Exhibit C

MISO 2013 Value Proposition

https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=169815

MISO
2013 Value Proposition

February 2014

The 2013 Value Proposition study shows that MISO provides between $2.1 and $3.0 billion in annual economic benefits to its region

What is the MISO Value Proposition?

The Value Proposition study is a quantification of value provided by MISO to the region including the entire set of MISO market participants and their customers

This value is provided through improved grid reliability and increased efficiencies in the use of generation resources enabled by MISO market operations

What is the MISO Value Proposition NOT?

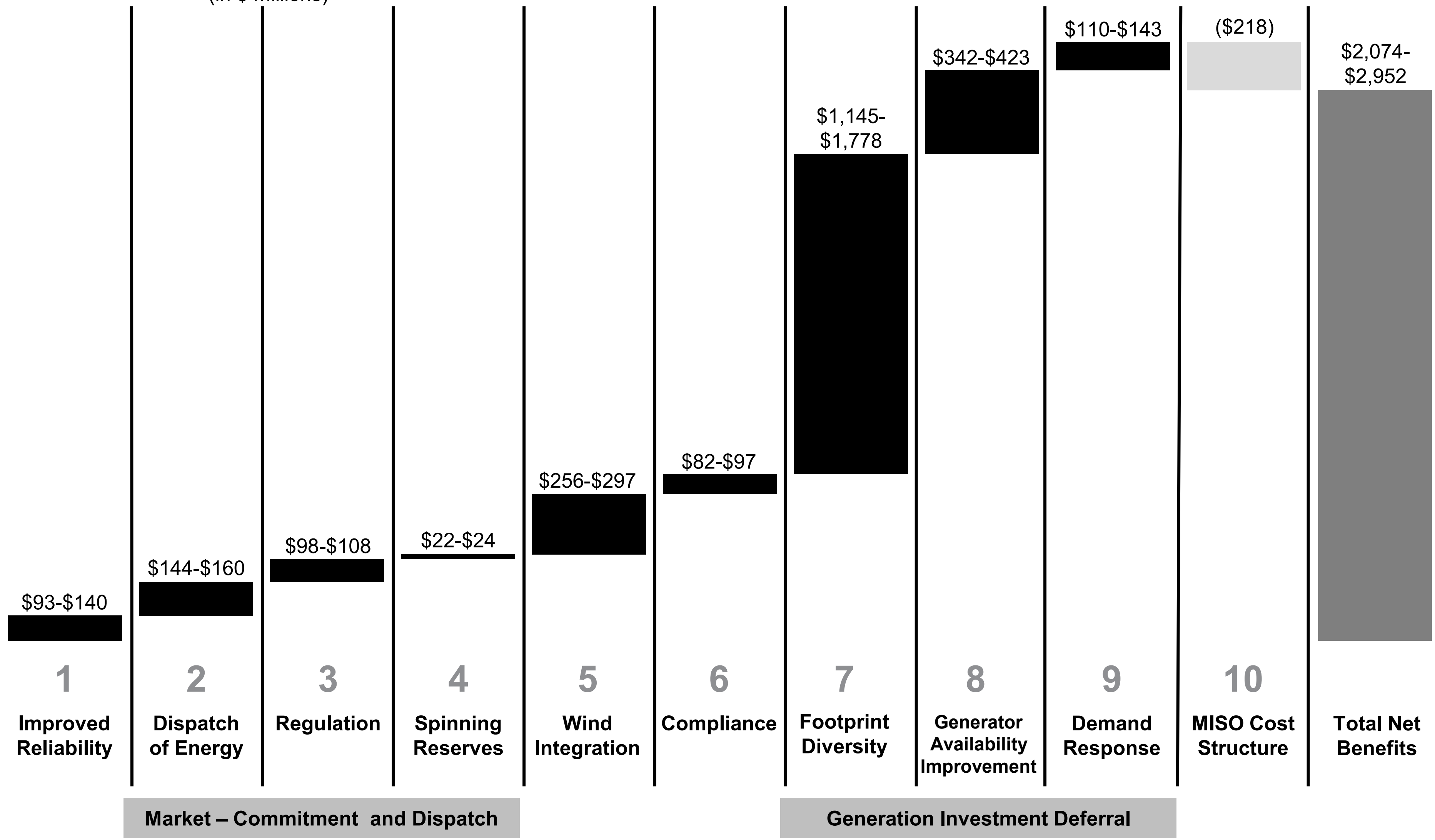
The Value Proposition study does not calculate savings received by market participants as a result of MISO membership

The Value Proposition study does not calculate the value for any individual market sector or state

The Value Proposition study will incorporate savings from the integration of the South region in 2014

MISO’s 2013 Value Proposition

Benefit by Value Driver
(in $ millions)



MISO's operating practices exceed industry standard practices, allowing enhanced reliability in its footprint

1 | Improved Reliability

	Industry Standard Practice	MISO Practice
System Monitoring and Visualization	• Real-time monitoring using SCADA on a local area basis • Use of standard vendor supplied displays • Operator interface of standard monitor display screen augmented with static map board • Ad-hoc and off-line voltage security analysis review	• Regional view/monitoring of the power system including: – A State Estimator - runs every 60 seconds – Contingency analysis of over 11,500 contingencies every four minutes – 24-hour shift engineer coverage responsible for maintaining security application performance • Extended use of custom tools and displays to allow for faster analysis and better situational awareness • Large video wallboard (14' X 165') that provides operators with live data reflecting the state of the power system and real-time market results • Performs multiple voltage security analysis daily during intra-day and next day planning
Congestion Management	• Performed using NERC Transmission Loading Relief (TLR) process or internally developed operating procedure based on congestion management system • 30 – 60 minute response time	• Market-based congestion management that relies on a five-minute security constrained economic dispatch to mitigate transmission congestion on a least-cost basis allows for more timely and efficient congestion management
Backup Capabilities	• Offline and/or scaled down backup facility • Significant time to bring backup facility up in the event a failover or failback is needed • Testing of failover process performed annually	• 24 x 7 staffed back-up control center • On-line back-up facility with full coverage of power system and market applications • Less than 10 minutes required for failover or failback for critical applications • Testing of failover process is performed monthly for critical applications

MISO's operating practices exceed industry standard practices, allowing enhanced reliability in its footprint

1 Improved Reliability

	Industry Standard Practice	MISO Practice
Operator Training	• Classroom training only • Train to meet minimum NERC requirements • Five-person rotation (no training rotation) • Offline power system restoration procedure review	• Training methods include extensive use of full-dispatch training simulator • Training exceeds NERC requirements • Six-person rotation at key operator positions (allowing a training week during each cycle) • Annually conduct a regional "live" power system restoration drill that includes dozens of companies in the region
Performance Monitoring	• Performance reviewed on a "post-event" basis • Operator call review on a "post-event" basis	• Daily review of operational performance including: – Extensive review of established operational metrics – Monthly tracking of improvements – Frequent near-term performance feedback to operators and support personnel – Routine review of upcoming operational events • Standardized operator call review process incorporating established metrics that score calls for each operator on a routine basis • Feedback provided to each operator
Procedure Updates	• Procedures updated on an ad-hoc, as-needed basis	• Annual procedure review conducted on all control room procedures • Routine drills including member participation conducted on capacity emergency procedures

The Transmission System Availability Index can be used to evaluate the value of the improved reliability

Reliability Benefit

= Transmission System Availability Index (TSAI)

- Measured as a percent

X MISO Load

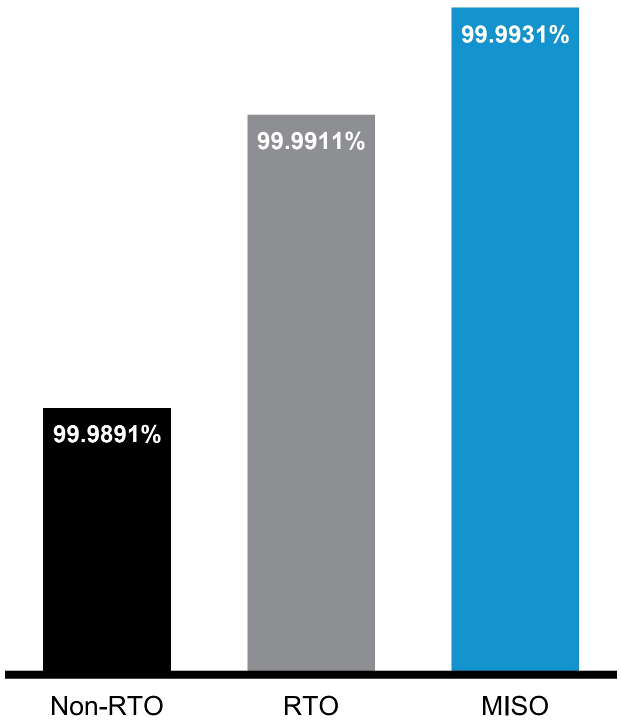
- Measured in MWh

X Cost of Outage

- Measured in cost per MWh

Analysis of NERC and Energy Information Administration outage data reveals that RTO regions serve their load more reliably…

Transmission System Availability Index (TSAI)[1,3]



TSAI Formulas

$$\text{TSAI} = 1 - \left(\frac{\text{Sum of MWh Load Interrupted}}{\left(\text{Sum of MWh Load Interrupted} + \text{Sum of MWh Load Served} \right)} \right)$$

$$\sum_{\#\ \text{of disturbances}}^{1} \left(\begin{array}{l} \text{Duration (hrs) X} \\ \text{Disturbance Size (MW) X} \\ \text{Load Loss Recovery Factor}^{2}\ (0.67) \end{array} \right)$$

[1]Disturbances with outages exceeding 1,000,000 customers and/or outage durations longer than one week were excluded from the analysis as it was assumed those characteristics fit the profile of a distribution-level disturbance
[2]The Load Loss Recovery Factor is used to account for the progressive recovery of load during an outage
[3]Data collected from: (a) NERC, 2000-2007 & 2009 disturbance data, (b) U.S. Energy Information Administration, 2000-2013 disturbance data, (c) U.S. Energy Information Administration, EIA-826 Database from August 2012 – July 2013, and (d) 2012 FERC Form 714s for individual ISO/RTOs

…providing between $93 and $140 million in annual benefits to the region

1 | Improved Reliability

		Reliability Benefit Low Estimate	Reliability Benefit High Estimate
	Transmission System Availability Index (TSAI)	RTO 99.991144% Non-RTO 99.989142% Difference 0.002002%	RTO 99.991144% Non-RTO 99.989142% Difference 0.002002%
X	MISO Load[1]	492,331,505 MWh	492,331,505 MWh
X	Cost of Outage	$9,452 per MWh[2]	$14,179 per MWh[2]
=	Reliability Benefit ($ in Mils.)	**$93**	**$140**

[1]MISO load from October 2012 to December 2012 obtained from MISO's 2012 FERC Form 714; MISO load from January 2013 to September 2013 obtained from preliminary 2013 FERC Form 714 data

[2]ICF, "The Economic Cost of the Blackout." The ICF paper defined a cost of outage range to be $7,440 to $11,160 per MWh. This range is supported by survey-based studies that estimate an electric consumer's (i.e. residential, commercial, industrial, and others) willingness-to-pay to avoid such outages. The cost of outage was adjusted from 2003 dollars to 2013 dollars using Actual CPI from the Bureau of Labor Statistics.

The Energy Market provides the region with a more efficient means of committing/dispatching generation

Historical Perspective

Prior to MISO's creation the region operated as a decentralized, bilateral market. Transmission operations and bilateral power transactions were characterized by physical transmission constraints managed through mechanisms that limited transmission utilization, high transaction costs, low market transparency, pancaked transmission rates, decentralized unit commitment and dispatch.

What changed with MISO?

MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers provided by Market Participants.

The day-ahead market is a forward financial market for energy. Its clearing process produces a set of financially binding schedules according to which sellers are financially responsible to deliver and purchasers are financially responsible to buy energy at defined locations. The day-ahead market process is based upon a unit commitment model that minimizes total production costs over 24 hours. The primary purpose of the day-ahead market is to clear and schedule sufficient supply to satisfy cleared day-ahead demand, using a set of resources that minimize production costs. The purpose of the real-time market is similar, but is based on actual rather than bid demand and must also function to determine economic re-dispatch to manage congestion dynamically.

The improved commitment and dispatch provide between $144 and $160 million in annual benefits

Assumptions / Inputs

- Modeled based on the MISO Commercial and Network Model
- Analysis performed in PROMOD®
- Pre-MISO market analysis
  - Transmission system utilization was de-rated by 10%
  - Hurdle rates between control areas: $3 for dispatch hurdle rate and $10 for commitment hurdle rate
- Post-MISO market analysis
  - Improved transmission system utilization by 10%
  - Hurdle rates between control areas were eliminated

Calculation Methodology

This benefit is best modeled by using an industry standard technique called production cost modeling. Analysis by a number of independent firms has consistently found that a market, such as MISO's, that centrally commits and dispatches generation for a large region will be more cost-efficient than dividing that same generation portfolio into a number of sub-regions and then committing and dispatching them.

Low Estimate ($ in Mils.)	$144
High Estimate ($ in Mils.)	$160

Ancillary Service Markets have resulted in reduced regulation requirements and improved commitment and dispatch efficiency

Historical Perspective

Prior to the launch of MISO's Regulation Market each Balancing Authority (BA) maintained regulation within its area. This often resulted in the BAs within MISO's footprint working "against" each other – some regulating up while others were regulating down.

What changed with MISO?

With the start of MISO's Regulation Market the amount of regulation required within the MISO footprint has dropped significantly. This is a result of working towards a centralized common footprint regulation target rather than a number of non-coordinated regulation targets within the footprint.

The implementation of the Regulation Market also changed the pricing mechanism for regulation by moving from tariff pricing to market pricing. This pricing change is not a true benefit from an economic perspective and, therefore, is not included in the Value Proposition. The effects of the new pricing mechanism for Regulation are tracked and reported in MISO's monthly market operations report.

Those regulation-related improvements result in $98 to $108 million in annual benefits

Assumptions / Inputs

Pre-ASM average regulation[1]	1,105 MW
Post-ASM average regulation[2]	397 MW
Regulation reduction	708 MW
Production cost savings per MW[3]	\$138,382 – Low case \$152,948 – High case

Calculation Methodology

- The reduced requirements for regulation frees up low cost generation units (where regulation was previously held) to serve the energy needs of the region. This component is valued using production cost analysis.
- Calculation is based on the difference between pre-ASM and post-ASM regulation multiplied by the production cost savings per MW

Low Estimate (\$ in Mils.)	\$98
High Estimate (\$ in Mils.)	\$108

[1]Pre-ASM MISO average regulation (MW) from 4/1/2005 to 12/31/2008 and adjusted for membership changes
[2]Post-ASM average regulation (MW) from October 2012 to September 2013 from October 2013 MISO Informational Forum presentation
[3]Based on MISO production cost modeling using PROMOD® software

Similarly, the ASM has resulted in reduced spinning reserve requirements and improved efficiency

Historical Perspective

Pre-Contingency Reserve Sharing Group (CRSG)
Each Balancing Authority (BA) determined their spinning reserve requirement based on their individual (or Reserve Sharing Group) standards.

Post-CRSG/Pre-Ancillary Services Market (ASM)
Each BA determined their spinning reserve requirement based on the CRSG standards.

Post-ASM
MISO determines their spinning reserve requirement based on Midwest CRSG requirements.

What changed with MISO?

Starting with the formation of the CRSG and continuing with the implementation of the Spinning Reserve Market, the total spinning reserve requirement has been reduced. It is currently reduced by 14% from pre-ASM CRSG standards. This reduced requirement frees up low cost capacity to meet energy market needs.

The implementation of the Spinning Reserve Market also changed the pricing mechanism for spinning reserves by moving from tariff pricing to market pricing. This pricing change is not a true benefit from an economic perspective. Therefore it is not included in the Value Proposition. The affects of the new pricing mechanism for spinning reserves are tracked and reported in MISO's monthly market operations report.

Those spin-related improvements provide annual benefits of $22 and $24 million

Assumptions / Inputs

Pre-ASM average spinning reserves requirement[1]	1,092 MW
Post-ASM average spinning reserves requirement[2]	935 MW
Spinning reserves requirement reduction	157 MW
Production cost savings per MW[3]	$138,382 – Low case $152,948 – High case

Calculation Methodology

- The reduced requirements for spinning reserves frees up low cost generation units (where spinning reserves were previously held) to serve the energy needs of the region. This component is valued using production cost analysis.
- Calculation is based on difference between pre-ASM and post-ASM spinning reserves multiplied by the production cost savings per MW

Low Estimate ($ in Mils.)	$22
High Estimate ($ in Mils.)	$24

[1]2006 Spinning Reserves (based on reserve requirement of 2,635 MW multiplied by 45%) adjusted for membership changes
[2]Monthly weighted average spinning reserve requirement (MW) from October 2012 to September 2013 from MISO's 2013 October Informational Forum presentation
[3]Based on MISO production cost modeling using PROMOD® software

MISO's regional planning enables more economic placement of wind resources in the region

Local design of wind generation build-out

Combination design of wind generation build-out

ILLUSTRATIVE

Local Design = Renewable energy requirements and goals will be met with resources within the same state as the load

Combination Design = Renewable energy requirements and goals will be met with a combination of local resources and resources outside of the state with high ranking renewable energy zones

The economic benefit of optimizing wind into MISO's footprint is $256 to $297 million in annual benefits

Assumptions / Inputs

	2010 to 2013
Wind turbine build	
Local – without MISO[1]	5,326 MW
Combination – with MISO[2]	4,797 MW
Cumulative wind savings	528 MW
Wind turbine cost midpoint[3] (in millions)	
Local – without MISO	$45,849
Combination – with MISO	$39,840
Difference	$6,009
Cost/MW[4]	$2,446,664–Low estimate $3,058,882–High estimate

Calculation Methodology

- Avoided cost benefit annualized using an estimated revenue requirement. The annual revenue requirement is calculated using an annual charge rate that includes a rate of return, property tax rate, insurance cost rate, fixed O&M, and depreciation. Annual charge rate calculated using EGEAS software.
- Calculation does NOT include any production cost savings from either the wind generation or the congestion relief from new transmission. As these benefits occur they will be reflected in the Dispatch of Energy benefit.

Low Estimate ($ in Mils.)	$256
High Estimate ($ in Mils.)	$297

[1]Wind build out without MISO for 2010 to 2013 was calculated based on the results of the Regional Generation Outlet Study II (RGOS II). RGOS II was modified to include the MISO footprint only. RGOS II results (modified for the MISO footprint) showed that wind turbines required to meet renewable energy mandates may be reduced by approximately 11% through the combination design siting methodology. The 11% additional wind under the local design was applied to the actual wind added in MISO's footprint to calculate the wind build out in the region without MISO.
[2]Registered wind added to MISO footprint from 1/1/2010 to 9/30/2013
[3]Wind turbine costs shown reflect midpoint of low and high fixed charges for entire book life (25 years) of turbine
[4]High and low estimate of the initial book value of a 1 MW onshore wind turbine generator. Estimates calculated using EGEAS software. Book/tax life = 25/15 years.

MISO adds both quantitative and qualitative value by performing several compliance activities on behalf of its members

	Before MISO	With MISO
Standards Development	• Utilities were varied in their approach to standards engagement. Many have historically been "standards takers," relying on the good judgment of others in the industry to develop standards. This worked well in a voluntary compliance environment.	• By collaborating and participating in the standards creation, MISO and its members can better manage the ultimate compliance responsibilities • MISO engages in several NERC drafting teams to actively manage the scope of standards development and to limit the number of changes required to MISO and stakeholders • MISO's collaborative efforts lighten the workload on all members for a given level of input and control of the process
NERC Compliance	• Many parties in the MISO region were responsible for managing NERC compliance: – 3 Reliability Coordinators – 20+ Interchange Authorities – 20+ Transmission Service Providers – 20+ Balancing Authorities (BA) – Several Planning Authorities – Individual Reserve Sharing Administration	• With MISO as the central balancing authority in the region, many compliance responsibilities have consolidated and member responsibilities have decreased: – 1 Reliability Coordinator – MISO – 1 Interchange Authority – MISO – 1 Transmission Service Provider – MISO – Significantly fewer BA Compliance Requirements – LBAs – Fewer Planning Authorities – Single Reserve Sharing Administrator – MISO – Centralization of some Transmission Operator Requirements – MISO • Allows members to avoid hiring compliance-dedicated staff or reduce existing compliance-driven staff to track these compliance-related issues
Tariff Compliance	• Each utility managed the compliance of their individual tariffs and their separate OASIS functions	• Under MISO, tariff compliance was consolidated thereby saving time and money for our members

MISO has quantified the compliance activities performed on behalf of its members for our Transmission Asset Management (TAM) and Operations areas of the company

TAM Tariff and Order 890 Compliance

- Through performing the studies and processes described in our FERC approved Tariff, MISO supports the long-term transmission planning and compliance of our members. In particular, MISO's compliance efforts support the following areas:
  - Long Term Expansion Planning
  - Generator Interconnection
  - Transmission Service Requests
  - Loss of Load Expectation
  - Resource Adequacy
  - FERC 715 Market Rates Filing
- MISO's planning process provides mechanisms to ensure that the regional planning process is open, transparent, coordinated, includes both reliability and economic planning considerations, and includes mechanisms for equitable cost sharing of expansion costs
- 29 Transmission Owners (TOs) signed our Order 890 proposal and are listed in Attachment FF-4, while 36 TOs were MISO members the majority of 2013

TAM NERC Compliance

- Through performing the compliance activities required for our NERC Planning Coordinator role, MISO enables our members to avoid hiring extra staff to track these compliance related issues. TAM's NERC compliance efforts include the following areas:
  - Long Term Expansion Planning
  - Seasonal Assessments, including studies on
    - Transmission
    - Generation
    - Resource Adequacy

Operations

Operations ensures compliance with NERC requirements applicable to a Reliability Coordinator, Balancing Authority, Transmission Service Provider, and Interchange Authority; and with the MISO Tariff. Operations staff manage:

706 NERC Requirements

1,980 Tariff Requirements

MISO's compliance activities provide between $82 and $97 million in annual benefits to the region

Assumptions / Inputs

Full-time equivalents (FTEs) savings[1]	• Transmission Asset Management	
	– Tariff Compliance:	3.0 - 4.0
	– Order 890 Compliance:	4.0 - 6.5
	– NERC Compliance:	3.0 - 3.5
	• Operations Compliance:	24.0
Affected members[2]	Large-size members: 5 - 6 Medium-size members : 8 - 9 Small-size members: 16 - 21	
Hourly rates	Internal rate: $66/hr (70% - 90% of hours) External rate: $ 100-170/hr (10% - 30% of hours)	

Calculation Methodology

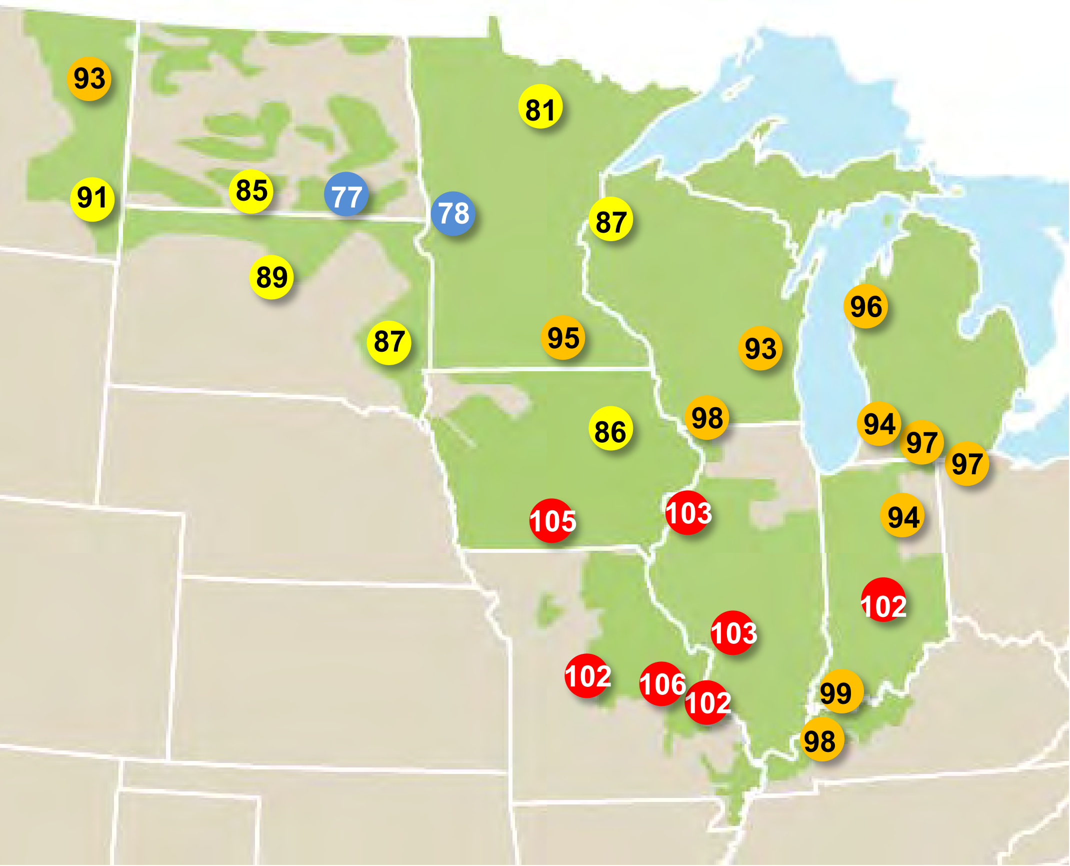
- The full-time equivalents savings were based on internal MISO analysis
- The compliance benefit was calculated by multiplying the estimated FTEs needed to perform each compliance activity, the affected members, and the labor rate per hour.

Low Estimate ($ in Mils.)	$82
High Estimate ($ in Mils.)	$97

[1]Full-time equivalents (FTEs) for large-size members based on internal MISO analysis. Medium-size members estimated to save 50% of a large-size member's FTEs. Small-size members estimated to save 25% of a large-size member's FTEs.
[2]Members were divided into large, medium, and small based on their electric sales (in MWh). Members with sales above 30 million MWhs are classified as large. Medium-size members have electric sales between 10 million and 30 million MWhs. Small-size members have electric sales below 10 million MWhs.

MISO’s large footprint increases the load diversity, allowing for a decrease in regional planning reserve margins for Local Resource Zones from 21.95% to 14.2%

High Temperatures on July 23, 2012
MISO Peak of 98,576 MW for 2012

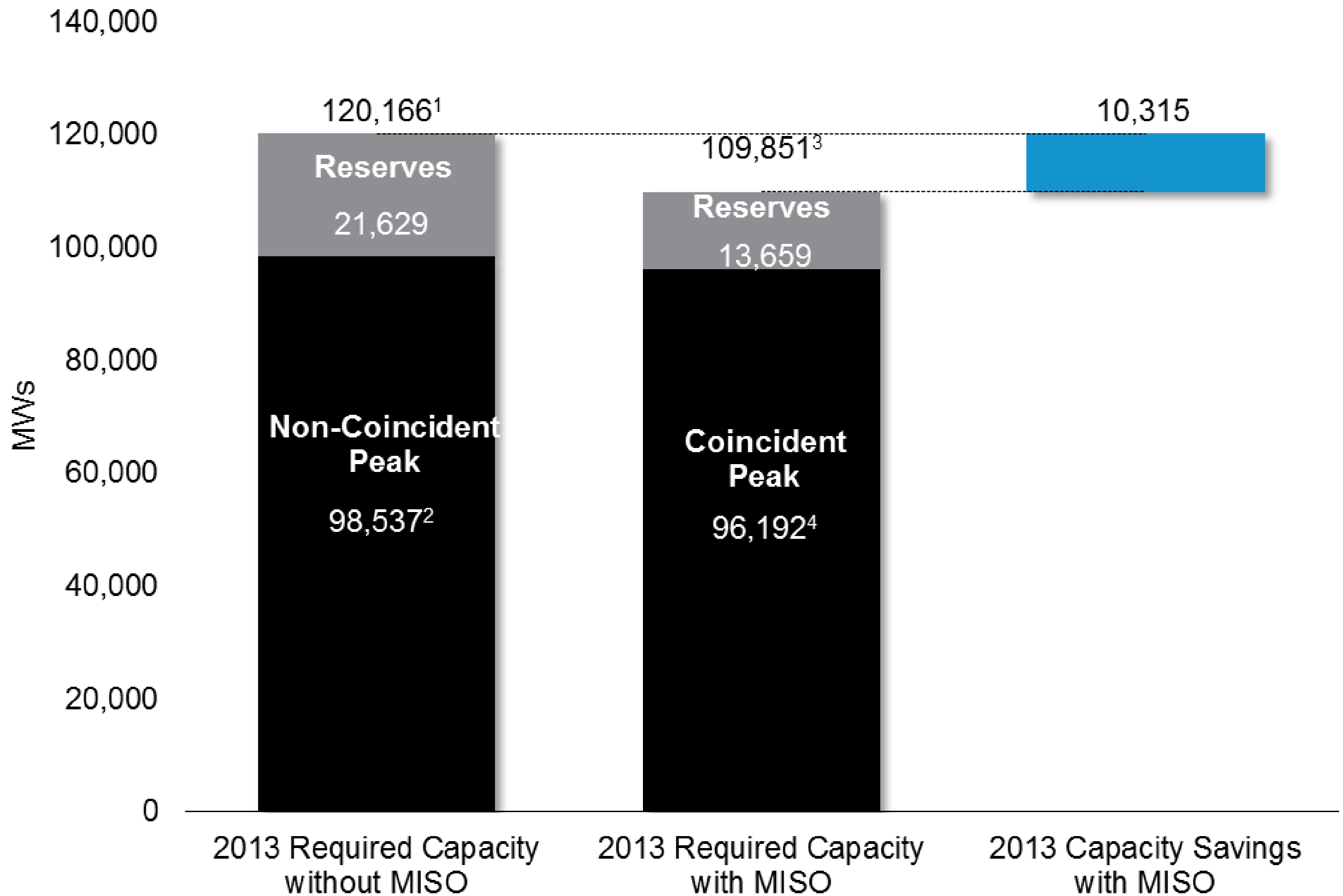


Load Diversity Explained

The high temperature map illustrates that the peak for each Load Serving Entity (LSE) does not occur at the same time.

Prior to MISO, individual LSEs maintained reserves based on their monthly peak load forecasts. Due to MISO’s broad and diverse footprint, LSEs now maintain reserves based on their load at the time of the MISO system-wide peak. This creates significant savings.

MISO's footprint diversity delays the need to construct 10,315 MW of additional capacity



[1]Estimated 2013 "without MISO" Local Reliability Requirement (installed capacity basis) for each Local Resource Zone less 3,277 MW of import capability of firm external purchases (per 2013 LOLE Study)
[2]Sum of Forecasted 2013 non-coincident peak provided by each Load Serving Entity in accordance with Module E for the 2013-2014 Resource Adequacy Planning Year
[3]2013 forecasted MISO coincident peak utilized in the 2013 Resource Adequacy auction [96,192 MW] X (1 + PRM%[14.2%])
[4]2013 forecasted MISO coincident peak used to determine the Resource Adequacy requirement utilized in the 2013 Resource Adequacy auction

MISO's footprint diversity results in annual benefits of between $1,145 and $1,778 million

Assumptions / Inputs

2013 planning reserve margin[1]	14.2%
2013 required capacity without MISO[2]	120,166 MW
2013 required capacity with MISO[3]	109,851 MW
Capital investment avoided, 2013	8,216 MW – Low est. 10,315 MW – High est.
Cost/MW[4]	$747,039–Low estimate $933,799–High estimate

Calculation Methodology

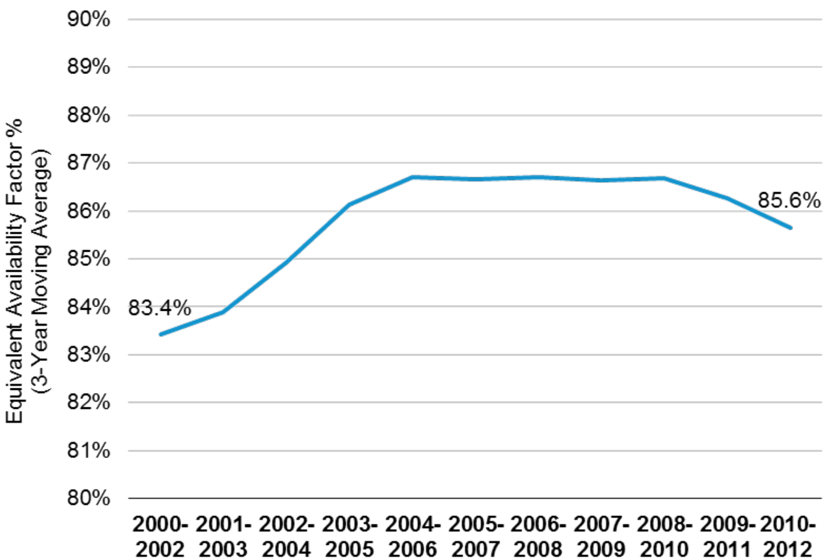
- The shift from localized use of the electrical system to regional use allows more efficient and effective use of the generation assets and allows a reduction in the planning reserve margins for the region
- Avoided cost benefit annualized using an estimated revenue requirement. The annual revenue requirement is calculated using an annual charge rate that includes a rate of return, property tax rate, insurance cost rate, fixed O&M, and depreciation. Annual charge rate calculated using EGEAS software.

Low Estimate ($ in Mils.)	$1,145
High Estimate ($ in Mils.)	$1,778

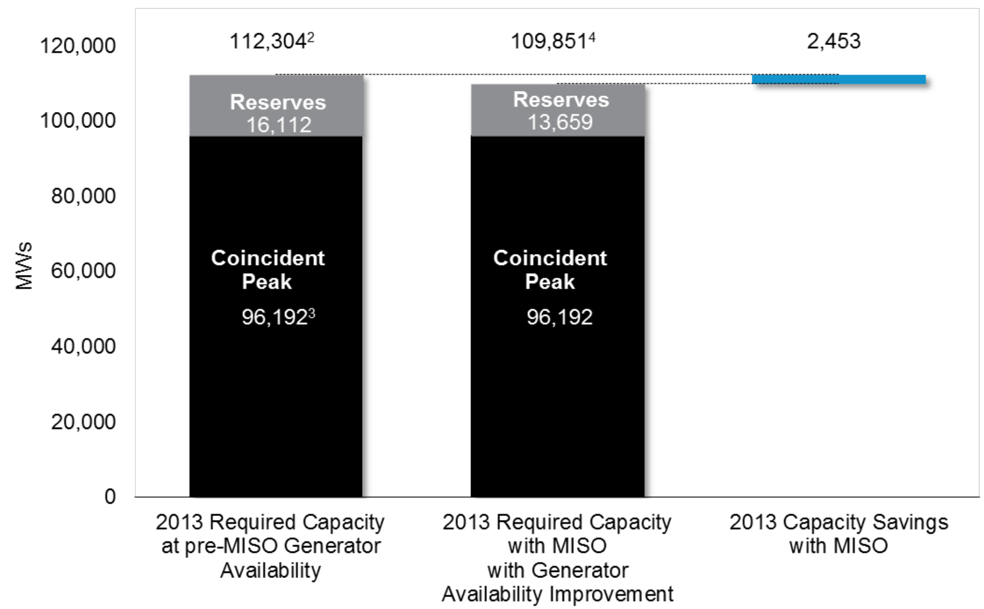
[1]MISO's Planning Year 2013 LOLE Study Report
[2]Estimated "without MISO" 2013 Local Reliability Requirement (installed capacity basis) for each Local Resource Zone less 3,277 MW of import capability of firm external purchases (per 2013 LOLE study)
[3]2013 forecasted MISO coincident peak utilized in the 2013 Resource Adequacy auction [96,192 MW] X (1 + PRM%[14.2%])
[4]High and low estimate of the initial book value of a 1 MW combustion turbine generator. Estimates calculated using EGEAS software. Book/tax life = 30/15 years.

MISO's wholesale power market has resulted in power plant availability improvements of 2.2%, delaying the need to construct 2,453 MW of new capacity

Generator Availability – All Units[1]



2013 With and Without MISO Comparison



[1]The generator availability improvement is calculated using Generator Availability Data System (GADS) data from 2000 to 2012. The equivalent availability factor (EAF) metric is used which is a measure of the actual maximum capability of a unit to generate electricity relative to the theoretically possible amount.
[2]2013 required capacity with MISO [109,851] X (1 + generator availability improvement % [2.23%])
[3]2013 forecasted MISO coincident peak used to determine the Resource Adequacy requirement utilized in the 2013 Resource Adequacy auction
[4]2013 forecasted MISO coincident peak used to determine the Resource Adequacy requirement utilized in the 2013 Resource Adequacy auction [96,192 MW] X (1 + PRM%[14.2%])

The delay in capacity construction results in an annual benefit of between $342 to $423 million

Assumptions / Inputs	
2013 planning reserve margin[1]	14.2%
Generator availability improvement[2]	2.23%
2013 required capacity at pre-MISO generator availability[3]	112,304 MW
2013 required capacity with MISO generator availability improvement (MW)[4]	109,851 MW
Capital investment avoided, 2013	2,453 MW
Cost/MW[5]	$747,039–Low estimate $933,799–High estimate

Calculation Methodology

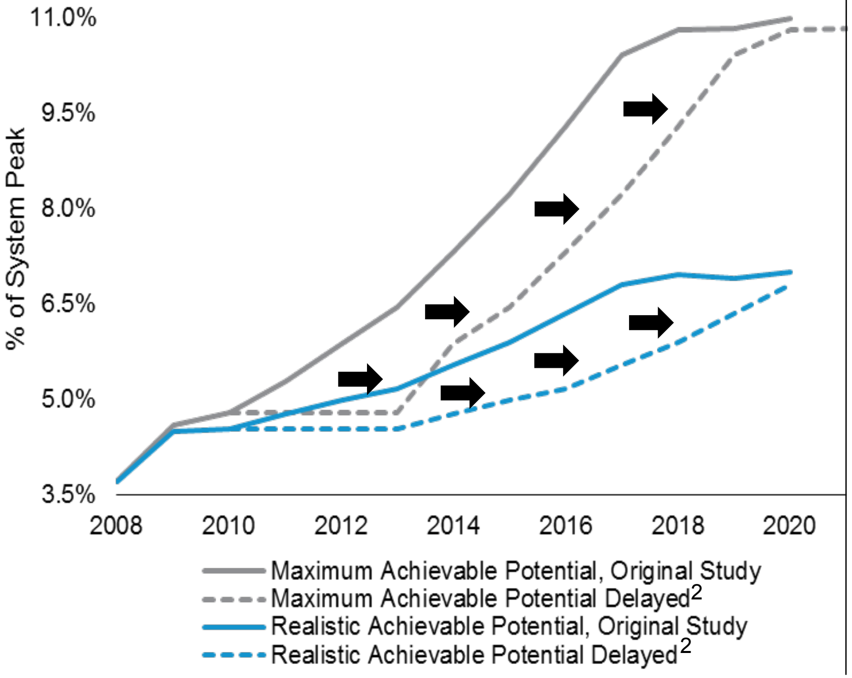
- Competitive wholesale power markets provide generation owners incentives to achieve higher power plant availability and lower forced outage rates, which reduces the need for constructing new generation capacity
- Avoided cost benefit annualized using an estimated revenue requirement. The annual revenue requirement is calculated using an annual charge rate that includes a rate of return, property tax rate, insurance cost rate, fixed O&M, and depreciation. Annual charge rate calculated using EGEAS software.

Low Estimate ($ in Mils.)	$342
High Estimate ($ in Mils.)	$423

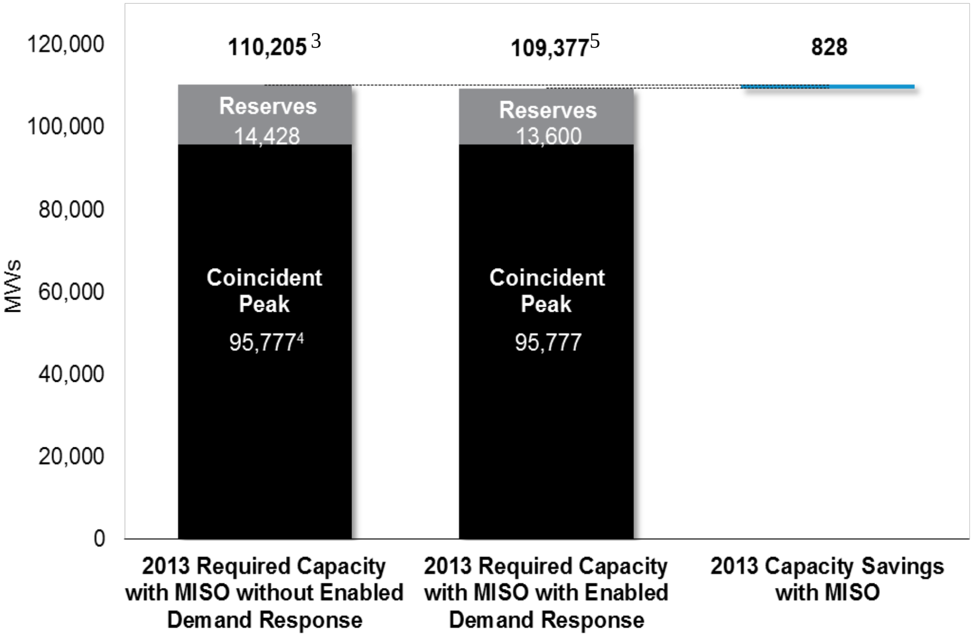
[1]MISO's Planning Year 2013 LOLE Study Report
[2]The generator availability improvement is calculated using Generator Availability Data System (GADS) data from 2000 to 2012. The equivalent availability factor (EAF) metric is used which is a measure of the actual maximum capability of a unit to generate electricity relative to the theoretically possible amount.
[3]2013 required capacity with MISO [109,851 MW] X (1 + generator availability improvement [2.23%])
[4]2013 forecasted coincident peak used to determine the Resource Adequacy requirement utilized in the 2013 Resource Adequacy auction [96,192 MW] X (1 + PRM%[14.2%])
[5]High and low estimate of the initial book value of a 1 MW combustion turbine generator. Estimates calculated using EGEAS software. Book/tax life = 30/15 years.

