	17	Wempletown to Paddock
36289 36389 1 ! CHERR; R 345-SILVE; R 345 1 (NI-NI)	036289036389 1	9/27/2016	8	9/29/2016	17	Cherry Valley to Silver Lake
36362 36310 1 ! NELSO; B 345-ELECT; B 345 1 (NI-NI)	036310036362 1	10/4/2016	8	10/6/2016	17	Nelson to Electric Junction
38894 38928 1 ! N APP 3 345-WERNER W 345 1 (WE-WE)	038894038928 1	3/29/2016	8	3/31/2016	17	North Appleton to Werner West
39359 39630 1 ! N APP 1 345-KEWAUNEE 345 1 (WE-WPS)	039359039630 1	5/17/2016	8	5/19/2016	17	Kewanee to North Appleton
38898 39304 1 [PT BCH2 345]-[FORST JT 345] (365-365)	038898039304 1	2/16/2016	8	2/18/2016	17	Point Beach to Forest Junction
61950 63032 1 BYRON 3 345 PL VLLY3 345 (600-600) NSP	061950063032 1	3/8/2016	8	3/10/2016	17	Prairie Island to Byron

Transmission additions outside ATC – CapX 2020

In an effort to capture the actions of the CapX 2020 utilities, it was agreed that the CapX 2020 Project Group I transmission projects should be included in the PROMOD models for the 2016 study year. This project group includes approximately 600 miles of 345-kV lines which connect across Minnesota, North Dakota, South Dakota, and Wisconsin along with a smaller 230-kV line in the Bemidji, Minnesota area. These projects are defined as follows:

Table 67 CapX 2020 Project Group I Definitions

Project Description	Primary Voltage	Approximate Mileage	Targeted In-Service Year
Bemidji - Grand Rapids	230 kV	70 Miles	2011
Southeast Twin Cities - Rochester - La Crosse, WI	345 kV	150 Miles	2011
Brookings, SD - Southeast Twin Cities	345 kV	230 Miles	2012
Fargo, ND - St. Cloud / Monticello Area	345 kV	250 Miles	2012

It was also determined that the CapX 2020 Project Group III transmission project in Wisconsin from North La Crosse to Columbia should be included for some of the 2016 study year analysis. This line has yet to reach the planning phase of the Group I projects and, as such, many of the developmental details remain uncertain. That project would have a primary voltage of 345 kV, be approximately 117 miles in length and has no targeted in-service year at this time.

Transmission Constraints — Initial list and updates

The constraints used in PROMOD cover the entire PROMOD study area, which includes transmission in the MISO and PJM systems. The constraints used in this analysis were originally supplied by the MISO as used in the MISO PROMOD studies for 2011 and 2016. These constraints were then augmented with additional flowgates based on historical system constraints, projected future constraints from other studies and projected constraints based on analysis of a sampling of various hours simulated by PROMOD throughout the year.

Appendix D: PROMOD Analysis Methodology

General Description

PROMOD is a security constrained economic dispatch computer simulation program.[22] The program simulates both the electric generation and transmission systems. It determines the least-cost generation dispatch over a large area for every hour while simultaneously respecting all known transmission constraints (flowgates). This is the same approach that Locational Marginal Price (LMP) markets, like the MISO and PJM markets, use to dispatch generation. In short, PROMOD simulates LMP markets. As a result, PROMOD can be used to help evaluate the cost-effectiveness of transmission projects, like Paddock-Rockdale, in a market environment.

For the Paddock-Rockdale analysis, all of the transmission and generation within MISO and PJM were simulated in PROMOD (the combination of these areas will subsequently be referred to as the “PROMOD footprint”).[23] Due to the large amount of information being processed, a one year PROMOD simulation typically takes about 20 hours.

The first step in the economic analysis of a new transmission project is to update the PROMOD input data to create a “reference” case (i.e. a case without the new project). This update includes all known transmission and generation changes for the study year including new and upgraded transmission lines, new and retired power plants, etc. This is followed by a one year reference case PROMOD run. The output from this run, including costs and key generator and transmission system characteristics, is reviewed for reasonableness for the study year. A new project, like Paddock-Rockdale, is then added to PROMOD and the simulation is rerun. The corresponding PROMOD output from the “project” case is again reviewed for reasonableness.

The cost difference between the reference and project cases is normally calculated to help determine the economic benefits associated with adding the project. Calculating the benefits, by using the cost differential, tends to reduce the impact of any inaccuracies in forecasts and input data because all of the inputs are identical except for the addition of the new project.

PROMOD utilizes a complete DC load flow model with impedance information for all elements of the transmission system. The model accounts for transmission losses and costs by determining how each generator impacts transmission losses and calculating a corresponding “dispatch penalty factor”. This factor is then included when PROMOD does its least-cost generation dispatch. For example, if a particular generator increases losses on the transmission system, PROMOD applies a higher dispatch penalty factor causing the generator to dispatch less relative to a plant that reduces overall transmission losses.[24]

A new transmission project may reduce overall transmission system losses and as result reduce the cost to serve load. To precisely capture this effect, particularly at peak-load, requires the use of an

[22] PROMOD was developed by NewEnergy Associates (NEA), a subsidiary of Siemens.
[23] To reduce simulation run times without significantly affecting result accuracy, distant areas were not modeled in detail, but rather by power transactions into and out of the PROMOD footprint.
[24] The peak load data in PROMOD for each control area includes transmission losses, which is appropriate if the “single pass” technique for calculating losses is used in the model. This is the MISO’s standard technique for accounting for the impact of losses on generation dispatch.

AC powerflow model, like Siemens' PSS/E[25], which can capture the change in transmission system losses associated with the addition of a new project.

PROMOD uses generator operating costs rather than bid costs to dispatch generation.[26] As a result, PROMOD does not capture the impact of bidding behavior on costs and the ability of some new transmission lines to enhance competition. This is part of the reason why additional analyses, like those done by the consulting firm, The Brattle Group, need to be done to fully capture the benefits of new transmission facilities.

The PROMOD model requires a large amount of input data (approximately 500 MB) for the transmission and generation systems. The following discusses the sources of this information in general terms and how related information is developed, such as flowgates for new transmission topology. It also discusses in more detail the various steps involved in PROMOD economic analyses and some of the key study parameters.