MISO enables direct load control & interruptible contracts and dynamic pricing, delaying the need to construct 828 MW of new capacity

Demand Response Potential Enabled by MISO[1]



2013 With and Without MISO Comparison



[1]The Brattle Group, "Fostering Economic Demand Response in the Midwest ISO", 12/30/2008. Represents increase in % of system peak reduction due to dynamic pricing, direct load control, and interruptibles for residential, commercial, and industrial customers.
[2]MISO is not realizing the rate of increase in the participation levels as assumed in the Brattle Group Report published in 2008. As such, MISO has kept the % of system peak reduction at the same levels used in the 2010 Value Proposition.
[3]2013 required capacity with MISO [109,377MW] + (2013 coincident peak [95,777 MW] X incremental demand response enabled by MISO [0.86%])
[4]Actual 2013 MISO coincident peak load set on July 18, 2013
[5]2013 coincident peak [95,777 MW] X (1 + PRM%[14.2%])

Demand response allows additional generation investment deferral resulting in annual benefits of $110 to $143 million

9 | Demand Response

Assumptions / Inputs

2013 MISO coincident peak[1]	95,777 MW
% of system peak reduction due to demand response[2]	Low estimate – 0.83% High estimate – 0.86%
Capital investment avoided, 2013	Low estimate – 791 MW High estimate – 828 MW
Cost/MW[3]	$747,039–Low estimate $933,799–High estimate

Calculation Methodology

Avoided cost benefit annualized using an estimated revenue requirement. The annual revenue requirement is calculated using an annual charge rate that includes a rate of return, property tax rate, insurance cost rate, fixed O&M, and depreciation. Annual charge rate calculated using EGEAS software.

Low Estimate ($ in Mils.)	$110
High Estimate ($ in Mils.)	$143

[1]Actual 2013 MISO coincident peak load set on July 18, 2013
[2]The Brattle Group Report "Fostering Economic Response in the Midwest ISO", page 70 (Realistic Achievable Potential for low estimate) and page 63 (Maximum Achievable Potential for high estimate). Represents increase in % of system peak reduction due to dynamic pricing, direct load control, and interruptibles for residential, commercial, and industrial customers. The increase in % of system peak reduction for dynamic pricing was multiplied by 50% to derive the high estimate.
[3]High and low estimate of the initial book value of a 1 MW combustion turbine generator. Estimates calculated using EGEAS software. Book/tax life = 30/15 years.

Administrative and operating costs represent a small percentage of the benefits

MISO Operating Costs[1]

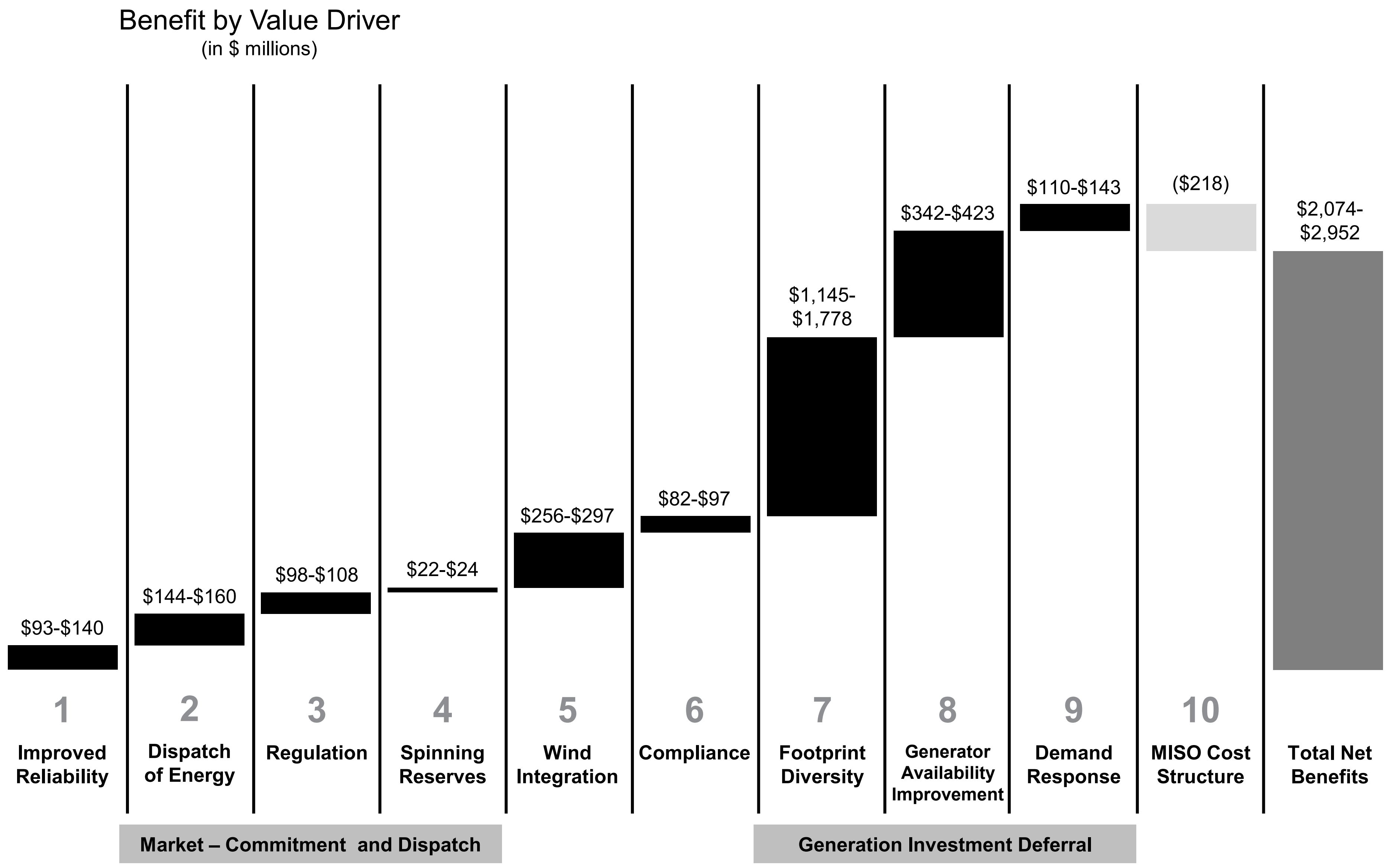
(in Mils.)

Cost Recovery Category	2013
Schedule 10	$86.2
Schedule 16	$11.8
Schedule 17	$116.3
Schedule 31	$3.3
Total Operating Cost	$217.6

[1]MISO Schedule 10, 16, 17 & 31 Budget for 2013

Note: MISO's administrative and operating costs encompass the material costs incurred by its members. There are additional cost impacts (both increases and decreases) that are incurred, but we deem these costs to be small and not have a material impact on the overall value that MISO provides.

MISO's 2013 Value Proposition



The MISO 2013 Value Proposition – Qualitative Benefits

1 | Price/Informational Transparency

2 | Planning Coordination

3 | Seams Management

Price and data transparency in the MISO market provides a host of benefits

1 | Price/Informational Transparency

	Before MISO	With MISO
Efficiency	• Bilateral markets lack price and data transparency, leaving participants searching for which plants are operating at what cost	• Every market participant can see pricing and information that results in increased market efficiencies
Investment	• Bilateral markets provided insufficient price signals which resulted in inefficient investment and placement of generation resources and transmission infrastructure	• Price signals sent by MISO's energy market provides investors in generation assets with the underlying data upon which they can anchor forecasts for future wholesale prices and provide the basis for market driven investments
Reliability	• Bilateral markets achieve reliability based on contractual rights and industry standards with little thought to economic impacts	• MISO enhances reliability by informing all market participants on the state of grid conditions and market operations through the public posting of electricity prices and other key system information • A reflection of real-time system conditions, high market prices in the MISO energy market provides specific signals where more generation is needed and valued while lower market prices indicate the reverse

MISO's transmission planning process is focused on minimizing the total cost of delivered power to consumers

	Before MISO	With MISO
Transmission Expansion Planning Model	• Reliability-based model – Focused primarily on grid reliability – Typically considers a short time horizon – Seeks to minimize transmission build	• Value-based model – Focused on value while maintaining reliability – Reflects appropriate time scales – Seeks to identify transmission infrastructure that maximizes value – Identifies the comprehensive value (reliability, economic, and policy) of projects
Planning Scale and Efficiency	• Local view – Objective of expansion is to address local needs – 26 individual entities optimizing the system within their area	• Regional view – Objective of expansion is to address aggregate regional needs consistent with value-based plans in addition to meeting local needs – Offers opportunities to find efficiencies across multiple Transmission Owners
Cost Allocation	• Free rider issues caused by a lack of alignment between transmission cost and the causers and beneficiaries	• MISO helps facilitate the cost allocation of transmission to minimize free rider issues • MISO regional cost allocation matches costs roughly commensurate with beneficiaries

MISO adds value by managing the seams around its footprint

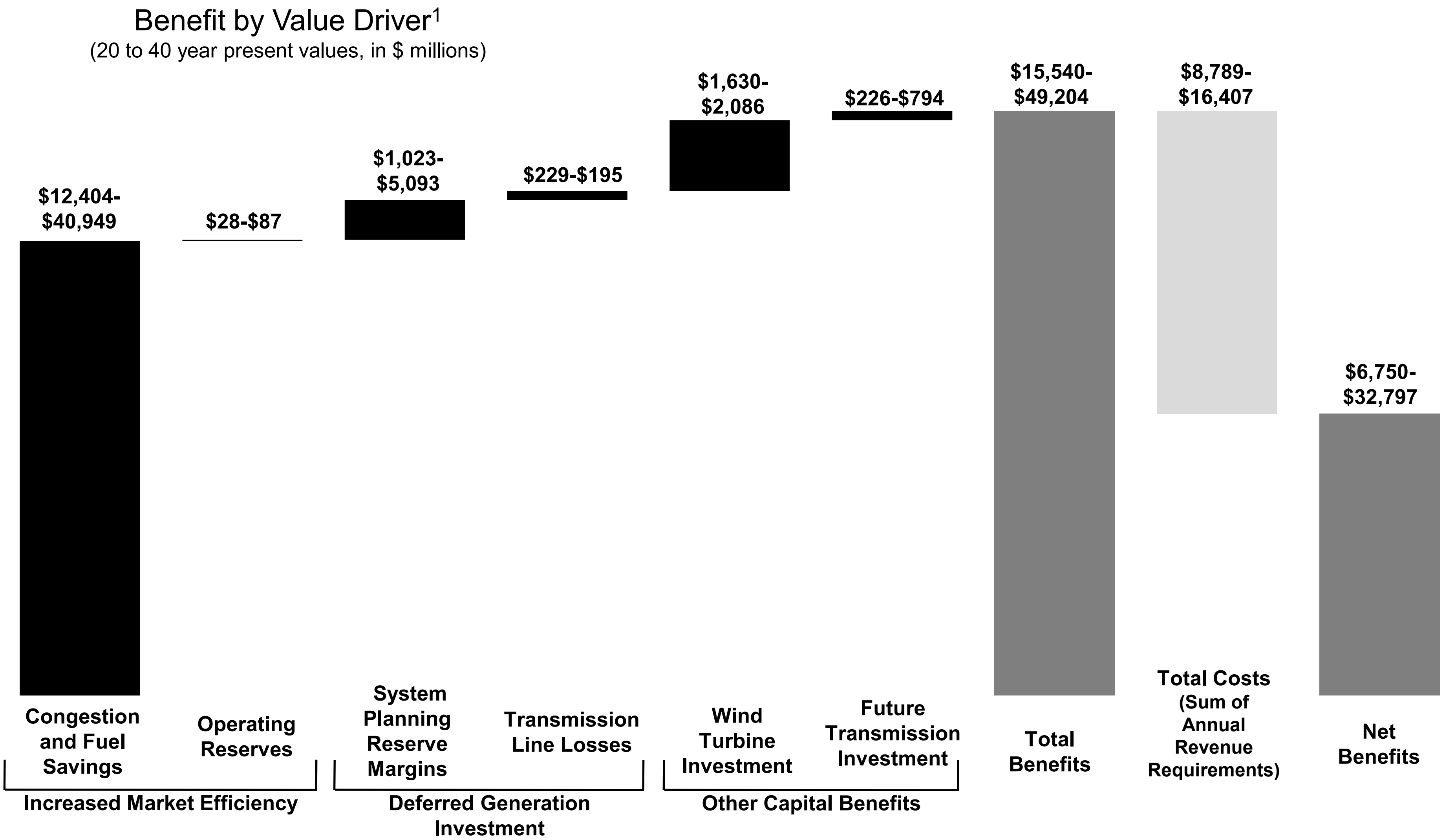
	Before MISO	With MISO
Interchange Transactions	• In order to avoid congestion, a utility or balancing authority (BA) would have seams agreements with each neighbor to monitor their flowgates when selling transmission service. Lacking such agreements, service was sold ignoring neighbors' flowgates with Transmission Loading Relief (TLR)—the only effective congestion management process. If firm service was sold, curtailment had implications to the owner of the firm service, and made the service unavailable when needed.	• Seams agreements between MISO and its neighbors eliminate the need for individual agreements between utilities or BAs • These agreements reduce the likelihood of parallel flows causing overloads on flowgates and the need to use TLRs to manage congestion except when unexpected events occur
Market Flows And Allocations	• A utility or BA served its own interests by classifying all of its generation to load flows as firm so the flows would not be curtailed. This would cause parallel flow issues for neighboring BAs in that firm flow curtailment using TLR had wide ranging implications. This required the utility or BA experiencing congestion to redispatch without compensation in order to manage parallel flow impacts from others.	• The seams agreements between MISO, PJM and SPP provide flowgate allocations between the seams parties that limit the amount of firm market flows. This requires the parties to the seams agreement to classify some of their respective market flows as non-firm so they can be curtailed using TLR. Having each market classify some of its market flows as non-firm means these flows are then subject to curtailment using TLR along with other non-firm usages.
Market-to-Market Process	• When congestion occurred within the Midwest region or PJM's footprint, the IDC assigned tag curtailments and/or market flow relief obligations to the flows. Prior to having a market-to-market process, utilities in the Midwest and PJM would bind their own flowgates based on the relief obligation from the IDC without regard to the cost of redispatch in order to meet the relief obligation.	• Under the market-to-market process, MISO and PJM both bind a coordinated flowgate with the objective of using the most cost effective generation to manage the congestion. There is an after-the-fact settlement used to compensate for assistance provided by the other market. By having both markets bind on a constraint located in one market, this sends the proper price signals to both markets and will help achieve price convergence at the border.

The MISO Value Proposition – Estimated Future Benefits

1 | Multi-Value Projects

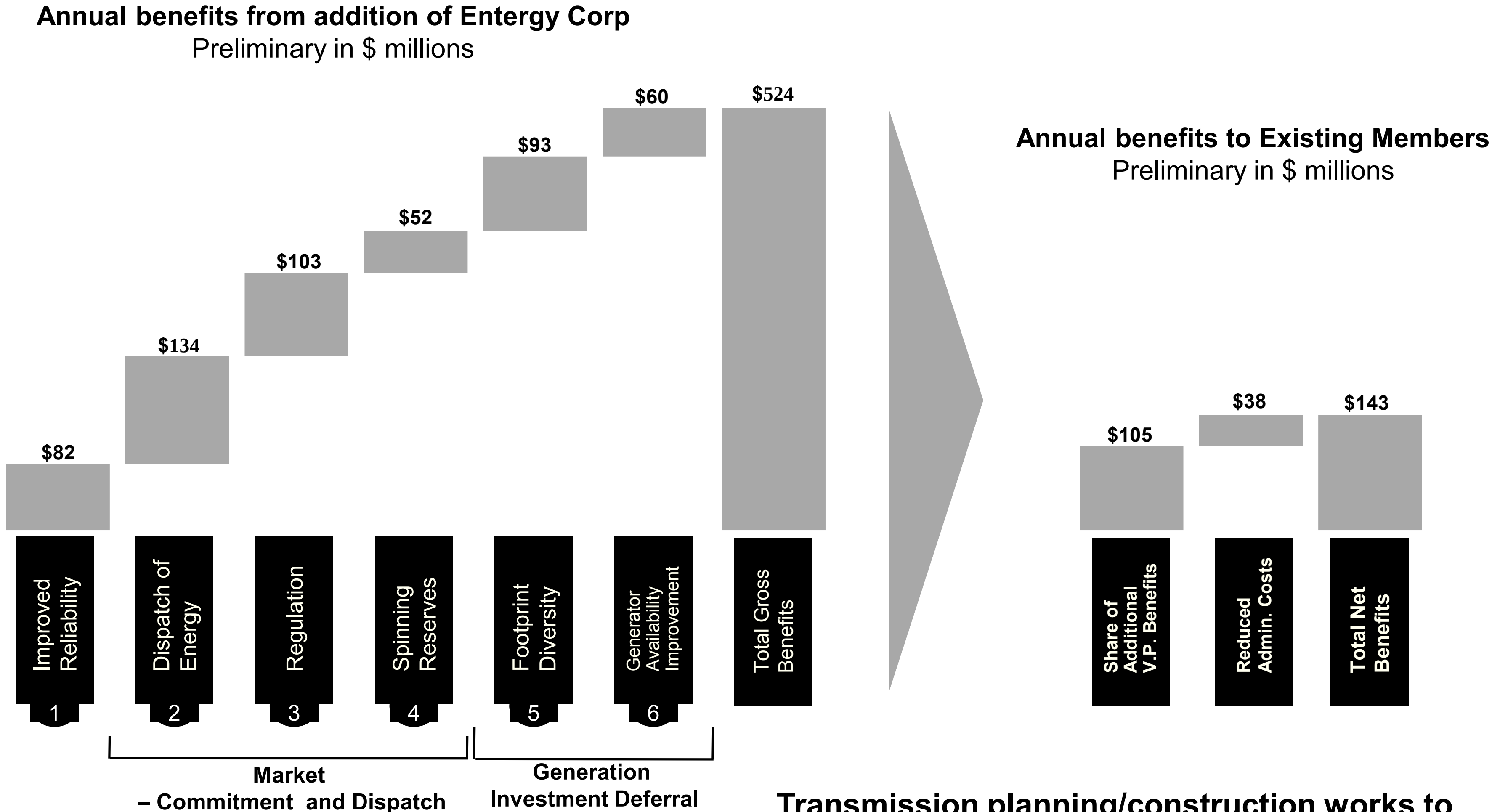
2 | Integration of South Region

MISO's approved Multi Value Project portfolio will create a robust transmission system—ensuring value creation well into the future



[1]MISO's 2011 Candidate Multi Value Project Portfolio Analysis. Figures shown are reflected in 2011 dollars.

Entergy's membership will benefit existing members by stabilizing footprint, reducing administrative costs and increasing value proposition



Transmission planning/construction works to increase value in virtually every benefit category

Exhibit D

Independent Assessment of Midwest ISO Operational Benefits

http://www.icfi.com/insights/reports/2007/independent-assessment-of-midwest-iso-operational-benefits

February 28, 2007

Independent Assessment of Midwest ISO Operational Benefits

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Executive Summary

Study Background

On April 1, 2005 the Midwest ISO began operation of the Midwest Markets, a "Day-2" hourly Locational Marginal Price (LMP) energy market. Market operations include centralized unit commitment and dispatch, a Day-Ahead Energy Market, a Real-Time Energy Market, and a Financial Transmission Rights (FTR) Market. The Midwest ISO is among the largest energy markets in the world covering more than 930,000 square miles and 1,760 pricing nodes. In addition to the unprecedented geographic scope of the organization and associated markets, the Midwest ISO began in late 2001 as a greenfield organization. In fact, the Midwest ISO is the first greenfield RTO[1] with a LMP[2] and centralized dispatch market structure in North America. And, unlike other RTOs with LMP and centralized dispatch, the Midwest ISO does not at this time operate a market for contingency or operating reserves. Instead, multiple individual Balancing Authorities in the region continue to be responsible for providing contingency and operating reserves.

Exhibit ES-1:
The Midwest ISO Market Footprint[3]

Source: Midwest ISO

The Midwest ISO market startup occurred during a challenging period for optimal performance of unit commitment and centralized dispatch. Challenges faced by the Midwest ISO energy market startup included record high natural gas, oil, coal, and emission allowance prices in the second half of 2005. Hurricanes Katrina and Rita combined with international events to drive natural gas and oil prices to levels well above historical norms between August and December 2005. These high fuel prices spilled over into coal and emission allowance markets, increasing

[1] RTO - Regional Transmission Organization
[2] LMP – Locational Marginal Price
[3] Note: The Midwest ISO's reliability footprint is larger than its energy market footprint.

the costs of operations and magnifying the economic effects of any operational inefficiencies. Finally, the Northeast blackout in August 2003, which affected entities in the Midwest ISO footprint as well as elsewhere in the Eastern Interconnect, increased the focus on reliability and would be expected to result in a conservative operating bias on the part of both the Midwest ISO and market participants as unit commitment and dispatch control were transferred to the Midwest ISO.

It should be noted that these challenges notwithstanding, the Midwest ISO's operational reliability was extremely high throughout the start-up. This study does not attempt to quantify the reliability benefits of coordinated unit commitment and dispatch but is instead focused exclusively on the economic benefits of unit commitment and dispatch activities.

ICF was engaged by the Midwest ISO to review its operations during a ten month period between June 1, 2005 and March 31, 2006, and to estimate a subset of the potential and actual benefits of the Midwest ISO Day-2 operations. This report presents the results of this independent analysis along with an in depth discussion of the Midwest ISO market, analytic approach, study assumptions, and conclusions.

Study Objectives

This study examines differences in production costs resulting from the transition from a Day-1 RTO to a centrally dispatched, LMP-based Day-2 market for the period between June 2005 and March 2006. In a Day-1 RTO each Balancing Authority makes unit commitment and dispatch decisions independently. A Day-2 LMP market employs centralized unit commitment and dispatch based on offers provided by generators to optimize the use of generation and transmission.

Specifically, this study asks three primary questions:

1) What are the **theoretical maximum potential benefits** available from centralized unit commitment and dispatch in the Midwest ISO footprint?

2) What percentage of these benefits were **achievable** during the study period given that the Midwest ISO market structure lacked several key characteristics of a full Day-2 market (i.e. centrally coordinated regulation and operating reserves) during this period?

3) What **benefits were actually achieved** through operation of the Midwest ISO market between June 2005 and March 2006?

It is important to note that the first two questions address the level of potential benefits available due to varying levels of market restructuring. This question has been examined many times by ICF and other parties. As such there is both a significant body of literature and an accepted industry methodology surrounding how to measure these potential benefits.

The third question "What level of benefits were actually achieved during actual operation?", is very ambitious given the size of the Midwest ISO and has not, to our knowledge, been addressed in previous studies of major electric power marketplaces. This ambitious scope of work required close cooperation with Midwest ISO stakeholders, access to Midwest ISO operators, processing of massive amounts of historical data and development of an extremely detailed generation and transmission model of the Midwest ISO footprint. ICF feels that this study provides an excellent representation of both the potential and actual benefits in terms of the details included in the analytic framework and the quality of the analytic results. At the same time, as discussed in Chapter 4 of this report, there may be some features of the modeling which may have resulted in a conservatively low estimate of actual benefits achieved and/or a high estimate of achievable benefits.

RTO Benefits Analyzed

This analysis was designed to focus on a subset of operational benefits available from Day-2 RTO operation which are quantifiable using commercially available models that simulate unit commitment and dispatch of electric generation. The focus was on production cost savings associated with centralized operations, and hence, primarily reflects estimation of the displacement of relatively more expensive generation with relatively less expensive generation made possible by centralized operations. In most cases the simulation indicated the potential displacement of gas-fired generation with coal-fired generation. This inter-fuel optimization is particularly important in the Midwest because the natural gas generation fleet includes a disproportionate level of expensive gas-fired peaking units as opposed to intermediate or less costly gas-fired combined cycle or gas-steam facilities. Further, Midwest ISO coal plants have very low operating costs even compared to other US coal-fired powerplants. Thus, any displacement of natural gas generation with coal generation can greatly decrease operating costs. Put another way, the use of a gas plant when somewhere else inside or outside of the Midwest ISO a coal plant with spare capacity and the needed transmission is available to displace the gas plant would increase costs significantly. As such, an important goal of grid optimization is to minimize these occurrences.

The primary benefits quantified in this study were related to potential improvements associated with:

- Regional security-constrained unit commitment (SCUC);
- Regional security-constrained economic dispatch (SCED);
- Improved utilization of existing transmission assets.

Some benefits of the RTO structure are more difficult to quantify than others, take significant time to be realized as they are associated with long-term capital investments, and lack industry accepted methodologies for their estimation. As a result, the following benefits are not assessed and are not reflected in the benefits estimate in this analysis:

- Reductions in planning reserve margins for generating capacity due to the increased reliability made possible by RTO information systems and inter-RTO coordination;
- Regionally coordinated transmission expansion planning;
- Improved long-term transmission and generation investment efficiency associated with improved visibility of congestion and its economic effects resulting from increased price transparency;
- Transmission access, expanded markets & reduced barriers to trade;
- Improved reliability through regional power flow visibility and dispatch;
- Improved generator availability and efficiency in peak price periods;

- Opportunities for greater participation of price responsive demand;

In order to simplify nomenclature, note that while the term "maximum potential benefits" is used in this study, it refers to the distinct subset of benefits described above, i.e., reductions in fuel and other variable operating costs under centrally coordinated rather than individual utility operations.

Analytic Approach and Cases Examined

An estimation of the benefits to be obtained from RTO operations by definition involves a comparison of what did occur ("actual Day-2 operations") to what would have occurred but for the existence of the RTO ("estimated Day-1 operations"). A simple comparison of 2004 actual operations (pre-Day-2) to 2005 operations (post-Day-2) is inappropriate due to a host of factors that include extreme variation in load, fuel prices, emission allowances prices, available generation, etc. Thus, ICF utilized a combination of historical data and detailed model analysis to develop estimates of maximum potential, achievable, and actual realized benefits of centralized dispatch in the Midwest ISO.

The primary analysis tool utilized was the GE Energy MAPS™ software model (MAPS) which is specifically designed for analysis of grid operations. MAPS was used to perform a security constrained unit commitment (SCUC) and a security constrained economic dispatch (SCED) of all generating facilities to meet peak and energy demand and operating reserve requirements in the Eastern Interconnect with a specific focus on the Midwest ISO footprint. MAPS is capable of simulating both a centralized dispatch regime in Midwest ISO (Day-2) and a Balancing Authority dispatch regime (Day-1).

Historical data derived from the Midwest ISO settlement system was utilized to calculate an estimate of the actual costs incurred during the study period. All scenarios used comparable facility operational characteristics, fuel prices, and emission allowance costs.

ICF prepared and analyzed four primary cases[4] in order to develop the study results. Each case involved a ten month study period between June 1, 2005 and March 31, 2006. These cases are:

- **<u>Day-1 Case</u>**: This case estimated the production cost of the Midwest ISO market assuming continued Day-1 operation for the study period. ICF used hurdle rates[5] derived from a model calibration exercise of the 2004 Day-1 Midwest ISO market to simulate continuation of decentralized Balancing Authority unit commitment and economic dispatch. Hurdle rates are the barriers to trade between Balancing Authorities needed to reproduce the actual operations observed in 2004 in the model.
- **<u>Day-2 Optimal Case</u>**: This case was designed to predict the theoretical maximum benefits from centralized operations in a Day-2[6] market as compared

™ MAPS is a registered trademark of General Electric Company

[4] Note that several additional cases including calibration and sensitivity cases were examined during this analysis and are discussed in Chapter 5

[5] Hurdle rates are discussed in detail in Chapter 3.

[6] Note that Midwest ISO actual operations differed significantly during the study period from the theoretical Day-2 Optimal Case modeled due to, for example, the manner in which regulation and operating reserves are currently provide in the Midwest ISO region versus the in the model representation . These differences are examined through sensitivity cases such as the "No-ASM Case".

to the Day-1 Case. This case specifically was used to predict the production costs of an optimal Midwest ISO Day-2 operation. Commitment and dispatch hurdle rates used in the Day-1 Case to simulate decentralized operation were eliminated in the Day-2 Case to simulate centralized unit commitment and footprint-wide economic dispatch.

- **Day-2 Actual Case**: This case was designed to determine the benefits achieved by the Midwest ISO's Actual Day-2 operation over the study period. ICF used actual hourly dispatch data from the Midwest ISO's Day-2 market operations to estimate actual production costs during this historical period.
- **No-ASM (Ancillary Services Market) Case**: This sensitivity case was designed to simulate achievable benefits from centralized dispatch given the fact that current Midwest ISO operations do not include centralized dispatch and commitment of regulation and operating reserves. Instead, the majority of these ancillary services are held by each Balancing Authority locally. The Midwest ISO filed an ASM plan on February 15, 2007 that would allow for future optimization of these services beginning in 2008.

Exhibit ES-2 provides a summary of the assumptions underlying the three primary cases analyzed in the MAPS model.

Exhibit ES-2:
Comparison of Cases Examined

Parameter	Day-1 Case	No-ASM case	Day-2 Case
SCUC	Commit to meet Balancing Authority (Company) load plus reserve	Midwest ISO wide centralized commitment	
SCED	Dispatch to meet Balancing Authority load plus economy interchange	Midwest ISO wide centralized dispatch	
Transmission Utilization	Reduced actual line limit based on prior Midwest ISO analysis of historical utilization data	100 percent of the actual line limit	
Reserves	Required reserves and headroom held by each Balancing Authority	Required reserves held by each Balancing Authority; headroom held by the Midwest ISO	All reserves held optimized over the full Midwest ISO footprint.

It is from the four cases that we derive our three primary study results, namely the estimate of the maximum potential benefits associated with Midwest ISO operations, the amount of benefits achievable given the market structure in place during the study period (i.e. without ASM), and the actual benefits achieved by Midwest ISO during the study period.

The three primary study results were developed as follows:

- Maximum theoretical potential benefits were assessed as the reduction in system[7] production costs between the Day-1 Case and the Day-2 Optimal Case.

[7] The System in this case is the US Eastern Interconnect

Because the only change between these cases is the simulated market structure within the Midwest ISO footprint any reductions in production costs are directly attributable to operation of the Midwest ISO Day-2 market.

- Achievable benefits were assessed as the reduction in system production costs between the Day-1 Case and the No-ASM case.
- Actual achieved benefits were assessed as the reduction in system production costs between the Day-1 Case and the Day-2 Actual Case.

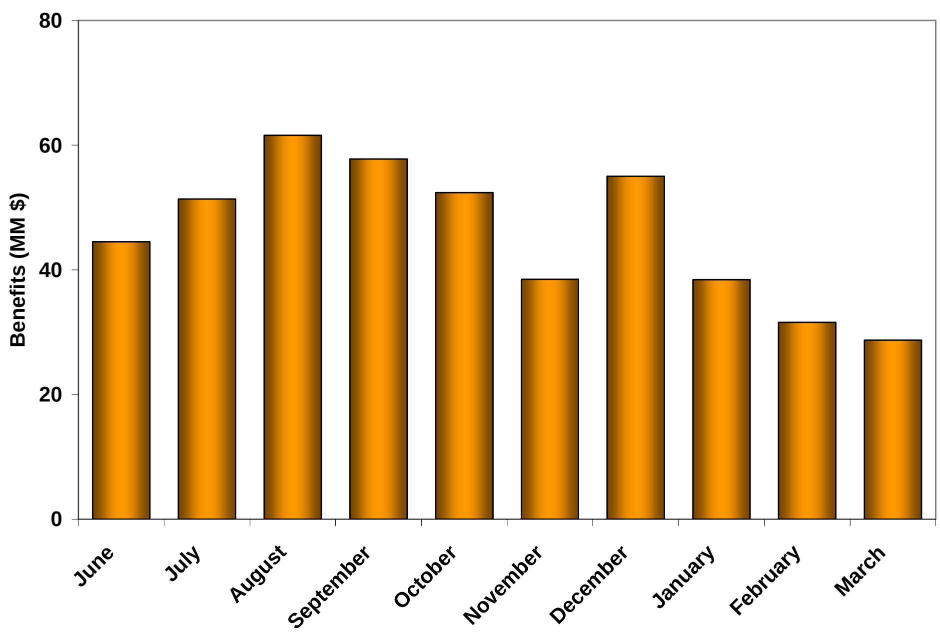
In each of the three cases the system production costs comprise the hourly fuel, variable operation and maintainence, NO_x emission allowance, and SO_2 emission allowance costs of every generator in the US Eastern Interconnect[8].

Detailed discussions of the analytic approach, calibration process, and cases examined is presented in Chapter Three.

Summary of Findings

Results of the ICF study indicate that the Day-2 market within the Midwest ISO footprint offers the potential for significant savings. Specifically, production cost savings of $460 million were estimated as the maximum benefits available to the Midwest ISO in an optimally operated Day-2 market including fully optimized reserves. This is $46 million per month on average. If this monthly level of benefits is assumed to be achieved for a 12 month period annual benefits would be $552 million. Exhibit ES-3 presents the maximum monthly benefits available in the Day-2 Optimal Case for the June 2005 to March 2006 period.

Exhibit ES-3:
Summary of Maximum Potential Benefits - June 2005 through March 2006



[8] Note that in the Day-2 Actual case only Midwest ISO generators are directly observable. This is discussed in detail in the Day-2 Actual methodology discussion below.

Exhibit ES-4 compares the maximum potential, achievable, and actual achieved benefits for the Midwest ISO during the ten month study period. The benefits are also shown on an annualized basis assuming that average benefits extended at the same average level for an additional two months.

Exhibit ES-4:
Summary of Midwest ISO Benefits – June 2005 through March 2006

Category	Benefits ($million)	Annualized Benefits ($million)
Theoretical Maximum Potential Benefits	460	552
Estimated Achievable Benefits Given Current Market Structure	271	325
Actual Benefits Achieved	58	70

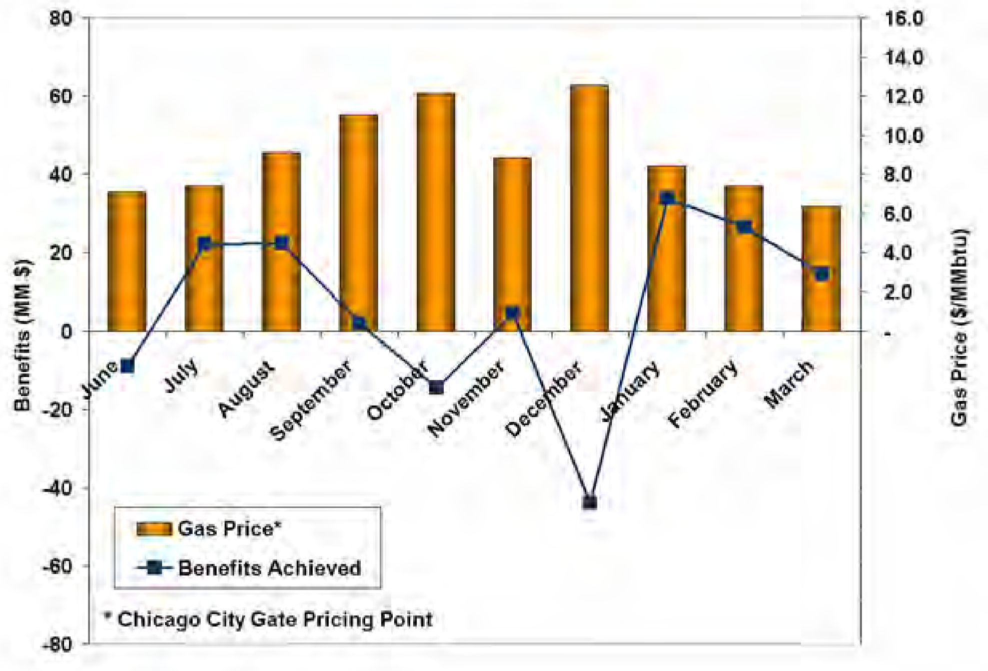
Our analysis yields the following three primary results:

- Up to $460 million in benefits were potentially achievable through optimal operation of the Midwest ISO grid during the study period. This represents a 3.8 percent decrease in overall Midwest ISO production costs compared to the parallel Day-1 estimate. This level of potential benefits is comparable to other studies of the potential benefits of centralized dispatch.[9]
- Of the $460 million in maximum potential benefits we estimate that approximately $271 million was actually achievable during the study horizon given the existing treatment of ancillary services. This represents 59 percent of the total potential and indicates that optimization of ancillary services is an important component of potential RTO savings. This $271 million translates to $325 million on an annualized basis.
- Of the $271 million achievable benefits, $58 million was realized through Midwest ISO operation of the grid. This translates to 21 percent of the achievable benefits. This $58 million is equivalent to $70 million on an annualized basis.

In order to analyze trends in the study results, we have disaggregated results on a monthly basis. Exhibit ES-5 presents the actual benefits achieved on a monthly basis for the study period along with monthly average natural gas prices.

[9] See Chapter 4 for a summary of previous study findings.

Exhibit ES-5:
Monthly Benefits Achieved and Historical Natural Gas Prices



This monthly analysis yields the following two secondary results:

- While benefits were lower during initial start up, significant improvement was demonstrated towards the end of the period. Benefits in the 2006 period were close to the maximum achievable absent optimization of ancillary services.

- The unprecedented period of high natural gas, coal, and emission allowance prices between September and December 2005 correlate with periods of lower achieved benefits, and in some cases increased costs, for Midwest ISO Day-2 compared to what was forecast for Day-1. Even as operations appear to have been improving (as seen in other data), the costs of sub-optimal commitment and dispatch were increasing due to rising generation input costs. In this environment, the cost impacts of even small incremental deviations from Day-1 optimization between gas and coal generation are economically magnified.

Conclusions

The overall outcome of this analysis demonstrates that potential RTO benefits are large and are measured in hundreds of millions of dollars per year. While on a percentage basis the potential improvement appears modest, the magnitude of the production costs involved is so large that on a dollar basis, the efficiency improvements are substantial.

RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation, and better use of import potential. These benefits will likely grow over time as:

- Reliance on natural gas generation within the Midwest ISO footprint grows as a result of the ongoing load growth and a general lack of non gas-fired development over the last 20 years. This may increase the scope for potential savings from centralized dispatch in future years.
- Tightening environmental controls and the resulting greater diversity in coal plant fleet variable operating costs will make optimization of coal plant utilization more important in future years.
- Tightening supply margins throughout the Eastern Interconnect over the next three to five years increase the importance of optimizing interchange with neighbors such as PJM, SPP, and others.
- Transmission upgrades which could increase the geographic scope of optimization within the Midwest ISO footprint.

The lack of an Ancillary Services Market (ASM) for footprint-wide reserve optimization limited the achievable results by as much as 40 percent during the study horizon.

A confluence of factors led to less than 100 percent of the achievable benefits realized during the study horizon. These include:

- The learning curve faced by both Midwest ISO and market participants during market inception resulted in suboptimal commitment and dispatch which limited achieved benefits; and
- Suboptimal commitment and dispatch during periods of extremely high gas prices had a significantly adverse impact on achieved versus potentially available benefits. This is because even small deviations from optimal dispatch can have large effects during extreme market conditions.

October and December 2005 were especially challenging periods for Midwest ISO operations due to record high fuel prices. For example, natural gas prices peaked at an average of $12.60/MMBtu in December 2005[10]. We note that had actual benefits achieved in December and October been at the average level for all other months in the study period total achieved benefits would have exceeded $146 million[11] or up to 54 percent of the total achievable benefits.

The percentage of benefits achieved showed an increasing trend over the study horizon, indicating increasingly efficient operations. This is especially evident in 2006 when fuel prices began to moderate.

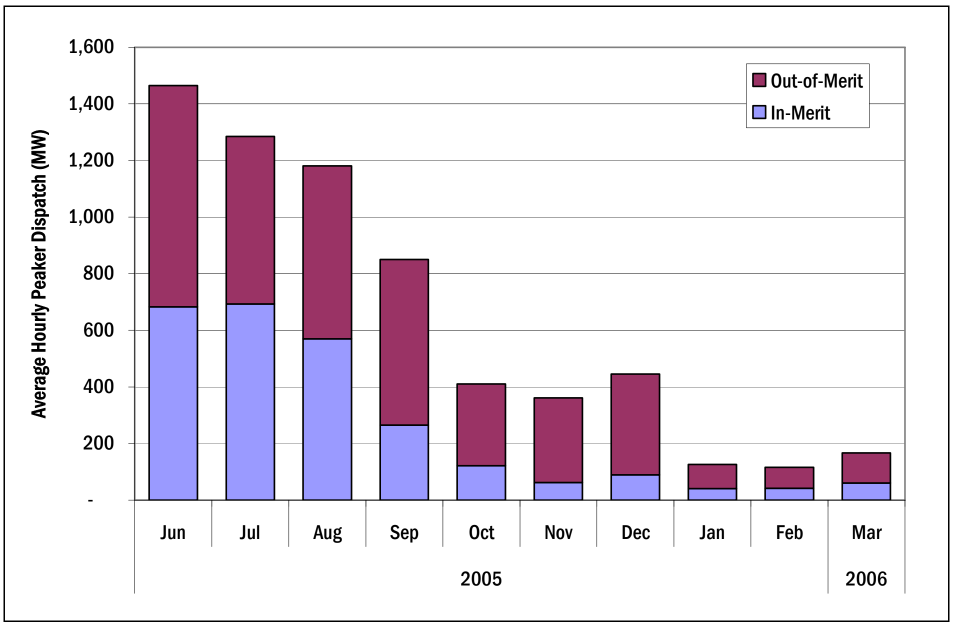
We further note that major developments led by the Midwest ISO will likely increase both the potential and achieved benefits on a going forward basis. These developments include the introduction of the Ancillary Services Market which is currently under review by FERC and expected to begin operation in 2008 and regional transmission investment initiatives such as MTEP 06 which will bring $3.6 billion in transmission investments to market by 2011 and targets elimination of 22 of the top 30 constraints in the footprint.

[10] Source: Gas Daily; Chicago City Gate price
[11] This illustrative back-of-the-envelope calculation assumes that losses of $14 and $43 million in October and December are replaced with savings of $14.5 million, the average achieved in the remaining months of the study.

Comparison to Results in Similar Analyses

ICF's findings in this study are consistent with several previous analyses. Exhibit ES-6 is an excerpt from the Market Monitor report highlighting economic and non-economic peaking unit dispatch in the Midwest ISO. Summer 2005 shows large amounts of out-of-merit peaking dispatch. While there is less in October and December, it is still above 2006 levels. The lower 2006 levels support our findings of an improving trend. The combination of out-of-merit dispatch and extremely high fuel prices yields is consistent with the study results indicating negative benefits achieved during the months of October and December 2005. Note, that the Market Monitor definition of out-of-merit dispatch does not precisely correspond to the definition of "economic dispatch" in the ICF study associated with market rules, and hence, care needs to be exercised in comparing the two analyses.

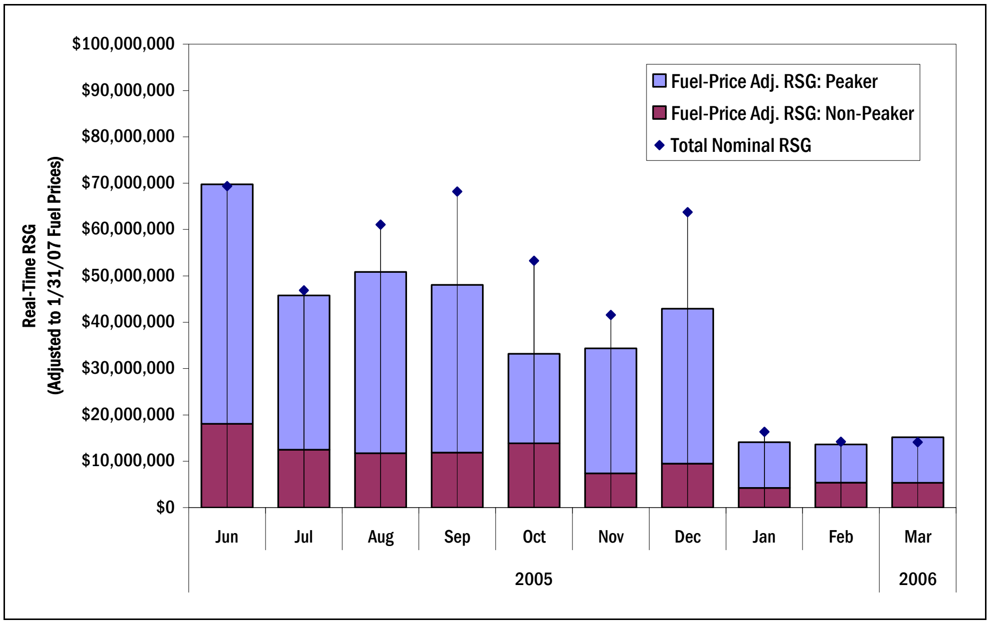
Exhibit ES-6:
Market Monitor Analysis of the Dispatch of Peaking Resources



Source: Midwest ISO Market Monitor

Our study results are also similar to a Midwest ISO review of Revenue Sufficiency Guarantee (RSG) trends shown in Exhibit ES-7 below. Here we see RSG payments by month are high in 2005 compared to 2006. Since these are payments for units not otherwise recovering their costs, the trend also supports our conclusion of improving performance.

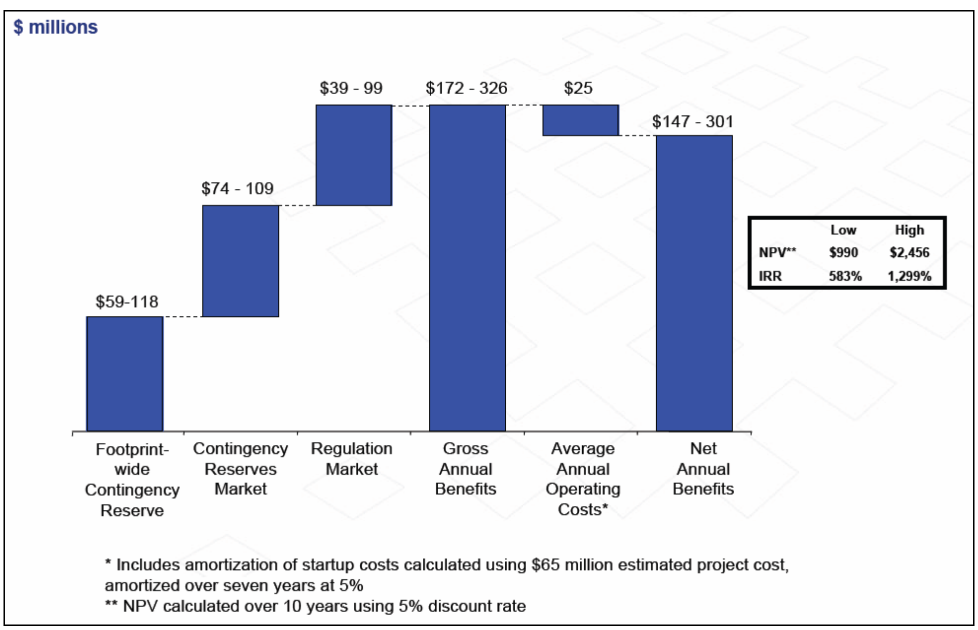
Exhibit ES-7:
Market Monitor Analysis of the Midwest ISO RSG Payments



Source: Midwest ISO Market Monitor

While the ICF study of the proposed Midwest ISO ASM market is not as detailed regarding reserves as that contained in a recent Midwest ISO filing, the theoretical value generated by ICF is within the range of the Midwest ISO value estimates generated and shown in the April 3, 2006 Filing to FERC where the comparable potential benefits are shown as $113 to $208 million (see the "contingency reserves" and "regulation market" bars in Exhibit ES-8 below).

Exhibit ES-8:
Midwest ISO Estimates of ASM Benefits and Costs



Source: Midwest Contingency Reserve Sharing and Midwest ISO Ancillary Services Market – Project Update, October 10, 2006

In conclusion, our findings indicate that substantial benefits are available and that an increasing percentage of those benefits were realized in the later months of the study. Further, we note that expected developments such as the proposed Midwest ISO ASM market will expand the scope of potential and achieved benefits on a going forward basis. The remainder of this report is organized in four primary chapters designed to paint a full picture of this study. These are:

- Chapter One: Evolution of the Midwest ISO
- Chapter Two: Analytic Approach and Cases Examined
- Chapter Three: Overview of Modeling Assumptions
- Chapter Four: Detailed Study Result and Conclusions

CHAPTER ONE:
EVOLUTION OF THE MIDWEST ISO

This chapter provides an overview of the Midwest ISO, including a regional perspective, and a summary of the past, present and future market structures. We discuss the region before the Midwest ISO was created, outline its most recent transition from a Day-1 to Day-2 market and provide some insight into the planned ancillary services market. Our discussion of market structure examines the Midwest ISO's unique history as the only truly greenfield RTO in the US. In a span of little more than a decade the Midwest ISO has evolved from a voluntary association of a few transmission owners to one of the largest energy markets in the world. Unlike similar RTO markets in the east, the Midwest ISO market did not develop out of pre-existing pooling arrangements under which centralized unit commitment and dispatch among multiple utilities was conducted prior to market implementation.

Regional Overview of the Midwest ISO[12]

Introduction

The Midwest ISO is a non-profit, member-based Regional Transmission Organization (RTO) covering all or portions of 15 US Midwestern states and the Canadian province of Manitoba. The Midwest ISO has a dual responsibility as a reliability coordinator for electric utilities that have transferred functional control over their transmission assets as well as those that have not and as a manager of an energy market for the electric utilities that have transferred functional control to the Midwest ISO. Exhibit 1-1 below shows the reliability footprint whereas Exhibit 1-2 shows the smaller market footprint.

[12] From the Midwest ISO website unless otherwise noted.

**Exhibit 1-1:
Midwest ISO Reliability Footprint**

Source: Midwest ISO

**Exhibit 1-2:
Midwest ISO's Market Footprint**

Source: Midwest ISO

Exhibit 1-3 provides summary statistics about the Midwest ISO's market and operations. The Midwest ISO covers an extremely large geographic area. This yields both significant scope for efficiency improvement due to RTO operations and significant challenges for development and implementation of a new market. Note also that the expansiveness of this area would also tend to complicate the efforts of market participants to optimize generation and transmission operations in a bilateral Day-0 or Day-1 marketplace.

Exhibit 1-3:
Midwest ISO Overview

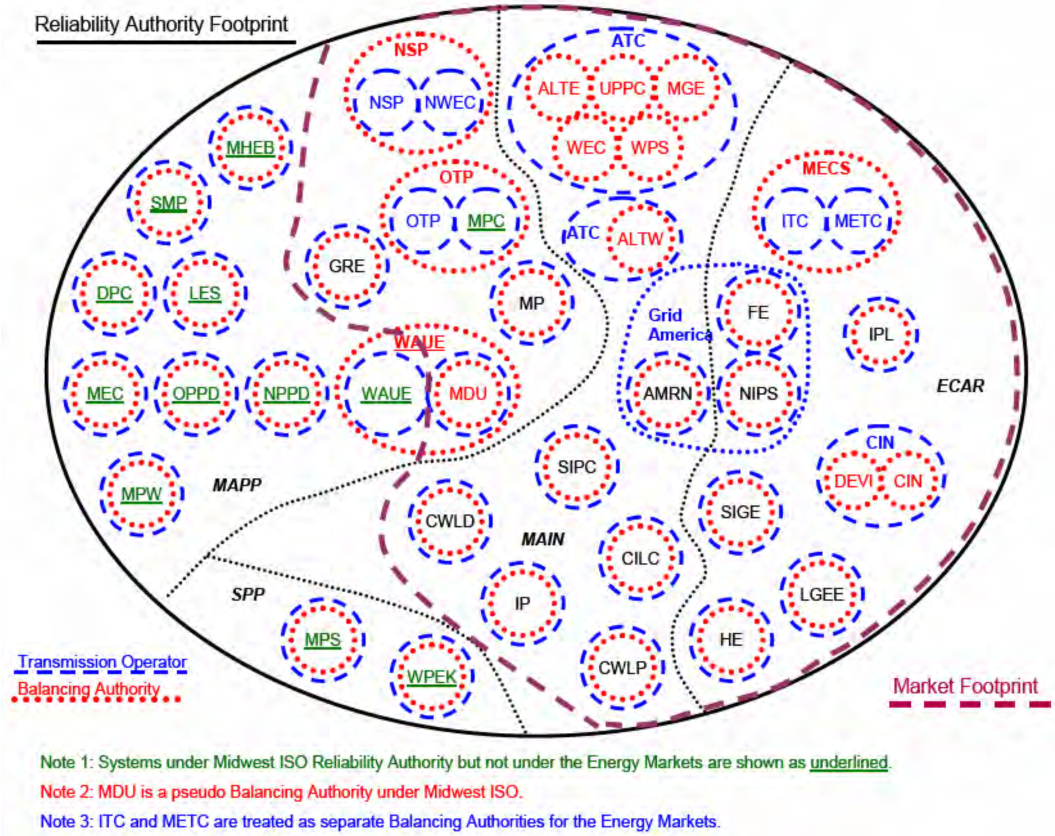
Metric	Parameter
Territory	920,000 square miles covering 15 US states and Canadian province of Manitoba. Control centers in Carmel, IN and St. Paul, MN
Market Participants	256 including 28 Transmission Owners with $13.9 billion in transmission assets under the Midwest ISO's functional control and 69 non-transmission owners
Generation Capacity	133,006 MW (market); 162,981 MW (reliability)
Peak Load (set July 31st, 2006)	116,030 MW (market); 136,520 MW (reliability)
Transmission	93,600 miles including 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, 69kV
Market Operations	Uses security-constrained unit commitment and economic dispatch of generation. Operates Day-Ahead Market, Real-Time Market, and Financial Transmission Rights (FTR) Market. Administers Open Access Transmission and Energy Markets Tariff ("TEMT")
Balancing Authorities	36 (reliability footprint)

Source: Midwest ISO Corporate Information Fact Sheet as of February 2007

The Midwest ISO energy market features security-constrained unit commitment and economic dispatch of generation with LMPs produced for 1,760 pricing nodes. Market operations include a Day-Ahead Market, a Real-Time Market, and an FTR Market. The Midwest ISO is responsible for administering the Open Access Transmission and Energy Markets Tariff (TEMT) mandated by the Federal Energy Regulatory Commission (FERC), the primary regulator of the wholesale US electricity sector.

As mentioned above, the Midwest ISO is both a reliability coordinator as well as an energy market operator. Exhibit 1-4 graphically represents the Midwest ISO's relationship with each Balancing Authority, whether primarily as a market operator or reliability coordinator. In addition, the Midwest ISO provides contractual services under agreements with Duke Power, MAPPCOR and the Midwest Contingency Reserve Sharing Group.

Exhibit 1-4:
Midwest ISO Balancing Authorities[13]



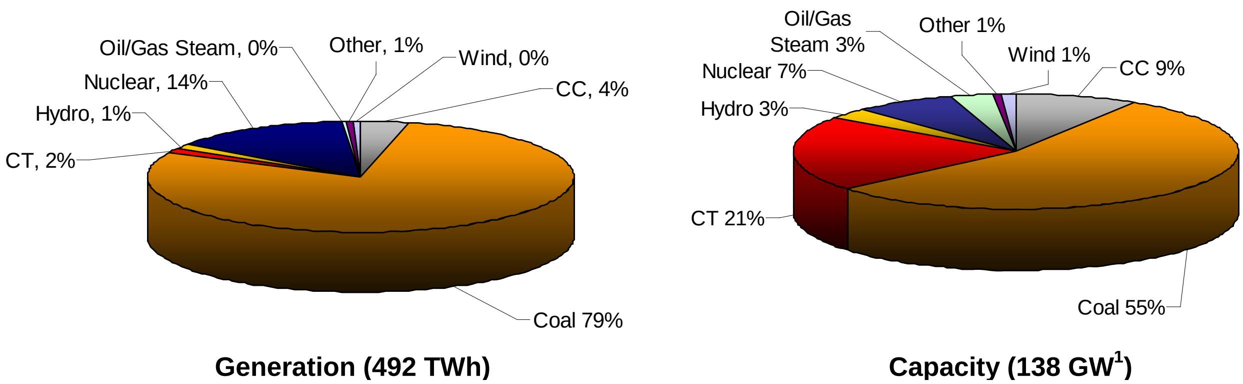
Source: Midwest ISO Business Practices Manual for Coordinated Reliability, Dispatch, & Control, Manual No. 006, 2005. Note that GridAmerica and ATC are no longer operational but the Balancing Authorities pictured are valid up to the end of the study period in March 2006. Since then, DEVI and LGEE are no longer operational (6/2006 and 9/2006, respectively) and SMP joined the market footprint (4/2006).

Midwest ISO Supply Mix

The Midwest ISO is one of the largest markets in the US with a net internal peak demand over 116 GW[14] and has a bimodal winter and summer peaking profile. Exhibit 1-5 shows the percentage breakdown of dispatch and capacity by generation source for the study horizon from June 2005 through to March 2006. During this time, generation for the ten months of the study period reached 488 TWh and capacity within the Midwest ISO was about 138 GW. Thus, the ratio of capacity to peak was approximately 119 percent.

[13] See Chapter 4 for a mapping of company acronyms.
[14] The peak demand record for Midwest ISO's market footprint of 116,030 MW was set on July 31, 2006.

Exhibit 1-5:
Generation and Capacity, June 2005 – March 2006



Source: Midwest ISO and ICF

Although the Midwest ISO exports energy during the study period, it is ultimately a net importer. On average, the Midwest ISO was a net exporter to SPP and IMO. The monthly average net export during the 10 study months was 306 MW per hour to SPP and 841 MW per hour to IMO, yielding a total of 1,147 MW per hour or 8 TWh over the ten months. On the other hand, the Midwest ISO imported on average 1,631 MW per hour from PJM, 1,543 MW per hour from Manitoba Hydro, 353 MW per hour from MAPP, and 1,613 MW per hour from SERC, yielding a total of 4,027 MW per hour or 29 TWh over the ten months. Note that Manitoba Hydro alone accounts for 38.3 percent of this generation import. This is 2.3 percent of the 492 TWh total. Overall, the Midwest ISO is a net importer of 2,880 MW per hour (4,027 MW per hour imports net 1,147 MW per hour exports) or 21 TWh over the ten months.

It is important to note that reliance on natural gas-fired generation capacity has been increasing in the Midwest ISO area in recent years where virtually all of the generation capacity added in the past decade relies on natural gas as its primary fuel. In fact, of the total capacity added to the Midwest ISO footprint in the past decade more than 92 percent is gas-fired. Furthermore, 72 percent of the existing gas capacity in the Midwest ISO is considered to be peaking capacity (i.e. gas-steam or combustion turbine). Hence, use of natural gas could well require the use of very costly sources from within this fuel category. The increased reliance on natural gas throughout the region is further evidenced in the January 2007 Midwest ISO Operations Report[15] which indicates that natural gas-fired generation was the marginal generation resource more that 30 percent of the time in January 2007 even though combined cycle and combustion turbine operation only accounted for 6 percent of total generation.

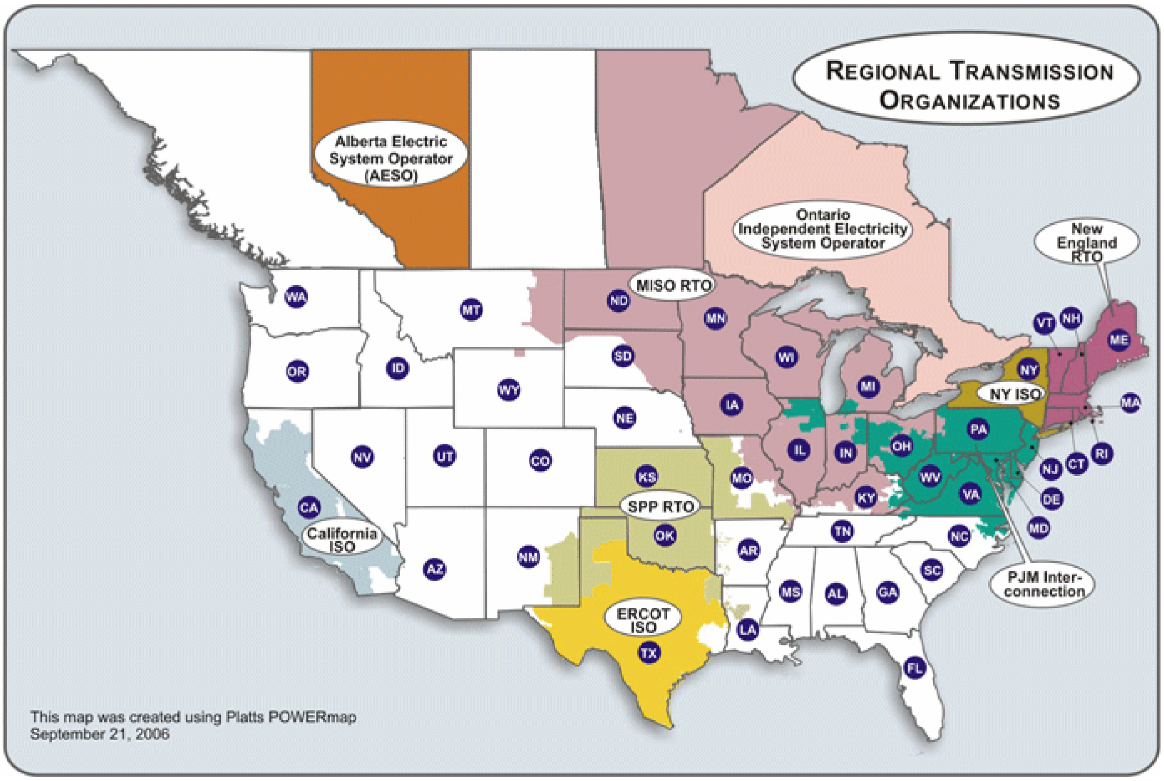
Midwest ISO's Interconnectivity with the Rest of the Grid

Electrically, the Midwest ISO is part of the Eastern Interconnection, the largest of the four distinct synchronous power grids in North America. As Exhibit 1-6 shows, the Midwest ISO system interconnects with the Ontario Independent Electricity System Operator to the north, the PJM Interconnection to the east, the Southwest Power Pool (SPP RTO) to the southwest and

[15] Midwest ISO Market Operations Report; January 2007

the Tennessee Valley Authority to the south.[16] The Midwest ISO has seams agreements or memorandums of understanding with each of these organizations but has forged the closest relationship with PJM, the region with which the Midwest ISO shares the largest and most complex border. Note that portions of PJM are nearly surrounded by the Midwest ISO (e.g. the Chicago area).

Exhibit 1-6:
FERC Certified RTOs



Source: FERC

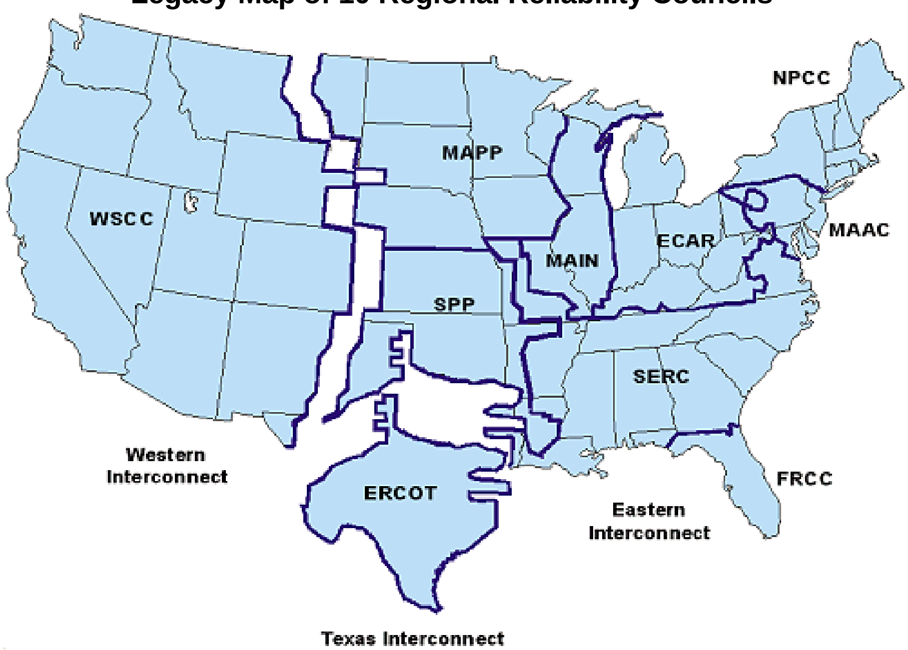
In 2002 the FERC directed the Midwest ISO and PJM to work toward development of a common market by October 1, 2004 in order to harmonize their practices to functionally create a single, transparent energy market.[17] The creation of a "joint and common" market for PJM and the Midwest ISO goes well beyond the "seams" coordination agreements between other neighboring RTOs. This Midwest ISO-PJM coordination agreement results in by far the largest market in the US stretching from eastern Montana through southwestern Missouri, Kentucky, Virginia, and counterclockwise through "Classic PJM", Michigan, and Minnesota. This tremendous size and new structure are major developments enhancing the transparency and depth of the wholesale markets in the region. Under the coordination agreement and with input from stakeholders, the two RTOs have implemented mechanisms to compensate for redispatch to relieve congestion and protocols for honoring reciprocal flowgates and they continue to address seams issues and reconcile differences in products to be traded using common standards.

[16] The Tennessee Valley Authority is not shown on the map but encompasses the entire state of Tennessee and portions of contiguous states.
[17] FERC, Docket Nos. EL02-65-000, July 31, 2002.

Midwest ISO Day-0 Operation

Before the Midwest ISO was created in 1996, the region operated as a decentralized market dominated by vertically integrated, investor-owned utilities (IOUs). While there was no common market for energy, there were sub-regions that communicated and cooperated on maintaining the reliability of their shared and interconnected transmission system. The organizations leading this effort were the regional reliability councils.[18] The Midwest ISO's current geographic footprint was originally divided between four regional reliability councils: the Mid-Continent Area Power Pool (MAPP); the Mid-America Interconnected Network (MAIN); the East Central Area Reliability Coordination Agreement (ECAR); and the Southwest Power Pool (SPP). Exhibit 1-7 shows a legacy map of each council's geographic reach.

Exhibit 1-7:
Legacy Map of 10 Regional Reliability Councils



Source: NERC

These councils are composed of stakeholders from across the electric industry including IOUs, IPPs, power marketers, and end-use customers. At the time, there were 10 regional reliability councils which reported to the North American Electric Reliability Council (NERC), a self-regulating organization that developed voluntary industry standards and best practices.[19] The geographic division of these councils provides an idea of the organization of the market and how electricity flowed. Typically, connections within each council were strong but somewhat weaker when crossing boundaries or even utility footprints. In this environment, most generators would supply local demand and interregional electricity transfers would be relatively more limited. Furthermore, the reliability councils also tended to focus on reliability rather than economic concerns.

In addition to physical transmission constraints that may have limited power flows, bilateral transactions to take advantage of opportunities to optimize generation usage between areas

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[18] The number of regional reliability councils and some of their footprints have changed since then and the map shown above is for reference purposes only.
[19] This has changed since and is discussed below.

was hampered by high transaction costs in the form of low market transparency and also due to transmission costs that penalized power that crossed regional or utility boundaries. For example, power sent from a source to a load far away often had to traverse several utility footprints before it reached its ultimate destination (wheeling), and was often burdened with "pancaked" transmission rates.[20] Depending on their magnitude, pancaked transmission tariffs can act as trade obstacles that effectively segment a market and limit interregional transfers. Similarly, decentralized unit commitment and dispatch operations from individual companies and Balancing Authorities increased costs and caused inefficiency relative to an optimum use of resources.

Midwest ISO Day-1 Operation

The high costs of pancaked transmission rates and the economic inefficiency of the US power market stifled non-utility generation investment and eventually led FERC to take action. On April 24, 1996 the FERC released the final ruling supporting competitive generation by mandating open access to the transmission system of incumbent utilities. FERC order 888 established a process for filing open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service.[21] This tariff was known as the Open Access Transmission Tariff (OATT) and is posted on the Open Access Same Time Information System (OASIS) website to foster transparency and liquidity.

About the same time, transmission owners in the Midwest had begun to discuss the formation of a voluntary association that would also help to eliminate trade barriers such as pancaked transmission rates. As Exhibit 1-8 shows, the Midwest ISO was established on February 12, 1996 and over the course of the next several years evolved into a regional transmission organization (RTO) and energy market operator.

Exhibit 1-8:
Key Dates in the Midwest ISO's Evolution

Date	Event	Market Type
February 12, 1996	Transmission owners convene to form the Midwest ISO	Day-0
September 16, 1998	FERC grants conditional approval as an independent system operator	
December 2001	RTO approval from FERC (first in the nation). Reliability operations (Day-1 markets) begin	Day-1
February 1, 2002	Transmission service begins under Midwest ISO Open Access Transmission Tariff	
April 1, 2005	Midwest Markets (Day-2) Launch	Day-2

On September 16, 1998, the FERC approved the application from 10 transmission-owning utilities in the Midwest to transfer functional control of their jurisdictional transmission facilities to the Midwest ISO and establish an open access transmission tariff.[22] The original 10 companies

[20] "Pancaked transmission rates" is a term commonly used to describe the practice of incurring multiple wheeling charges when moving power from one area to another across multiple utility territories, each with its own transmission system costs and associated wheeling charge. Since the tariff charges do not correlate with and almost always exceed marginal costs, they are economically inefficient.
[21] FERC, Docket No. RM95-8-000, Order 888, April 24, 1996.
[22] FERC, Docket No. ER98-1438-000, EC98-24-000, September 16, 1998.

were: Cincinnati Gas & Electric Company; Commonwealth Edison Company; Commonwealth Edison Company of Indiana; Illinois Power Company; PSI Energy, Inc.; Wisconsin Electric Power Company; Union Electric Company; Central Illinois Public Service Company; Louisville Gas & Electric Company; and Kentucky Utilities Company.[23]

The Midwest ISO's initiative went well beyond the mandate of Order 888 because it created an actual separation of duties rather than relying on a standard transmission tariff to decrease discrimination and end pancaked rates. Even though the transmission owners would retain ownership of their transmission facilities and physically operate and maintain them, they would turn over functional control and tariff administration responsibilities to the Midwest ISO to both provide non-discriminatory open access to the regional transmission grid and to increase system security and reliability. This structure would provide substantial benefits to transmission customers by:

- Eliminating transmission rate pancaking on a regional scale thereby producing an overall reduction in the costs of transmitting energy within the region;
- Offering one stop shopping for transmission service;
- Establishing uniform and clear rules by the ISO/RTO;
- Separating control over transmission facilities from generation and marketing functions;
- Allowing large scale regional coordination and planning of transmission;
- Enhancing reliability; and
- Fostering competition with sellers having access to more markets for their products and buyers having greater access to sources of supply.[24]

Encouraged by the Midwest ISO and other first movers in the industry, the FERC later released another final ruling on December 20, 1999 to spur the formation of RTOs nation-wide. While the FERC stopped short of a mandate in Order 2000, it did make it clear that RTO formation was preferred and that the Commission was ready to review and certify RTOs that met a series of requirements aimed at eliminating discrimination.[25] On December 21, 2001, the Midwest ISO became the first RTO in the nation certified by the FERC which heralded the Midwest ISO's move into a Day-1 market. It began providing transmission service under its approved OATT on February 1, 2002 and incorporated other hallmarks of Day-1 operation such as OASIS administration, Available and Total Transfer Capability (ATC and TTC) determination, Security Coordination, Transmission Planning, System Operations, and Market Monitoring.

[23] Originally there were 25 transmission-owning utilities involved in the creation of the Midwest ISO representing most of the transmission owners in MAIN and ECAR. Several of these utilities attempted to form their own RTOs but none have materialized and the Midwest ISO subsequently absorbed many of them into its expanding footprint.
[24] FERC, "Benefits Claimed by Applicants," Docket No. ER98-1438-000, EC98-24-000, September 16, 1998.
[25] Four characteristics: (1) independence from market participants; (2) appropriate scope and configuration; (3) operational authority over transmission facilities within the region; and (4) exclusive authority to maintain short-term reliability. Nine functions: (1) design and administer its own tariff; (2) manage congestion; (3) address parallel path flow; (4) serve as provider of last resort of all ancillary services; (5) administer its own OASIS and independently calculate TTC and ATC; (6) provide for objective monitoring of the markets it operates or administers; (7) take primary responsibility for planning and expansion of transmission facilities; and (8) participate in interregional coordination of reliability practices.

Market monitoring functions were also added, but were minimal, reflecting the then current bilateral market. In addition, the Midwest ISO relied exclusively on non-market mechanisms such as Transmission Loading Relief (TLR) calls with associated generation re-dispatch performed by the individual Balancing Authorities to manage transmission congestion.

Unlike other RTOs, the Midwest ISO was unique because the Balancing Authorities in its footprint work in tandem with the Midwest ISO, but were not part of the RTO organization. The Balancing Authorities continue to be part of their parent utility organizations and perform necessary functions such as balancing generation with load in their respective geographic regions and retaining responsibility for unit commitment and economic dispatch of generation to serve their load. The Balancing Authorities self-provided their ancillary services needs and administer operating reserves. They also maintain primary responsibility for ensuring resource adequacy.

Regulatory and Industry Challenges Affecting the Midwest ISO's Day-1 Operations

During this time, much was changing in the industry. The directive from the FERC spurred the creation of several other RTOs in the region which have all now dissolved. The effect on the Midwest ISO was an ever-changing membership base and thus geographic scope. By the time FERC approved the Midwest ISO's RTO application, Commonwealth Edison Company, Illinois Power Company and Ameren had withdrawn to join other RTOs (though the latter two merged and then rejoined the Midwest ISO in 2004). On the other hand, eight more utilities joined the Midwest ISO, namely: Indianapolis Power & Light; Indiana Municipal Power Agency; Lincoln Electric (Neb.) System; Minnesota Power; Otter Tail Power Company; UtiliCorp United (including Missouri Public Service, St. Joseph Light & Power and WestPlains Energy-Kansas); City Water, Light and Power (Springfield, Ill.); and Montana-Dakota Utilities. In addition, Manitoba Hydro entered into a coordination agreement and there were pending and conditional agreements with several other companies such as Sunflower Electric Power Corporation, Dairyland Power Cooperative, Great River Energy, and Southern Minnesota Municipal Power Agency. While this is not an exhaustive list of the changes the Midwest ISO experienced, it does underscore the difficult task the Midwest ISO had of integrating new members and its growing importance in the region. Despite these challenges, the Midwest ISO eventually became the only FERC-recognized RTO in the Midwest in December 2001.

The Midwest ISO Day-2 Operation

The Midwest ISO's Day-1 operation was an improvement over the status quo but still did not provide market-based congestion management and imbalance service as required by FERC of RTOs. Compared to its eastern neighbors, the Midwest ISO is a relative newcomer in implementing a transparent power market structure and pricing mechanisms.[26] The addition of FERC-required market-based transmission services required creation of day-ahead and real-time locational marginal price ("LMP") energy markets as had already occurred in the eastern RTOs. LMP-based energy markets would allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network.

[26] PJM RTO started its bid-based energy markets in April, 1997. ISO-New England launched its first Power Exchange (PX) market in May, 1999.

The process intensified on May 26, 2004 when the FERC conditionally approved the Open Access Transmission and Energy Market Tariff (TEMT) that was filed by the Midwest ISO on March 31, 2004. The proposed TEMT, and its later modifications, provide the terms and conditions necessary to operate Day-Ahead (DA) and Real-Time (RT) energy markets with LMP-based price signals thereby implementing the FERC-required market-based congestion management system. In addition, the Midwest ISO proposed to operate a market for Financial Transmission Rights (FTR), which provides market participants the opportunity to hedge their locational price risk associated with congestion. The Midwest ISO expended a total of $246.7 million to complete the development of the systems to implement Day-2 markets and expects annual revenue of between $120 million and $125 million to recover both these startup cost and ongoing operating costs.[27]

On April 1, 2005, the Midwest ISO officially commenced Day-2 operation and began centrally dispatching wholesale electricity and transmission service throughout much of the Midwest. The bids and offers in the market for the first two months were cost-based, and hence the ICF study focuses on the post June 30, 2006 period when the bids became market-based.

Energy Market

The Midwest ISO operates Day-Ahead and Real-Time (balancing) Energy Markets using security constrained unit commitment and economic dispatch of generation that provide for an optimal use of all resources within the region based on the bids and offers provided to the RTO. The Day-Ahead Market is a forward financial market for energy. The Day-Ahead clearing process results in a set of financially binding schedules according to which sellers are financially responsible to deliver and purchasers financially responsible to buy energy at defined locations. The Day-Ahead market process is based on a unit commitment model that minimizes total production costs over 24 hours. Thus, the Midwest ISO uses a tool similar to the tool used in this study. Typically the load cleared in the Day-Ahead Energy Market is less than the actual load cleared in the Real-Time Energy Market. This imbalance requires the Midwest ISO to commit additional units through a Reliability Assessment Commitment (RAC) process in order to meet the projected Real-Time load and required reserves.

Sources of energy in the day-ahead market include:

- Generator offers
- External transactions
- Virtual supply offers

Sources of demand in the day-ahead market include:

- Fixed demand bids
- Price sensitive demand bids
- External transactions
- Virtual demand bids

[27] Midwest ISO, FERC Form 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental, 109.1 and 123.1.

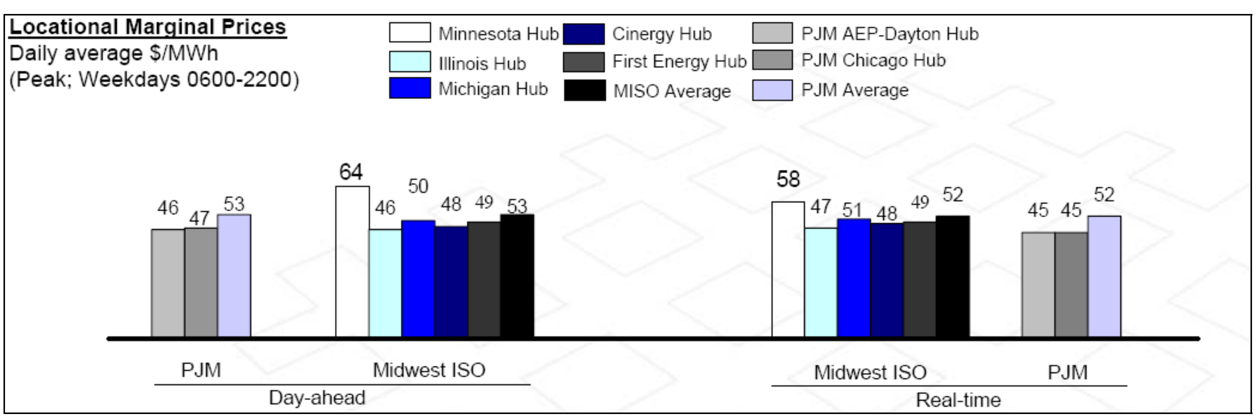
The Midwest ISO publishes a day-ahead schedule and a 24-hour day-ahead set of LMPs. The day-ahead schedules constitute financial contracts to supply or consume power. FTRs are also settled based upon the 24-hour day-ahead LMP values.

The Midwest ISO Day-Ahead market clearing process performs a unit commitment and dispatch based on supply offers and load bids and establishes hourly LMPs at each discrete price node on the grid. Those LMPs are used to settle both cleared supply and demand transactions at each price node. Generally each generator has a unique price nodes (one per generating unit, even where multiple generators are at a single plant). In contrast, due to practical metering considerations, loads are generally aggregated for settlement purposes based on the load-weighted average of the load zone.

The primary purpose of the Day-Ahead market is to clear (and schedule) sufficient supply to fully satisfy cleared Day-Ahead demand. The Day-Ahead market serves to utilize resources that minimize production costs accounting for operational limitations (e.g., unit notification and minimum start times). The purpose of the Real-Time market is similar, but is based on actual rather than bid demand and must also function to determine economic redispatch to manage congestion given dynamic supply and demand.

The Midwest ISO utilizes Locational Marginal Pricing (LMP), which is the market clearing price at a specific Commercial Pricing Node (CPNode) in the Midwest Market that is equal to the cost of supplying the next increment of load at that location. LMP values are separated into three components for settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node. Since the launching of the Midwest ISO's Energy Market in April, 2005, LMPs at some 1,760 points along the power grid are produced at five-minute intervals. The Midwest ISO has created four financial trading hubs - Cinergy, Illinois, Michigan and Minnesota - that provide market participants with convenient trading locations with corresponding price indices to facilitate bilateral trading and settlement of contracts. The hubs provide stable trading locations thereby reducing price uncertainty for parties who wish to contract, improve liquidity and generally support the development of a more robust wholesale electricity market. Exhibit 1-9 shows the January 2007 average daily LMPs for current Midwest ISO hubs in both the Day-Ahead and Real-Time markets. Differences between locations are primarily the result of congestion.

Exhibit 1-9:
Midwest ISO Hub Prices – January 2007



Source: Midwest ISO Market Operations Report; January 2007

Local Balancing Authority Operators (also known Balancing Authorities) continue to be responsible for many of their traditional functions, but operate their systems in response to signals issued by the Midwest ISO.

FTR Market

Although energy is the principal offering in the market, the Midwest ISO also provides tradable Financial Transmission Rights (FTRs) to allow market participants to hedge potential congestion costs. FTRs are allocated annually to market participants on the basis of historic transmission service. Immediately following the annual FTR allocation, the Midwest ISO also conducts an annual FTR auction. The Midwest ISO also conducts a monthly allocation and auction of FTRs to facilitate trading and to provide a measure of FTR market price transparency, although only final strike prices are published (bids, offers, and identities of market participants are confidential).

Currently the Midwest ISO FTR market includes FTR obligations. Obligations provide revenues to the holder if congestion restricts transmission from the FTR Receipt Point to the FTR Delivery Point. If congestion is in the reverse direction, they impose a charge on the holder.