Transmission System Data

Transmission system data including, ratings and impedances, comes from a NERC Multiregional Modeling Working Group (MMWG) case in PSS/E RAW data format. An updated version of this case from the MISO or NEA is often used. To ensure the most current ATC system is modeled, ATC strips out its own transmission topology from the PSS/E case and replaces it with the latest footprint from ATC's 10-Year Assessment for the specific study year.

Transmission Constraints-Flowgates

The flowgate list (referred to as the "Event file" in PROMOD) typically starts with data supplied by the MISO. However, the MISO flowgate list normally only reflects current transmission system topology and needs to be updated to reflect the transmission topology and ratings for future study years. The Event file must be manually updated to account for these topology and rating changes using data from the PSS/E RAW file.

The PROMOD Analysis Tool (PAT)[27] is used to help define any additional needed flowgates for a future study year. PAT is used to do a contingency analysis for a select series of hours throughout the year that represent different peak load and "market" generator dispatch patterns. Varying generator dispatch patterns throughout the year changes transmission flow patterns, which may require the addition of new flowgates to prevent transmission system overloads.

PAT's "Contingency Evaluator Tool" sequentially outages all transmission elements (e.g. line and transformers) to determine if any other transmission elements overload due to the outage. Contingency analyses must be done to meet NERC requirements that the transmission system be

[25] Power System Simulator for Engineering
[26] Technically, in the MISO market, generators submit "offers" and Load-Serving Entities (LSEs) submit "bids".
[27] A companion tool to PROMOD used for detailed evaluation of hourly output from PROMOD.

operated and planned to withstand the worst contingency without causing any overloads. The outaged element is referred to as the “contingency”. If another element tends to overload under contingency it is referred to as the “limiting element”. The most critical limiting element-contingency pairs found using PAT are translated into flowgates for inclusion in the Event file. For future study years, both new generation and transmission may change flow patterns on the transmission system and require new flowgates be added to prevent overloads (particularly under contingency).

Generator Input Data

Most of the generator input data is contained within PowerBase, which is the database provided for use with PROMOD. PowerBase contains generator data, such as summer and winter capacities, heat rates, forced outage rates, etc. which comes from NEA. They in turn get most of their data from the Platts database[28] and public information sources, like the EPA’s Continuous Emission Monitoring System and NERC’s GADS databases. Planned future generation is added to PROMOD as described in the following section.

Reserve Margins

For future study years, sufficient new generation needs to be included in PROMOD to meet the long term planning reserve margins set by the NERC’s regional Reliability Councils. Minimum planning reserve requirements are set based on the assumption that other reliability regions will have generation reserves to help during a generation emergency. Emergencies can occur when, for example, a large plant breaks down and insufficient generation is available to replace it locally. In this case the system is designed to rely on neighboring reliability regions to make up the shortfall at least until additional generation can be brought on locally. Being able to rely on generation from neighboring reliability regions lowers the overall costs for everyone because each region can build less generation and still meet its NERC reliability requirements.[29] Please see the PROMOD Study Assumptions for more details about the methodology for adding new generation and amount that was needed to meet the planning reserve margins.

Fuel Cost Forecasts

NEA gets plant-specific fuel forecasts for coal-fired units from the Platts database. Please see the PROMOD Study Assumptions for details about how the fuel forecasts for natural gas and fuel oil were developed.

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[28] Formerly the Resource Data International (RDI) database.
[29] Minimum planning reserve margin requirements are typically based on a Loss of Load Expectation (LOLE) requirement, which is normally loss of load of no more than one day in ten years on the bulk power system.

Generator Forced Outage Rates

NEA provides generator Forced Outage Rates (FORs) in PowerBase based on national averages for various plant sizes and types. These averages come from the NERC's GADS database. Forced Outage Rate data included in PowerBase are "Equivalent FORs" (EFORs) to account for partial as well as full generator outages.

PROMOD Analysis Methodology

For major projects, like Paddock-Rockdale, an iterative process is used to help determine the full project benefits. PROMOD is run and the most significant PROMOD transmission constraints are identified. An appropriate transmission solution is developed to address the most significant constraint (that ATC has the ability to fix) and the analysis is rerun with the solution implemented to determine the next most significant constraint.[30] This process is repeated until it is apparent that resolving the next constraint is not cost-effective based on the PROMOD analysis (i.e. additional transmission projects are only added if sufficient additional production cost savings are obtained to cover the cost of fixing the constraint). The "project" includes the primary project, like Paddock-Rockdale, plus any smaller cost-effective "fixes" identified as part of the iterative process. For the Paddock-Rockdale project, the only fix that was found to be cost-effective was upgrading the Rockdale 345/138 kV T22 transformer and thus this fix is included as part of the proposed Paddock-Rockdale project.

Number of Draws

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 based on each plant's EFOR. Different outage patterns (known as "draws") result in somewhat different annual costs from PROMOD. A single draw is used for all reference/project case PROMOD run combinations that are being compared to ensure that any cost difference is not the result of different generator outage patterns.

Scheduled Generator Maintenance

PROMOD automatically schedules generator maintenance outages to maximize reliability (which is done by minimizing the LOLE). The only exception to this is that NEA hard wires nuclear plant maintenance outages in PROMOD. A maintenance outage "blackout" period is defined from Mid-June through August. A single maintenance outage schedule is used for all reference/project case PROMOD run combinations that are being compared to ensure that any cost difference is not the result of different scheduled maintenance patterns.

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[30] Constraints are ranked for relief primarily based on their shadow price, but also to some degree on the number of hours they are constraining. Both of these are outputs from PROMOD. The shadow price is the production cost that could be saved if the constraint could be relieved by 1 MW.

PROMOD Benchmarking/Tuning

Both the MISO and ATC have found that PROMOD tends to underestimate LMPs relative to the MISO market. Adjustments can be made to help "tune" PROMOD so that its output better mimics actual market prices. For tuning PROMOD, ATC started with the same PROMOD case that MISO used for its January 2006 tuning tests.[31] In its tuning runs, MISO reduced the total coal-fired capacity in PROMOD using an indirect modeling technique (i.e. by requiring the coal-fired units to provide the spinning reserves). ATC also reduced the total coal-fired capacity but used a different technique in order to reduce the capacities on all coal-fired generation by the same percentage. ATC tested various capacity percentage reductions (e.g. 5%, 6%, 7%, 8% and 9%), but as the following table shows, an 8% reduction in the capacity of coal-fired generators produced a good correlation for ATC's load-weighted LMP.