The Midwest ISO TEMT also provides for the eventual introduction of FTR options**.** These instruments provide revenues to the holder if congestion restricts transmission from the FTR Receipt Point to the FTR Delivery Point. If congestion is in the reverse direction, no charge is imposed on the holder.

Capacity and Ancillary Services Markets

There is currently no capacity market operated by the Midwest ISO, and resource adequacy continues to be addressed at the regional and state level. Module E of the TEMT addresses Resource Adequacy requirements, including planning reserve margin requirements for market participants serving load within the Midwest ISO footprint. The Midwest ISO adequacy requirements are based on existing Reliability Resource Organization (RRO) and state standards. According to Module E, transmission customers serving network load must designate firm Network Resources relied upon to assure adequate generation is available to meet both load and applicable reserve requirements.

Planning reserve requirements in the Midwest ISO footprint varied by NERC Region during the study period. At the time, MAPP and MAIN each had a 15 percent planning reserve requirement while ECAR had no explicit planning reserve requirement. In place of planning reserve requirements, ECAR reviews available and planned capacity and performs a probabilistic Loss of Load Expectation (LOLE) to determine if sufficient capacity exists to meet forecast demand in both the short and long term. The target LOLE is 1 day in 10 years (0.1 day/year). Similar to the capacity market, markets for operating reserves and ancillary services are expected to be developed in the future (see Day-3 discussion below).

Regulatory and Industry Challenges Affecting the Midwest ISO's Day-2 Operations

While the Midwest ISO was developing plans to transition to a Day-2 operation, the [28] August 14, 2004 blackout, affected Midwest ISO members and others, and increased reliability concerns. The Energy Policy Act of 2005 specifically addressed this by empowering the FERC to designate a single Electric Reliability Organization for the country with the ability to create and enforce mandatory reliability standards on the entire US electric industry, subject to the FERC's approval. On July 20, 2006, the NERC was certified as the Electric Reliability Organization and its proposed reliability standards are currently under the FERC's review.

Additional challenges faced by the Midwest ISO energy market startup included record high natural gas, oil, coal, and emission allowance prices in the second half of 2005. Hurricanes Katrina and Rita combined with international events to drive natural gas and oil prices to levels well above historical norms between August and December 2005. For example, natural gas prices peaked at an average of $12.60/MMBtu in December 2005. [29] These high prices spilled over into coal and emission allowance markets, increasing the costs of operations and magnifying the economic effects of any operational inefficiencies experienced during initial market operations.

Comparative Analysis

This section offers a high level comparison of the evolutionary stages the Midwest ISO has progressed through. We offer this summary before we introduce the Midwest ISO's proposed ancillary services market in the next section. Exhibit 1-10 compares the division of responsibilities between the Day-0, Day-1 and Day-2 operations.

[28] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, 1 (April 2004).
[29] Source: Gas Daily Chicago City Gate price

Exhibit 1-10:
Roles and Responsibilities During Day-0, Day-1 and Day-2 Operation

Responsibilities	Day-0	Day-1	Day-2
OASIS Administration[1]	Balancing Authority	Midwest ISO	Midwest ISO
OATT Tariff Administration[1]	Balancing Authority	Midwest ISO	Midwest ISO
ATC and TTC Calculation	Balancing Authority	Midwest ISO	Midwest ISO
Load Forecasting	Balancing Authority	Balancing Authority	Balancing Authority
Outage Scheduling	Balancing Authority	Midwest ISO	Midwest ISO
Security Coordination	Balancing Authority	Balancing Authority/ Midwest ISO	Midwest ISO
Transmission Planning	Balancing Authority	Midwest ISO	Midwest ISO
Unit Commitment and Dispatch	Balancing Authority	Balancing Authority	Midwest ISO
Congestion Management	Balancing Authority (redispatch/TLR)	Midwest ISO (redispatch/TLR)	Midwest ISO (LMP)
Resource Adequacy	Balancing Authority	Balancing Authority	Balancing Authority
FTR Market Management	N/A	N/A	Midwest ISO
Day-Ahead and Real-time Market Administration	N/A	N/A	Midwest ISO
Billing and Settlement	N/A	Midwest ISO	Midwest ISO
Market Monitor	N/A	Independent (Minimal)	Independent

[1] Individual utility OASIS sites and OATTs were in effect under Day-0 operation

In the decentralized Day-0 market, all functions were the responsibility of the local Balancing Authority. In contrast, the Midwest ISO took over some of these responsibilities in the Day-1 market. Between Day-0 and Day-1, the depth of coordination between the Midwest ISO and Balancing Authorities is dramatically different. The salient distinction is that each Balancing Authority was responsible for a small geographic footprint with limited regional coordination

Under Day-2 operation, the Midwest ISO expanded its Day-1 responsibilities to include a market-based method for managing congestion featuring operation of Day-Ahead and Real-Time energy markets, and a market for FTRs. Because of the introduction of a Day-Ahead market, a Real-Time market and an FTR market, the need for market monitoring responsibilities for Day-2 increased significantly. Those responsibilities are currently carried out by an Independent Market Monitor (IMM), Potomac Economics. The Midwest ISO manages the single Midwest ISO-wide transmission tariff under both Day-1 and Day-2 operations. Under both Day-1 and Day-2 operation, all market participants take transmission service from the Midwest ISO under its tariff.

As described in this chapter, while the physical fundamentals remain largely unchanged in the Day-1 and Day-2 scenarios, there are significant structural and operational differences, especially in key operational areas such as unit commitment and dispatch, transmission scheduling, and congestion management. Specifically, there is centralized operation with access to greater data and the ability to apply mathematical and economic optimization to these areas.

Future Enhancements to Midwest ISO Operations

On February 15, 2007, the Midwest ISO submitted to the FERC its proposal to create an Ancillary Services Market ("ASM") for the procurement of regulation and operating reserves.[30] Some refer to this proposed structure as a "Day-3" market to differentiate it from the existing Midwest ISO operations. In order to prepare for the implementation of ASM, the Midwest ISO proposes to assume the role of the single Midwest ISO Balancing Authority with the majority of the current Balancing Authorities serving only as Local Balancing Authorities. The transfer of authority is to ensure that the Midwest ISO will be able to procure required operating reserves through the proposed ASM.

Currently the procurement of regulation and operating reserves is the responsibility of each Balancing Authority via a cost-based process. Energy on the other hand is procured through a market-based process from the Midwest ISO. The proposed ASM seeks to create Day-Ahead and Real-Time markets for regulation and operating reserves like those currently existing for energy in the Midwest ISO and like those currently existing in other RTOs employing LMP Day-2 structures.

The Midwest ISO has evaluated potential benefits of ASM market implementation and has found that it will greatly expand the scope of potential savings available to market participants. This conclusion is corroborated by the findings of this analysis. See Exhibit ES-8 above which summarizes the significant expected benefits and costs of the ASM market initiative based on the evaluation previously performed by the Midwest ISO.

[30] Midwest ISO, Docket No. ER07-550-000, February 15, 2007.

CHAPTER TWO
ANALYTIC APPROACH AND CASES EXAMINED

Introduction

This chapter discusses the analytic approach to analyzing the changes in production costs associated with the transition to centralized operations. This approach involves several computer model simulations of the Midwest ISO operations between June 2005 through March 2006.

It is emphasized that this estimate of the benefits from Day-2 centralized information and operations does not include some of the other potential benefits associated with market restructuring, which may best be treated on a qualitative basis.

The approach to estimating the three primary outputs of this analysis involves calculating the difference between the Day-1 system[31] production cost and that of the respective Day-2 case. The primary outputs are: (1) the maximum theoretical savings of an Optimal Day-2 operation, (2) the achievable theoretical savings of the Midwest ISO's Day-2 operation, and (3) the estimated achieved benefits of the Day-2 Actual Midwest ISO operation.

This chapter is presented in six principal sections as follows:

- Cases Examined
- Methodology for Assessing Day-1 and Day-2 Optimal Costs in the MAPS Framework
- Model Calibration
- Modeling Treatment Across Cases
- Methodology for Assessing Day-2 Actual Costs
- Stakeholder Participation Process

Cases Examined

ICF prepared and analyzed four primary cases in order to develop the study results. These cases are:

- **Day-1 Case**: This case estimated the production cost of the Midwest ISO market assuming continued Day-1 operation for the study period. ICF used hurdle rates[32] derived from a model calibration exercise of the 2004 Day-1 Midwest ISO market to simulate continuation of decentralized Balancing Authority unit commitment and economic dispatch. Hurdle rates are the barriers to trade

[31] The System in this case is the US Eastern Interconnect
[32] Hurdle rates are discussed in detail in Chapter 3.

between Balancing Authorities needed to reproduce the actual operations observed in 2004 in the model.

- **<u>Day-2 Optimal Case</u>**: This case was designed to predict the theoretical maximum benefits from centralized operations in a Day-2[33] market as compared to the Day-1 Case. This case specifically was used to predict the production costs of an optimal Midwest ISO Day-2 operation. Commitment and dispatch hurdle rates used in the Day-1 Case to simulate decentralized operation were eliminated in the Day-2 Case to simulate centralized unit commitment and footprint-wide economic dispatch.
- **<u>Day-2 Actual Case</u>**: This case was designed to determine the benefits achieved by the Midwest ISO's Actual Day-2 operation over the study period. ICF used actual hourly dispatch data from the Midwest ISO's Day-2 market operations to estimate actual production costs during this historical period.
- **<u>No-ASM (Ancillary Services Market) Case</u>**: This sensitivity case was designed to simulate achievable benefits from centralized dispatch given the fact that current Midwest ISO operations do not include centralized dispatch and commitment of regulation and operating reserves. Instead, the majority of these ancillary services are held by each Balancing Authority locally. The Midwest ISO filed an ASM plan on February 15, 2007 that would allow for future optimization of these services beginning in 2008.

From these cases, we estimate the maximum potential benefits associated with the Midwest ISO Day-2 market; the achievable benefits given the actual implementation of the Midwest ISO Day-2 market; and the actual benefits achieved by the Midwest ISO during the study period. In each case, the benefit is assessed by comparing the production cost in the Day-1 Case to that in the respective Day-2 Case. The maximum theoretical potential benefits is assessed as the change in system production costs between the Day-1 Case and the Day-2 Optimal Case; and the achievable benefits as the change in system production costs between the Day-1 Case and the No-ASM Case. In both cases, the only change relative to the Day-1 Case is the simulated market structure within the Midwest ISO footprint. Therefore any changes in production costs are directly attributable to the Midwest ISO Day-2 or No-ASM market. The actual achieved benefits are assessed as the change in system production costs between the Day-1 Case and the Day-2 Actual Case.

In each case, the system production costs comprise the fuel costs, the variable operation and maintenance costs, and the NO_X and SO_2 emission allowance charges for every generator in the US Eastern Interconnect. In the Day-2 Actual case, only Midwest ISO generators are directly observable using actual market generation data from the Midwest ISO market systems. In this case we estimate the production cost of generators external to the Midwest ISO footprint using an Interchange Index which is discussed in detail later in this chapter.

[33] Note that Midwest ISO actual operations differed significantly during the study period from the theoretical Day-2 Optimal Case modeled due to, for example, the manner in which regulation and operating reserves are currently provide in the Midwest ISO region versus the in the model representation . These differences are examined through sensitivity cases such as the "No-ASM Case".

Methodology for Assessing Day-1 and Day-2 Costs in the MAPS Framework

ICF used GE Energy's MAPS computer model for estimating the benefits associated with transforming the Midwest ISO market from a bilateral to a centrally coordinated market. MAPS is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors from a solved power flow case to determine how power from generating plants will flow over the AC[34] transmission network[35]. This feature enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission facility limits and security constraints. ICF used MAPS to perform a security constrained unit commitment and economic dispatch of generating resources to meet load and reserve requirements. ICF modeled a ten month historical period on a bi-hourly basis for calibration purposes (2004), and for forecasting purposes (2005 and 2006).

The outputs of the modeling exercise include power plant dispatch, hourly nodal and zonal prices, power flows on monitored transmission lines and interfaces, and a full reporting of all production costs expended within the Eastern Interconnect to meet load and reserve requirements. These costs include fuel use, emission allowance costs and variable non-fuel operation and maintenance (VOM) costs.

Model Calibration

A key element of the approach to estimating RTO benefits involves the use of "hurdle rates" to capture inefficiencies associated with decentralized markets. Two hurdles were used, a commitment hurdle and a dispatch hurdle. The analysis used commitment hurdles to capture company operation (decentralized operation) and dispatch hurdles to capture non-tariff related dispatch inefficiencies associated with scheduling and dispatching practices amongst multiple transmission providers.

A key feature of the Midwest ISO's Day-1 operation was the decentralized commitment of generation resources by individual Balancing Authorities. Unit commitment is the decision to bring a powerplant on line and make it available for dispatch at a given time and for many plants requires start-up in advance of the time when the plant would be used i.e in advance of dispatch. Under Day-1 operation, each Balancing Authority was responsible for commitment of generation to meet its load plus reserve requirements. As described earlier, hurdle rates are a modeling construct that allows us to simulate these aspects of decentralized operation by imposing an additional cost component, in most cases a significant additional cost component, on using resources outside a Balancing Authority's control. This naturally provides the economic incentive, within the modeling context, for local resources to be committed ahead of external resources, thereby simulating the Day-1 framework for unit commitment.

The determination of the appropriate level of hurdle rates is achieved through a detailed model calibration exercise in which hurdle rates are introduced in the model to calibrate the simulated model outcome to historical market outcomes. ICF calibrated to four primary parameter during this exercise, namely Midwest ISO net interchange, generation by Balancing Authorities,

[34] Alternating Current
[35] MAPS uses a linearized Direct Current (DC) Network approximation. Generation shift factors determine the amount of injected power flowing on particular transmission lines and other system elements such as transformers.

generation by unit type, and generation by unit. Since production cost models are not designed to solve for these hurdle rates, calibration exercises tend to be iterative processes whereby an initial assumption of these hurdle rates is used and refined with each successive iteration until the model outcome is reasonably close to the historical actual market outcome. Each of these parameters was calibrated to match their 2004 historical outcomes as closely as possible. The results of the calibration exercise are discussed in Chapter 4.

Without the use of commitment hurdle rates, most production cost models would assume a single region-wide market where all units are equally eligible to commit to serve the region-wide load based on economics. For example a unit in Illinois could be committed to serve load in Ohio and vice versa, to the extent it is economic to do so. The use of commitment hurdles provides the MAPS model with a means to recognize market and operational boundaries such as between the Midwest ISO and PJM as well as practices across companies operating separately within the Midwest ISO region such as Ameren, Duke Energy, and Xcel Energy. During the commitment process, these commitment hurdles ensure that only company resources are committed to meet company load first before being made available to meet the needs of other interconnected companies.

The Project Steering Committee in consultation with the Midwest ISO selected 2004 as the appropriate year to calibrate the model for this study. Therefore, ICF used April – December 2004 market data provided by the Midwest ISO and Stakeholders for this calibration exercise. Exhibit 2-1 provides a high level overview of the data used for the calibration and the associated sources.

Exhibit 2-1:
Summary of Calibration Data

Parameter	Source
2004 Hourly Demand	Midwest ISO
Existing Generator Cost and Performance	Stakeholders
Existing Generator Interconnection Nodes	Midwest ISO
Operating Reserve Requirements	Regional Reliability Organizations
Existing Transmission Network	Midwest ISO
Transmission Access Rates	Midwest ISO
“Must-Take” Contracts	Stakeholders
Voltage Support Facilities	Stakeholders
Coal Prices (2004)	SNL Financial
Natural Gas Prices (2004)	Gas Daily
Oil Prices (2004)	Bloomberg
SO_2 and NO_X Allowance Prices	Air Daily
2004 Actual Unit Generation (MWh)	Platt’s and SNL Financial

The commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provides information to guide refinement of the commitment or dispatch hurdles, or both. Specifically, for each unit within the Midwest ISO, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead.[36] Thus the total number of hours the

[36] The forward looking view ensures that each unit’s operating characteristics such as minimum uptime and downtime are not violated.

unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation, especially for units that showed large deviations, to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2004 did not dispatch as much in the 2004 calibration model and also did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdle was adjusted. In contrast, if the unit was committed as expected, but did not dispatch as much as it actually did historically, then the dispatch hurdles were adjusted.

Modeling Treatment across Cases

A large number of parameters were treated consistently across all the cases. These include basic supply/demand fundamentals such as demand levels, physical supply characteristics, fuel prices, environmental allowance prices, etc. Additionally, any transmission or generation capacity expansion was modeled consistently across all cases, as was the treatment of must-run/must-take contracts.

There were, however, key structural and operational parameters that were modeled differently across the cases to capture the alternative simulated market structures. Exhibit 2-2 summarizes the treatment of key parameters in the modeling of the cases and the major differences across cases from a modeling perspective. These major areas of differences are captured through the treatment of:

- Unit commitment and dispatch;
- Transmission rates;
- Operating reserves; and
- Utilization of existing transmission assets.

Exhibit 2-2:
Summary of Key Differences Across Reference Cases

Parameter	Day-1 Case	No-ASM Case	Day-2 Optimal Case
Security Constrained Unit Commitment (SCUC)	Commit to meet Balancing Authority load plus reserve	Midwest ISO region-wide centralized commitment	
Security Constrained Economic Dispatch (SCED)	Dispatch to meet Balancing Authority load plus economy interchange;	Midwest ISO region-wide centralized dispatch	
Hurdle Rates	H1 – Hurdle designed in model to force unit commitment by Balancing Authority – Applicable only to unit commitment (SCUC) – does not directly affect SCED	None	
	H2 – Realized hurdles from model calibration exercise to capture non-tariff related dispatch inefficiencies		
Transmission Tariffs	Midwest ISO-wide uniform tariff		
Transmission Limits	Reduced actual line limit based on prior Midwest ISO analysis of historical data	100 percent of the actual line limit	
Operating and Regulation Reserves	Based on existing Midwest ISO Operating Reserve requirement. Each Balancing Authority provides operating reserves based on their allocation under the Reserve Sharing Agreement		Based on centralized footprint-wide operating reserve market

Unit Commitment and Dispatch

The Day-1 Case model was configured to permit each company to commit its resources to serve native load. This was achieved by the use of hurdle rates designed to constrain each Balancing Authority's generation resources to serving its load first. In addition, ICF used small, uniform, dispatch hurdle rates to capture non-tariff related Day-1 market inefficiencies associated with Balancing Authority operations.

The application of the commitment hurdles was evaluated carefully to ensure that the desired effect was achieved i.e., for each company or Balancing Authority least cost units were committed before the more expensive units. In many of the models used for cost benefit analyses, such as MAPS, the commitment decision for a generation unit is based on its priority cost. The lowest priority cost generation resource within a Balancing Authority or within a company's fleet of resources gets committed first to serve its load. In turn, each unit's priority cost is determined by two key components:

- its variable costs, [37] and
- its natural location factor[38] with respect to transmission constraints and losses.

[37] The variable cost components of each unit's priority costs include fuel, variable operation and maintenance cost, start-up costs and emissions cost.

When commitment hurdles are introduced in the model as a means to simulate a decentralized market, a third component is introduced to the priority cost equation. This third component, if not properly applied, can introduce distortions to the resultant unit commitment stack. Since the commitment hurdle is designed to constrain a group of generation resources available within a Balancing Authority or belonging to a company to serve its load, appropriate care should be taken to ensure that the impact of the commitment hurdle is uniform across that target group of resources. These commitment hurdles, if applied across Balancing Authority tie-lines, can introduce locational biases to the target resources and the effect would be a non-uniform impact of the commitment hurdle across the target resources. For example, assume a particular Balancing Authority has a single tie with its external electrical world. If a $20/MWh commitment hurdle is placed at this tie, then the impact of the commitment hurdle on each of the units within that particular Balancing Authority will depend on each unit's shift factor across that tie. Thus, if two units in that Balancing Authority have different shift factors across this tie, the impact of the commitment hurdle will not be uniform and may distort the priority costs of both units. Thus, an improper application of the commitment hurdle may have the unintended consequence of committing the more expensive generation resource before the cheaper generation resource.

To avoid this problem, ICF did not apply the commitment hurdles at the Balancing Authority ties. Instead, ICF used special operating nomograms to uniformly apply the commitment hurdle to each company's units to achieve the dual objectives of:

- Constraining units within the company/Balancing Authority to commit to the Balancing Authority/company load first before committing to some other load;
- Ensuring that units within each Balancing Authority/company maintain their true commitment priority derived from their variable costs and their natural location factors.

Modeling of Transmission Facility Limits and Flowgate Utilization

ICF has explicitly modeled all designated NERC and Midwest ISO flowgates[39] in this analysis. Flowgates are usually the sensitive and often stressed locations in the grid. Transmission flowgates are frequently monitored for potential line overloads should there be contingency and/or emergency conditions such as outage of line(s) or generation plant(s) or both. Approximately 1300 NERC flowgates, 100 Midwest ISO flowgates and 10 rule-based limits (nomograms) were modeled with explicit monthly limits for this analysis.

Although flowgate limits vary on an hourly basis, such variability is not practical to include in a market simulation model. ICF in consultation with the Steering Committee determined that inclusion of monthly limits in the model would be adequate for this analysis. For Day-1 modeling, every flowgate limit was reduced by a certain percentage (see Exhibit 3-21) based on actual flowgate utilization during level-3 and higher TLR events. This assumption is based on analysis performed by the Midwest ISO and documented in a memorandum distributed to the study stakeholder group. The decision to utilize a single flow gate limit for every hour of the

[38] The natural location factor of a generation unit is a measure of its locational advantage or disadvantage with respect to constraints within the transmission system. It is represented by a matrix of the unit's shift factor on all transmission system elements with respect to a designated Reference location on the grid. Thus, all units have their matrix of shift factors. These shift factors change with a change in the Reference Location and/or a change in the grid topology.

[39] NERC defines certain transmission lines or paths through which power flow from power transactions are calculated during system operation. These are typically lines or paths that could get congested and impact power transactions. These points are called flowgates.

month means that in some hours the actual flow gate limit was greater than simulated whereas in other hours the actual flow gate limit was less than simulated. The larger the gap between actual and simulated flow gate limit the greater the error in the simulation result for that hour relative to what actually occurred. Assuming more or less equal distribution of “over” and “under” hours, the average effect should not greatly impact the analytic results.

Treatment of Operating Reserves

ICF modeled operating reserves based on the operating reserve requirement within the Midwest ISO market. This Midwest ISO reserve requirement mandates a total of 3,655 MW[40] of operating reserves for the Midwest ISO region.

In the Day-1 and No-ASM Cases the treatment of operating reserves was consistent with the actual Midwest ISO’s operation. Operating reserves are largely decentralized and held locally by the Balancing Authorities. Each Balancing Authority is responsible for meeting its share of the Midwest ISO operating reserve requirement.

One of the benefits of Day-2 market operation is efficiency gains resulting from a centralized provision of regulation and operating reserves. The modeling of regulation and operating reserves in the Day-2 Optimal Case reflected a centralized regulation and operating reserve market. Regulation and operating reserves were held at the Midwest ISO level, and the most economical generation resources were committed and dispatched to meet demand and required regulation and operating reserves on a region-wide basis. This approach determined the maximum <u>theoretical</u> benefits achievable from Day-2 operation of the Midwest market including both energy and ancillary services.

The Midwest ISO, however, did not operate a centralized ancillary services market in its implementation of Day-2 operation during the study period. Regulation and operating reserves were still decentralized and held locally by the Balancing Authorities similar to Day-1 operation. The No-ASM Case was designed to evaluate the impact of this variation in implementation on the overall benefits of the Day-2 operation. Therefore, in the No-ASM Case the majority[41] of regulation and operating reserves were held locally at the Balancing Authority level. This approach determined the <u>achievable</u> benefits from the Midwest ISO’s implementation of the Day-2 market.

Treatment of Losses

MAPS is capable of modeling the primary methodologies currently used in power markets to capture the effect of losses on the operation of the grid, namely average and marginal losses. In its Day-1 market, the Midwest ISO used average loss implementation. This framework assumes that losses are proportional to power produced, and losses are allocated to market participants based on a pro-rata share of total transmission losses. This treatment is consistent with the Midwest ISO’s closest neighbors PJM[42] and SPP. In its Day-2 market, the Midwest ISO implemented marginal losses, similar to the New York ISO and the New England ISO. Under the marginal loss approach, transactions are assessed charges for losses based on their

[40] See Chapter Three for a detailed accounting of the components of this reserve assumption.
[41] Headroom reserves equal to 700 MW are assumed to be held by the Midwest ISO in this case.
[42] Note that PJM intends to implement a marginal loss regime in June 2007.

incremental impact on system losses, which accounts for the locational impact of injections on system losses.

The MAPS model treats losses uniformly system-wide. Since ICF modeled the entire Eastern Interconnect, the implementation of losses selected for a particular case applied system-wide. For example, if average losses were selected for the Midwest ISO Day-1, MAPS would assume average losses for the entire Eastern Interconnect in the model. Given this limitation and the fact that most of the Eastern Interconnect operates under average rather than marginal losses, ICF chose to model average losses for the entire system in all cases since this would introduce the least bias to the model results.

Methodology for Assessing Day-2 Actual Costs

To calculate the estimated benefits achieved by the Midwest ISO over the ten month study period, ICF utilized the actual hourly generation data provided by Midwest ISO from Day-2 market operations to develop the Day-2 Actual Case. Estimated production costs were computed from this data by multiplying the actual generation in MWh by an estimated average cost per MWh for each generating unit. The results of this calculation were compared against model derived production cost estimates for the Day-1, Day-2 Optimal, and No-ASM cases in order to develop the estimated benefits achieved. The key to this effort was calculating an estimated production cost for the actual operation that would be consistent with our simulated MAPS production cost estimates for the comparison cases. This consistency is achieved by estimating actual production cost using actual generation and model-based production costs. Any difference between actual offers and model-assumed production cost may introduce error into the comparison of actual and hypothetical achievable benefits. Thus, although this technique is required to develop a meaningful comparison of production cost between the hypothetical and actual cases, the resulting inconsistency between the actual dispatch (based on actual offers) and hypothetical dispatch (based on assumed offers) introduces a difficult to quantify error in the estimated study result. Estimating the size of this error is not within the scope of this analysis.

Day-2 Actual Approach

The production costs savings for the Day-2 Optimal Case is defined as the total system production costs for the Day-1 Case ($) less the total system production costs for the Day-2 Optimal Case. In this analysis, the “total system” is defined as the US Eastern Interconnect. We include this wide scope in our modeling to account for all market participant responses to the change in the Midwest ISO market structure. That is, in our modeling framework both Midwest ISO market participants and non-Midwest ISO market participants may respond to the changes occurring in the Midwest ISO market structure in order to minimize their operating costs. This adds to the scope of the analysis, but this expansion is necessary.

There are two broad production cost components that are considered in estimating the total system production costs. Namely, 1) costs from local generation and 2) costs from generation outside the Midwest ISO footprint. In the Day-1, Day-2 Optimal, and No-ASM Cases both of these values are direct outputs of the ICF modeling exercise.

In the Day-2 Actual Case, the comparison to Day-1 system production costs is not directly possible because we can only directly measure production costs within the Midwest ISO given the actual hourly data available for generation from units within the Midwest ISO market footprint. For example, we do not have access to a consistent set of hourly generation, unit cost and performance, and actual fuel cost data for facilities in PJM, SPP, or other regions.

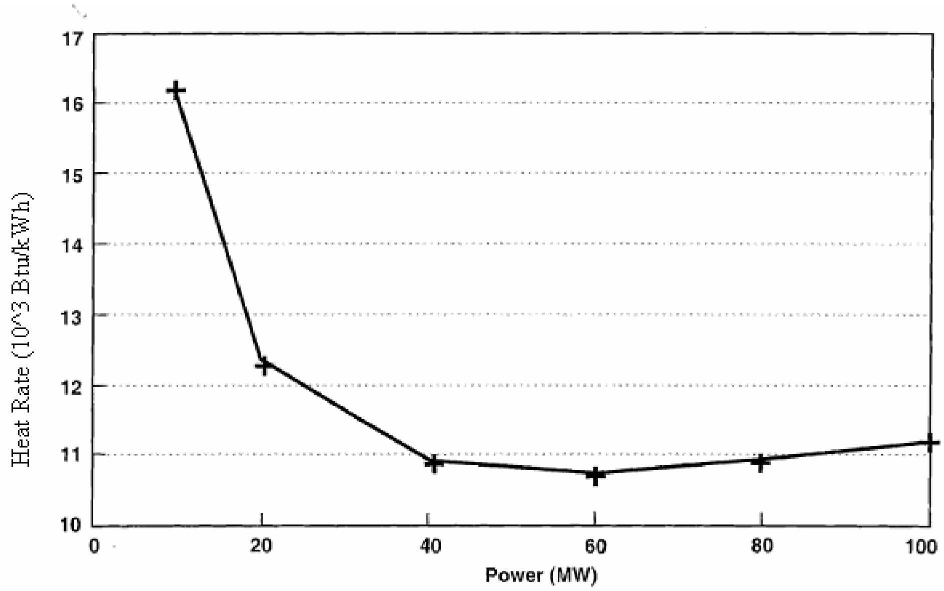
We discuss the approach used to estimate each of these two cost components for the Day-2 Actual Case below.

Costs from Local Generation

Each local generation unit has four main sub-components of costs associated with generation dispatch. These costs are fuel, non-fuel variable operating and maintenance costs (VOM), NO_X emission costs and SO_2 emission costs. The approach used to capture costs for each sub-component is described below.

Fuel Cost: The cost of fuel used by each local generator is calculated for every unit in the Midwest ISO for every hour by multiplying fuel used (MMBtu) by the fuel price ($/MMBtu). The fuel used is calculated by mapping the unit's actual hourly dispatch in MWh to the estimated instantaneous heat rate of that unit based on the unit's output/heat rate curve used in the MAPS model. See sample heat rate curve below.

Exhibit 2-3:
Illustrative Heat Rate Curve of a Unit in the MAPS Model



Source: ICF

The heat rate (Btu/kWh), in conjunction with the hourly unit output (MWh), provides the quantity of fuel used in MMBtu for that hour. This quantity is then multiplied by the monthly average fuel price ($/mmBtu) to calculate a total fuel cost for each unit in each hour. For example a CT with an instantaneous heat rate of 10,000 Btu/kWh at the 30 MW set point in a given hour will realize a fuel cost of $1,800 per hour as shown below:

*$6.00/MMBtu * 10,000 Btu/kWh / 1000 * 30 MW = $1,800/hr in fuel costs*

VOM Cost: Non-fuel VOM costs are calculated by multiplying the stakeholder-provided VOM costs ($/MWh) by total unit output (MWh). For example a CT with a VOM of $4/MWh generating 30 MW in a given hour will realize VOM cost of $120 per hour. See calculation below:

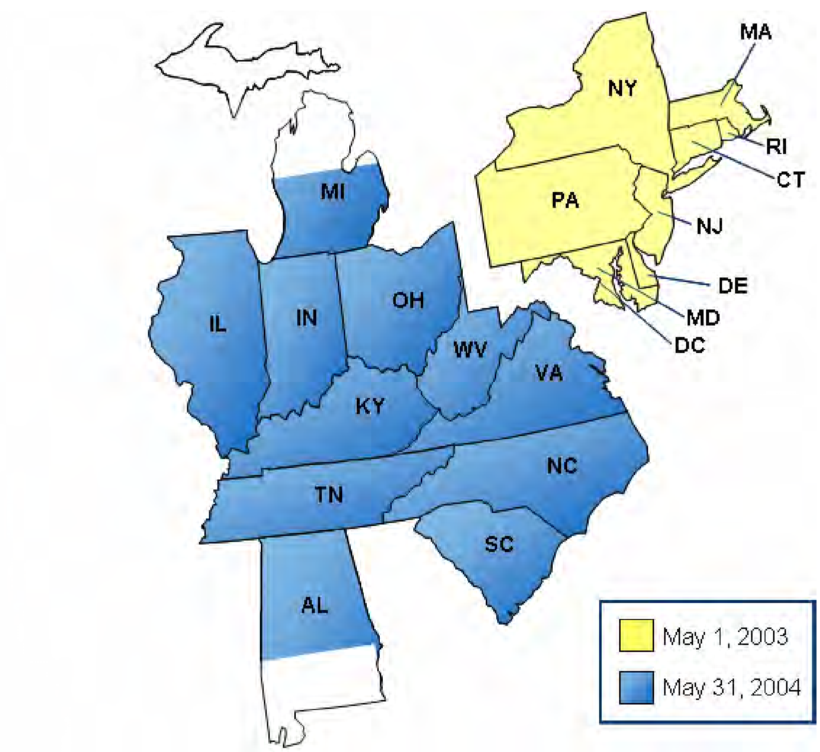
*$4.00/MWh * 30 MW = $120/hr in VOM costs*

NO_X Allowance Costs: Emissions cost associated with the consumption of NO_X allowances are calculated by multiplying the NO_X output (tons) by the monthly average allowance price ($/ton). The total NOx pollutant output is derived from fuel used (MMBtu) by the unit and the unit's emission rate (lb/MMBtu) as provided by Stakeholders and confirmed with data from SNL Financial. Note that NOx costs are calculated for SIP[43] Call affected units in summer months only. For example, a CT with a 10,000 Btu/kWh heat rate, generating 30 MWs in a given hour with an emission rate of 0.1 lbs/MMBtu will realize a NOx emission costs of $45 per hour as shown below if we assume an allowance price of $3,000/ton:

*10,000 Btu/kWh * 30,000 kWh / 10e6 * 0.1 lb/MMBtu / 2,000 lb/ton * 3000$/ton = $45/hr*

Note that the SIP Call policy is a regional emissions policy covering only a portion of the Midwest ISO footprint. Exhibit 2-4 below highlights the state by state coverage of the SIP Call program.

Exhibit 2-4:
NOX SIP Call States



Source: ICF

[43] State Implementation Plan.

SO_2 Allowance Costs: Similarly, SO_2 allowance costs are calculated by multiplying SO_2 output (tons) by the monthly average allowance price ($/ton). The SO_2 output is derived from fuel used (MMBtu) by the unit and the unit's emission rate (lb/MMBtu). The emission rate is calculated from the pollutant content of the fuel burned (lb/MMBtu), and any applicable emission reductions (%) resulting from installed SO_2 scrubbers – i.e. from flue gas desulfurization equipment.

For example, a conventional coal unit with a heat rate of 9,000 Btu/kWh generating 300 MWs in a given hour with an emission rate of 1.0Ibs/MMBtu will realize the SO_2 emission costs below:

*9,000 Btu/kWh * 300,000 kWh / 10e6 * 1.0 lb/MMBtu / 2000 lb/ton * $700/ton = $945*

Non-Midwest ISO Unit Production Costs

To maintain consistency with the production cost framework of the model, we have assumed that the Non-Midwest ISO region unit production costs are consistent with model costs realized in the Day-2 Optimal Case adjusted for any changes in Midwest ISO net interchange with neighboring regions on a monthly basis. Total production costs for all generators outside of the Midwest ISO are comprised of hourly production costs related to fuel, VOM, NO_X and SO_2 expenses. These costs are aggregated to a monthly total and adjusted to account for any differences in net interchange in that month between simulated Day-2 Optimal model results and actual operations. For example, if net interchange results indicated fewer imports in the Day-2 Optimal case than actual operations, an import adder was added to ensure that production costs in the Day-2 Actual Case included costs associated with the correct number of megawatt hours. In this example the import adder would be the product of the change in imports (MWh) times the average production costs realized outside of the Midwest ISO footprint for that month in the Day-2 Optimal Case. We believe that this is an appropriate treatment on external production costs and note that the "import adder" accounts for less that 0.08 percent of the Day-2 Actual production cost estimate over the ten month period.

Note that generation from hydroelectric facilities, wind facilities and from Canadian imports were not included for production cost purposes as these units are set to match historical generating patterns and do not vary their operation across cases considered. In other words, the Day-1, Day-2 Optimal, No-ASM, and Day-2 Actual Cases all include the same generation pattern for these units on an hourly basis.

Stakeholder Participation Process

This study was driven by an open and interactive Stakeholder process designed to ensure the accurate representation of the Midwest ISO system and to benefit from the feedback of all Stakeholders. A Project Steering Committee comprising key Midwest ISO personnel provided guidance and administration in providing ICF with the relevant data and coordinating the gathering of Stakeholder data. This ensured an efficient process of data transfer and data verification.

Although the scope of the study was developed and approved by the Midwest ISO, it was done in consultation with other Stakeholders, including municipal utilities, cooperative utilities, and independent power producers active in the Midwest ISO market. The following outline details the steps taken by ICF to ensure Stakeholder participation:

- **Establishing an open channel of communication** - ICF created a secure website to register all Stakeholders (see Exhibit 2-5). This electronic format has proven to be extremely efficient in communicating any updates and changes to a large group of participants. It also served as an open forum for each Stakeholder to address concerns or make corrections as well as a central drop off point for uploading and downloading documents. There were a total of 94 registered participants from 56 organizations ranging from utilities to independent power producers to local utility commissions. This website is in addition to traditional channels of communication such as conference calls, emails, written communication, etc.

Exhibit 2-5:
Stakeholder Information Website

Source: ICF

- **Sharing information** – In order to ensure that all Stakeholders were aware of the parameters of the study, ICF distributed a 200 page document detailing the proposed assumptions and methodology. The website was used as the central distribution point.

- **Ensuring an inclusive and interactive process** – After all the Stakeholders received the methodology and assumptions document, ICF opened a review and comment period. Stakeholders submitted comments or questions on the established website to assure their concerns and comments were visible to all parties. In all, 91 comments were received and ICF replied to all of them either clarifying certain points or, where appropriate, making model adjustments. The website was used as the central distribution point for ICF responses.

- **Face-to-face Meetings** – ICF held a Stakeholder meeting in late February 2006. ICF and the Midwest ISO used this venue to introduce stakeholders to the study scope, goals, and the general study approach.
- **Verifying Data** - ICF initially received much of the model input data directly from the Midwest ISO. However, to verify this data, ICF entered into confidentiality agreements with individual Stakeholders, who then reviewed and commented upon generation resource thermal and cost data used for modeling. This ensured that the results of our analysis reflect as accurately as possible the actual condition of the Midwest ISO market during the study period. In all, Stakeholders accounting for 80 percent of installed capacity reviewed detailed assumptions data for their facilities. Data items reviewed included:
    - Plant Name and Unit Number
    - Ownership share
    - Balancing Authority Name
    - CPNode Name
    - Interconnection Node Name
    - Online Date
    - Retirement Date
    - Unit Type/Prime Mover
    - Maximum Summer/Winter Capacity (MW)
    - Primary/Secondary Fuel
    - 2004/2005/2006 Average Fuel Cost($/MMbtu)
    - Minimum Runtime/Downtime (Hrs)
    - Ramp Up/Down Rate (MW/hr)
    - Average Full Load Heat Rate (Btu/Kwh)
    - Variable O&M ($/MWh)
    - Start Up Cost ($000)
    - Must run status

Through this iterative and open process, ICF was able to assure a high degree of model input data accuracy, enhancing the model representation and hence the evaluation of the theoretical maximum, achievable, and actual achieved benefits available to Midwest ISO market participants as a result of the Midwest ISO Day-2 market.

CHAPTER THREE:
OVERVIEW OF MODELING ASSUMPTIONS

Chapter Three presents an overview of the modeling assumptions used by ICF in this analysis. This chapter is broadly broken into three parts (1) Supply Side Assumptions (2) Demand Assumptions and (3) Transmission Assumptions. This study was driven by a multi-faceted and interactive Stakeholder process designed to ensure the accurate representation of the Midwest ISO system and to benefit from the feedback of all Stakeholders. The Midwest ISO and its stakeholders provided the majority of the study assumptions. The table below lists the major data elements and their sources.

Exhibit 3-1:
Data and Source for Modeling Assumptions

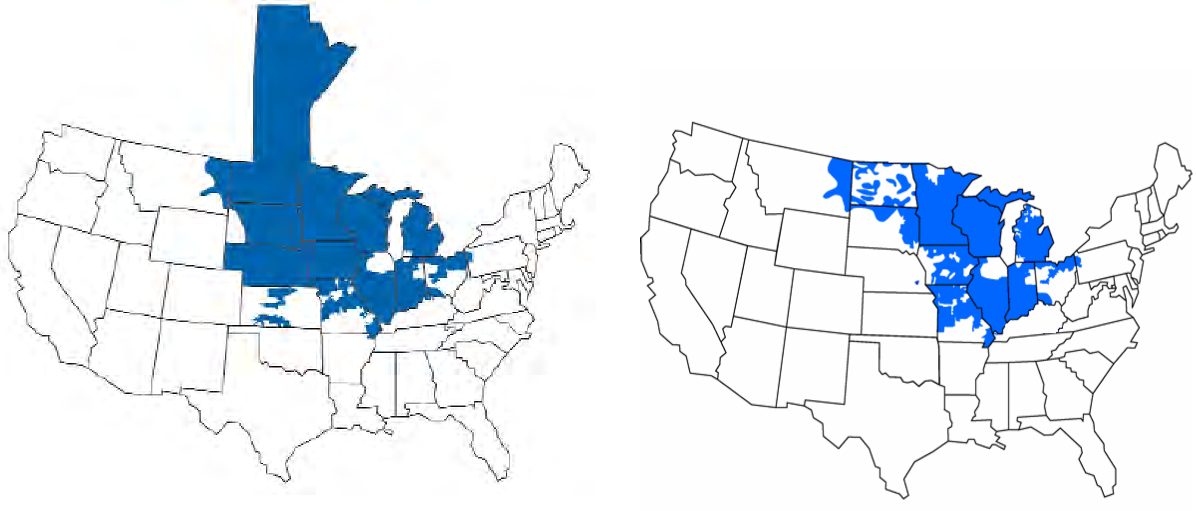
Data Element	Source
Unit heat rates	Stakeholders/Midwest ISO
Unit primary fuel	Stakeholders/Midwest ISO
Unit secondary fuel	Stakeholders/Midwest ISO
Unit ramp rates	Stakeholders/Midwest ISO
Unit NOx emission rates	Stakeholders/Midwest ISO/ICF
Unit interconnection nodes	Stakeholders/Midwest ISO
Must-run requirements	Stakeholders/Midwest ISO
Hourly unit dispatch (2004,2005 and 2006)	Midwest ISO
Zonal Definitions	Midwest ISO
Hourly Demand by Zone (2004, 2005 and 2006)	Midwest ISO
Midwest ISO internal and external interfaces and flowgates	Midwest ISO
Tariff detail; firm and non-firm 2004	Midwest ISO
Hourly Imports from Canada	Midwest ISO
Power flow cases	Midwest ISO
Spinning reserve requirements	Midwest ISO
Fuel prices	ICF; based on historical data
Midwest ISO Members	Midwest ISO
Emissions costs	ICF; based on historical data

For all cases analyzed, the Midwest ISO was modeled as an integrated system within the larger Eastern Interconnect. ICF assumptions were used for the rest of the eastern interconnect wherever historical data was not available. Exhibit 3-2 compares the geographic reliability and market footprints for the Midwest ISO while Exhibit 3-3 shows a schematic representation of the Balancing Authorities in these footprints. For this analysis, ICF focused on the 26 Balancing Authorities within the Midwest ISO market footprint. These 26[44] Balancing Authorities were modeled as separate markets in Day-1 for the purpose of unit commitment and operating reserves. In the Day-2 Optimal Case simulation, unit commitment and operating reserves was performed on a Midwest ISO-wide basis.

[44] DEVI and CIN are aggregated in this analysis

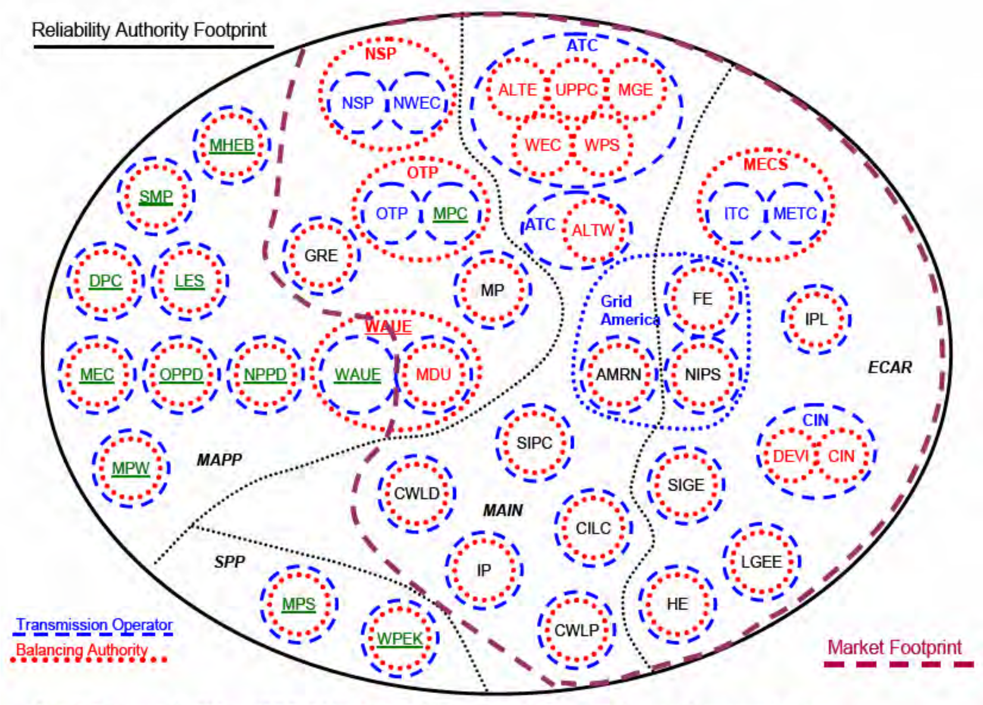
Exhibit 3-2:
The Midwest ISO Reliability and Market Footprints

Reliability Footprint **Market Footprint**



Source: Midwest ISO

Exhibit 3-3:
The Midwest ISO Balancing Authorities in the Reliability and Market Footprints



Note 1: Systems under Midwest ISO Reliability Authority but not under the Energy Markets are shown as underlined.

Note 2: MDU is a pseudo Balancing Authority under Midwest ISO.

Note 3: ITC and METC are treated as separate Balancing Authorities for the Energy Markets.

Source: Midwest ISO Business Practices Manual for Coordinated Reliability, Dispatch, & Control, Manual No. 006, 2005. See Demand Section below for acronym definitions. Note that GridAmerica and ATC are no longer operational but the Balancing Authorities pictured are valid up to the end of the study period in March 2006. Since then, DEVI and LGEE are no longer operational (as of 6/2006 and 9/2006, respectively) and SMP has joined the market footprint (as of 4/2006).

Supply-Side Assumptions

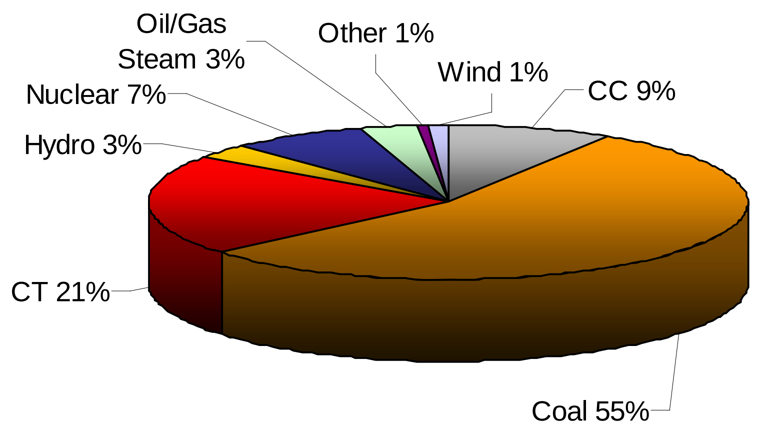
This section focuses on the key supply-side assumptions underlying the analysis. These include the following 5 broad categories:

- Existing Capacity;
- New Builds;
- Fuel Prices (natural gas, coal, oil);
- Environmental Compliance and Allowance Prices; and
- Existing Unit Characteristics (Heat Rates, VOM, Ramp-up rates etc)

Existing Capacity

The Midwest ISO capacity mix is dominated by base load generation in the form of coal and nuclear plants as shown in Exhibit 3-4. These units together comprise 62 percent of the Midwest ISO supply mix. When compared to other areas of the US the Midwest ISO is characterized as having relatively more baseload generation and little in the way of intermediate generation resources such as combined cycle. In the study period, we see that combined cycle units comprise only 9 percent of the capacity mix while units traditionally used for peak periods such as oil/gas steam and combustion turbine capacity accounted for a total of 24 percent of the mix. Thus, while the Midwest ISO is characterized as heavily baseload, during peak periods the area relies extensively on gas-fired peaking units with higher marginal costs.

Exhibit 3-4:
The Midwest ISO Capacity Mix, June 2005 through March 2006



Total Installed Capacity: 138 GW[45]

Source: Midwest ISO

[45] Midwest ISO total installed capacity by capacity type as of March 2006.

New Builds

From April 2004 to March 2006, a total of approximately 6.4 GW of new capacity came on-line within the Midwest ISO footprint. As noted earlier, the Midwest ISO has been increasing its reliance on natural gas-fired generation in recent years. This is evidenced by the fact that approximately 80 percent of the new capacity that came online during the study period was gas-fired, and virtually none was coal-fired. Indeed, in one case (Port Washington), the new gas plant was effectively replacing an older coal-fired powerplant.

Exhibit 3-5:
Midwest ISO Capacity Mix

Unit Name	Balancing Authority	Unit Type	Online Date	Capacity (MW)
Emery Generating Station	ALTW	Combined Cycle	5/18/2004	570
Riverside Energy Center	ALTE	Combined Cycle	6/1/2004	602
Trimble County	LGEE	Combustion Turbine	6/25/2004	600
West Campus Cogeneration Facility	MGE	Combined Cycle	4/26/2005	168
Angus Anson 3	NSP	Combustion Turbine	6/1/2005	160
Blue Lake 6 & 7	NSP	Combustion Turbine	6/1/2005	320
Sheboygan Falls	ALTE	Combustion Turbine	6/2/2005	350
Fox Energy Center (Kaukauna)	WPS	Combined Cycle	6/6/2005	550
Venice (AUEP)	AMRN	Combustion Turbine	6/10/2005	400
Port Washington	WEC	Combined Cycle	7/16/2005	545
Northome Wood Plant	MP	Other	8/1/2005	20
Butler Ridge	WEC	Renewable	10/1/2005	54
Crescent Ridge	IP	Renewable	10/1/2005	51
Green Field Wind Farm	WEC	Renewable	10/1/2005	80
Kaukauna (WPPI)	WEC	Combustion Turbine	10/1/2005	52
Arrowsmith 267	AMRN	Renewable	12/1/2005	400
Faribault Energy Park	NSP	Combined Cycle	12/1/2005	250
Top Of Iowa Wind Farm II	ALTW	Renewable	12/1/2005	100
Blue Sky Wind Farm	WEC	Renewable	12/31/2005	80
Tremont Wind	GRE	Renewable	12/31/2005	100
Walworth County Wind Easement	MDU	Renewable	12/31/2005	50
Fenton Wind Power Project	NSP	Renewable	1/1/2006	200
Fremont Energy Center	FE	Combined Cycle	1/1/2006	700
Manitowoc	WPS	Steam Turbine	3/31/2006	63
Combined Cycle				3,385
Combustion Turbine				1,882
Other				20
Renewable				1,115
Steam Turbine				63
Total Capacity Additions (MW)				**6,465**

Source: Midwest ISO

Existing Unit Cost and Performance Characteristics

Existing unit cost and performance data was provided by the Midwest ISO and confirmed by Stakeholders during the data review process. Stakeholder comments were provided on a confidential basis and are therefore not included in this report. Note that ICF compared all Stakeholder data submissions to ICF standard assumptions, Midwest ISO data, and publicly available data when possible. Any inconsistencies were discussed with appropriate parties and resolved on a case-by-case basis. For example, generator capacity was reviewed in detail in comparison to historical bid and offer data. Some adjustments to Stakeholder data were made to reflect capacity actually available for dispatch during the study horizon. Appropriate care was taken to ensure that the effect of reserves was not double counted in this exercise.

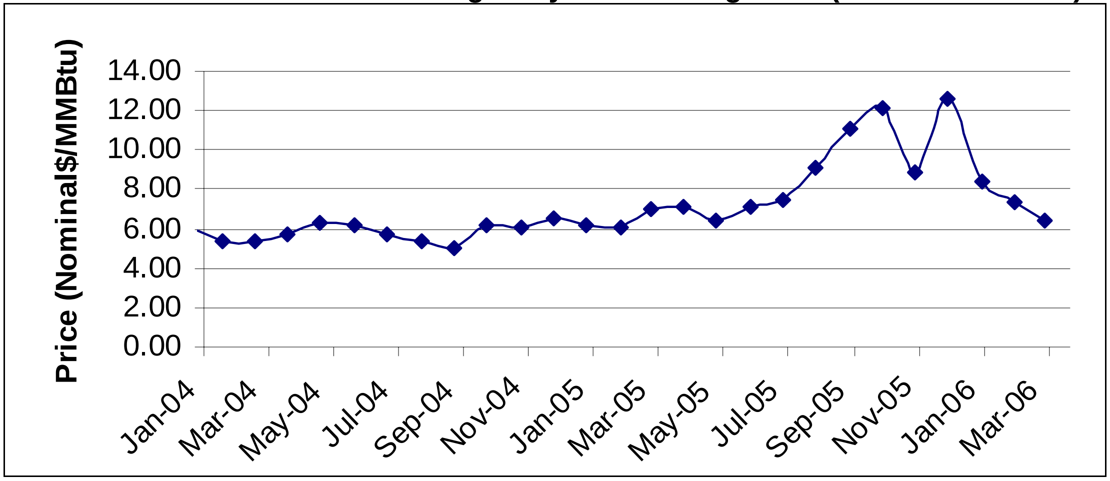
Unit Outages and Derates

ICF has explicitly modeled all unit outages and derates reported to the Midwest ISO during the study period. This data was provided by the Midwest ISO. Outages and derates were incorporated in the model on a daily basis for every generator within the Midwest ISO footprint, therefore any unit that experienced planned or unplanned outage extending at least one full day during the study period was made unavailable for the exact same duration during which it experienced an outage. This was done by assigning a start/stop date when the unit was unavailable. In the event that there was no derate reported to the Midwest ISO but historical generation records indicate that a unit was available at less than 100 percent for an extended period of time, ICF inferred derate where appropriate. These inferred derates were applicable to only a few units and did not significantly affect study results. The decision to utilize a daily average outage rate for every hour of the day means that in some hours the actual generating capacity was greater than simulated whereas in other hours the actual generating capacity was less than simulated. The larger the gap between actual and simulated generating capacity the greater the error in the simulation result for that hour relative to what actually occurred. Assuming more or less equal distribution of “over” and “under” hours, the average effect should not greatly impact the analytic results.

Natural Gas

A majority of the existing generation capacity within the Midwest ISO consists of low cost nuclear and coal units. As noted previously, natural gas has played an increasingly important role in the system as demand growth increases utilization of existing gas assets and almost all new capacity constructed in the past decade has been gas-fired. Combined cycles and combustion turbines, both of which rely on natural gas, accounted for over 80 percent of the new additions from April 2004 to March 2006; most of the remainder were intermittent renewable capacity. It is important to note that since mid-2002 natural gas prices have steadily increased and by late 2005, prices reached record levels. In 2005, the August – December average natural gas prices at Henry Hub reached close to $12/MMBtu with supplies curtailed as a result of Hurricane Katrina. Annual natural gas prices at Henry Hub averaged $8.89/MMBtu (2007$) in 2005, i.e., 33 percent higher than previous year levels. In 2006, natural gas prices averaged $6.80/MMtu (2007$), nearly 24 percent below 2005 average levels. While 2005 may have been a record year for high power and natural gas prices, the 2006 trend continued to show strong prices in both the fuel and power markets post-Katrina. This is evident in Exhibit 3-6 which shows, the gas prices from a representative pricing point for gas delivered to the Midwestern US, specifically the Chicago City Gate Pricing Point. Note that increased volatility in fuel markets was experienced during the later half of 2005. Between July and December 2005, the average monthly natural gas price increased by 69 percent on a nominal basis. This monthly average belies even greater volatility on a daily basis.

Exhibit 3-6:
Natural Gas Prices for the Chicago City Gate Pricing Point (Nominal$/MMBtu)



Source: Gas Daily

ICF developed natural gas price assumptions using historical delivered gas prices for the study period. ICF collected actual delivered gas prices for the various gas pricing points in the Eastern Interconnect. Every pricing point was mapped to ICF's gas supply regions. ICF used the monthly volume weighted average to calculate average monthly delivered gas price for every supply region. Each generator in the model is then mapped to a specific historical price stream based on geographic location and the pipeline network. Exhibit 3-7 shows the average monthly delivered natural gas prices utilized in this analysis.

Exhibit 3-7:
Delivered Natural Gas Prices (Nominal$/MMBtu) – January 2004 through March 2006

Month-Year	ECAR[1]	ECAR-KY[2]	ECAR-MECS[3]	MAIN-ILMO[4]	MAIN-WUMS[5]	MAPP[6]
Jan-04	6.34	7.91	6.01	6.11	6.09	6.00
Feb-04	5.64	5.92	5.48	5.39	5.40	5.24
Mar-04	5.61	5.67	5.58	5.42	5.43	5.11
Apr-04	5.98	6.03	5.96	5.72	5.73	5.36
May-04	6.55	6.65	6.51	6.31	6.32	5.92
Jun-04	6.56	6.59	6.41	6.20	6.22	5.85
Jul-04	6.16	6.16	6.15	5.69	5.87	5.68
Aug-04	5.68	5.62	5.65	5.38	5.44	5.26
Sep-04	5.35	5.19	5.16	5.00	4.95	4.60
Oct-04	6.50	6.19	6.33	6.21	6.05	5.50
Nov-04	6.44	6.31	6.29	6.12	6.12	5.95
Dec-04	6.89	7.08	6.64	6.58	6.64	6.43
Jan-05	6.24	7.02	6.24	6.16	6.16	5.96
Feb-05	6.36	6.50	6.29	6.12	6.13	5.85
Mar-05	7.18	7.34	7.15	6.98	7.01	6.64
Apr-05	7.57	7.51	7.41	7.06	7.09	6.88
May-05	6.78	6.72	6.64	6.44	6.45	6.04
Jun-05	7.44	7.50	7.27	7.11	7.11	6.56
Jul-05	7.83	8.07	7.58	7.42	7.43	7.10
Aug-05	9.73	10.22	9.34	9.12	9.14	8.63
Sep-05	11.20	11.73	10.40	11.03	11.09	9.04
Oct-05	14.15	14.21	13.07	12.15	12.15	11.10
Nov-05	10.50	10.29	9.40	8.85	8.93	8.21
Dec-05	13.23	13.70	12.47	12.57	12.53	11.82
Jan-06	9.03	9.50	7.25	8.43	8.46	7.89
Feb-06	7.94	8.28	7.67	7.40	7.43	7.26
Mar-06	7.30	7.37	6.78	6.36	6.45	6.15
Averages by Year						
2004	6.13	6.27	6.01	5.83	5.85	5.57
2005	9.03	9.25	8.62	8.43	8.44	7.83
2006	8.09	8.38	7.23	7.40	7.45	7.10

Source: Gas Daily, ICF

[1] ECAR: Actual delivered gas price as reported for Columbia Gas Pricing Point. ECAR includes Cinergy & First Energy.

[2] ECAR-KY; Actual delivered gas price as reported for Transco Pricing Point ECAR-KY includes Balancing Authorities in the state of Kentucky

[3] ECAR-MECS; Actual delivered gas price as reported for Michigan City Gate Pricing Point. ECAR- MECS region includes Detroit Edison and Consumers Energy

[4] MAIN-ILMO: Actual delivered gas price as reported for Chicago City Gate Pricing Point. MAIN-ILMO includes Balancing Authorities in Illinois & Missouri.

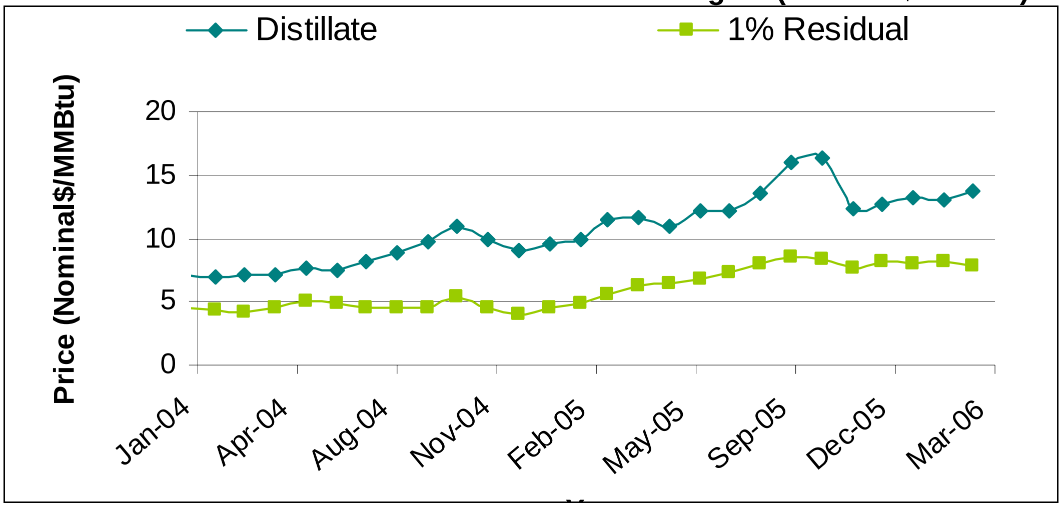
[5] MAIN-WUMS: Actual delivered gas price as reported for Alliance, Into Interstates Pricing Point. MAIN-WUMS includes Wisconsin & Upper Michigan.

[6] MAPP: Actual delivered gas price as reported for Northern Ventura Pricing Point. MAPP includes Balancing Authorities in the reliability region of MAPP.

Oil Prices

ICF used historical delivered oil prices during the study period for this analysis. The delivered oil price is a sum of the actual WTI monthly crude price from Bloomberg and estimated transportation differentials developed by ICF. Oil prices, most noticeably distillate oil prices, also increased significantly during the last quarter of 2005, though not as dramatically as natural gas. Exhibit 3-8 graphs the average monthly delivered distillate and 1 percent residual oil prices for the MAIN sub-region within the Midwest ISO. Exhibit 3-10 shows the average monthly prices of delivered oil to the ECAR, MAIN and MAPP sub-regions.

Exhibit 3-8:
Distillate and 1% Residual Prices for the MAIN Region (Nominal$/MMBtu)



Source: Bloomberg; ICF

Exhibit 3-9:
Delivered Oil Prices (Nominal$/MMBtu)

Month-Year	ECAR		MAIN		MAPP	
	Distillate	1% Residual	Distillate	1% Residual	Distillate	1% Residual
Jan-04	7.2	4.5	7.2	4.5	7.2	4.5
Feb-04	6.9	4.3	6.9	4.3	6.9	4.3
Mar-04	7.2	4.2	7.2	4.2	7.2	4.3
Apr-04	7.2	4.6	7.2	4.6	7.2	4.6
May-04	7.7	5.1	7.7	5.1	7.7	5.1
Jun-04	7.5	4.9	7.5	4.9	7.5	4.9
Jul-04	8.2	4.6	8.2	4.6	8.2	4.6
Aug-04	8.9	4.5	8.9	4.5	8.9	4.6
Sep-04	9.7	4.6	9.7	4.6	9.7	4.6
Oct-04	11.0	5.4	11.0	5.4	11.0	5.4
Nov-04	10.0	4.5	10.0	4.5	10.0	4.5
Dec-04	9.0	4.0	9.0	4.0	9.0	4.0
Jan-05	9.6	4.6	9.6	4.6	9.6	4.6
Feb-05	9.9	4.9	9.9	4.9	9.9	4.9
Mar-05	11.4	5.6	11.4	5.6	11.4	5.6
Apr-05	11.6	6.3	11.6	6.3	11.6	6.3
May-05	10.9	6.4	10.9	6.4	10.9	6.4
Jun-05	12.2	6.8	12.2	6.8	12.2	6.8
Jul-05	12.2	7.3	12.2	7.3	12.2	7.3
Aug-05	13.5	8.0	13.5	8.0	13.6	8.0
Sep-05	16.0	8.5	16.0	8.5	16.0	8.5
Oct-05	16.4	8.4	16.4	8.4	16.4	8.4
Nov-05	12.4	7.7	12.4	7.7	12.4	7.7
Dec-05	12.7	8.2	12.7	8.2	12.7	8.2
Jan-06	13.2	8.0	13.2	8.0	13.2	8.0
Feb-06	13.1	8.1	13.1	8.1	13.1	8.1
Mar-06	13.8	7.8	13.8	7.8	13.9	7.8
Averages by Year						
2004	8.38	4.60	8.38	4.60	8.38	4.62
2005	12.40	6.89	12.40	6.89	12.41	6.89
2006	13.37	7.97	13.37	7.97	13.40	7.97

Source: Bloomberg, ICF

Coal Prices

Coal units make up approximately 55 percent of the Midwest ISO capacity mix and more than 82 percent of the generation mix during the 2004 calibration period. Thus, the prevailing prices of coal are an important component of the analysis. In order to develop a consistent coal cost dataset ICF used delivered coal prices reported by SNL Financial (SNL) because the company has a comprehensive database of power plants with consistent data for the study time period from June 2005 to March 2006. SNL bases this data upon reported coal prices for regulated facilities. Because unregulated coal plants are not required to report historical costs, SNL develops estimated fuel costs for these facilities based on fuel costs reported by similar regulated plants. SNL calculates the weighted average price from reported prices for each state and each fuel type and applies this to unregulated plants. ICF received a list of coal plants with accompanying data from SNL and matched the Midwest ISO coal plants to that list. SNL provided the following information:

- Name of coal plant;
- Fuel contract counter party;
- Fuel contract type (spot or contract);
- Amount of coal received for each contract (1,000 of tons);
- Delivered coal price (nominal$/MMBtu); and
- Sulfur content of coal for each contract.

ICF originally intended to use spot price as the best estimate of the replacement cost of coal prices during the study period. Unfortunately, due to the long-term contracts that dominate the coal industry, less than 40 percent of the reported prices were spot prices. While it may have been feasible to extrapolate the spot prices to cover all data points, available spot prices tend to cluster around a handful of coal plants. For most of the ten months, spot price data were available for less than 50 unique plants out of the more than 140 coal facilities in the Midwest ISO footprint. Because coverage was low, there was insufficient data to extrapolate a contract/spot relationship. Therefore, ICF used the total delivered price which is a weighted average of both spot and contract prices for each facility. The decision to utilize a weighted average coal price for every hour of the month means that in some hours the actual coal price was greater than simulated whereas in other hours the actual coal price was less than simulated. The larger the gap between actual and simulated coal price the greater the error in the simulation result for that hour relative to what actually occurred. Assuming more or less equal distribution of “over” and “under” hours, the average effect should not greatly impact the analytic results.

Exhibit 3-10 below shows a sample of representative coal plants and associated prices per month.

Exhibit 3-10:
Representative Delivered Coal Prices (Nominal$/MMBtu)

Plant Name	Balancing Authority	2005							2006			
		Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Average
Avon Lake	FE	1.48	1.50	1.50	1.51	1.54	1.44	1.60	1.65	1.68	1.74	1.56
Clay Boswell[1]	MP	1.03	1.00	1.00	1.00	1.02	1.04	1.04	1.02	1.02	1.02	1.02
Coal Creek[1]	GRE	1.04	0.79	0.85	0.87	0.89	0.83	0.71	0.86	0.80	0.87	0.85
Edgewater[1]	ALTE	1.26	1.17	1.23	1.23	1.35	1.37	1.41	1.41	1.60	1.52	1.35
Coffeen[1]	AMRN	1.11	1.09	1.17	1.15	1.15	1.13	1.18	1.24	1.27	1.34	1.18
Ghent	LGEE	1.68	1.67	1.65	1.77	1.79	1.79	1.81	1.85	1.90	2.12	1.80
Harding Street	IPL	1.45	1.45	1.45	1.46	1.56	1.58	1.58	1.43	1.46	1.42	1.48
R.M. Schahfer	NIPS	1.49	1.59	1.56	1.48	1.51	1.53	1.51	1.76	1.73	1.72	1.59
Sherburne County[1]	NSP	1.04	1.00	1.03	1.00	1.03	1.02	1.06	1.12	1.13	1.14	1.06
Walter C Beckjord	CIN	1.87	1.98	1.96	1.96	2.15	2.29	2.33	2.31	2.25	2.16	2.13

[1] Plant did not have any spot contracts during the study horizon.

Environmental Compliance Costs

As mentioned above, sulfur content for each coal contract was provided by SNL Financial. ICF developed a weighted average SO_2 content for each facility for each month for use in the model. Where appropriate, this fuel content was reduced to reflect installed scrubbers. Stakeholder and ICF data was used to develop a similar estimate of NO_X emission rates for all SIP Call affected facilities. These emission rates (lb/mmBtu) were then multiplied by the prevailing SO_2 and NO_X emission allowance prices ($/ton) to develop an hourly emission cost. Exhibit 3-11 below details the monthly SO_2 and NO_X prices utilized in this analysis.

Exhibit 3-11:
Title IV SO2 Allowance Prices and NOX SIP Call Prices (Nominal$/Ton)

Month-Year	SO_2	NO_X
Jan-04	248	2,611
Feb-04	267	2,325
Mar-04	274	2,149
Apr-04	279	2,017
May-04	333	2,196
Jun-04	394	2,276
Jul-04	541	2,452
Aug-04	482	2,236
Sep-04	487	2,101
Oct-04	568	2,159
Nov-04	678	2,297
Dec-04	706	2,233
Jan-05	700	3,570
Feb-05	654	3,428
Mar-05	688	3,414
Apr-05	841	3,330
May-05	805	2,940
Jun-05	758	2,401
Jul-05	812	2,287
Aug-05	858	2,598
Sep-05	885	2,485
Oct-05	968	2,647
Nov-05	1,319	2,475
Dec-05	1,587	1,950
Jan-06	1,503	2,722
Feb-06	998	2,577
Mar-06	910	2,459
Averages By Year		
2004	*438*	*2,254*
2005	*906*	*2,794*
2006	*1,137*	*2,586*

Source: *Air Daily*

Must-Take Contracts and Reliability Must-Run (RMR) Units

As noted in the Approach section, all economic contracts are assumed to be implicitly modeled. However, non-economic contracts such as those with must-take characteristics have to be pre-specified (forced) into the model. After detailed discussions with Stakeholders, no must-take contracts were modeled. Several facilities are considered "must-run" due to voltage and system support issues. These assumptions were provided by Stakeholders and are shown in Exhibit 3-12 below.

Exhibit 3-12:
Must Run Assumptions

Item #	Company	Unit	RMR Capacity (MW)	Comments
1	GenSys - Dairyland	JP Madgett	390 MW coal	All 3 need to be running at min load or higher in summer and winter. Must run except for Apr, May, Sept. and Oct. Only one unit (of 3) can go down during these 4 months
		Genoa 3 (G3)	365 MW coal	
	Alliant	Lansing 4	30 MW Coal	
2	Cinergy	Beckjord 1	94 MW Coal	Annual - One unit on at all times to support the 138 kV system.
3	Cinergy	Beckjord 2	94 MW Coal	Annual; One of the five units must be online at all times
	Cinergy	Beckjord 3	128 MW Coal	
	Cinergy	Beckjord 4	150 MW Coal	
	Cinergy	Beckjord 5	238 MW Coal	
4	WE Energies	Valley Coal	134 MW Coal	Annual with some variance in seasonal capacities
5	Alliant	6th Street- 3	2 MW Coal	Annual; One or more units must be operating at all times
	Alliant	6th Street- 4	16 MW Coal	
	Alliant	6th Street- 7	16 MW Coal	
	Alliant	6th Street- 8	31 MW Coal	
6	CMS	Midland Cogen	400 MW	Annual
7	Ameren	Hutsonville 3	31 MW Coal	Must run at minimum load in all peak hours
		Hutsonville 3	32 MW Coal	
8		Edwards 1	43 MW Coal	One unit must be operating at minimum load in all hours
		Edwards 2	110 MW Coal	
		Edwards 3	147 MW Coal	
9		Mexico	66 MW CT	One unit must be operating at minimum load if demand in Jefferson City exceeds 200 MW
		Morberly	66 MW CT	
		Morneau	66 MW CT	
10		Vermillion	Coal and CT	One unit must be operating an minimum load in all peak hours
11	Duke	Cayuga 1	300 MW Coal	One unit must be operating at 300 MW in all hours
		Cayuga 2	300 MW Coal	
12		Wabash 1	275 MW Coal – Summer 200 MW Coal – Winter	
14		Gibson 5	214 MW Coal – Summer 275 MW Coal – Winter	
14	First Energy	Bayshore 1	136 MW Petcoke	Must-run at maximum load

Source: Stakeholders; Midwest ISO

Demand-Side Assumptions

Exhibit 3-13 details the Midwest ISO membership included in ICF's study by year.

Exhibit 3-13:
Midwest ISO Membership

Member	Member in 2004?	Member in 2005?	Member in 2006?
Alliant East (ALTE)	Yes	Yes	Yes
Alliant West (ALTW)	Yes	Yes	Yes
Ameren (AMRN)	Yes	Yes	Yes
Central Illinois (CILC)	Yes	Yes	Yes
Cinergy (CIN/DEVI)[1]	Yes	Yes	Yes
Consumers Energy (ITC)	Yes	Yes	Yes
Columbia Water Light & Power (CWLD)	Yes	Yes	Yes
City Water Light & Power (CWLP)	Yes	Yes	Yes
Detroit Edison (ITC)	Yes	Yes	Yes
First Energy (FE)	Yes	Yes	Yes
Great River Energy (GRE)	Yes	Yes	Yes
Hoosier Energy (HE)	Yes	Yes	Yes
Illinois Power (IP)	Yes	Yes	Yes
Indianapolis Power and Light (IPL)	Yes	Yes	Yes
Louisville Gas & Electric (LGEE)[1]	Yes	Yes	Yes
Montana Dakota Utilities (MDU)	Yes	Yes	Yes
Madison Gas & Electric (MGE)	Yes	Yes	Yes
Minnesota Power (MP)	Yes	Yes	Yes
Northern Indiana Public Service (NIPS)	Yes	Yes	Yes
Northern States Power (NSP)	Yes	Yes	Yes
Ottertail Power Coop (MPC)	Yes	Yes	Yes
Southern Indiana Gas and Electric (SIGE)	Yes	Yes	Yes
Southern Illinois Power Coop. (SIPC)	Yes	Yes	Yes
Upper Peninsula Power (UPPC)	Yes	Yes	Yes
We Energies (WEC)	Yes	Yes	Yes
Wisconsin Public Service (WPS)	Yes	Yes	Yes

[1]DEVI and LGEE are no longer in the Midwest ISO market footprint as of June 2006 and September 2006, respectively. Since they were in the Midwest ISO before the end of the study period in March 2006, both were included in ICF's study. On the other hand, SMP (Southern Minnesota Municipal Power Agency) joined the market footprint in 4/2006, after the study period so was not included in ICF's analysis.

Historical energy demand for each Balancing Authority was provided by the Midwest ISO on an hourly basis for 2004, 2005, and relevant periods in 2006. Exhibit 3-14 details the Midwest ISO peak demand and net energy for load by Balancing Authority from 2004 to 2006 as derived from this data.

Exhibit 3-14:
Midwest ISO Peak Demand and Net Energy for Load

Balancing Authority	Peak Load (MW)			Average % of Midwest ISO's Total Peak Load	2004 Net Energy for Load (GWh)			Average % of Midwest ISO's Total Net Energy for Load
	2004	2005	2006		2004	2005	2006	
FE	12,357	13,697	12,190	11.80%	69,830	71,863	31,390	12.00%
HE	626	679	553	0.57%	2,841	3,361	1,450	0.57%
CIN	11,441	13,294	11,558	11.23%	64,842	68,808	29,578	11.30%
SIGE	1,761	1,835	1,664	1.63%	10,525	11,194	4,961	1.83%
LGEE	6,247	7,155	6,326	6.07%	34,388	37,223	15,869	6.07%
IPL	2,917	3,117	2,726	2.73%	15,417	15,984	6,867	2.63%
NIPS	3,269	3,630	3,358	3.17%	18,870	19,321	8,761	3.30%
ITC (MEC)	19,522	21,904	18,820	18.57%	104,325	108,469	46,554	17.93%
AMRN	11,949	12,920	10,656	10.93%	61,349	64,475	27,170	10.57%
IP	2,917	4,192	2,726	3.03%	15,417	20,964	6,867	2.90%
CILC	1,164	1,289	1,064	1.07%	5,754	6,087	2,458	0.97%
CWLP	441	468	379	0.40%	1,934	2,049	844	0.30%
SIPC	293	276	261	0.27%	1,428	1,424	614	0.20%
WEC	6,087	6,698	5,647	5.67%	34,879	35,669	15,211	5.93%
WPS	2,241	2,436	2,305	2.17%	13,939	14,373	6,276	2.40%
MGE	631	666	578	0.60%	3,357	3,396	1,466	0.60%
UPPC	154	215	149	0.13%	932	895	408	0.17%
LES	737	762	676	0.70%	3,279	3,464	1,468	0.60%
GRE	2,030	2,558	2,170	2.07%	6,962	13,141	5,667	1.87%
MPC	2,001	2,144	2,195	1.97%	11,802	11,974	5,587	2.07%
MP	1,868	1,848	1,717	1.70%	12,633	12,627	5,838	2.17%
ALTE	2,490	2,731	2,365	2.33%	13,454	13,925	6,092	2.30%
ALTW	3,464	3,745	3,332	3.27%	19,927	20,741	8,810	3.43%
NSP	8,808	8,797	8,395	8.03%	45,506	47,996	21,152	7.97%
Midwest ISO Total	**105,415**	**117,056**	**101,808**	**100%**	**573,591**	**609,423**	**261,357**	**100%**

Source: Midwest ISO

Operating Reserves

Spinning and Non-Spinning Reserve requirements in the Midwest ISO are determined separately for each Balancing Authority. The operating reserve criterion for each of these Balancing Authorities is based on their reliability council requirements. For example, the Balancing Authorities that fall under the MAIN reliability council use the MAIN operating reserve criteria to determine their requirements. Similarly Balancing Authorities that fall under ECAR and MRO reliability councils use their respective reliability council operating reserves requirements. Exhibit 3-15 shows the operating reserve criteria for the various balancing authorities under Midwest ISO market footprint during the study horizon[46]. Note that reserve requirements specified on a percentage basis such as those within the ECAR area were translated to a single annual MW requirement for modeling purposes.

Exhibit 3-15:
Operating Reserve Criteria for Midwest ISO Balancing Authorities

<table>
<tr><th>Balancing Authority</th><th>Spinning Reserve Requirement</th><th>Non-Spinning Reserve Requirement</th><th>Total Operating Reserve Requirement</th></tr>
<tr><td>ALTE</td><td>30.71</td><td>30.71</td><td>61.41</td></tr>
<tr><td>ALTW</td><td>56.29</td><td>56.29</td><td>112.58</td></tr>
<tr><td>AMRN</td><td>110.03</td><td>110.03</td><td>220.06</td></tr>
<tr><td>CILC</td><td>50</td><td>21.25</td><td>71.25</td></tr>
<tr><td>CE</td><td>266.22</td><td>266.22</td><td>532.43</td></tr>
<tr><td>CWLP</td><td>6.82</td><td>6.82</td><td>13.65</td></tr>
<tr><td>IP</td><td>54.14</td><td>54.14</td><td>108.28</td></tr>
<tr><td>MGE</td><td>9.4</td><td>9.4</td><td>18.8</td></tr>
<tr><td>SIPC</td><td>6</td><td>4</td><td>10</td></tr>
<tr><td>UPPC</td><td>1.5</td><td>1.5</td><td>2.99</td></tr>
<tr><td>WEC</td><td>87.43</td><td>87.43</td><td>174.87</td></tr>
<tr><td>WPS</td><td>31.89</td><td>31.89</td><td>63.78</td></tr>
<tr><td>GRE</td><td>41</td><td>62</td><td>103</td></tr>
<tr><td>MP</td><td>69</td><td>46</td><td>115</td></tr>
<tr><td>NSP</td><td>290</td><td>193</td><td>483</td></tr>
<tr><td>OTP</td><td>42</td><td>27</td><td>69</td></tr>
<tr><td>Total</td><td>1,191</td><td>999</td><td>2,160</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>CIN</td><td rowspan="8">2.5% * projected peak[47] load of the day</td><td rowspan="8">1.5% * projected peak load of the day</td><td rowspan="8">-</td></tr>
<tr><td>FE</td></tr>
<tr><td>HE</td></tr>
<tr><td>IPL</td></tr>
<tr><td>NIPS</td></tr>
<tr><td>LGEE</td></tr>
<tr><td>DECO</td></tr>
<tr><td>SIGE</td></tr>
</table>

Source: Midwest ISO

[46] Note that these reliability organization footprints have changed significantly in recent years with the addition of Reliability First and the dissolution of MAIN.
[47] Peak load as calculated by respective Balancing Authorities

Following discussions with the Steering Committee we have included an additional 2,000[48] MW of operating reserve requirement in order to effectively simulate typical Midwest ISO operations. The additional reserves were added to entire Midwest ISO footprint to account for the following three reserve categories:

- Regulation reserves which are not explicitly characterized in the MAPS modeling framework;
- A portion of supplemental or non-spinning reserves which, according to Midwest ISO operators, are typically held as spinning reserves in day-to-day operations; and
- and "headroom" that is typically held by Midwest ISO dispatchers to allow sufficient dispatch and ramp capability to respond to changes in instantaneous load within the current multiple Balancing Authority structure.

These additional spinning reserves were allocated to Balancing Authorities based on the ratio of the actual spinning reserve requirements. Exhibit 3-17 shows the total megawatt spinning reserve requirement modeled in our Day-1 Case.

Exhibit 3-16:
Spinning Reserves Requirements for Midwest ISO Balancing Authorities

Midwest ISO Balancing Authority	Spinning Reserve Requirement (MW)
ALTE	68
ALTW	124
AMRN	243
CE	256
CILC	110
CIN	166
CWLD	13
DECO	404
FE	409
GRE	177
HE	35
IP	119
IPL	95
LGEE	88
MGE	20
MDU	2
MP	152
NIPS	97
NSP	640
OTP	93
SIGE	46
SIPC	13
CWLP	15
UPPC	4

[48] 800 MW for regulation reserves which Midwest ISO regularly holds, 700 MW to reflect the need for flexibility to meet instantaneous load in Real-Time operation, 500 MW to reflect the need for non-spinning reserves.