Table 68 PROMOD Tuning to Actual MISO Day-Ahead LMP Market Results[1]

Load-Weighted LMP ($/MWHr)	Actual Market Results[2]	PROMOD Results After Tuning[3]	Difference Between Market and Tuned PROMOD Results	PROMOD Results Before Tuning	Difference Between Market and Un-Tuned PROMOD Results
ATC	$61.02	$60.90	$0.12	$51.77	$9.25
MISO	$55.52	$53.95	$1.57	$44.48	$11.04
Difference	$5.50	$6.95		$7.29	

[1]The tuning time period was June 2005 through April 2006.

[2]Provided by The Brattle Group.

[3]Capacity of coal-fired units reduced by 8% in PROMOD to simulate "economic" rather than maximum capacities.

Like MISO, ATC also used the new "bid-up" logic switch in PROMOD for the tuning runs. This switch adds generator start up and no-load costs and minimum operating times to PROMOD's generator commitment algorithm. It also increases PROMOD run times by about 50%, but ensures that only units that can cover their production costs are committed by PROMOD. For example, this logic prevents a combined cycle plant that has a minimum run time of 8 hours from being dispatched in PROMOD if it can only operate at a profit (based on how much it is being paid by the market through its LMP) for 3 of the 8 hours. The practical effect of using the "bid-up" logic in this case is that PROMOD would likely dispatch combustion turbines (which typically have much shorter minimum run times) in place of the combined cycle (CC) plant, just as would likely occur in the market. Because combustion turbines are higher cost than combined cycle plants, bid-up logic would tend to increase LMPs calculated by PROMOD closer to market values under the circumstances of our example.[32]

[31] Please refer the MISO presentation called "PROMOD IV Assumptions Discussion-Control Area Consolidation Study", subtitle, "Economic Studies & Models", for additional details on MISO's benchmarking efforts and results.

[32] In brief, the LMP is generally determined by the generator(s) on the margin, i.e. the last generator dispatched, which is normally the highest cost generator.

Appendix E: Detailed Description of the "Drivers" for the Futures and Corresponding Matrix

Peak Demand and Energy Growth Assumptions

The peak demand and energy growth assumptions used in the PROMOD analysis were developed based on a comprehensive review of historical growth in both US energy and peak load, which suggests that Load Factors have been relatively stable.

In table 69, the average growth of peak demand over the period 1990 to 2004 was 2.1 percent per year, while the annual growth in Total Sales over the same time period was 1.9 percent. While the growth in Peak and Total Sales were not exactly identical, the two growth rates were similar enough to produce a relatively flat Load factor, which was 60.3 percent in 1990 to 59.9 percent in 2004.

Table 69 US Peak, Energy and Load Factor Data

Year	Non-coincident Summer Peak (MW)	Total Sales (GWh)	Annual Peak Growth	Annual Energy Growth	Load Factor (percent)
1990	546,331	2,728,690			60.3
1991	551,418	2,775,727	0.9%	1.7%	60.9
1992	548,707	2,776,978	-0.5%	0.0%	61.2
1993	575,356	2,880,572	4.9%	3.7%	61.0
1994	585,320	2,954,199	1.7%	2.6%	61.2
1995	620,249	3,032,458	6.0%	2.6%	59.8
1996	616,790	3,118,713	-0.6%	2.8%	62.0
1997	637,677	3,172,731	3.4%	1.7%	60.4
1998	660,293	3,303,664	3.5%	4.1%	59.9
1999	682,122	3,367,731	3.3%	1.9%	58.9
2000	678,413	3,489,302	-0.5%	3.6%	61.2
2001	687,812	3,386,254	1.4%	-3.0%	59.8
2002	714,565	3,476,081	3.9%	2.7%	59.8
2003	709,375	3,512,163	-0.7%	1.0%	59.7
2004	729,013	3,573,410	2.8%	1.7%	59.9

Source: Peak and Load Factor data are from Table 2.1 and Total Sales data are from Table 6.1 EEI Statistical Yearbook (Published August 2005)

Total Sales are defined as Sales to Ultimate Customers plus Sales for Resale (Requirements and Non-Requirements.)

A similar analysis was done for ATC. In table 70, the average growth of peak demand over the period 1991 to 2004 was 2.4 percent per year, while the annual growth in Total Sales over the same time period was also 2.4 percent, which resulted in a flat Load factor (62.2 percent in 1991 to 62.5 percent in 2005.)

Table 70 ATC Peak, Energy and Load Factor Data

Year	Non-Coincident Summer Peak (MW) (4)	Total Sales (MWh) (5)	Annual Peak Growth	Annual Energy Growth	ATC Load Factor (percent)
1990		48,873,014		-0.1%	
1991	9,498	51,726,762		5.8%	62.2
1992	9,148	51,031,756	-3.7%	-1.3%	63.7
1993	9,556	53,213,201	4.5%	4.3%	63.6
1994	9,907	55,688,055	3.7%	4.7%	64.2
1995	10,725	57,791,903	8.3%	3.8%	61.5
1996	10,469	60,581,468	-2.4%	4.8%	66.1
1997	10,259	61,974,514	-2.0%	2.3%	69.0
1998	11,031	63,979,484	7.5%	3.2%	66.2
1999	11,742	64,300,448	6.4%	0.5%	62.5
2000	11,797	65,850,765	0.5%	2.4%	63.7
2001	12,754	65,859,957	8.1%	0.0%	58.9
2002	12,685	67,587,956	-0.5%	2.6%	60.8
2003	12,880	68,933,698	1.5%	2.0%	61.1
2004	12,138	69,089,606	-5.8%	0.2%	65.0
2005	13,206	72,331,506	8.8%	4.7%	62.5

Source: Non-coincident summer peak and Total Sales data are from FERC Form 1

Note 4: The non-coincident summer peak demand is the sum of the summer peak demands for Madison Gas & Electric, Edison Sault Electric, South Beloit Water Gas & Electric, Upper Peninsula Power Company, We Energies, Wisconsin Power & Light, Wisconsin Public Service, and Wisconsin Public Power Inc.

Note 5: Total Sales is the sum of Total Sales for Madison Gas & Electric, Edison Sault Electric, South Beloit Water Gas & Electric, Upper Peninsula Power Company, We Energies, Wisconsin Power & Light, Wisconsin Public Service, and Wisconsin Public Power Inc.

Load Growth within ATC (MW and MWh)

Given the flat load factors for both the United States and ATC, a prospective estimate for energy growth is used to project the growth in peak demand. To determine a forward-looking estimate for energy, a five-year moving average of the geometric mean for ATC energy was used. As table 71 illustrates, the expected growth in energy for the ATC footprint is 1.9 percent, which was rounded to 2 percent.

Table 71 Forward-Looking Estimates for ATC Energy Growth

Year	Total Sales (MWh)	Annual Energy Growth	5-Year Moving Average Standard Deviation	5-Year Moving Average Geometric Mean
1988	47,857,737			
1989	48,916,825	2.2%		
1990	48,873,014	-0.1%		
1991	51,726,762	5.8%		
1992	51,031,756	-1.3%		
1993	53,213,201	4.3%	0.0297	1.0214
1994	55,688,055	4.7%	0.0317	1.0263
1995	57,791,903	3.8%	0.0278	1.0341
1996	60,581,468	4.8%	0.0259	1.0321
1997	61,974,514	2.3%	0.0101	1.0396
1998	63,979,484	3.2%	0.0104	1.0375
1999	64,300,448	0.5%	0.0164	1.0292
2000	65,850,765	2.4%	0.0157	1.0265
2001	65,859,957	0.0%	0.0137	1.0168
2002	67,587,956	2.6%	0.0141	1.0175
2003	68,933,698	2.0%	0.0118	1.0150
2004	69,089,606	0.2%	0.0124	1.0145
2005	72,331,506	4.7%	0.0192	1.0190

Geometric Mean of the data	2 percent
Standard Deviation	2 percent
Lower Bound based on two standard deviations	-2 percent
Upper Bound based on two standard deviations	6 percent

Given the wide range of energy growth and based on feedback from ATC customers, it was assumed a more reasonable range would be 0.5 percent for the lower bound and 3.0 percent for the upper bound.

Load Growth outside ATC (MW and MWh)

As table 72 illustrates, the neighboring states have had similar historical growth rates, except for the states of Illinois and Michigan. It was, therefore, assumed that the energy and peak demand growth rates assumed for ATC would also be used for the surrounding states.

Table 72 Sales to Ultimate Customers for Total Electric Industry (GWhrs)

	2001	2002	2003	2004	2005	Annual Growth
Wisconsin	54,751	56,251	56,396	57,029	58,899	1.8%
Michigan	91,986	92,878	88,372	95,245	98,837	1.8%
Illinois	125,405	125,804	123,247	127,465	133,103	1.5%
Indiana	80,779	83,449	82,368	84,374	86,913	1.8%
Minnesota	40,634	41,661	41,531	42,051	43,617	1.8%
Iowa	29,669	30,852	30,834	30,199	32,062	2.0%

Source: Tables 6.5 and 6.6 from EEI Statistical Yearbooks (Published December 2006, August 2005, August 2004, and May 2003)

Low-Cost Generation within ATC

A significant driver in evaluating the economic benefits of transmission projects that increase import capability into a congested area is the amount of low-cost generating capacity within the area. In addition to the approximately 1,750 MW of coal-fired capacity that has been approved by the PSCW and is under construction, including Elm Road 1 and 2 and Weston 4, additional coal-fired power plants have been proposed but have not been approved by the PSCW. These include Alliant Energy's 280 MW power plant at Nelson Dewey and a future 515 MW Weston 5 plant. Elm Road 1 and 2 and Weston 4 are included in all futures. Please see tables 51, 52, 58, and 59 in previous sections for precise lists of which generator units were added or retired to the 2011 and 2016 cases.

Retirement of some smaller, older and less efficient coal-fired units within the ATC footprint is also included in some of the futures. Operators may choose to retire some older smaller coal-fired units rather than add costly pollution control equipment to meet the requirements of CAIR and CAMR.

Renewable Energy in ATC and Wisconsin

To account for the additional renewable energy needed to meet the Wisconsin renewable energy objective, it was necessary to first calculate the existing amount of renewable energy within the ATC footprint. Calculation of the renewable energy in the PowerBase database showed that ~3.9% of the total energy produced in Wisconsin came from renewable resources in the 2011 study model. The same calculation revealed that ~5.5% of the total produced energy in Wisconsin was from renewable resources in the 2016 study model. These numbers were used as a basis for determining the additional renewable resources that would be needed from sources external to the ATC footprint in order to meet the Wisconsin renewable portfolio standard. The following tables show a breakdown of the sources of renewable energy (inside/outside Wisconsin) that were necessary based on the previously calculated existing renewable generation:

Table 73 2011 ATC Renewable Source Percentages

Inside / Outside Renewable Percentages		
Scenario	2011 Inside ATC Renewable	2011 Outside ATC Renewable
Robust Economy Case (8% Renewable Requirement)	49%	51%
High Retirements Case (8% Renewable Requirement)	49%	51%
High Environmental Case (10% Renewable Requirement)	39%	61%
Slow Growth Case (6% Renewable Requirement)	65%	35%
Fuel Supply Disruption Case (9% Renewable Requirement)	44%	56%
High Growth Wisconsin Case (8% Renewable Requirement)	49%	51%

Table 74 2016 ATC Renewable Source Percentages

Inside / Outside Renewable Percentages		
Scenario	2016 Inside ATC Renewable	2016 Outside ATC Renewable
Robust Economy Case (10% Renewable Requirement)	55%	45%
High Retirements Case (10% Renewable Requirement)	55%	45%
High Environmental Case (15% Renewable Requirement)	37%	63%
Slow Growth Case (6% Renewable Requirement)	92%	8%
Fuel Supply Disruption Case (12% Renewable Requirement)	46%	54%
High Growth Wisconsin Case (10% Renewable Requirement)	55%	45%

CapX 2020 Transmission

The CapX 2020 Project Group I projects as detailed previously were all added as a part of the 2016 futures. One of the two variations of the Robust Economy future incorporated a 345 kV project from North La Crosse to Columbia. The other variation analyzed the implications of not including this line in this future.