Midwest ISO Balancing Authority	Spinning Reserve Requirement (MW)
WEC	192
Total	**3,652**

Source: Midwest ISO

Consistent with current Midwest ISO operations, we have assumed that the 700 MWs of the total 3,652 MW of spinning reserves which is associated with regulation is optimized by the Midwest ISO across the entire footprint in the No-ASM Case. In the Day-2 Optimal Case these reserves are optimized across the entire footprint. We note that there is some variability surrounding the exact estimate of ASM related benefits depending on treatment of reserves. While this study was not as detailed in its estimation of the benefits of the proposed ASM market as some other studies, the estimate is reasonable based on the assumptions and consistent with findings in other studies.

Canadian Imports and Exports

Canadian regions of the Eastern Interconnect are not endogenously characterized in the version of MAPS utilized in this analysis. Any Midwest ISO interchange with Canadian provinces were specified instead as an hourly load or resource consistent with actual study period interchange, thus capturing the appropriate hourly impact of interchange with these areas in all cases analyzed. Exhibit 3-17 highlights the monthly the two most relevant net interchanges for the Midwest ISO. On average, the Midwest ISO imports 1,541 MW per month from Manitoba Hydro and exports 839 MW per month to the Ontario Independent Market Operator (IMO).

Exhibit 3-17:
Imports from Manitoba Hydro and Ontario Independent Market Operator

Month-Year	Manitoba Hydro	Ontario Independent Market Operator
Jun-05	1,307	-935
Jul-05	1,207	-445
Aug-05	1,483	-415
Sep-05	1,852	-1,006
Oct-05	1,884	-811
Nov-05	1,777	-820
Dec-05	1,656	-1,016
Jan-06	1,618	-1,073
Feb-06	1,539	-1,112
Mar-06	1,089	-759
Average	**1,541**	**-839**

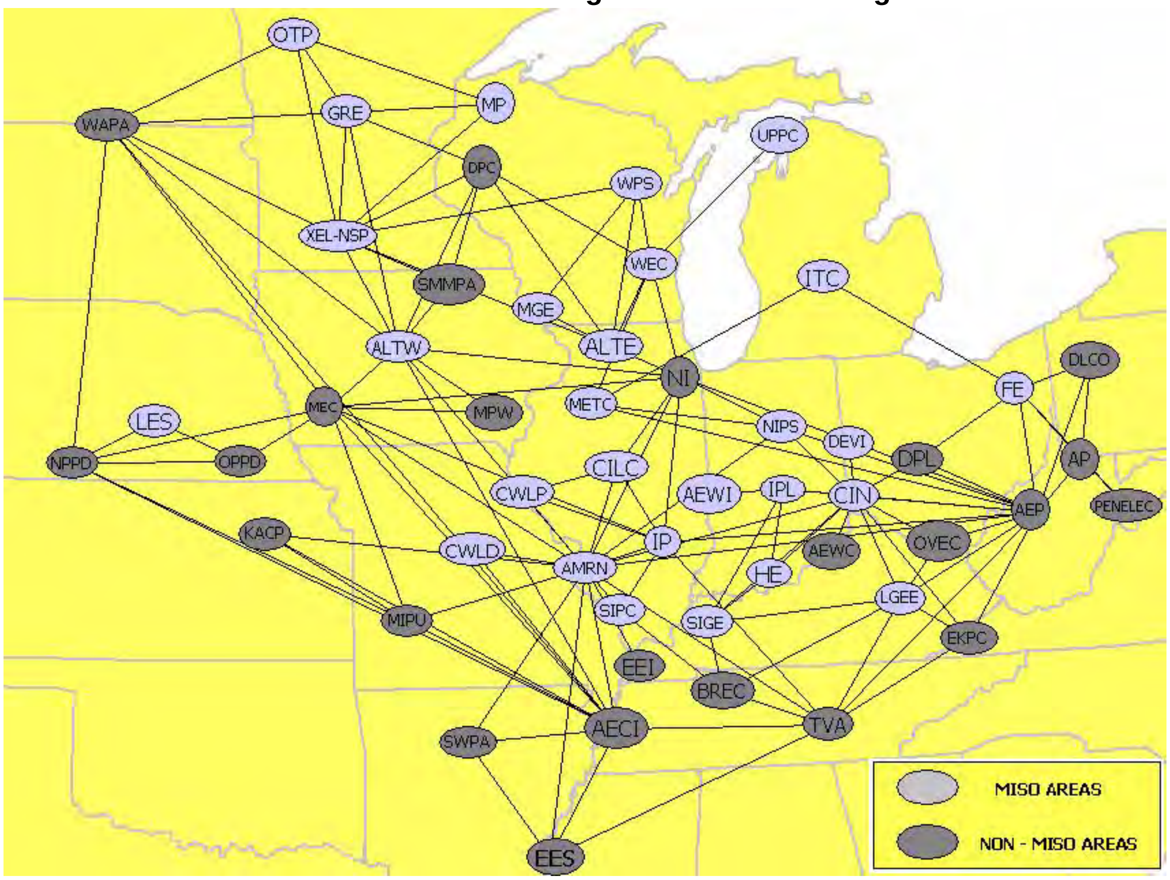
Note: Positive numbers indicate imports into and negative numbers indicate exports from the Midwest ISO.

Transmission Assumptions

Network Model

For this analysis, ICF used a summer 2004 MMWG network model provided by the Midwest ISO. A network model provides MAPS with a detailed transmission system representation of the grid. All transmission facilities rated 69 kV and higher were explicitly modeled with their normal, long-term, and short-term emergency limits based on data provided in Midwest ISO's network model. Exhibit 3-18 shows Balancing Authority interconnections for Midwest ISO and neighboring zones as specified in the Midwest ISO network model.

Exhibit 3-18:
Midwest ISO Balancing Authorities and Neighbors



Transmission Facility- Additions and Upgrades

This network model was modified to account for new line additions and upgrades for year 2005. The table below shows the transmission facilities that were added or upgraded in 2005. There were no major upgrades during the three months studied in 2006.

Exhibit 3-19:
Major Transmission Facility Additions and Upgrades

Project Description	Region	Ckt	Voltage (kV)	Action
Spurlock-Kenton	LGEE	2	138	Removed
North Appleton – Werner West-Rocky Run	ATC LLC		345	Up-rate
Lakefield to Fox Lake	XEL	1	161	Upgrade
Chanarambie - Lake Yankton - Lyon Co.	XEL	2	230	New 2nd transformer
Nobles to Chanarambie new 115 kV	Ameren	3	138	New Transmission Line
Maple River 230/115 kV Transformer	XEL	2	230/115	New 2nd Transformer
Beckjord to Silver Grove	Cinergy	1	138	New Transmission Line
Warren to Toddhunter	Cinergy	1	138	New Transmission Line
Madison West to Scottsburg	Cinergy	1	138	New Transmission Line
New Transformer at Scottsburg	Cinergy	1	138/69	New Transformer
Herbert Lake Transformer	MH	1	230/115	New 2nd Transformer
St. Francois – Rivermines	Ameren	3	138 Kv	New Transmission Line

Source: Midwest ISO

Flowgates

ICF has explicitly modeled all designated NERC and Midwest ISO flowgates[49] in this analysis. Flowgates are usually the sensitive and often stressed locations in the grid and the most frequent requiring generation redispatch to keep flows within limits. Transmission flowgates are frequently monitored for potential line overloads should there be contingency and/or emergency conditions such as outage of line(s) or generation plant(s) or both. There are approximately 1,000 NERC flowgates, 100 Midwest ISO flowgates and 10 rule-based limits (nomograms) that were modeled with explicit monthly limits for this analysis.

Although flowgate limits vary on an hourly basis, it is not practical to include hourly flowgate limits in the simulation model. ICF and Midwest ISO decided to model monthly limits. For Day-1 modeling, every flowgate limit was reduced by a certain percentage (Exhibit 3-20) based on actual flowgate utilization during level-3 and higher TLR events. This assumption is based on analysis performed by the Midwest ISO and documented in a memorandum distributed to the study stakeholder group.

[49] NERC defines certain transmission lines or paths through which power flow from power transactions are calculated during system operation. These are typically lines or paths that could get congested and impact power transactions. These points are called flowgates.

Exhibit 3-20:
Model Treatment of Flowgate Limits in Day-1 and Day-2

Region	Simulated Day-1 Case	Simulated Day-2 and No-ASM Cases
Midwest ISO - MAPP	84%	100%
Midwest ISO -ATC	89%	100%
Rest of Midwest ISO	91%	100%
SPP	91%	100%
Rest of the Eastern Interconnect	100%	100%

CHAPTER FOUR:
DETAILED STUDY RESULTS AND CONCLUSIONS

This chapter discusses: (1) calibration cases results, (2) study findings, (3) potentially conservative features of the analysis which may have resulted in underestimates of the achieved benefits and/or overestimates of achievable benefits, (4) comparison of the study findings with other studies, and (5) conclusions.

Calibration Case Results

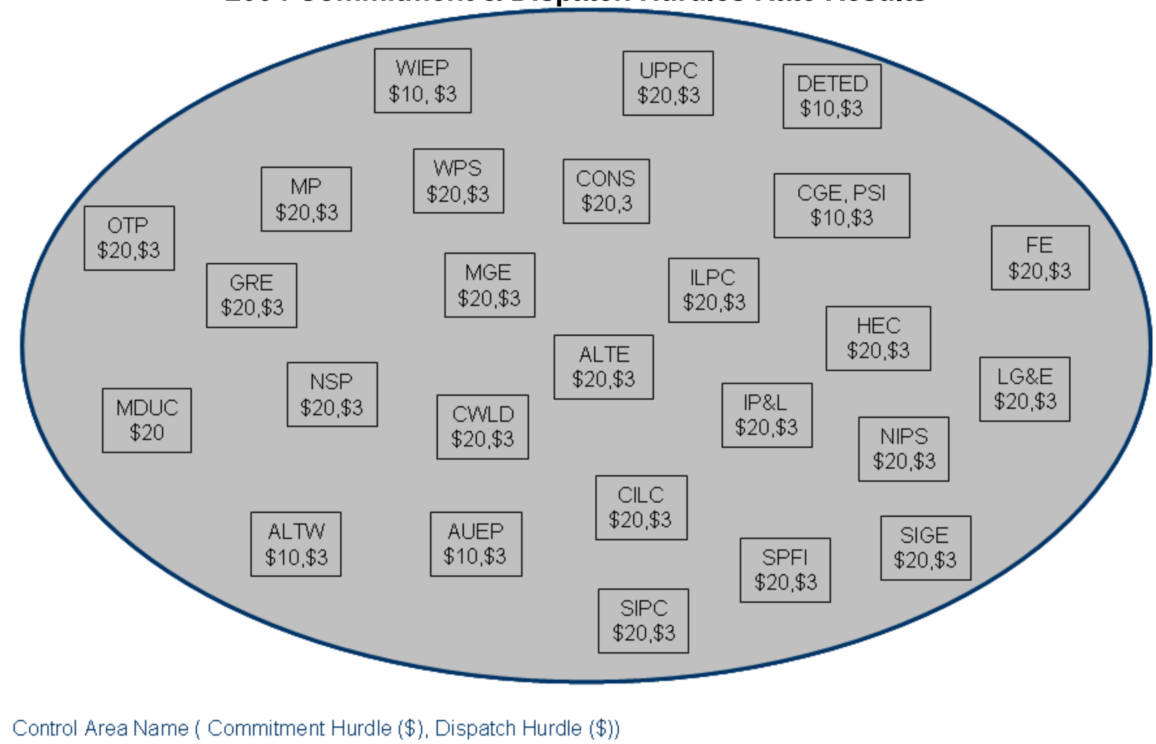
Calibrated Hurdle Rates

The determination of the appropriate level of hurdle rates is achieved through a detailed modeling exercise in which hurdle rates are introduced in the model to calibrate the simulated model outcome to historical market outcomes. The commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provides information to guide fine tuning of the commitment or dispatch hurdles, or both. Specifically, for each unit within the Midwest ISO, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead[50]. Thus the total number of hours the unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation, especially for units that showed large deviations, to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2004 did not dispatch as much in the 2004 calibration model and also did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdles affecting that unit were adjusted. In contrast, if the unit was committed as expected, but did not dispatch as much as it actually did historically, then the appropriate dispatch hurdles were adjusted.

The primary result of the calibration process is a set of dispatch and commitment hurdle rates for each Balancing Authority in the Midwest ISO footprint. These results are shown in Exhibit 4-1 below. Through an iterative process we determined that a relatively low uniform $3/MWh dispatch hurdle combined with commitment hurdles varying between $10/MWh and $20/MWh provided the best calibration results. A $20 commitment and $5 dispatch hurdle was utilized into and out of the Midwest ISO as well as between all non Midwest ISO zones. This was sufficient to calibrate Midwest ISO net interchange during the study period.

[50] The forward looking view ensures that each unit's operating characteristics such minimum uptime and downtimes are not violated.

Exhibit 4-1:
2004 Commitment & Dispatch Hurdles Rate Results



Source: ICF Calibration Case

As discussed in Chapter Two above, these hurdle rates were translated from the 2004 Calibration Case to the Day-1 June 2005 to March 2006 case. This allowed us to simulate an expected commitment and dispatch result assuming that the Midwest ISO operated as a Day-1 market during the study period of June 2005 through March 2006. Hurdle rates were then removed from the model in our Day-2 Optimal and No-ASM cases to reflect fully efficient centralized commitment and dispatch. These hurdles are intended to simulate barriers to trade between Balancing Authorities. The change in production costs between the Day-1, Day-2 Optimal, and No-ASM Cases then yield the primary study results, i.e. the level of savings available due to restructuring of the Midwest ISO marketplace.

Note that generator input costs (i.e. the price of natural gas, coal, oil products, and emission allowances) varied significantly between the calibration and study periods as well as within the study period. Therefore, commitment hurdle rates in the Day-1 and No-ASM Cases were indexed to average natural gas prices on a monthly basis.

Calibration Statistics

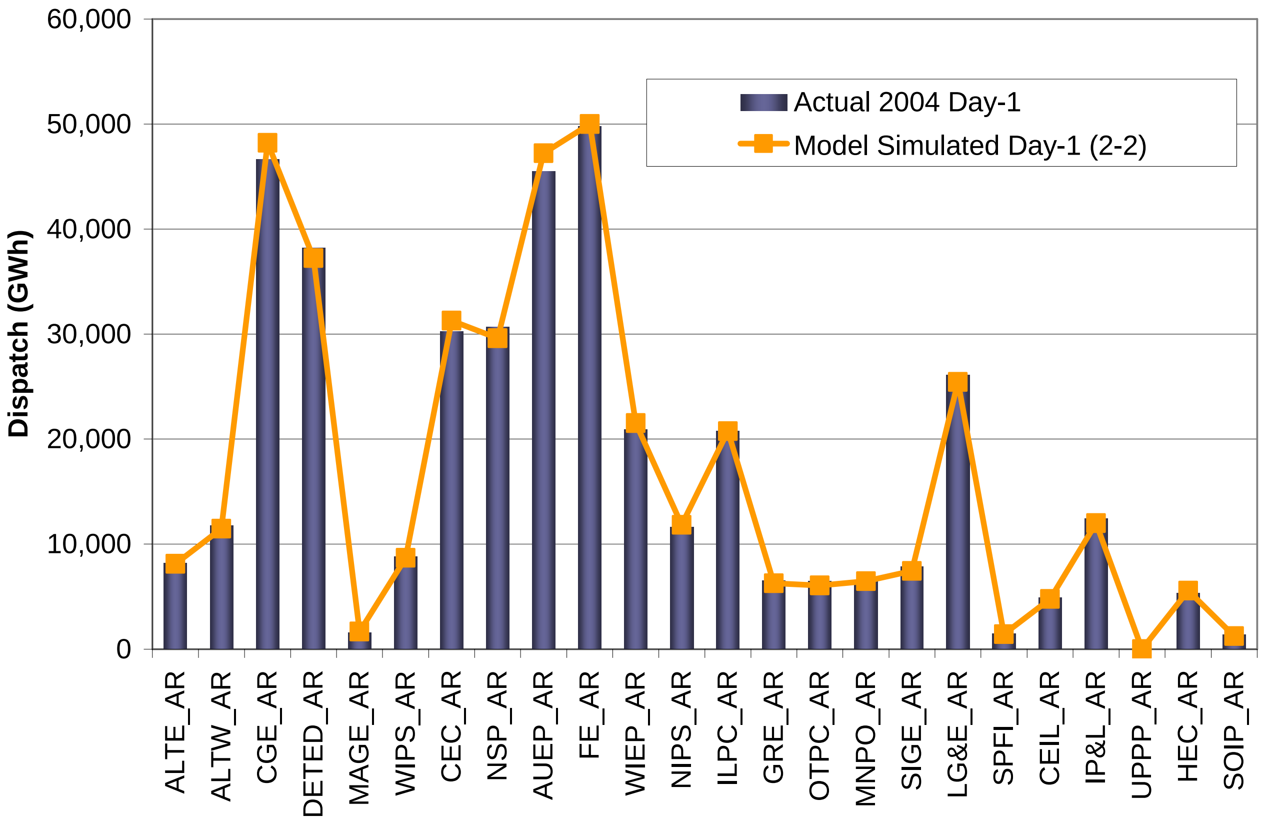
ICF performed a series of calibration cases while performing this study. Results of each case were compared against historical data and a final calibration case which represented a “best-fit” to historical market operation was chosen. ICF calibrated to four primary parameters during this exercise, namely Midwest ISO net interchange, generation by Balancing Authority, generation by unit type, and generation by unit. Exhibits 4-2 through 4-7 below demonstrate the excellent fit achieved during this exercise.

Exhibit 4-2:
Summary Calibration Statistics

Calibration Parameter	Correlation	R-Squared
Dispatch by Area	0.999	0.999
Dispatch by Unit Type	1.000	0.999
Dispatch by Unit	0.995	0.990

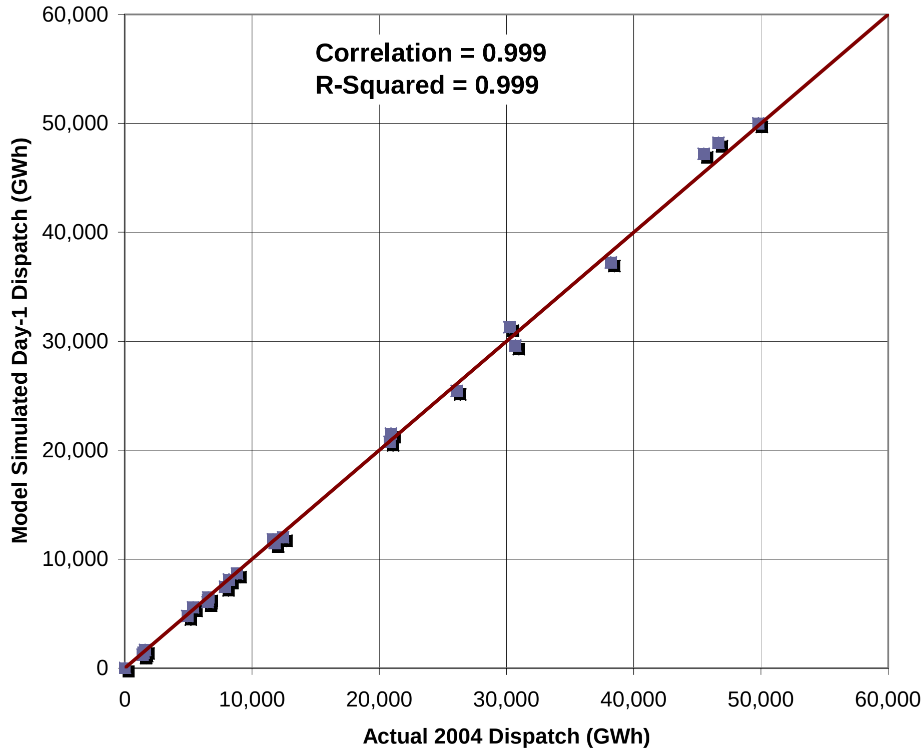
Source: ICF

Exhibit 4-3:
Total Dispatch by Balancing Authority – 2004 Actual vs. ICF Calibration



Source: ICF

Exhibit 4-4:
Total Dispatch by Balancing Authority– 2004 Actual vs. ICF Calibration



Source: ICF

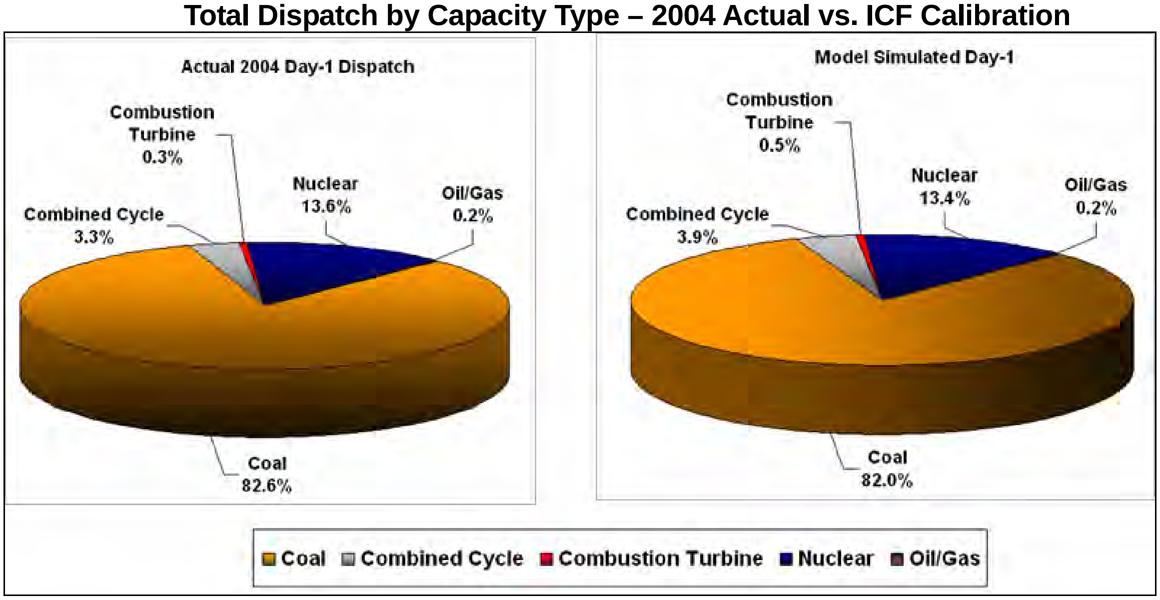
Exhibit 4-5:
Total Dispatch by Balancing Authority – 2004 Actual vs. ICF Calibration

Balancing Authority	Abbreviation	2004 Actual Dispatch	Calibration Results
Alliant East	ALTE	8,187	8,124
Alliant West	ALTW	11,780	11,467
Cinergy	CGE	46,657	48,215
Detroit Edison	DETED	38,207	37,231
Madison Gas & Electric	MAGE	1,596	1,665
Wisconsin Public Service	WIPS	8,830	8,688
Consumer's Energy	CEC	30,232	31,282
Northern States Power	NSP	30,699	29,609
Ameren	AUEP	45,500	47,208
First Energy	FE	49,792	50,005
Wisconsin Electric	WIEP	20,921	21,521
Northern Indiana Public Service	NIPS	11,646	11,826
Illinois Power	ILPC	20,807	20,757

Balancing Authority	Abbreviation	2004 Actual Dispatch	Calibration Results
Great River Energy	GRE	6,535	6,273
Otter Tail Power	OTPC	6,513	6,068
Minnesota Power	MNPO	6,566	6,481
Sothern Indiana Gas & Electric	SIGE	7,874	7,456
Louisville Gas & Electric	LG&E	26,095	25,440
Springfield Water & Power	SPFI	1,464	1,416
Central Illinois Lighting Co.	CEIL	4,905	4,779
Indianapolis Power & Light	IP&L	12,437	12,003
Upper Peninsula Power	UPPP	0	0
Hoosier Energy	HEC	5,364	5,567
Southern Illinois Power Corp	SOIP	1,405	1,237
Grand Total		**404,009**	**404,319**

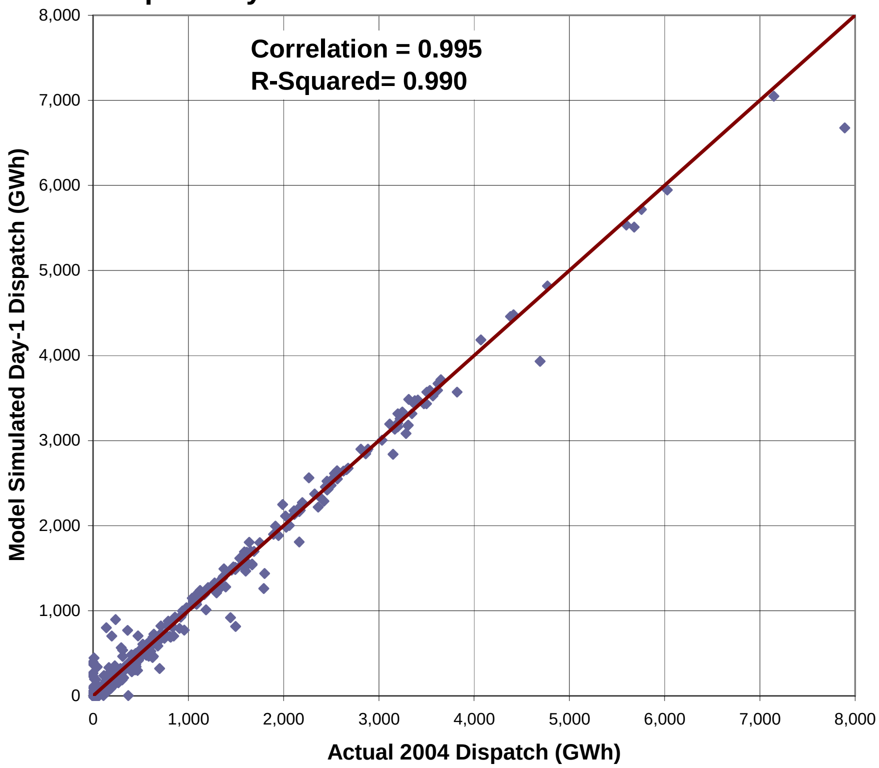
Source: ICF

Exhibit 4-6:
Total Dispatch by Capacity Type – 2004 Actual vs. ICF Calibration



Source: ICF

Exhibit 4-7:
Total Dispatch by Generator – 2004 Actual vs. ICF Calibration

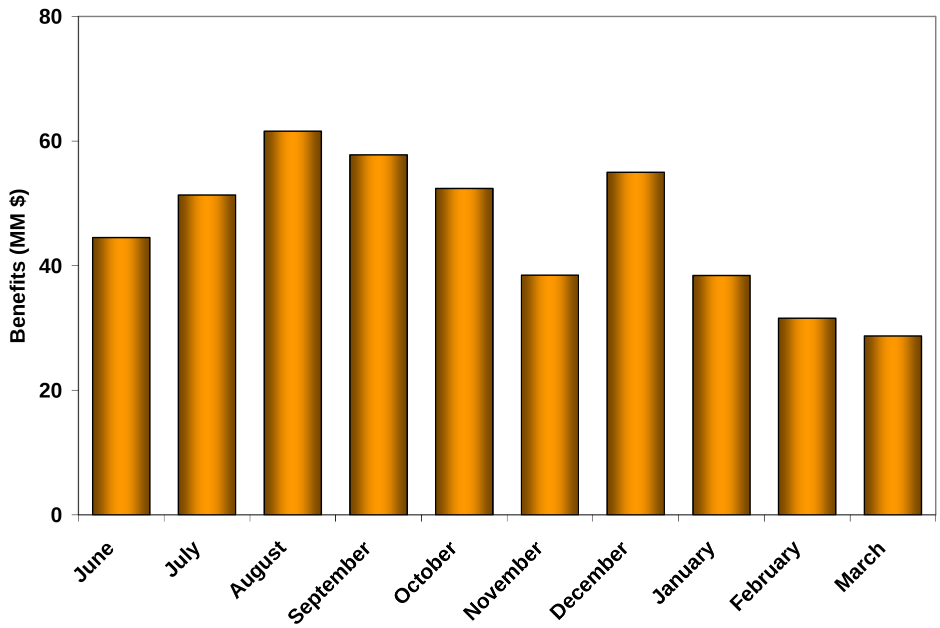


Source: ICF

Study Findings

Results of the ICF study indicate that the Day-2 market within the Midwest ISO footprint offers the potential for significant savings. Specifically, production cost savings of $460 million were estimated as the maximum benefits available to the Midwest ISO in an optimally operated Day-2 market including fully optimized reserves. This is $46 million per month on average. If this monthly level of benefits is assumed to be achieved for a 12 month period annual benefits would be $552 million. Exhibit 4-8 presents the maximum monthly benefits available in the Day-2 Optimal Case for the June 2005 to March 2006 period.

Exhibit 4-8:
Summary of Maximum Potential Benefits - June 2005 through March 2006



Source: ICF

Exhibit 4-9 compares the maximum potential, maximum achievable, and actual achieved benefits for the Midwest ISO during the ten month study period. The benefits are also shown on an annual basis assuming that average benefits extended at the same average level for an additional two months.

Exhibit 4-9:
Summary of Midwest ISO Benefits – June 2005 through March 2006

Category	Benefits ($million)	Annualized Benefits ($million)
Theoretical Maximum Potential Benefits	460	552
Estimated Achievable Benefits Given Current Market Structure	271	325
Actual Benefits Achieved	58	70

Source: ICF

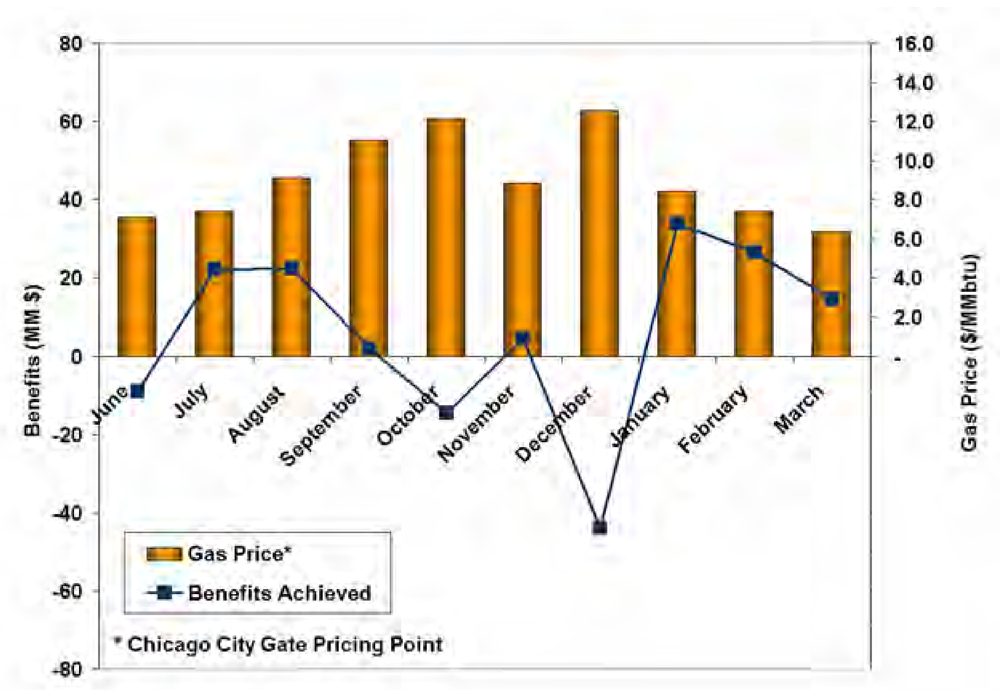
Our analysis yields the following three primary results:

- Up to $460 million in benefits were potentially achievable through optimal operation of the Midwest ISO grid during the study period. This represents a 3.8 percent decrease in overall Midwest ISO production costs compared to the parallel Day-1 estimate. This level of potential benefits is comparable to other studies of the potential benefits of centralized dispatch.[51]

- Of the $460 million in maximum potential benefits we estimate that approximately $271 million was actually achievable during the study horizon given the existing treatment of ancillary services. This represents 59 percent of the total potential and indicates that optimization of ancillary services is an important component of potential RTO savings. This $271 million translates to $325 million on an annualized basis.
- Of the $271 million achievable benefits, $58 million was realized through Midwest ISO operation of the grid. This translates to 21 percent of achievable benefits. This $58 million is equivalent to $70 million on an annualized basis.

In order to analyze trends in the study results, we have further disaggregated results on a monthly basis. Exhibit 4-10 presents the actual benefits achieved on a monthly basis for the study period along with monthly average natural gas prices.

Exhibit 4-10:
Monthly Benefits Achieved and Historical Natural Gas Prices



Source: ICF

Exhibit 4-11 presents our monthly results of both maximum potential and actual achieved benefits in tabular form. Natural gas prices and the percentage of benefits achieved on a monthly basis are presented for reference as well. Note that emission allowance[52] and

[51] See Chapter 4 for a summary of previous study findings.
[52] See Exhibit 3-11 for additional detail.

delivered coal prices[53] also increased significantly during this period. For example, SO_2 allowance prices increased from $248 per ton in January 2004 to more than $1,587 per ton in December 2005.

Exhibit 4-11:
Monthly Potential and Achieved Benefits

Period		Theoretical Maximum Potential Benefits (MM$)	Actual Benefits Achieved (MM$)	Percentage Achieved
2005	June	44	(9)	(20%)
	July	51	22	43%
	August	62	22	37%
	September	58	2	3%
	October	52	(15)	(28%)
	November	38	4	11%
	December	55	(44)	(80%)
2006	January	38	34	88%
	February	32	27	84%
	March	29	14	50%
Total		**460**	**58**	**12%**

This monthly analysis yields the following two secondary results:

- While benefits were lower during initial start up, significant improvement was demonstrated towards the end of the period. Benefits in the 2006 period were close to the maximum achievable absent optimization of ancillary services.
- The unprecedented period of high natural gas, coal, and emission allowance prices between September and December 2005 correlate with periods of lower achieved benefits, and in some cases increased costs, for Midwest ISO Day-2 compared to what was forecast for Day-1. Even as operations appear to have been improving (as seen in other data), the costs of sub-optimal commitment and dispatch were increasing due to rising generation input costs. In this environment, the cost impacts of even small incremental deviations from Day-1 optimization between gas and coal generation are economically magnified.

Potentially Conservative Factors Vis-à-vis the Benefits Achieved and Achievable

Because this analysis compares the results of three MAPS model analyses with a detailed review of actual market operations during the study period, significant efforts were made to incorporate as many "real-world" phenomena as possible directly into the model. A number of these issues are discussed in Appendix A. While we believe that the majority of these issues are captured in our modeling, several variables could not be fully modeled within the MAPS framework or within the context of this study. Thus, there may be some features of the modeling that may have resulted in a conservatively low estimate of actual benefits achieved and/or a high estimate of achievable benefits. Some of these issues are discussed below, and the full set of issues considered in this regard is provided in Appendix A.

[53] See Exhibit 3-10 for additional detail.

- **Choice of Calibration Year** – As discussed in Chapter 2, ICF, in consultation with the Study Steering Committee, chose 2004 as the calibration year due to data availability. During the review process, several stakeholders noted that 2004 was not an "average" year within the Midwest ISO footprint. Actual demand in the summer of 2004 was lower than expected and correspondingly we see that natural gas dispatch may have been lower than a "normal" year. The choice of a cooler than average year could potentially bias our calibrated hurdle rates downward, yielding a conservative estimate of potential benefits when these hurdle rates are translated to a hotter 2005 time period.

- **Day-Ahead vs. Real-Time Commitment** - While the MAPS model simulates a Day-Ahead market designed to minimize total production costs, a portion of the units required to reliably serve Real-Time demand and congestion management needs are committed after Day-Ahead market in the RAC process. The RAC process objective function is different than the Day-Ahead objective function in that the RAC commits resources in merit-order considering only start-up and no load costs. As a result the commitment obtained in MAPS may be more efficient (more optimal) that can be achieved in actual operations. In other words, when the MAPS model is dispatching peaking facilities to meet real-time load it optimizes overall production cost, assuming the ability to commit Day Ahead with perfect certainty, while the RAC process considers only start-up and no load costs and must be conducted in Real-Time when load is known with certainty. The consequence is that in actual operations units with lower start-up costs, but higher production cost may be committed. MAPS is not designed to simulate this particular market structure. We believe that all else being equal this difference may lead to an aggressive estimate of the potential achievable benefits. That is, some portion of the estimated $271 million in achievable benefits may not have been achievable given this difference between model and actual operations. This variable would not affect the estimate of achieved benefits. It may be valuable to further evaluate whether it would be beneficial to modify the Midwest ISO TEMT and systems to base the RAC process on minimization of total production costs, including start up and operating costs.

- **Bid Inflexibility** – The MAPS model assumes that all generators will, on average, submit bids with ramp rates and costs consistent with actual operating costs and physical facility operating limitations. This is not always the case during actual operations. Inflexible bids offered by market participants tend to limit the flexibility of dispatchers to respond to changing demand efficiently. Our assumption of fully flexible bids would tend to increase the estimate of achievable benefits. This issue is less important for the estimate of maximum potential benefits. In addition, to the extent inflexibility may have reduced actual benefits during initial market start-up, increasing flexibility is expected as participants gain operating experience and realize economic benefits of increasing the flexibility made available for dispatch.

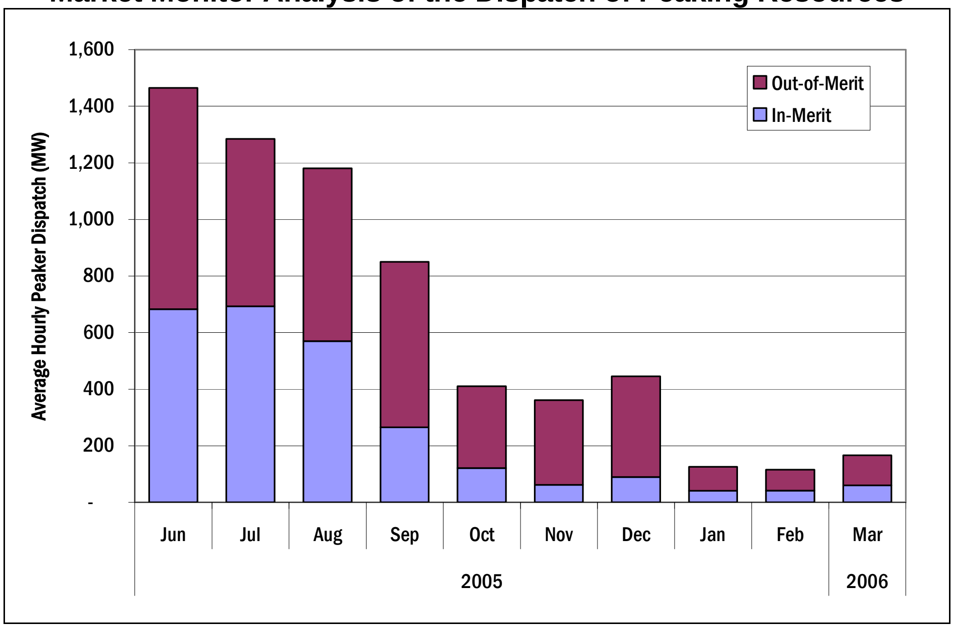
- **Offered Capacity –** There is some evidence that initial stakeholder capacity assumptions[54] overstated the actual capacity offered by market participants in some months. Any overstatement of capacity would tend to decrease our model estimates of production costs and lead to a conservative estimate of actual benefits achieved. Based on evaluation of actual offer behavior during the study period, model assumption were refined, but it is not practical to include hourly or daily changes in offered capacity levels as occurs in Real-Time operations,

[54] See Chapter 3 for a discussion of how capacity assumptions were developed.

Comparison to Results in Similar Analyses

ICF's findings in this study are consistent with several previous analyses. Exhibit ES-6 is an excerpt from the Market Monitor report highlighting economic and non-economic peaking unit dispatch in the Midwest ISO. Summer 2005 shows large amounts of out-of-merit peaking dispatch. While there is less in October and December, it is still above 2006 levels. The lower 2006 levels support our findings of an improving trend. The combination of out-of-merit dispatch and extremely high fuel prices yields is consistent with the study results indicating negative benefits achieved during the months of October and December 2005. Note, that the definition of out-of-merit dispatch does not precisely correspond to the definition of "economic dispatch" in the ICF study associated with market rules, and hence, care needs to be exercised in comparing the two analyses.