Natural Gas Price Forecast

Table 75 Natural Gas Price Forecast

Year	US Wellhead Price ($ per 1000ft^3)	Annual Price Change
1990	1.71	0.012
1991	1.64	-0.042
1992	1.74	0.059
1993	2.04	0.159
1994	1.85	-0.098
1995	1.55	-0.177
1996	2.17	0.336
1997	2.32	0.067
1998	1.96	-0.169
1999	2.19	0.111
2000	3.68	0.519
2001	4.00	0.083
2002	4.50	0.118
2003	4.88	0.081
2004	5.46	0.112
2005	7.51	0.319

Source: Energy Information Administration Natural Gas Navigator

Geometric Mean of the price data	8 percent
Standard Deviation	18 percent
Lower Bound based on two standard deviations	-30 percent
Upper Bound based on two standard deviations	40 percent

Coal Price Forecast

Table 76 Coal Price Forecast

Year	Average Open Market Mine Price ($ per short ton)	Annual Percent Change
1990	21.76	-0.003
1991	21.49	-0.012
1992	21.03	-0.022
1993	19.85	-0.058
1994	19.41	-0.022
1995	18.83	-0.030
1996	18.5	-0.018
1997	18.14	-0.020
1998	17.67	-0.026
1999	16.63	-0.061
2000	16.78	0.009
2001	17.38	0.035
2002	17.98	0.034
2003	17.85	-0.007
2004	19.85	0.106

Source: Energy Information Administration Coal Delivered Prices

Geometric Mean of the price data	-1 percent
Standard Deviation	4 percent
Lower Bound based on two standard deviations	-10 percent
Upper Bound based on two standard deviations	10 percent

Coal Availability in Wisconsin

The bounds on coal availability were set using information from customers with recent experiences with coal availability. Only the lower bound was impacted. The information was reviewed by the five largest customers for plausibility.

Environmental Regulations Driving Generation Portfolios outside ATC

Environmental regulation bounds were set using laws that have been enacted and will be going into effect over the next several years (CAIR and CAMR). The “upper” bound – Kyoto levels of CO^2 regulations – was originally set using information from the MISO futures team. The $44/ton CO^2 tax was independently verified by The Brattle Group as being within the plausible range.

Generation Portfolios outside ATC

Generation portfolios for areas outside of ATC including MISO and Commonwealth Edison were developed as described previously under the section titled "Generation additions outside ATC – MISO & Commonwealth Edison". As explained in that section, E3 developed specific mixes of generation for 2011 and 2016 for the defined footprint using two different sets of growth assumptions:

1. 2% demand and energy growth over the period and middle of the road assumptions on all other pertinent variables (e.g. environmental regulations, renewable portfolio standards, etc.), regarded as "status quo"
2. 1.2% demand and energy growth in a Kyoto world with $44/ton CO^2 tax and a heavy reliance on IGCC plants

E3 provided the amount and mix of generation that would be built across the footprint in each of the scenarios. ATC used the information in the "status quo" scenario to develop specific levels of generation build in each of the futures that corresponded to each particular energy growth rate. The mix of generation remained the same in each future (except High Environmental) but the levels were adjusted to ensure that there was enough generation built to cover load growth. Finally, we also added in a mine-mouth Coal Campus, in some scenarios, to reflect the concept of "moving coal by wire" rather than by rail.

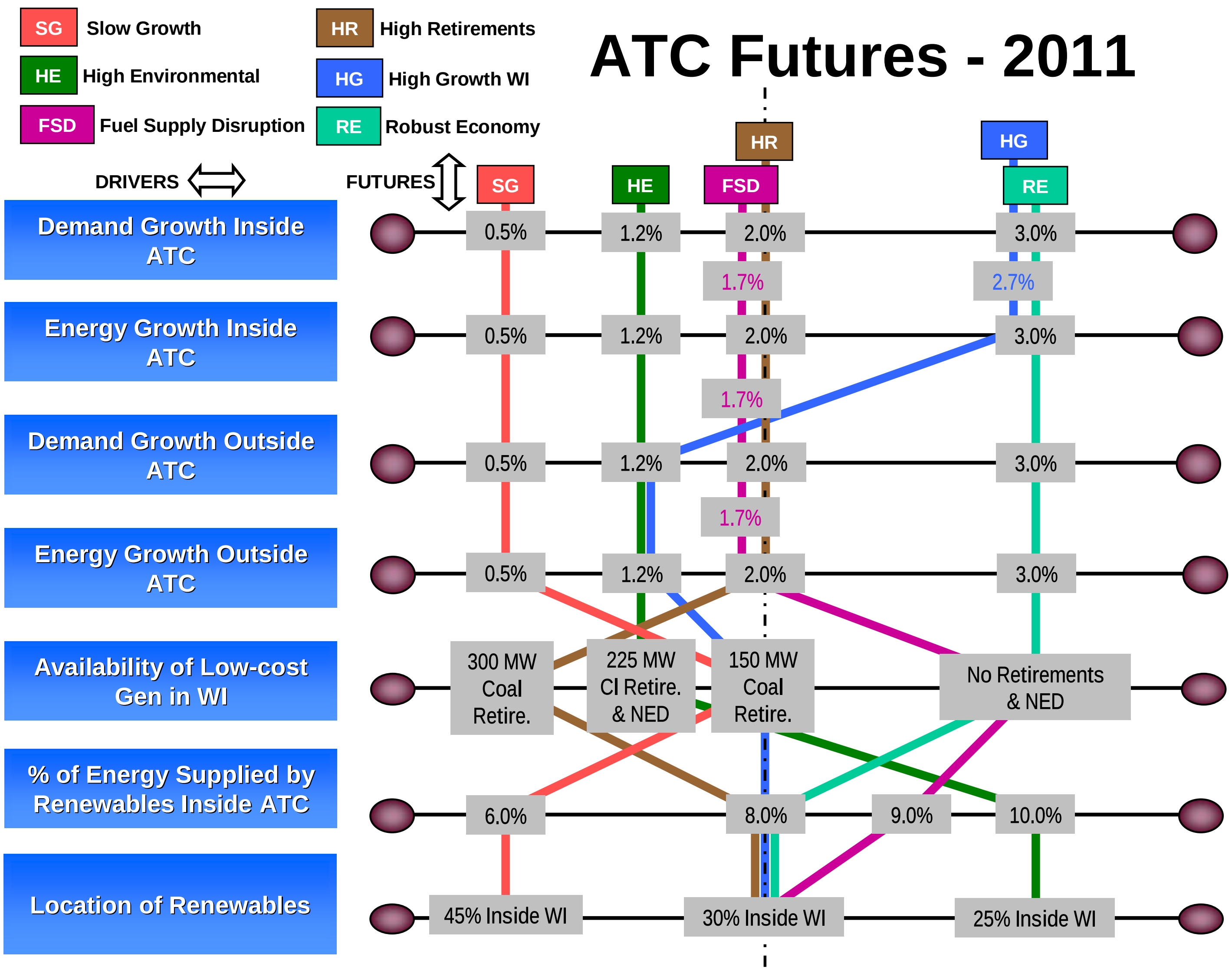
Table 77 shows the total megawatts of non-renewable generation which was added outside of the ATC footprint (as further detailed previously) along with the portion of that generation which is attributed to the Illinois Coal Campus.

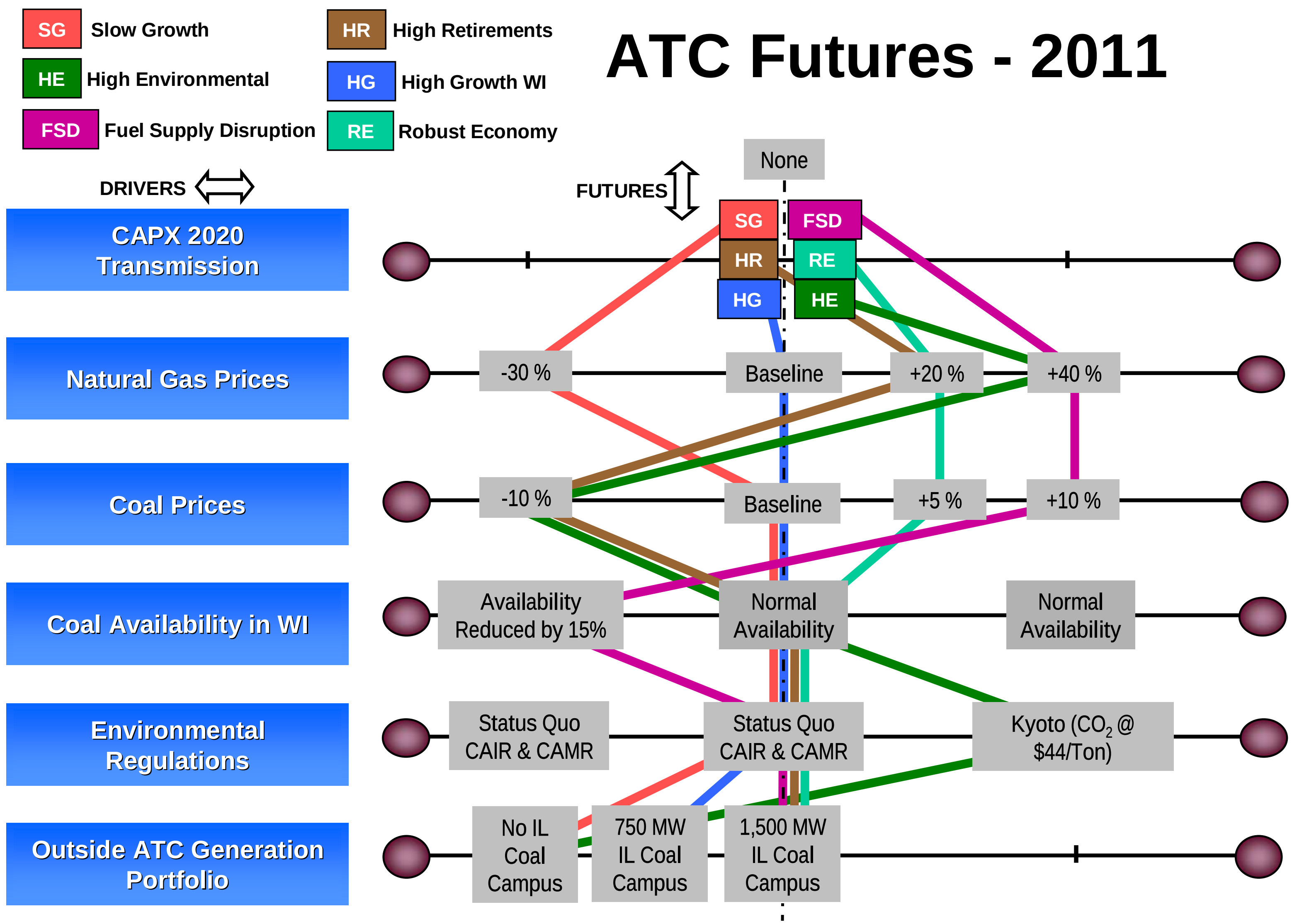
Table 77 2011 and 2016 Non-Renewable Additions