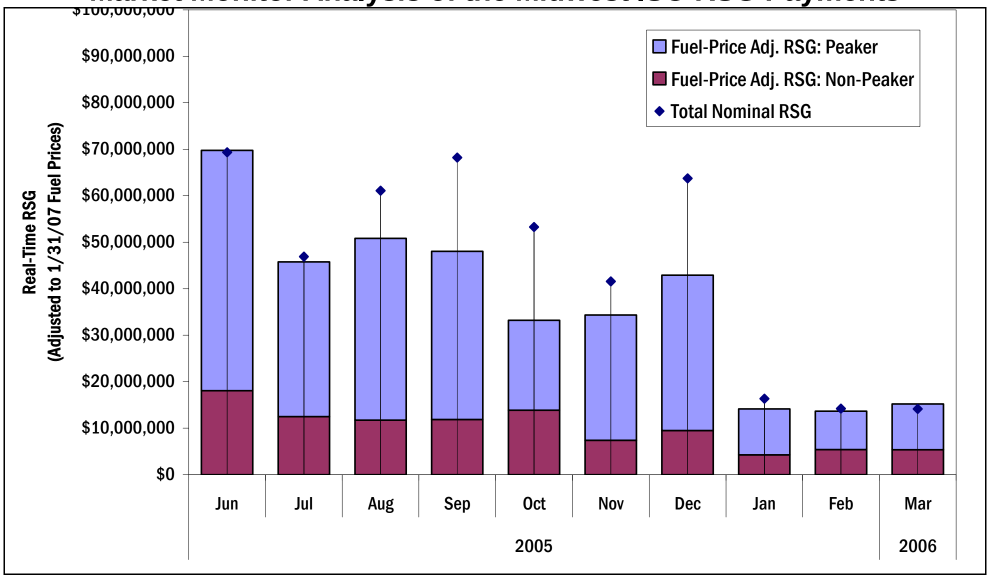
Exhibit 4-12:
Market Monitor Analysis of the Dispatch of Peaking Resources



Source: Midwest ISO Market Monitor Report Feb. 14, 2007

Our study results are also similar to a Midwest ISO review of Revenue Sufficiency Guarantee (RSG) trends shown in Exhibit 4-13 below. Here we see RSG payments by month are high in 2005 compared to 2006. Since these are payments for units not otherwise recovering their costs, the trend also supports our conclusion of improving performance.

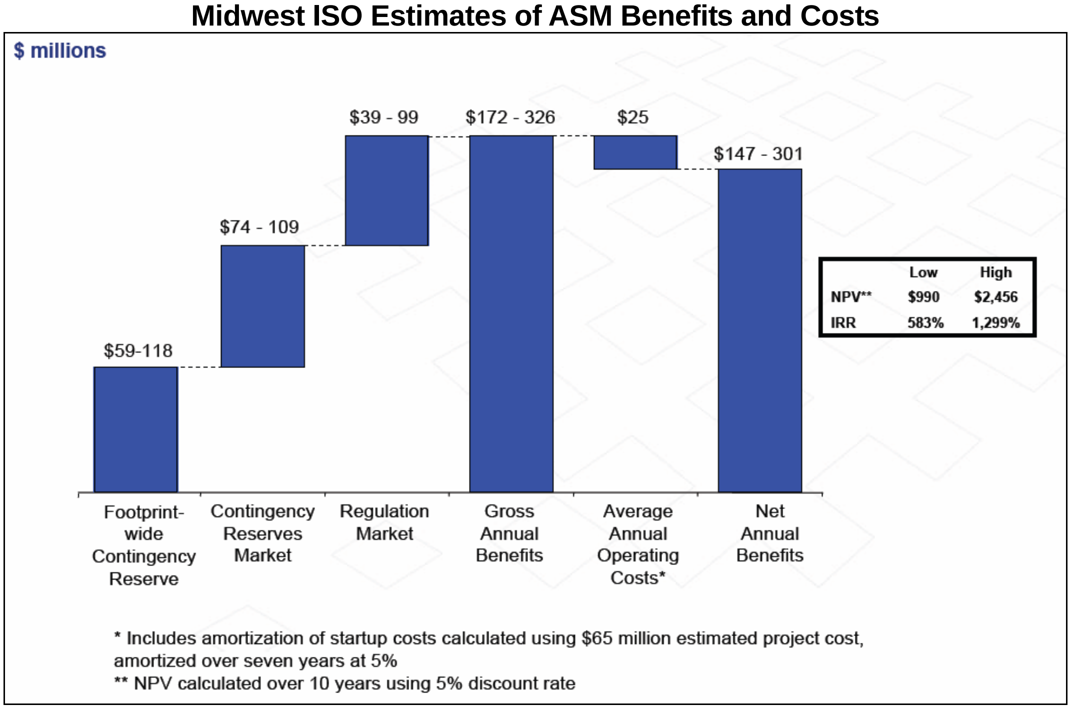
Exhibit 4-13:
Market Monitor Analysis of the Midwest ISO RSG Payments



Source: Midwest ISO Market Monitor report Feb. 14, 2007

While the ICF study of the proposed Midwest ISO ASM market is not as detailed regarding reserves as that contained in a recent Midwest ISO filing, the theoretical value generated by ICF is within the range of the Midwest ISO value estimates generated and shown in the April 3, 2006 Filing to FERC where the comparable potential benefits are shown as $113 to $208 million (see "contingency reserves" and "regulation market" bars in Exhibit 4-14 below).

Exhibit 4-14:
Midwest ISO Estimates of ASM Benefits and Costs



Source: Midwest Contingency Reserve Sharing and Midwest ISO Ancillary Services Market – Project Update, October 10, 2006

Exhibit 4-15 shows some of the cost benefit studies associated with transitions from either Day-0 or Day-1 to greater coordination. This study estimated that the maximum potential cost savings to be 3.8 percent and hence is not dissimilar to findings in other studies.

Exhibit 4-15:
Summary of Previous Cost-Benefit Studies

Study Subject	Base Market Structure - Change Market Structure	Study / Forecast Period	Estimated Market Size - Energy Demand (TWh)[12]	Estimated Production Cost Savings Compared to Base Case
Midwest ISO [1]	Day-1 to Day-2 (No ASM)	Jul-05 to Mar-06	345	2.2%
	Day-1 to Day-2 ASM	Jul-05 to Mar-06		3.8%
Midwest ISO [2]	Day-2 to ASM	2006-2013[11]	345	1.1% to 2.2%[13]
Midwest ISO [3]	Day-1 to Day-2	N/A	345	5.8% to 14.0%[14]
Midwest ISO Short Term Study[4]	Day-1 to Day-2	7/7/2005	345	1.3%
		Peak Hour 7-Jul-05		2.6%
Midwest ISO [5]	Day-1 to Day-2	Peak Hour 7-Jul-03	345	22.7%
ERCOT[6]	Day-1 to Day-2	2005-2014	289	Approx. 1%
SEARUC[7]	Day-0 to Day-2	2004-2013	4,011	1.2% (SeTrans)
				1.8% (GridSouth)
				0.8% (GridFlorida)
				1.3% (Total SEARUC)
FERC RTO Benefit Study[8]	Day-0 to Day-2	2002-2021	4,011	0.6% (transmission only case)
				3.9% (RTO Case)
GridFlorida Cost Benefit Analysis[9]	Day-0 to Day-1	2004-2016	226	0.1% (Day-1)
	Day-0 to Day-2	2004-2016		1.4% (Delayed Day-2)
SPP[10]	Day-1 to Day-1 EIS	2006-2015	218	2.5%

[1] ICF International, *Independent Assessment of Midwest ISO Benefits*, February 28, 2007.
[2] Midwest ISO, *Midwest Contingency Reserve Sharing And Midwest ISO Ancillary Service Markets*, October 10, 2006.
[3] Midwest ISO, *Value Review: Analysis of Pre-MISO and Post-MISO Market*, October 19, 2005.
[4] ICF International, *Analysis of the Benefits of the Midwest ISO's Day-2 Market*, October 31, 2005.
[5] Ernest Orlando Lawrence Berkeley National Laboratory, *The Potential Impacts of a Competitive Wholesale Market in the Midwest: A Preliminary Examination of Centralized Dispatch*, October 2004.
[6] Tabors, Caramanis & Associates, *Market Restructuring Cost-Benefit Analysis for the Electric Reliability Council of Texas*, November 30, 2004.
[7] Charles River Associates, *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*, November 6, 2002
[8] ICF International, *Economic Assessment of RTO Policy*, February 26, 2002.
[9] ICF International, *Cost-Benefit Study of the Proposed GridFlorida RTO*, December 12, 2005.
[10] Charles River Associates, *Cost-Benefit Analysis Performed for the SPP Regional State Committee*, April, 23, 2005.
[11] Historical 2004 data presented for illustrative purposes only.
[12] Estimated date range. Data includes amortization of startup costs over seven years estimated to begin in 2006.
[13] Note, this study did not explicitly report total production costs. Benefits were estimated at $172 to $326 million per year and were compared to ICF's estimate of Midwest ISO production costs, yielding 1.1% to 2.2% in production cost savings.
[14] Note, this study did not explicitly report total production costs. Benefits were estimated at $708 million to $1.8 billion per year and were compared to ICF's estimate of Midwest ISO production costs, yielding 5.8% to 14.0% in production cost savings.

Conclusions

The overall outcome of this analysis demonstrates that potential RTO benefits are large and are measured in hundreds of millions of dollars per year. While on a percentage basis the potential improvement appears modest, the magnitude of the production costs involved is so large that on a dollar basis, the efficiency improvements are substantial.

RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation, and better use of import potential. These benefits will likely grow over time as:

- Reliance on natural gas generation within the Midwest ISO footprint grows as a result of the ongoing load growth and a general lack of non gas-fired development over the last 20 years. This may increase the scope for potential savings from centralized dispatch in future years.
- Tightening environmental controls and the resulting greater diversity in coal plant fleet variable operating costs will make optimization of coal plant utilization more important in future years
- Tightening supply margins throughout the Eastern Interconnect over the next three to five years increase the importance of optimizing interchange with neighbors such as PJM, SPP, and others.
- Transmission upgrades which could increase the geographic scope of optimization within the Midwest ISO footprint.

The lack of an Ancillary Services Market (ASM) for footprint wide reserve optimization limited the achievable results by as much as 40 percent during the study horizon. We note that there is some variability surrounding the exact estimate of ASM related benefits depending on treatment of reserves. For example, an alternative treatment of reserves might involve variation of reserves levels with demand on an hourly or monthly basis. While this study was not as detailed in its estimation of the benefits of the proposed ASM market as some other studies the estimate included in this study shows they represent a significant portion of total potential benefits.

A confluence of factors led to less than 100 percent of the achievable benefits realized during the study horizon. These include:

- The learning curve faced by both Midwest ISO and market participants during market inception resulted in suboptimal commitment and dispatch which limited achieved benefits; and
- Suboptimal commitment and dispatch during periods of extremely high gas prices had significantly adverse impact on achieved versus potentially available benefits. This is because even small deviations from optimal dispatch can have large effects during extreme market conditions.

October and December 2005 were especially challenging periods for Midwest ISO operations due to record high fuel prices. For example, natural gas prices peaked at an average of

$12.60/MMBtu in December 2005[55]. We note that had actual benefits achieved in December and October been at the average level for all other months in the study period total achieved benefits would have exceeded $146 million[56] or up to 54 percent of the total achievable benefits.

The percentage of benefits achieved showed an increasing trend over the study horizon, indicating increasingly efficient operations. This is especially evident in 2006 when fuel prices began to moderate.

We further note that major developments led by the Midwest ISO marketplace will likely increase both the potential and achieved benefits on a going forward basis. These developments include the introduction of the Ancillary Services Market which is currently under review by FERC and expected to begin operation in 2008 and regional transmission investment initiatives such as MTEP 06 which will bring $3.6 billion in transmission investments to market by 2011 and targets elimination of 22 of the top 30 constraints in the footprint.

[55] Source: Gas Daily; Chicago City Gate price

[56] This illustrative back-of-the-envelope calculation assumes that losses of $14 and $43 million in October and December are replaced with savings of $14.5 million, the average achieved in the remaining months of the study.

Appendix A:
Issues Identified and Resolved by the Study Steering Committee

As discussed above, the study Steering Committee met regularly and was responsible for ensuring that this analysis included an accurate depiction of actual Midwest ISO operations. The table below highlights many of the issues identified by the Steering Committee and the associated resolutions.

Issue	Description	Resolution
1. Choice of calibration year	Because 2004 realized historically low dispatch of CT units throughout the Midwest ISO, the choice of 2004 as a calibration year may have biased hurdle rates downward and therefore limited potential benefits.	This is treated as a potentially conservative element of this analysis.
2. DA vs. RT Commitment	The Day-Ahead Market load typically clears below Real-Time load, requiring additional generation commitments in the Reliability Assessment Commitment (RAC). In an effort to avoid over committing generation in Real-Time, operators defer potential commitments identified in the Forward (Day-Ahead) RAC until closer to Real-Time. Units committed in Real-Time, when demand is more certain, tend to be faster starting units, typically CTs.	This variable was incorporated in the model as "load uncertainty" during the commitment stage of the modeling process.
3. "Head room" to account for shifts in instantaneous load	Real-Time operations under the currently divided Balancing Authority responsibilities required reserves held to respond to rapid demand changes in excess of those reserves held by Balancing Authorities to respond to generation and transmission contingencies. However, like many market models, MAPS models demand in a manner that is analogous to Day-Ahead (known and gradually changing load) rather than Real-Time (uncertain and responded to with 5-minute dispatch), and therefore does not reflect the increased need for regulation.	This variable was incorporated in the model as incremental reserves.
4. DA vs RT commitment algorithm	MAPS models a Day-Ahead market designed to minimize production costs. The Midwest ISO RAC objective function is to minimize start-up and no-load costs without consideration of incremental energy costs.	This is largely considered a potentially conservative element in the analysis, partially reflected in model treatment of load forecast error.

Issue	Description	Resolution
5. Co-optimized reserves	The Day-2-Optimal Case assumes co-optimized energy and reserves. The Midwest ISO market does not currently co-optimize these products. The ICF model reflects a scenario that includes implementation of ASM.	This is treated as a potentially conservative element of this analysis.
6. Centralized vs. decentralized reserves in Day-2	The Day-2-Optimal Case assumes the Midwest ISO manages reserves centrally in Day-2. Currently, reserves are held and managed by the Balancing Authorities.	The study involved a sensitivity case on this variable.
7. Hourly vs bi-hourly runs	Bi-hourly MAPS runs may reduce demand for peaking capacity.	It was confirmed that this is not a significant issue through testing and conversations with GE.
8. Transmission outages	No explicit modeling of transmission outages in the MAPS framework.	Review of actual transmission outages indicated that this is a minor issue with a relatively small effect on model results.
9. Interchange with exogenous regions	Actual Midwest ISO interchange with Manitoba and Ontario in the model, could be a potential issue because supply and demand for these regions are not explicitly included in the MAPS framework.	This was incorporated directly in the model. The approach is to model actual hourly net interchange between Midwest ISO and the exogenous Canadian regions in both the Day-1 and Day-2 Optimal Cases.
10. Losses in the Interchange Index	Appropriate treatment of losses in the calculation of Day-2 Actual costs could be important.	Losses are treated consistently between the actual and model cases.
11. Bias in the Powerflow Case	A need exists to review the powerflow case provided by the Midwest ISO for this analysis for any potential bias. MAPS utilizes a single power flow over study period and failure to assure representative power flow could result in model bias.	No potential bias was found

Issue	Description	Resolution
12. Bid Inflexibility	Midwest ISO market dispatch is based on market participant generation offers. MAPS model dispatch is based on assumed dispatch cost and unit physical characteristics. Market participants may choose to offer less that full unit flexibility restricting the dispatch and leading to suboptimal dispatch and therefore increased production costs. This inflexibility varies by hour and is not represented in the model.	This is treated as a potentially conservative element of this analysis.
13. ECOMAX	Stakeholder provided capacity assumptions should be validated against offered capacity to assure potential output levels are not overstated relative to the capacity available in the marketplace. Prior analysis by the Midwest ISO indicated large potential differences between annual nameplate capacity and capacity made available for hourly dispatch.	ICF, SAIC, and Midwest ISO staff Midwest ISO reviewed actual market bid data for the study period in detail and corrected for an initial 3 GW overstatement of capacity. The potential for monthly discrepancies is treated as a potentially conservative element of this analysis.
14. Offered ramp rates	Actual offered unit ramp rates may differ from physical ramp rates. This differential may limit the Midwest ISO's ability to achieve the full range of benefits possible.	See # 12 above.
15. Must-run	Market participants may offer more must-run units than are included.	See # 12 above
16. Historical outages and unit derations	Aggregate treatment of unit outages may not accurately reflect actual periods of shortage in the Midwest ISO system.	Analysis has incorporated all reported outages and unit derates in MAPS model.
17. Coal Prices	Analysis uses coal prices as an average of both contract and spot prices for each facility realized during the study period. This may not fully capture the volatility in coal markets during this period.	Because spot market coal transaction data is thin and not publicly available, ICF believes the approach and does not expect this to be a significant driver of either potential or actual benefits.
18. Treatment of wind and hydro	Wind and hydro require treated with appropriate operating patterns in the MAPS model.	Analysis inputs reflect appropriate dispatch patterns.

Issue	Description	Resolution
19. Taum Sauk	The Taum Sauk pumped storage facility has not operated since Dec 13, 2005.	Incorporated in the model
20. Behind-the Meter units	Treatment of BTM units in the model may affect results.	The BTM units were confirmed to be correct in the model.
21. Midwest ISO flowgate ratings in the D2-Optimal Case	The MAPS model reflects the assumption that transmission flowgate capacity is utilized at 100 percent of flowgate limit in the Day-2 Optimal Case. Real-Time operations are often below that limit.	Given the difficulty in developing a consistent model assumption to accurately reflect this issue we have assumes 100 percent utilization in the Day-2 and No-ASM cases.
22. Hourly vs. instantaneous load	MAPS model reflects integrated (average) hourly load. Capacity commitments must be adequate to cover instantaneous load during the peak hour.	This variable was incorporated in the model as "load forecast error" during the commitment stage. (see #3 above for related discussion)

Exhibit E

Technology Development and Marketing Plan for the Lignite Vision 21 Project

and

ABB – Phase II Transmission System Impact Study Summary Report

LMFS-99-31
TECHNOLOGY DEVELOPMENT AND MARKETING PLAN FOR THE LIGNITE VISION 21 PROJECT

CONTRACTOR: Lignite Energy Council

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CONTRACT AMOUNT: $132,000

Project Schedule – 11 Months
Contract Date – 6/29/99
Start Date – 7/1/99
Completion Date – 6/01/00

Project Deliverables
First Quarterly Report – 11/30/99✓
Draft Final Report – 7/01/00✓
Final Report – 8/01/00✓

OBJECTIVE / STATEMENT OF WORK

The purpose of the Lignite Vision 21 Project (LV 21) is to revitalize growth in the lignite industry. An objective of the LV 21 Technology Development and Marketing Plan is to assist in the development of additional lignite-based electrical generation in North Dakota.

Specific Project Management Objectives for the Phase I LV 21 are:

- establish and maintain project management over the Phase I contracts, activities and support studies;
- coordinate activities of the Advisory Committees providing technical and business expertise and assistance for development and implementation of the Lignite Vision 21 Project;
- identify the most promising advanced lignite-based generation technologies;
- identify environmental and transmission issues and enhancements;
- evaluate innovative alternative extraction technologies;
- develop marketing and development strategies for potential industry and government partners;
- develop a detailed Project Development Phase II plan;
- identify funding for Phase II; and
- develop the marketing, technology and commercialization plan for the Lignite Vision 21 Project.

Specific Advanced Generation Objectives are as follows:

- determine the development status of advanced technology systems;
- identify and describe each advanced technology system;

- identify the characteristics of North Dakota lignite and identify those characteristics that do not penalize and may provide a competitive advantage for North Dakota lignite;
- estimate technical performance and economics; and
- recommend most promising advanced technology system.

STATUS

Project management of Phase I LV 21 activities were concluded with the successful completion of the four major studies and submission of the Phase II plan. The summary results of the four studies are:

1. Electrical Transmission Study: The Industrial Commission contracted directly with ABB Power and the Lignite Energy Council (LEC) provided project management and supervision for this study. The North Dakota Electric Transmission Study is project LMFS-99-33. ABB identified a transmission route that could accommodate up to 800 MW of additional generation and export from North Dakota. While no existing firm capacity is available for North Dakota export and non-firm capacity is available only part of the time, upgrading of the existing Antelope Valley-Huron line to 500 kV could provide an attractive option to increase North Dakota export. This option should be evaluated in more detail including site-specific consideration and stability studies (see LMFS-99-33 for details).

2. Environmental Enhancement Study: The Industrial Commission contracted directly with Research Data International and the LEC provided project management and supervision for the study. The Environmental Enhancement Study is project LMFS-99-32. The study concluded environmental impacts during construction and operation of a LV 21 power plant are within manageable levels utilizing current emission control technologies (see LMFS-99-32 for details).

3. Advanced Generation Study: The Lignite Energy Council subcontracted with Black & Veatch for the Advanced Generation Technologies Study. The Advanced Generation Study identified pulverized coal fired technology with supercritical steam, circulating fluidized bed and integrated gasification combined cycle as the technologies with the highest probability to meet the LV 21 criteria. Advanced technologies criteria are $1,000/kW EPC Costs, < 0.15 lbs NO_x/MBtu, and 0.18 lbs/MBtu SO_2. Additional criteria and performance standards are presented in the report.

4. Alternative Lignite Extraction Technologies: The Industrial Commission contracted directly with Dakota Gasification Company (DGC) and the LEC provided project coordination and review. The Alternative Lignite Extraction Technologies study is project LMFS-99-30. The study identified underground coal gasification, a concept called LANL and coal-bed methane as alternative technologies that warranted further study.

The contractor, Lignite Energy Council, in consultation with industry/state agency advisory panels, developed a detailed project plan for LV 21 Phase II. Activities for Phase II are project management, identification of wholesale customers and equity owners, marketing activities and planning for Phase III.

ABB Project Summary Report

	LIGNITE VISION 21 PROJECT			
Title:	**PHASE II TRANSMISSION SYSTEM IMPACT STUDY SUMMARY REPORT**	Department ESC	Date Feb 6, 2001 Rev. 2-23-01	Page 1

Author(s):	**Reviewed by:**	**Approved by:**
R.J.Koessler D. Martin		

Summary:

Electric Systems Consulting (ESC) of ABB Power T&D Company, Inc., has been contracted by the Lignite Energy Council to study the transmission system requirements for seven potential sites for a new 500-MW coal-fired generating unit in North Dakota. This study developed one to three alternatives for each site with one main alternative for exporting the power from North Dakota to the Minneapolis / St. Paul area. This is only one of many potential alternatives that could be developed and analysis of this alternative was limited to the technical performance to meet MAPP criteria. The evaluation did not consider contractual obligations, prior requests for transmission capacity, analysis of any potential SSR problems, or other commercial and environmental aspects.

This report is a summary of the results of the studies for each of the sites plus the common facilities for all of the sites to export power from North Dakota. For each of the seven sites in North Dakota, alternatives were developed for exporting power from North Dakota to the Minneapolis / St. Paul area. A common set of system upgrades and additions were identified for the sites for increasing the North Dakota Export (NDEX) and transferring the power to the Minneapolis / St. Paul area. The seven sites are shown in the attached diagram and described below by the nearest power system feature.

Site #1 – Beulah Mine near Coyote Station
Site #2 – Center Mine near Milton Young Station
Site #3 – Falkirk Mine near Coal Creek Station
Site #4 – Freedom Mine near Antelope Valley Station
Site #5 – Great Northern Properties near Belfield Substation
Site #6 – Gascoyne Mine near Hettinger Substation
Site #7 – LUSCAR near Tioga Substation

Initially studies were made for identifying the common facilities required to export 2,450 MW from North Dakota with the new Lignite Vision 21 500-MW power plant. Studies were also made for identifying the facilities required to export 2,800 MW from North Dakota with the new Lignite Vision 21 500-MW power plant plus an additional 350 MW in transmission reservations. The transmission facilities common to all sites for increasing the NDEX to 2450 MW and transmitting the power to Minneapolis/St. Paul are listed as follows:

- Upgrade the operation of the Antelope Valley-Broadland 345 kV line to 500 kV and continue the line to Split Rock. This results in a 409-mile, 500 kV line from Antelope Valley to Split Rock, 299 miles of this 500 kV line will be the result of upgrading the existing A. Valley to Broadland line, which was built for 500 kV, but is currently operated at 345 kV. The remaining 110 miles will be new construction.
- The new 500 kV line is 88% shunt compensated (350 Mvar line shunts at each end of the line using existing 225 Mvar reactors plus new 125 Mvar reactors) to prevent excessive overvoltages during load rejection and energization.
- One 345/500 kV autotransformer (approximately 1,200 MVA) at Antelope Valley and Split Rock.
- A 70-mile, 345 kV circuit between Split Rock and Lakefield Junction.
- For high NDEX transfer scenarios (i.e., the Summer Off-Peak case), a 50-Mvar shunt capacitor at the Groton 345 kV station (to support voltages at that station following outage of the Antelope Valley to Split Rock 500 kV circuit).

Upgrading the Antelope Valley-Broadland 345 kV line to 500 kV and extending it to Split Rock is required to increase the transmission capacity for higher exports and to increase the system stability. Adding a line from Split Rock to Lakefield is required to provide a second 345 kV line to carry power out of the Split Rock (Sioux Falls) area. Without this line, an outage of the Split Rock-Sioux City 345 kV line results in overloads on the 230 kV system. These new lines are shown in the attached map of the electrical system. The new 500 kV line addition from Broadland to Split Rock is colored orange and in bold and the new Split Rock-Lakefield 345 kV line is red and in bold.

The transmission facilities required for increasing the NDEX to 2,800 MW (with generator tripping of the LV21 unit upon outages involving the A.Valley-Split Rock 500 kV line) and transmitting the power to Minneapolis / St. Paul are listed below. Only those facilities that are in addition to or modify the facilities listed above for the 2,450 MW NDEX are listed below (ie. this list is for the incremental facilities).

- 35% series compensation of the Antelope Valley-Split Rock 500 kV line
- 25% series compensation of the Leland Olds-Groton-Split Rock 345 kV line
- 220 Mvars in additional shunt compensation along the Leland Olds to Split Rock 345 kV line.
- A Broadland 500 kV station with a 1,000-MVA 500 / 230 kV transformer
- Line reactor compensation of the proposed 500 kV line is modified to the existing 225-Mvar reactors at Antelope Valley and Broadland

The transmission facilities required for increasing the NDEX to 2,800 MW without generator tripping of the LV21 unit requires additional series capacitors as listed below.

- 35% series compensation of the Antelope Valley-Split Rock 500 kV line
- 65% series compensation of the Leland Olds-Groton-Split Rock 345 kV line
- 65% series compensation of the Leland Olds-Ft. Thompson 345 kV line

The cost estimates for the common facilities to increase the NDEX to 2,450 MW and to 2,800 MW are listed as follows:

Costs for NDEX Upgrade to 2,450 MW	$130,529,000
Costs for NDEX Upgrade to 2,800 MW With Generator Tripping	$153,039,000
Costs for NDEX Upgrade to 2,800 MW Without Generator Tripping	$162,039,000

The confidential site reports identify the facility additions or modifications required for each specific site in addition to those common facilities listed above. These facilities insure that power can be transmitted from the nearby power system station identified in the site list above to the common facilities for a NDEX of 2,450 MW.

Since the three main EHV lines that export power from North Dakota emanate from the Antelope Valley and Leland Olds Stations, the closer the sites are to Antelope Valley and Leland Olds the less miles of transmission lines that need to be built or reinforced to export the power. In general it is required to transmit the power to Antelope Valley and / or Leland Olds Stations or to one of the 345 kV lines that ties into these stations in order to export the power. For some of the sites, alternatives were evaluated for connecting to the local 345 kV or 230 kV systems and enhancing the system to export the power versus building a 345 kV line directly from the site to the Antelope Valley and / or Leland Olds Stations.

Another consideration is the isolation between the generating stations in central North Dakota. The Coal Creek power plant and station is electrically isolated from the Antelope Valley and Leland Olds transmission system. The Coyote and Milton R. Young power plants and stations are also electrically isolated from the Antelope Valley and Leland Olds transmission system. Connecting these systems together generally has an adverse impact on system stability. Alternatives that connect these systems in general will need to increase the system stability by additional enhancements such as series capacitors. Some alternatives also included an Inter-phase Power Controller (IPC) to transmit power between these stations. The IPC transmits power but still results in the station being de-coupled for system faults, that is the IPC does not transmit fault current. This keeps the systems isolated so faults on one system do not excessively impact the other system and therefore do not adversely impact the system stability.

Some of the transmission alternatives for the sites required additional series compensation in the Antelope Valley-Split Rock 500 kV line and / or the Leland Olds-Groton-Split Rock 345 kV line. These alternatives would leave less flexibility to expand the transmission system for future increases in the NDEX. The site studies did identify the total system requirements for each site to insure that each site will meet the MAPP system requirements for steady-state and stability performance.

Conclusions:

Facilities were identified for each site which result in all sites having the capability to export 2,450 MW. The common facilities for increasing the export level to 2,450 MW and to 2,800 MW have been identified for transfers to the Minneapolis / St. Paul area. For these common facilities an estimated cost has been provided. The individual site reports contain the facilities required for each specific site.

Figure 1: Site Locations Map

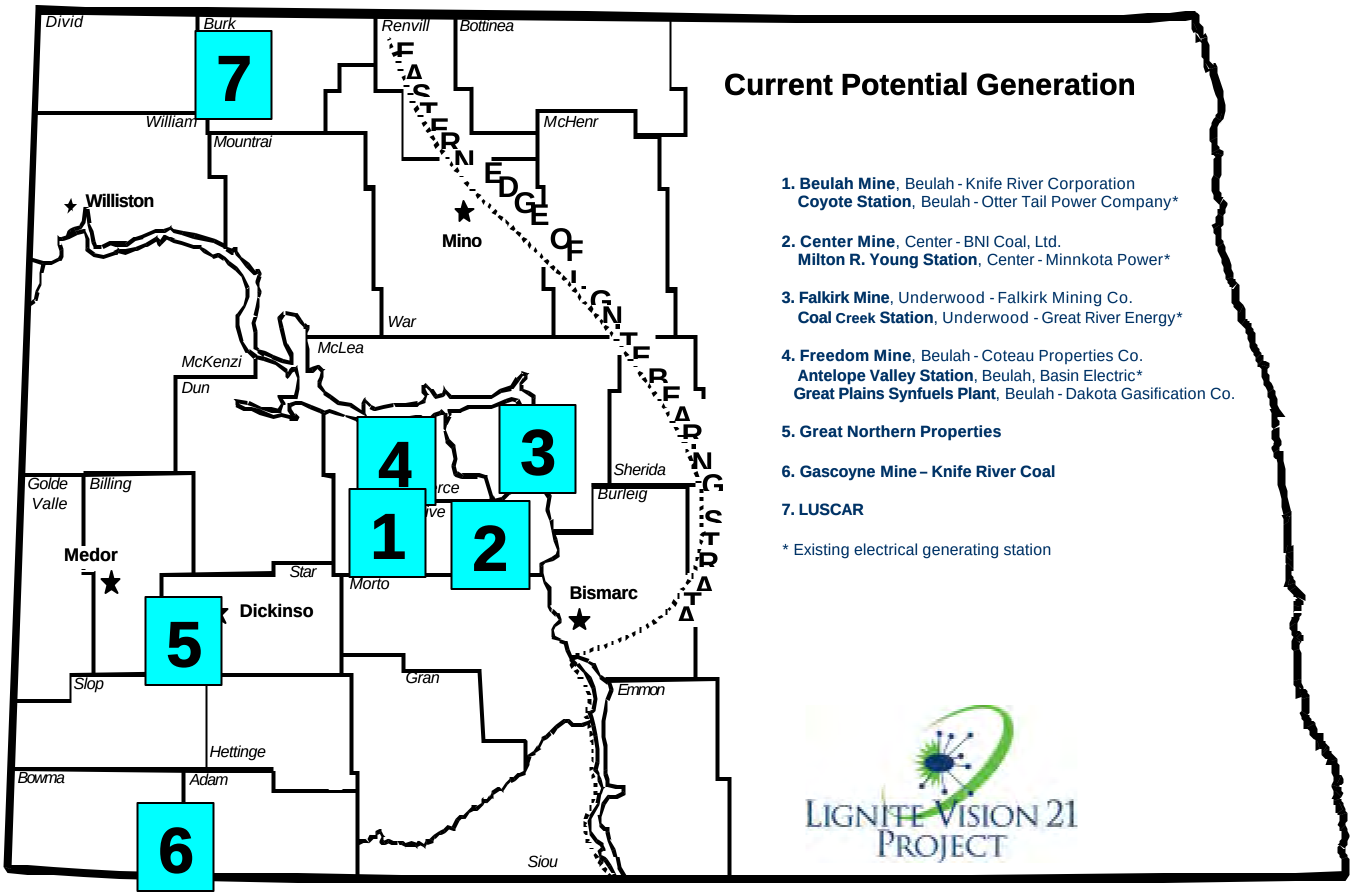

Figure 2: Transmission Route Map

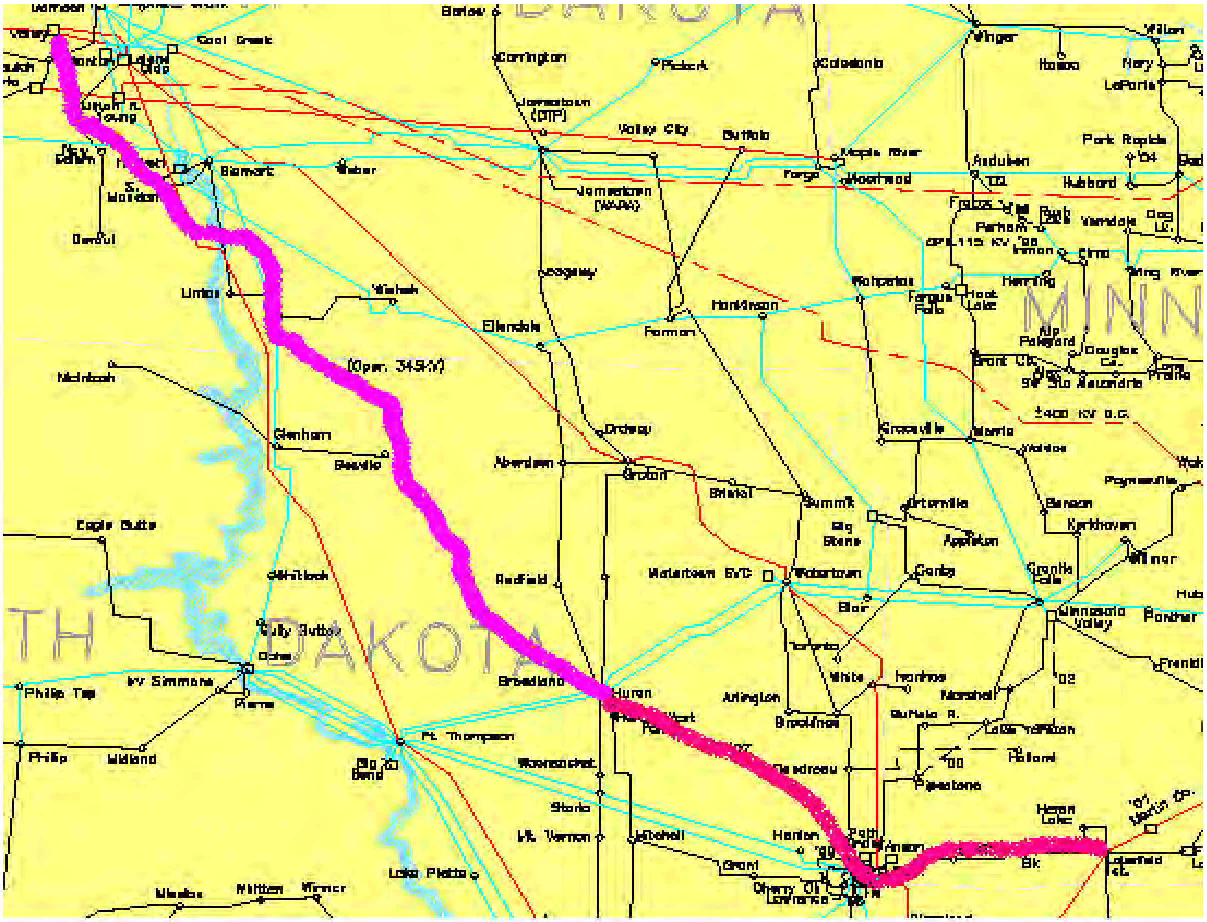

Exhibit F

Wisconsin Interface Reliability Enhancement Study

WIREs Phase II Study

http://nocapx2020.info/wp-content/uploads/2012/02/wiresphaseii20120214-515026913742.pdf

WISCONSIN INTERFACE RELIABILITY ENHANCEMENT STUDY

WIREs PHASE II

A REPORT TO THE
WISCONSIN RELIABILITY
ASSESSEMENT ORGANIZATION
(WRAO)

JUNE 1999

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EXECUTIVE SUMMARY

This document is a report of the technical analyses performed by the Wisconsin Interface Reliability Enhancement study (WIREs) group. The WIREs group was formed under the auspices of the Wisconsin Reliability Assessment Organization (WRAO) in the spring of 1998 in response to transmission reliability concerns stemming from events in 1997 and 1998 which caused reliability margins to drop below historically observed levels. The WIREs group consists of participants from utilities in Illinois, Iowa, Minnesota, Wisconsin, and the Canadian Province of Manitoba and the Mid-Continent Area Power Pool (MAPP) and Mid-America Interconnected Network (MAIN) reliability councils. Regulatory agencies in Illinois, Iowa, Minnesota, and Wisconsin also participated as ex officio members.

This report represents the second phase of a two-phase study effort designed to identify transmission constraints on the regional bulk power transmission system and to evaluate transmission reinforcement alternatives to alleviate those constraints. The Phase I study effort, culminating in August of 1998 with the release of the *Wisconsin Interface Reliability Enhancement Study Phase I* report, consisted of a screening analysis to determine regional transmission constraints and the identification of a set of representative transmission reinforcement alternatives that would increase the simultaneous transfer capability into Wisconsin to 3000 MW. The 3000 MW simultaneous import capability was achieved by importing 2000 MW across transmission interconnections to the west and 1000 MW across transmission interconnections to the south or 1000 MW from the west and 2000 MW from the south. To the north and east Wisconsin has no transmission interconnections because of Lakes Superior and Michigan.

The Phase I study effort also constituted the basis for a report developed by the Public Service Commission of Wisconsin (PSCW) for the Wisconsin Legislature on the regional electric transmission system.

The WRAO, in its *Report of the Wisconsin Reliability Assessment Organization on Transmission System Reinforcement in Wisconsin*, has considered the technical analyses of the WIREs group along with environmental screening studies, policy considerations, geographical diversity, and ability to construct to formulate a recommended transmission reinforcement plan.

Alternative Transmission Reinforcement Plans Considered

The Phase II study effort refined the Phase I study results by further defining relative performance differences between alternative transmission reinforcement plans. The set of twelve original representative system reinforcements, which were identified in the Phase I study effort, were refined into seven transmission reinforcement plans. The reinforcements are referred to as “plans” because several projects, in addition to a major high voltage transmission line, are required to achieve the transfer capability objective. All of the projects associated with a particular “plan” are included in the cost estimates detailed in Chapter 8 of this report.

The major transmission system additions associated with each of the seven reinforcement plans evaluated in this study are:

- Plan 1c (Salem – Fitchburg 345 kV)
- Plan 2e (Prairie Island – Columbia 345 kV)
- Plan 3j (Arrowhead – Weston 345 kV)
- Plan 5a (Chisago – Weston 345 kV)
- Plan 5b (Apple River – Weston 230 kV)
- Plan 9b (Lakefield – Columbia 345 kV)
- Plan 10 (King – Weston 345 kV)

PERFORMANCE EVALUATION

The relative performance differences of the reinforcement alternatives were established with multiple evaluation techniques. Those evaluation techniques included the following:

- *Detailed power flow simulations*
- *Generator response to transmission line switching operations*
- *Dynamic stability*
- *Voltage stability*
- *Impact on the MAPP transmission system*
- *Construction cost estimates*
- *Impact on system losses*
- *Evaluated cost proxy*

The study group utilized a 2002 summer power flow model to evaluate the characteristics of each reinforcement plan. The 2002 model was chosen due to the lead time required to evaluate, license, engineer, and construct a transmission reinforcement of these magnitudes.

Detailed Power Flow Simulations

Several detailed power flow simulations were performed on each reinforcement plan to determine:

- the reactive voltage support required to achieve the 3000 MW simultaneous import capability
- the maximum transfer capability
- the sensitivity of the 3000 MW import capability to modeling assumptions

The detailed power flow simulations verify that each of the reinforcement plans is capable of supporting 3000 MW of simultaneous import capability. However, some plans provide more incremental transfer capability above the 3000 MW target than others. In addition, the maximum transfer capability of some plans is more sensitive to changes in modeling assumptions than others. The Table ES-1 (rows a-d) summarizes the power flow simulation results and shows the maximum transfer capability of each reinforcement plan under different modeling assumptions.

Generator Response to Transmission Line Switching Operations

The ability to transfer power across the western interface is currently limited by the Arpin phase angle. The Arpin phase angle limitation is a proxy for the maximum amount of stress introduced to the Weston generators when any portion of the King – Eau Claire – Arpin 345 kV line is switched. A sudden loss of any portion of the King – Eau Claire – Arpin 345 kV line results in a system “separation” between MAPP and eastern Wisconsin. When the line is re-closed across this “separation” an instantaneous change in power output is experienced on the Weston generator units which places mechanical stress on the shaft of each unit. The Weston units experience this phenomena due to their physical proximity to the western interface. The current Arpin phase angle limitation is 60 degrees (the maximum “separation”).

Rather than focus on the Arpin phase angle as a proxy measurement for the impact on the Weston generating units, the WIREs group focused on a direct measurement; the instantaneous change in power output of the Weston units upon the closure of the Eau Claire – Arpin 345 kV line. Analysis of the present day system calculated the Weston "delta P" corresponding to the re-close of the Eau Claire - Arpin 345 kV line with a phase angle difference of 60 degrees demonstrated that Weston Unit #3 would experience a “delta P” of 37.2% (or 0.372 per unit).