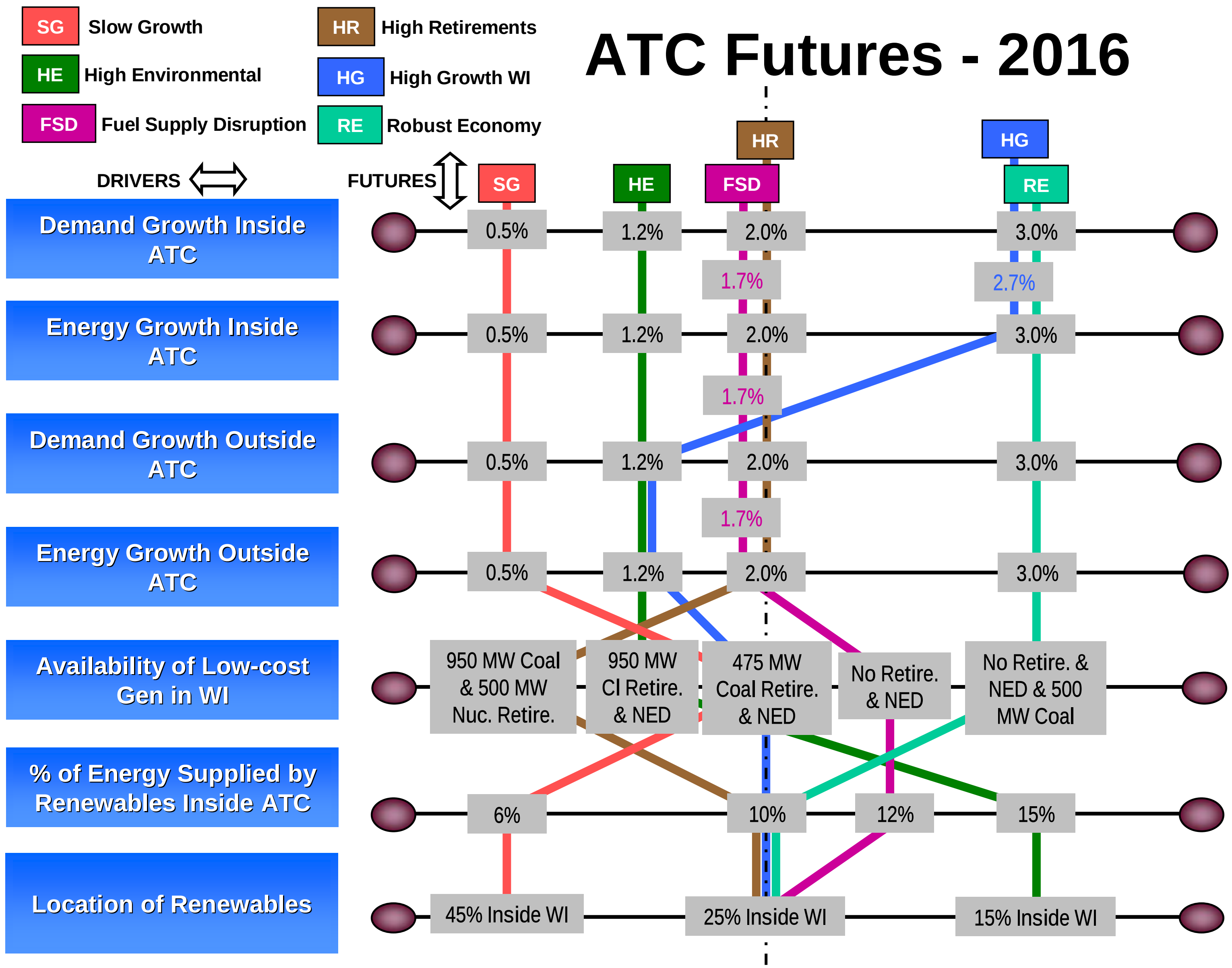
Non-Renewable Generation Portfolios Outside ATC		
Scenario	2011 Total Additions	2016 Total Additions
Robust Economy Case	26,133 MW (1,500 MW Coal Campus)	46,063 MW (6,000 MW Coal Campus)
High Retirements Case	13,339 MW (1,500 MW Coal Campus)	26,883 MW (1,500 MW Coal Campus)
High Environmental Case	1,330 MW (0 MW Coal Campus)	14,227 MW (0 MW Coal Campus)
Slow Growth Case	0 MW (0 MW Coal Campus)	0 MW (0 MW Coal Campus)
Fuel Supply Disruption Case	8,850 MW (1,500 MW Coal Campus)	21,279 MW (3,750 MW Coal Campus)
High Growth Wisconsin Case	1,700 MW (750 MW Coal Campus)	12,689 (1,500 MW Coal Campus)

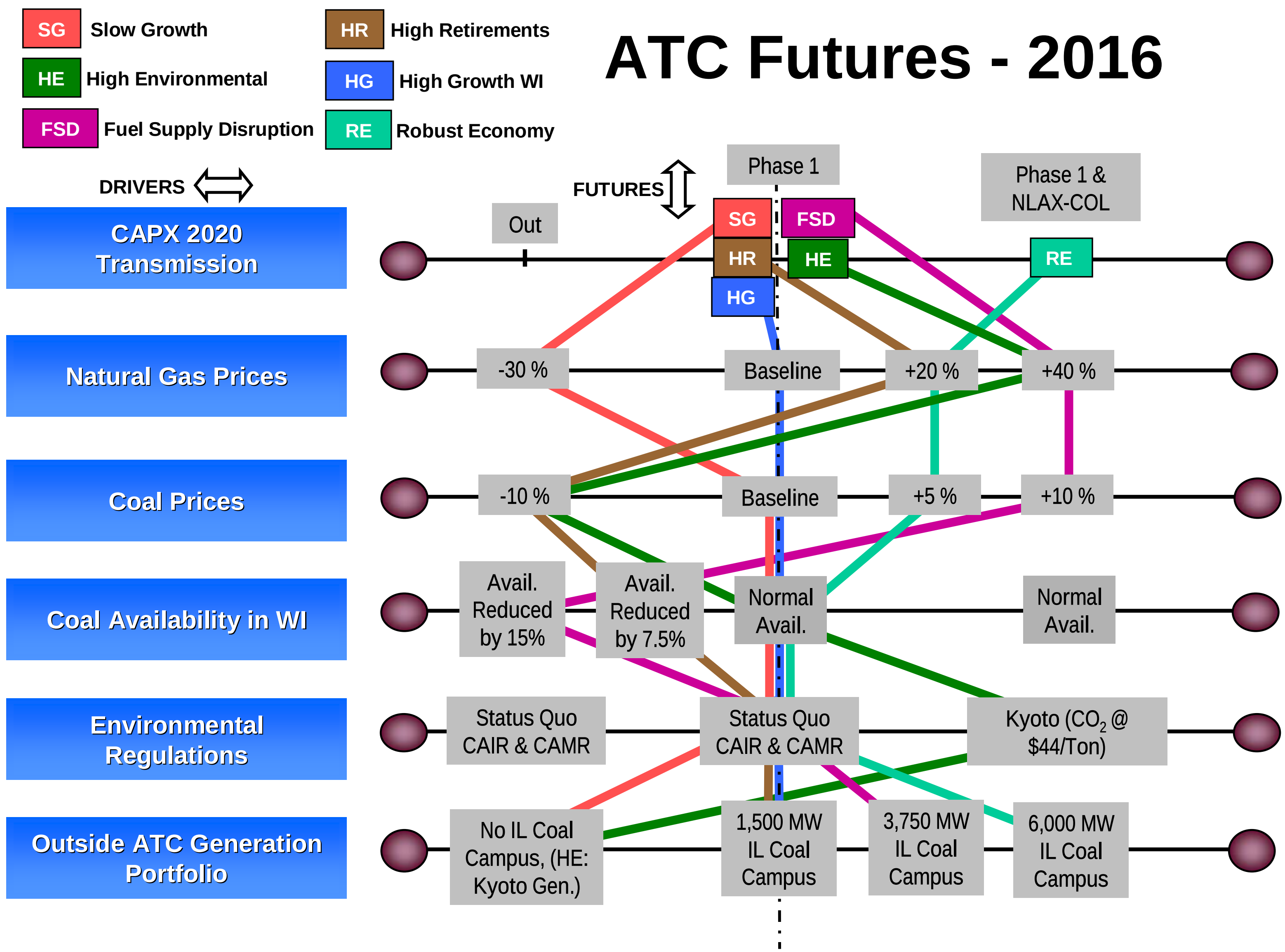
Futures Matrix

(The Futures Matrix which appears on the following pages is a graphic representation of the information in Table 6)




SG Slow Growth
HE High Environmental
FSD Fuel Supply Disruption
HR High Retirements
HG High Growth WI
RE Robust Economy
ATC Futures - 2011
DRIVERS
FUTURES
None
SG
FSD
HR
RE
HG
HE
CAPX 2020 Transmission
Natural Gas Prices
-30 %
Baseline
+20 %
+40 %
Coal Prices
-10 %
Baseline
+5 %
+10 %
Coal Availability in WI
Availability Reduced by 15%
Normal Availability
Normal Availability
Environmental Regulations
Status Quo CAIR & CAMR
Status Quo CAIR & CAMR
Kyoto (CO_2 @ $44/Ton)
Outside ATC Generation Portfolio
No IL Coal Campus
750 MW IL Coal Campus
1,500 MW IL Coal Campus


SG Slow Growth
HE High Environmental
FSD Fuel Supply Disruption
HR High Retirements
HG High Growth WI
RE Robust Economy
ATC Futures - 2016
DRIVERS
FUTURES
Demand Growth Inside ATC
Energy Growth Inside ATC
Demand Growth Outside ATC
Energy Growth Outside ATC
Availability of Low-cost Gen in WI
% of Energy Supplied by Renewables Inside ATC
Location of Renewables
SG
HE
FSD
HR
HG
RE
0.5%
1.2%
2.0%
3.0%
1.7%
2.7%
950 MW Coal & 500 MW Nuc. Retire.
950 MW CI Retire. & NED
475 MW Coal Retire. & NED
No Retire. & NED
No Retire. & NED & 500 MW Coal
6%
10%
12%
15%
45% Inside WI
25% Inside WI
15% Inside WI


SG Slow Growth
HE High Environmental
FSD Fuel Supply Disruption
HR High Retirements
HG High Growth WI
RE Robust Economy
ATC Futures - 2016
DRIVERS
FUTURES
CAPX 2020 Transmission
Natural Gas Prices
Coal Prices
Coal Availability in WI
Environmental Regulations
Outside ATC Generation Portfolio
Out
Phase 1
Phase 1 & NLAX-COL
SG
FSD
HR
HE
HG
RE
-30 %
Baseline
+20 %
+40 %
-10 %
Baseline
+5 %
+10 %
Avail. Reduced by 15%
Avail. Reduced by 7.5%
Normal Avail.
Normal Avail.
Status Quo CAIR & CAMR
Status Quo CAIR & CAMR
Kyoto (CO_2 @ $44/Ton)
No IL Coal Campus, (HE: Kyoto Gen.)
1,500 MW IL Coal Campus
3,750 MW IL Coal Campus
6,000 MW IL Coal Campus

Glossary of Abbreviations

APC: Adjusted production cost(s)
Alliant: Alliant Energy
Alliant-WPL: Alliant Energy-Wisconsin Power & Light
ALTE: Alliant East Control Area
ATC: American Transmission Company
BES: Bulk Electric System
CAIR: Clean Air Interstate Rule
CAISO: California ISO
CAMR: Clean Air Mercury Rule
CPCN: Certificate of Public Convenience and Necessity
COL: Columbia
ECCH: Expanded Congestion Cost Hedge
EHV: Extra High Voltage
EIA: Energy Information Administration
EMF: Electromagnetic field
ECAR: East Central Area Coordination Agreement
EUE: Expected Unserved Energy
FCTTC: First Contingency Total Transfer Capability
FTR: Financial Transmission Right
GADS: Generator Availability Data System [used by NERC]
GW: gigawatt
GWh: gigawatt-hour
HHI: Herfindahl-Hirschman Index
IGCC: Integrated Gasification Combined Cycle [coal plant]
IMM: Independent Market Monitor
kV: kilovolt
LLMP: Load-weighted Locational Marginal Price
LMP: Locational Marginal Price
LOLE: Loss of Load Expectation
LSE: Load-Serving Entity
LV: Low Voltage
MAIN: Mid-American Interconnected Network
MCC: Marginal Congestion Component
MGE: Madison Gas and Electric; also, Madison Gas and Electric Control Area
MLC: Marginal Loss Component
MISO: Midwest Independent System Operator
MTEP: Midwest Transmission Expansion Planning
MW: megawatt
MWh: megawatt-hour
NCA: Narrow Constrained Area
NED: Nelson Dewey

NERC: North American Electric Reliability Corporation
NLAX: North LaCrosse
NPV: Net Present Value
O&M: Operations and Maintenance
PAT: PROMOD Analysis Tool
PSCW: Public Service Commission of Wisconsin
RECB: Regional Expansion Criteria and Benefits
ROW: right-of-way
RSI: Residual Supplier Index
TCA: Tabors Caramanis and Associates
WE: We Energies
WEC: We Energies Control Area
WPPI: Wisconsin Public Power Inc.
WPS: Wisconsin Public Service Corp.; also, Wisconsin Public Service Control Area
WUMS: Wisconsin Upper Michigan System