Analysis of each of the seven reinforcement plans at the target simultaneous transfer capability of 3000 MW (2000 MW west/1000MW south) indicates that each plan except for Plan 1c (Salem – Fitchburg 345 kV) results in a “delta-P” less than 37.2% limit. The Weston “delta-P” results for each of the seven reinforcement plans are shown in Table ES-1 (row e)

Dynamic Stability

Dynamic stability is the measure of the system’s ability to react to a major system disturbance such as a short circuit on a transmission line, the opening of a line, the loss of a large generator, or the switching of a major load. Dynamic stability evaluates the ability of the system’s generation units to remain synchronized and to “recover” from a system disturbance.

The dynamic stability analyses performed in this study considered the following:

1. WUMS and MAPP area disturbances
2. New facility disturbances
3. Maximum Columbia & Weston generation output sensitivities
4. Breaker failure performance (Rocky Run area)
5. Damping of the ¼ Hertz mode of oscillation
6. Incremental transfer capability assessment based on ¼ Hertz mode of oscillation.
7. Dynamic reactive support requirements

In general, all plans met established transient voltage and rotor angle criteria for the WUMS 2000 MW west – 1000 MW south import transfer condition. No additional reactive voltage support (VAr) requirements, over and above those identified through the power flow analyses, were identified.

The most pronounced difference between the reinforcement plans was observed for disturbances involving a loss of a major Twin Cities 345 kV outlet facility. For a loss of either the King – Eau Claire – Arpin 345 kV or the Prairie Island – Byron 345 kV transmission line, differences in transient voltage performance within MAPP and WUMS and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode of oscillation is currently a stability limiting condition for the Twin Cities export (TCEX) limitation.

The damping of the ¼ Hertz (Hz) oscillation mode is dependent on transfer levels. To determine the maximum transfer capability at which the ¼ Hz mode is a limit, an incremental transfer capability (ITC) number was calculated based on the loss of either the King or Prairie Island 345 kV lines. The dynamic stability results of the ¼ Hz mode of oscillation are shown in Table ES-1 (row f).

Some generator stability problems were identified in the Rocky Run area for delayed clearing breaker failure cases studied with maximum generation at the Weston generating plant. These were found to be problems inherent in the base case and can be corrected with reduced failed breaker clearing times.

Voltage Stability

Voltage stability is the measure of a system's ability to maintain adequate voltage profiles following a major system disturbance such as the loss of a critical transmission line. Without adequate voltage support, a system could experience "voltage collapse", a condition characterized by declining voltages that cannot support customer load. The results of this analysis show that voltage instability is not encountered at a western interface transfer of 2000 MW.

The WIREs group undertook the voltage stability assessment with the MAPP Transmission Reliability Assessment Working Group and Power Technologies Inc. (PTI), a power system study consultant. The consultant's study work focused on western interface transfers because the western interface is more susceptible to voltage collapse than the southern interface. Past operating experience indicates that the southern interface is limited by thermal overload constraints rather than by voltage stability concerns.

In order to determine the maximum western interface transfer at which voltage instability is encountered, transfers were increased beyond the 2000 MW level (all other limitations were ignored). Results of this sensitivity are shown in Table ES-1 (row g) and demonstrate that some reinforcement plans provide more western interface transfer capability before voltage instability is exhibited.

Impact on the MAPP Transmission System

The impact of the seven reinforcement plans on the neighboring MAPP system was evaluated by considering the change in flow on the MAPP flowgates. Flowgates are a set of transmission lines with a single flow capability that define a thermal, voltage, or stability limitation. The geographical areas represented by the MAPP flowgates are shown in the figure below.

The change in flow on each flowgate due to the addition of a reinforcement plan to the system was determined by measuring the before and after reinforcement flow at a transfer level of 3000 MW (2000 MW western transfer / 1000 MW southern transfer). These results demonstrate that most reinforcement plans reduce flow on the MAPP flowgates as they are defined today[1]. The results are shown in Table ES-1 (rows h-l).

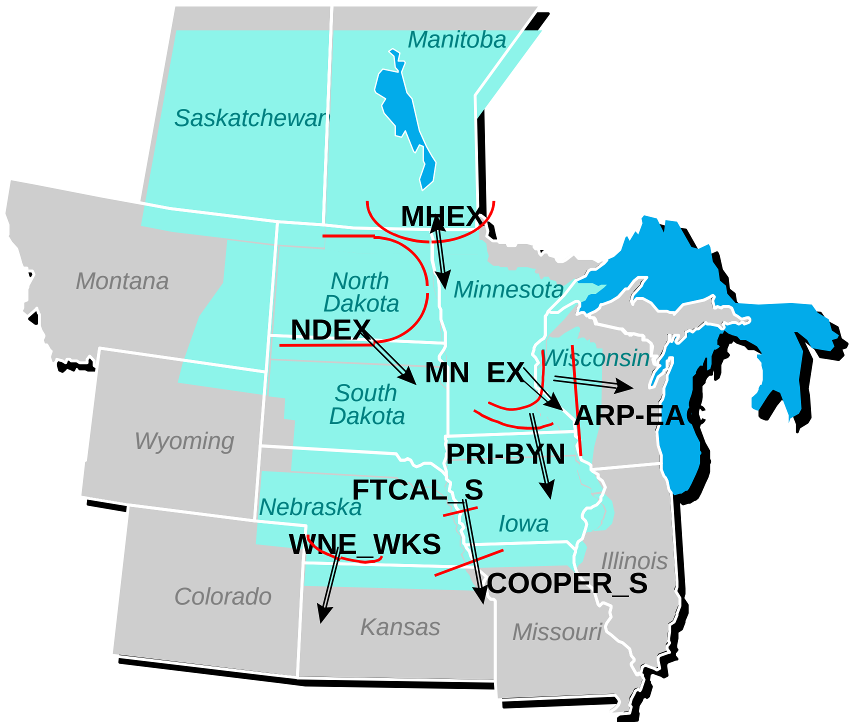

Figure ES- 1

Impact of System Losses

An analysis was undertaken to quantify the relative cost of system losses among the reinforcement plans. The costs associated with losses are summarized as an equivalent capital investment adjustment to the initial capital construction cost for each alternative. An equivalent capital cost adder is calculated for each reinforcement plan that is relative to the plan with the least losses. The capital cost adder for each reinforcement plan is shown in Table ES-1 (row m).

[1] It is important to note that some flowgate definitions and ratings may change when a major transmission reinforcement is added to the system.

The process computes the lifetime costs for the installed generating capacity and associated energy to serve the losses that would prevail for each alternative. Transmission losses are included for the MAPP, MAIN, and SPP Regions. The cost adder is based on subtracting the life time costs of the lowest cost alternative, from the cost of all alternatives. Three components of adjusted capital cost were computed. These are due to generation capacity to supply the losses, annual energy losses to serve load, and annual energy losses due to point-to-point transactions.

<u>Capacity Cost</u>
Each plan causes the greatest demand for losses at some anticipated transfer level condition. In the cost evaluation, the maximum amount of loss caused by a plan is assigned a cost of 400 $/kW. The resulting cost represents the cost for installed generating capacity that would be required to serve the losses.

<u>Energy Loss for Load</u>
Each plan has energy losses associated with the annual hourly loss that occurs as the load pattern is served. An annual load pattern is sufficiently predictable, so that the resulting cost for Energy Loss for Load is a constant for each plan. The annual energy to serve load in each plan has been set at 30 % of the energy that would be lost if the peak load occurred all hours in the year. The annual energy lost as a consequence of serving load is priced out at 15 $/MWh. The resulting annual energy cost is equated to a levelized annual carrying charge. The annual carrying charge dollars are then converted to an equivalent capital investment, by dividing by 15 %.

<u>Energy Loss for Transactions</u>
Each plan has energy losses that are required to support the various point-to-point transactions that are planned. After determining the annual energy associated with the point-to-point transactions, a capital investment is computed by dividing by 15 %. Due to the varying degrees that future point-to point usage can occur, the annual Energy Loss for Transactions have been computed over a range of operating conditions. For example 5% of the time a 2000 MW import into WUMS from the West and a 1000 MW import from the South is one operating point along with, 40% of the time at a 1000 MW West import and 0 MW South import, etc.

Construction Cost Estimates

The cost estimates for the WIREs reinforcement plans are comprised of three parts. These three parts are cost of transmission lines, cost of substation terminal additions, and the cost of associated projects. The total construction cost, expressed as a range of values for each reinforcement plan, is shown in Table ES-1 (rows n and o). The construction cost estimates contain a range to account for discrete “study areas” between substation end-points. A team of environmental analysts retained by the WRAO to examine the seven reinforcement plans developed the “study areas”.

The three segments of the construction cost estimates are discussed below.

<u>Cost of Transmission Lines</u>
Black & Veatch, an engineering consultant retained by WRAO for this purpose, developed the cost estimates for the transmission lines. The transmission line

cost estimates were based on the study areas defined for each plan by an environmental consultant working with WRAO and the WIREs group. For each study area, a single circuit cost estimate and a cost estimate that utilized all potential double circuiting opportunities were developed. In most cases, four cost estimates were developed for each reinforcement plan (two study areas times two cost estimates).

Cost of Substation Terminal Additions
The cost estimates for the substation terminal additions and enhancements required for each WIREs plan were developed by the utilities whose service territories contained the substations under consideration. Black & Veatch supplied standard substation "component costs" which were used by each utility in determining the estimated cost for these improvements. The component costs used are listed in a subsequent section.

Cost of Associated Projects
The associated projects are various system improvements which were required enhancements in order for the WIREs plan under consideration to achieve the stated power transfer goals. The cost estimates for these projects were developed by the utilities whose service territories contained the system elements under consideration.

Evaluated Cost Proxy

An evaluated cost proxy, which merged the construction cost, the equivalent capital cost adder for losses, and other savings from avoided local load serving projects is included in Table ES-1 (row p and q). The evaluated cost proxy is a portrayal of the overall economic impact of each reinforcement plan based on construction cost, the cost of losses, and a credit for avoided facilities. As with the construction cost estimates, the evaluated cost proxy is shown as a range to account for the different "study areas" for each reinforcement plan (the "study areas" were developed by the WRAO's environmental team).

Table ES-1 WIRE Study - Summary of Plans' Performance Evaluation

	Performance Results All Reinforcement Plans Satisfy 3000 MW Simultaneous Import Objective *ver3- 4/9/99*	Salem-Fitchburg 345 kV 1c	Prairie Island-Columbia 345 kV 2e	Arrowhead-Weston 345 kV 3j	Chisago-Weston 345 kV 5a	Apple River-Weston 230 kV 5b	Lakefield Jct-Columbia 345 kV 9b	King-Weston 345 kV 10
	Southern Interface Transfer Capability (with 1000 MW western bias)							
a	**Transfer Capability - Southern Interface**	**2450**	**2370**	**2130**	**2150**	**2010**	**2400**	**2140**
	Western Interface Transfer Capability (with 1000 MW southern bias)							
b	**Transfer Capability - Western Interface (MW)**	**2210**	**2580**	**2280**	**2270**	**2120**	**2750**	**2300**
c	**Transfer Capability - Source Sensitivity (MW)**	**2110**	**2550**	**2190**	**2190**	**2140**	**2810**	**2200**
d	**Transfer Capability - Sink Sensitivity (MW)**	**2160**	**2720**	**1860**	**1880**	**2160**	**2590**	**1890**
e	**Weston Delta P (per unit improvement from existing limit @ 2000 MW)**	**-0.013**	**0.015**	**0.036**	**0.166**	**0.064**	**0.009**	**0.247**
f	**Dynamic Stability - .25 Hz Damping (MW incremental xfer through WUMS)**	**50**	**720**	**450**	**670**	**220**	**120**	**480**
g	**Voltage Stability (western transfer level MW - no southern import)**	**2615**	**3245**	**2615**	**2865**	**2865**	**3105**	**2865**
	Other Factors							
h	**MAPP OPPD Flowgate Loading (avg % loading change from base case)**	**-1.2%**	**-9.3%**	**-7.9%**	**-8.6%**	**-5.5%**	**-12.4%**	**-7.9%**
i	**MAPP COOPER_S Flowgate Loading (% loading change from base case)**	**-7.9%**	**-18.1%**	**-14.7%**	**-16.1%**	**-11.6%**	**-22.3%**	**-15.4%**
j	**MAPP ECL-ARP Flowgate Loading (% loading change from base case)**	**-0.8%**	**-6.3%**	**-19.7%**	**-24.3%**	**-10.6%**	**-7.5%**	**-20.2%**
k	**MAPP PRI-BYR Flowgate Loading (% loading change from base case)**	**1.3%**	**-26.1%**	**-15.5%**	**-18.3%**	**-9.0%**	**7.0%**	**-16.5%**
l	**MAPP MN EX Flowage Loading (% loading change from base case)**	**0.3%**	**-17.6%**	**-17.0%**	**-20.6%**	**-6.7%**	**8.1%**	**-20.2%**
	Economic Factors							
m	**Losses (Capital Cost Adder w/r to Plan 3j - million $)**	**$50.2**	**$27.2**	**$0.0**	**$1.4**	**$38.7**	**$29.0**	**$20.8**
n	**Construction Cost Range (single ckt - million $)**	**$116 - $145**	**$169 - $176**	**$177 - $210**	**$172 - $205**	**$118 - $144**	**$227 -**	**$136 - $139**
o	**Construction Cost Range (doubl ckt - million $)**	**$158 - $227**	**$243 - $265**	**$266 - $310**	**$240 - $284**	**$171 - $208**	**$395 -**	**$210 - $262**
p	**Evaluated Cost Proxy Range (single ckt - million $)**	**$166 - $195**	**$195 - $202**	**$177 - $199**	**$126 - $149**	**$157 - $173**	**$256 -**	**$157 - $160**
q	**Evaluated Cost Proxy Range (double ckt - million $)**	**$208 - $277**	**$269 - $291**	**$266 - $299**	**$194 - $228**	**$210 - $237**	**$424 -**	**$231 - $283**

Table ES - 1

SUMMARY OF TECHNICAL STUDY RESULTS

The evaluation techniques utilized in this study demonstrate that each reinforcement plan, with the exception of Plan 1c, is capable of supporting a simultaneous transfer of 3000 MW over the western and southern interfaces into Wisconsin. The Weston delta-P performance of Plan 1c (Salem – Fitchburg 345 kV) is slightly less than criteria which indicates that Plan 1c could not sustain a simultaneous import of 3000 MW without adding additional facilities to the plan.

Each of the evaluation techniques considered in this study were considered in isolation. In other words, the voltage stability transfer capability did not consider thermal limitations and vice-versa. The absolute transfer capability of each reinforcement plan is a function of all potential limitations including thermal, voltage, dynamic stability, and Weston delta-P. The following "radar-plot" attempts to capture how a different type of system limitation limits the transfer capability of each reinforcement plan.

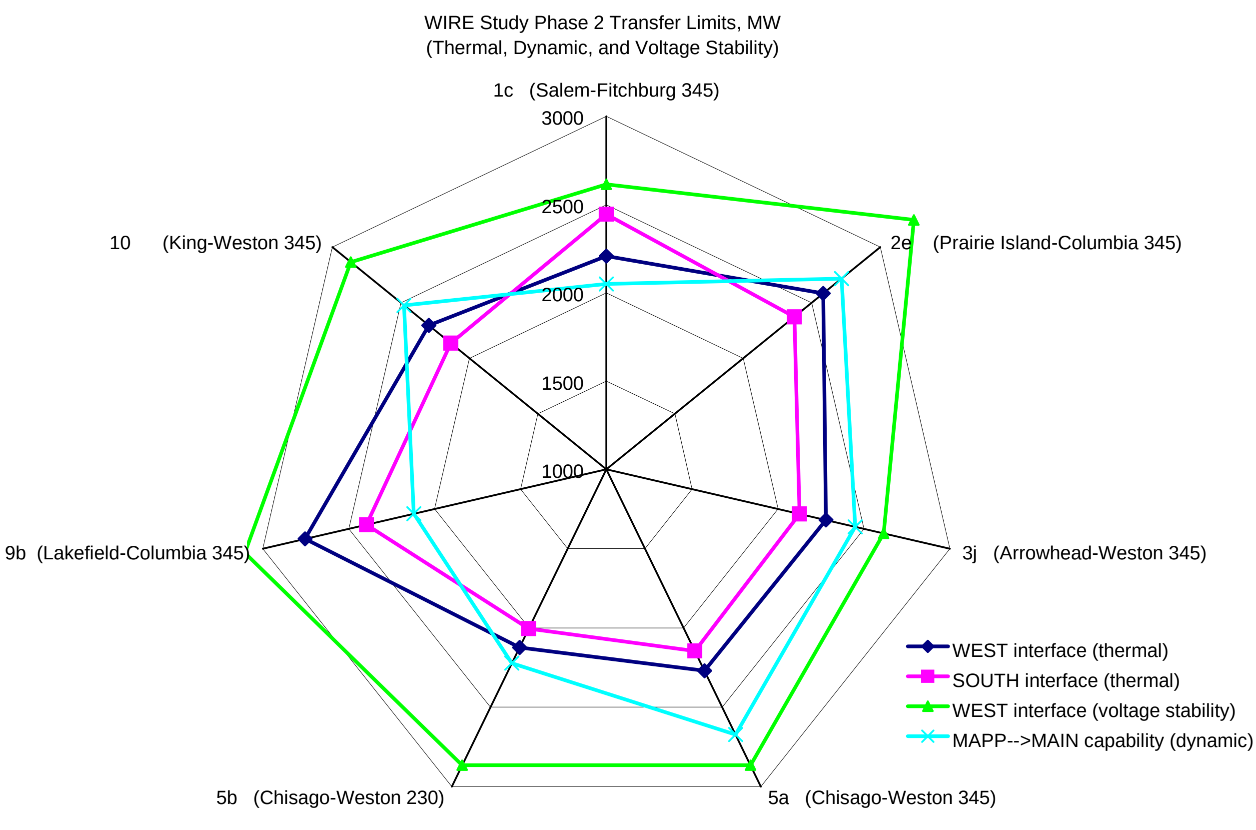

Figure ES- 2

Chapter 1 INTRODUCTION

1.1 Background

The Phase I study effort, culminating in August of 1998 with the release of the *Wisconsin Interface Reliability Enhancement Study Phase I* report, consisted of a screening analysis to determine regional transmission constraints and the identification of a set of representative transmission reinforcement alternatives. The Phase I screening analysis focused primarily on thermal overload constraints and transmission reinforcements indicative of the type of transmission additions necessary to alleviate those thermal constraints. The twelve transmission reinforcements considered in the Phase I analysis were:

1. Salem – Fitchburg 345 kV (1c)
2. Prairie Island – Columbia 345 kV (2e)
3. Salem – Paddock 345 kV (2f)
4. Arrowhead – Weston – S Fond du Lac 345 kV (3e)
5. Arrowhead – Weston 345 kV (3j)
6. Arrowhead – Weston 230 kV (3k)
7. Chisago – Weston 345 kV (5a)
8. Chisago – Rocky Run 500 kV (6c)
9. Wilmarth – Byron – Columbia 345 kV (8b)
10. Huron – Split Rock – Lakefield – Adams – Genoa – Columbia 345 kV (9a)
11. Plano – Plano Tap 345 kV (12)
12. Arrowhead – Plains 345 kV (13c)

The Phase I study effort did not consider transmission planning criteria such as voltage performance, dynamic stability, voltage stability, detailed construction costs, and the economic evaluation of loss estimates. Before considering these detailed planning criteria, the WIRE study team refined the twelve representative reinforcements into seven reinforcement plans. The reinforcement plans were developed by comparing the relative performance of the twelve original options and selecting those most representative of the reinforcements studied in the Phase I process.

Reinforcement Options 3j and 5a were selected for the Phase II study process because both plans met the 2000/2000/3000 MW transfer capability objective (based on thermal limitations) at a relatively reasonable cost. In addition, both options performed reasonable well based on the Phase I Arpin phase angle, Weston delta-P, and on-peak loss savings analyses.

Reinforcement Option 6c was eliminated from further analysis in the Phase II study process because the transfer capability objective (based on thermal limitations) was achieved with options that require lower voltages that do not require rather expensive 500 kV to 345 kV step-down transformers. In addition, the 500 kV operating voltage of this option limits the ability to enhance local load serving. This option is also relatively expensive when compared to other options.

Reinforcement Options 3e, 3k, and 13c were all eliminated from further analysis in the Phase II process because none of the options provided any additional benefit over Options 3j and 5a. Each performed inferior to Options 3j and 5a from a thermal transfer capability perspective, and from an Arpin phase angle/Weston delta-P perspective.

Reinforcement Option 12 was eliminated from further study as a stand-alone reinforcement plan. The Plano – Plano Tap 345 kV facility remains as an integral project contained within each of the Phase II reinforcement plans. However, on a stand-alone basis, Option 12 did not sufficiently address the Arpin phase angle/Weston delta-P issue and it is suspect to voltage collapse.

Reinforcement Option 2e was selected for the Phase II study because it provides relatively good performance from an Arpin phase angle/Weston delta-P and construction cost standpoint. In addition, this option provides for another outlet from the Twin Cities area.

Reinforcement Options 9a and 8b were eliminated from further study. The construction cost of Option 9a is excessive when compared to Option 2e. Option 8b is suspect to increase loading on the Twin Cities southern ties when compared to Option 2e.

Reinforcement Option 2f was eliminated because of its similarity to Option 1c. Option 1c was carried into the Phase II analysis even though it performed only marginally well when compared to other options. Option 1c was retained to provide a measure against which to compare the dynamic stability performance of options electrically closer to the existing western interface.

Three new reinforcement plans were developed based on the options evaluated in the Phase I process. Plan 9b (Lakefield Jnc – Adams – Genoa – Columbia 345 kV) is a trimmed version of the Phase I Option 9a and is less costly from a construction cost standpoint. Plan 5b (Apple River – Weston 230 kV) was added to consider dynamic and voltage stability performance of a lower voltage version of Plan 5a. Plan 10 (King – Weston 345 kV) was added because of the potential dynamic stability differences between it and Plan 5a (Chisago – Weston 345 kV). The group discussed the King – Weston reinforcement in the Phase I process but noted that from a thermal standpoint, it is electrically similar to Plan 5a. However, potential dynamic and voltage stability differences prompted the group to add Plan 10 to the Phase II process.

1.2 SIGNIFICANCE OF PHASE II STUDY RESULTS

The performance criteria evaluated in this study represent a benchmark upon which the reinforcement plans are compared. Each performance evaluation is considered based upon a “snapshot” of system conditions. Therefore, the results presented in this report are not absolute values valid for all operating conditions. A change in any one of a number of modeling assumptions such as load level, load distribution, generation profiles, transmission system topology, and simultaneous transfers would likely impact the results detailed in this report. The WIRE study team notes that a change in any one of the modeling assumptions could lead to a ±10% change in the 3000 MW transfer capability of each plan.

The transfer capability limits and performance measures established in this report are not the same as, nor calculated on the same basis as, the available transfer capability (ATC) values posted on the Open Access Same-Time Information System (OASIS). The ATC values posted on the OASIS define the commercial availability of the transmission system on a firm and non-firm basis and include such factors as transmission reliability margin (TRM) and capacity benefit margin (CBM). The transfer capability limits within this report are not intended to establish the commercial availability of the transmission system and should not be used as such. The transfer capabilities within this report are analogous to those reported in the Transmission Assessment Study Guide (TASG) and Future System Study Guide (FSSG) reliability studies performed by MAIN.

Chapter 2 Detailed Power Flow Simulations

The Phase I study effort consisted of a high-level screening analysis to identify thermal constraints on the regional transmission system during heavy transactions into Wisconsin. The Phase I study effort also identified a representative set of transmission reinforcement options to attain a simultaneous transfer capability of 3000 MW over Wisconsin's western and southern interfaces. The Phase I screening analysis utilized linearized power flow techniques ("DC" power flow analysis) that do not capture voltage limitations or heavy VAr (Volt-Amp reactive) flows.

The Phase II study effort refined the analysis conducted in Phase I by considering the transfer capability beyond the 3000 MW level, sensitivities to input assumptions, and the consideration of voltage limitations and VAr flow ("AC" power flow analysis). This section describes the Phase II power flow simulations and results.

2.1 Transfer Capability - Background

The power flow simulations were conducted with the PSS/E power flow package, a nationally recognized tool for transmission system planning studies. The PSS/E activity TLTG evaluates a linearized network model (DC load flow) to estimate the import or export limits of a specified region. To develop power exports/imports, the activity identifies a "study" system in which generation is increased (sources) and an "opposing" system in which generation is decreased (sinks). Power transfer distribution factors (PTDF) relate the change in exports/imports to branch and interface flows. Maximum transfer capabilities are determined by extrapolating the line and interface flows using the PTDFs and comparing them to specified ratings.

Default Sources/Sinks

Base case imports into WUMS totaled approximately 375 MW from the west and 150 MW from the south respectively. In order to evaluate the reinforcement plans using TLTG and meet the study objective of 2000 MW non-simultaneous transfer capability on each WUMS interface, additional sources west of WUMS had to total 1625 MW and additional sources south of WUMS had to total 1850 MW. Conversely, sinks within WUMS had to be identified to facilitate the imports.

Due to the lack of available generation in the MAPP region, the study used a combination of load reduction in western MAPP and the addition of unplanned generating units in Nebraska and North Dakota to provide the 1625 MW exported to WUMS. Load was reduced to 90% of peak in the following control areas: Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), Lincoln Electric System (LES), Western Area Power Administration (WAPA), and Otter Tail Power (OTP). The load reduction method produced approximately 925 MW of available capacity. The remaining 700 MW was split between two 350 MW generators. One unit was added at the Gentleman facility located in Nebraska and another was added at the Antelope Valley facility in North Dakota.

The load reduction represents a shoulder peak condition in western MAPP in which cooler weather frees up generation for export to WUMS while that area experiences high temperatures and peak load conditions. This scenario has occurred several times in the past as weather systems move from west to east. The study did not consider load reduction in eastern MAPP (Minnesota, Iowa and western Wisconsin) because of its proximity to WUMS.

The study utilized available generating capacity in Southern Illinois and ECAR to provide exports totaling 1850 MW to WUMS. Southern Illinois generation participated in 10% of that total, with ECAR accounting for the remaining 90%.

The study used all on-line generating units within WUMS to sink imported power. The amount each unit participated in the specified transaction was directly proportional to its MW output in the base case.

Base Case Biasing

In an effort to simulate a 3000 MW simultaneous transfer into WUMS, the transfer capability limits on each WUMS interface were tested with a 1000 MW transfer "bias" on the opposite interface. The transfer capability analysis of the WUMS western interface was conducted with the 1000 MW "bias" on the southern interface; the southern interface transfer capability was tested with a 1000 MW "bias" on the western interface. When a 2000 MW transfer capability on a particular interface is achieved with the simultaneous 1000 MW "bias", the total simultaneous import capability is 3000 MW.

Monitored Elements

The study monitored all transmission system elements above 100 kV in and emanating from the following regions: Wisconsin, Western Upper Peninsula of Michigan, Illinois, Eastern Missouri, Minnesota, Iowa and Eastern Nebraska.

The study also defined and monitored three "interfaces":

1. Arpin -- Eau Claire 345 kV line.
2. Prairie Island -- Byron 345 kV line.
3. Twin Cities Exports

Contingencies

All single branches, 100 kV and up, contained within and tied to the monitored regions were taken as contingencies, with one exception; Commonwealth Edison submitted a separate contingency list for all facilities located in their service territory. The ComEd list included many multi-segment contingencies and operating guides. Several utilities also submitted operating guides to implement in association with various 345 kV system contingencies.

Participation Factor Cutoffs

The transfer capability output reports identified segments with Power Transfer Distribution Factors (PTDF) greater than 2%. The study group only considered PTDFs greater than 3% as significant. Generally, segments with PTDFs less than 3% that appear as limitations in transfer studies have high initial base case flows associated with local area load serving problems.

2.2 Transfer Capability Sensitivity Studies

The modifications of the default source and sink lists provide a method to test the transfer capability robustness of each plan with respect to thermal limitations. The sensitivity analysis focused on the WUMS western interface and utilized a base case biased with WUMS southern imports totaling 1000 MW to properly compare the projects against the 3000 MW simultaneous import design criteria.

Source Sensitivity

The base transfer capability study utilized 700 MW of unplanned generation at the Gentleman and Antelope Valley sites, combined with load scaling in western MAPP, as source points for WUMS imports. The source sensitivity replaced the unplanned generators with a generation unit at the Lakefield Junction 345 kV substation (in southwestern Minnesota) and continued to use load scaling in western MAPP to free up capacity for exports. Transfer capability limits were chosen in a manner consistent with the base study.

Sink Sensitivity

The base transfer capability study used all WUMS generation as sink points for transactions. The sink sensitivity utilized the following five generator sites:

Columbia Unit 1	514 MW
Edgewater Unit 5	372 MW
Oak Creek Unit 8	280 MW
Point Beach Unit 1	495 MW
Kewaunee Unit 1	530 MW

This sink methodology is consistent with past and present MAIN system capability studies and can summarize the impact of large unit outages on the eastern Wisconsin transmission system. Transfer capability limits were chosen in a manner consistent with the base study.

2.3 Transfer Capability Limit Results

The reinforcement of facilities limiting WUMS imports to levels below the 2000 MW/3000 MW design criteria were assumed to be part of the respective plan’s scope and subsequently included in the overall cost estimates. In an effort to identify the reasonable WUMS import level beyond the targeted criteria, all “simple” reinforcements were included in the plan scope until a "significant" limit was attained. "Simple" reinforcements included any or all of the following: terminal equipment upgrades, re-sagging of existing line conductor or the replacement of line conductor on existing structures. "Significant" limits generally required the complete reconstruction of an existing line or the addition of a new line to eliminate the transfer capability limitation identified in the transfer simulation.

The results of the maximum transfer capability with the default source/sink list and the maximum western interface transfer capability with the source and sink sensitivities are shown in the following tables. The results presented are based on thermal limitations only; other limitations (such as steady state voltage profiles, voltage stability, and dynamic stability) are discussed in subsequent sections of this report. The term FCTTC is the acronym for First Contingency Total Transfer Capability.

Plan	Description	Western Interface FCTTC With 1000 MW Southern Bias	
		(MW)	Limiting Element
1c	Salem-Fitchburg 345 kV	2208	Seneca-Genoa 161 kV
2e	Prairie Island-LaCrosse-Columbia 345 kV	2584	Wien-T Corners 115 kV
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2278	Nelson Dewey-Cassville 161 kV
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2269	Sand Lake-Port Edwards 138 kV
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2123	Nelson Dewey-Cassville 161 kV
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2753	Elk Mound-Barron 161 kV
10	King-Eau Claire-Weston 345 kV	2295	Nelson Dewey-Cassville 161 kV

Table 2.3- 1

Plan	Description	Southern Interface FCTTC With 1000 MW Southern Bias	
		(MW)	Limiting Element
1c	Salem-Fitchburg 345 kV	2445	Itasca-Tonne Blue 138 kV
2e	Prairie Island-LaCrosse-Columbia 345 kV	2373	Itasca-Tonne Blue 138 kV
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2125	Turkey River-Cassville 161 kV
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2145	Turkey River-Cassville 161 kV
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2005	Turkey River-Cassville 161 kV
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2396	Itasca-Tonne Blue 138 kV
10	King-Eau Claire-Weston 345 kV	2135	Turkey River-Cassville 161 kV

Table 2.3- 2

Plan	Description	Western Interface FCTTC With 1000 MW Southern Bias	
		Source Sensitivity (MW)	Sink Sensitivity (MW)
1c	Salem-Fitchburg 345 kV	2110	2160
2e	Prairie Island-LaCrosse-Columbia 345 kV	2550	2720
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2190	1860*
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2190	1880*
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2140	2160
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2810	2590
10	King-Eau Claire-Weston 345 kV	2200	1890*

* The Port Edwards - Sand Lake 138 kV limit removed with $6M expenditure to rebuild the line
* Next valid limit at 2150 MW

Table 2.3- 3

Tables 2.3-1 and 2.3-2 demonstrate that each reinforcement plan is capable of supporting simultaneous transfer capability of at least 3000 MW based on thermal limitations. Each plan is capable of at least 2000 MW of transfer capability across either the western or southern interface while simultaneously importing 1000 MW on the opposite interface (2000 + 1000 = 3000 MW). Some reinforcement plans support more incremental transfer capability above the 3000 MW objective than others do.

The western interface source/sink transfer capability sensitivity results shown in Table 2.3-3 show that all plans meet the 3000 MW objective when the sources are modified from the default. However, the sink sensitivity results show that Plans 3j, 5a, and 10 fall just short of the of the 3000 MW objective when the sink list is modified. The results demonstrate that the Port Edwards – Sand Lake 138 kV line is sensitive to changes in the sink (or import) participation point list. An expenditure of $6 million is required to remove the limitation and restore western interface transfer capabilities to the 2000 MW target. The $6 million estimate is not included in the construction cost estimates for Plan 3j, 5a, and 10 because the limitation surfaced in a sensitivity analysis to test for robustness.

2.4 AC Analysis – Determination of Reactive Voltage Support Requirements

All power transfer studies conducted in the Phase 1 evaluation utilized DC power flow techniques that identify thermal overload problems only. A DC power flow analysis assumes that system voltage profiles are held constant throughout the power flow simulation. However, voltage profiles throughout the transmission system are impacted when the system topology is changed due to the loss of a transmission element or when power transfers are initiated. In order to ascertain the voltage response of the system to these events, an AC power flow analysis is required.

The AC power flow analysis of the seven reinforcement plans was performed with PSS/E, a power system simulation package developed by Power Technologies, Inc. The AC power flow analysis considered transmission contingencies in Wisconsin and parts of Iowa, Minnesota, and Illinois. Resulting voltage profiles were monitored to determine voltage violations. Voltage profiles (especially voltages less than about 95% of nominal) can heavily impact the flow on the transmission system. For this reason, transmission system elements were monitored for thermal overload violations as well.

The WIREs 2002 summer base case, which was developed in Phase 1, was used for the AC power flow analysis. A small number of system modifications were made to the base case to correct minor modeling errors. The power flow model was then altered to simulate a western interface transaction of 2000 MW and a southern interface transaction of 1000 MW. Transactions from the west were simulated by reducing load within western MAPP companies and adding "unplanned" generation. Transactions from the south were simulated by increasing the output of existing generation in southern Illinois and ECAR. Section 2.1 of this report describes the default source/sink list used to simulate western and southern interface transactions.

An AC power flow analysis was conducted on this "3000 MW import" power flow case to determine first contingency voltage violations and to confirm the thermal transfer capabilities established with the DC power flow analysis. A second, yet highly critical, component of the AC power flow analysis is the identification and location of shunt capacitor banks required to support system voltage profiles. Shunt capacitor banks were added to the system in order to maintain a voltage of 90% of nominal during critical transmission contingencies.

2.5 AC ANALYSIS – REACTIVE VOLTAGE RESULTS

In general, the AC power flow analysis did not identify any thermal overload problems that were not observed in the DC power flow analysis. However, the 69 kV interface between Alliant-East and Dairyland Power Cooperative did exhibit thermal overloads for outages of the King – Eau Claire – Arpin 345 kV line. In particular, the Council Creek 69 kV interconnection and 69kV lines around the Tomah, Sparta, and Monroe Co. substations overloaded in the base case when a 3000 MW transaction is simulated. The implementation of regional accepted operating guides provided relief for the overloaded 69 kV interconnections. These 69 kV overloads were not identified in the DC power flow analysis because only those facilities 100 kV and above were monitored.

Shunt capacitor bank requirements were defined by adding static VAr compensators (SVCs) on various transmission buses where low voltages occurred in the base case. A SVC is a device that automatically adjusts its VAr output to hold voltages at a pre-defined set point. The physical size and location of switched capacitor banks were determined from the output of the SVCs. The study was then re-performed with the SVC replaced with switched capacitor banks to verify that the voltage support requirements for each reinforcement plan were correct. The following table shows the switched capacitor bank requirements (in MVArs) for each of the seven reinforcement plans:

Location	1c	2e	3j	5a	5b	9b	10
T-Corners	160	150	45	30	40	90	30
Hume	50	20	20	20	40	40	10
Rocky Run	80	80	40	50	40	80	40
Spring Green	18	18	18	18	18	18	18
Eden	27	27	27	27	27	27	27
Kirkwood	18	18	18	18	18	18	18
Highway 8 Tap	---	---	250	160	250	---	---
Weston	---	---	20	---	---	---	---
Hillsboro	20	20	20	20	20	20	20
Arrowhead	---	---	120	---	---	---	---
Total	373	333	578	343	453	293	163

Table 2.5- 1

Table 2.5-1 shows that the capacitor bank requirements vary from 163 MVArs for Plan 10 (King - Eau Claire - Weston 345 kV) to 578 MVArs for Plan 3j (Arrowhead - Weston 345 kV). The capacitor bank requirements for Plans 3j, 5a, and 5b are driven by the fact that these options do not “stop” at an existing substation that already contains reactive support. For example, Plan 10 “stops” at the Eau Claire substation which already contains a substantial amount of capacitor banks (320 MVArs).

2.6 AC Analysis – Verification of Transfer Capability

Included in the Phase II analyses were full AC power flow solutions for the full set of contingencies. The full AC power flow solutions identified a number of line segments that would overload with an intact system or under a first contingency without any incremental transfers. In reviewing the output from these “base case” power flow solutions, many of the same “base case” problems were identified in each of the reinforcement plans. To assist in evaluating the impact of the “base case” problems, two tables were developed showing the loading on these lines.

The first table “ACCC Comparison-Intact System” included as Appendix A1, compares the performance of the each plan and to the base case without any transfers for an intact system. The results show small differences between the reinforcement plans. Of more importance, this table also shows the small increase in flow on these line segments as transfers are increased to 3000 MW (2000 MW West, 1000 MW South). This small increase in flow during transfers indicates that flow on these facilities is primarily caused by local area load serving requirements rather than by transfers. Also shown in this table is the impact of increased generator reactive power (VAr) output to support system voltages during transfers. Additionally, the increased power (MW) output of some of the area swing generators to supply the losses is illustrated.

The second table “ACCC Comparison-Selected Contingencies” included as Appendix A2, compares the performance of the options for selected contingencies. These include outages of several 345 kV lines into Wisconsin. The operating guides associated with these outages are also shown. In reviewing this table, the relative performance of the reinforcement plans is more pronounced than in the table for the intact system. For example, the two plans which terminate at Columbia (Plans 2e & 9b) substantially increase the flow on the Columbia - South Fond du Lac 345 kV line. Similarly, Plans 1c, 2e and 9b have a lesser impact on the Paddock - Wempleton 345 kV line than the other plan.

Chapter 3 GENERATOR RESPONSE TO SWITCHING (Delta-P)

3.1 Background

“Delta P” is defined as the sudden change in average power experienced by a generating unit at the instant following a transmission system switching operation (t=0+). The number is expressed in per unit (p.u.) calculated on the generator rated MVA base.

The Weston generating units, located in central Wisconsin and near the Arpin – Eau Claire interface, have experienced large power swings associated with the re-closure of the Arpin—Eau Claire 345 kV line. When this line is open, a phase angle difference between the western and eastern Wisconsin transmission systems is imposed; this is known as the Arpin phase angle problem. Past operating experience has indicated that in order to avoid damage to the generators at the Weston plant due to large power swings, the 345 kV breaker at Arpin should only be closed when the phase angle difference is 60 degrees or less. The Arpin phase angle limitation is a “proxy” limit for the maximum instantaneous power change on the Weston power plant generators before damage is sustained.

Analysis of the present day system calculated the Weston "delta P" corresponding to an Arpin 345 kV breaker re-close with a phase angle difference of 60 degrees. The calculations demonstrated that Weston Unit #3 would experience a “delta P” of 0.372 p.u. when the Eau Claire – Arpin 345 kV line is closed across a 60 degree phase angle.

For each reinforcement alternative, the study calculated the Weston Unit #3 “delta P” associated with a re-close of the Arpin 345 kV breaker assuming WUMS simultaneous import levels of 2000 MW from the west and 1000 MW from the south. If the resultant “delta P” is less than 0.372 p.u., the re-close was considered successful/permissible. Higher “delta P”s indicated a degradation when compared to the criteria used to operate today's system.

3.2 Delta-P Results

The following table presents the results of the Weston generator response to the switching of the Arpin – Eau Claire 345 kV line.

Impact of an Arpin - Eau Claire 345 kV Reclose on Weston Generator Unit #3

Reinforcement Option	Total WUMS Import (MW)	Weston #3 delta P (pu)		delta P Reduction at Max. Import
Base System	700 MW (550w/150s)	0.372	(1)	0.000
1c	3000 MW (2000w/1000s)	0.385		-0.013
2e	3000 MW (2000w/1000s)	0.357		0.015
3j	3000 MW (2000w/1000s)	0.336		0.036
5a	3000 MW (2000w/1000s)	0.206		0.166
5b	3000 MW (2000w/1000s)	0.308		0.064
9b	3000 MW (2000w/1000s)	0.363		0.009
10	3000 MW (2000w/1000s)	0.125		0.247

Notes:
(1) This is the existing sytem delta-P limit for Weston #3 with a 60 degree Arpin phase angle separation.

Table 3.2- 1

Table 3.2-1 demonstrates that each of the reinforcement plans except Plan 1c (Salem – Fitchburg 345 kV) result in a delta-P of less than the 0.372 per unit criterion at a simultaneous import of 3000 MW. At the 3000 MW level, Plan 1c exceeds the 0.372 per unit criterion by 0.013 per unit. Therefore, the transfer capability of Plan 1c is slightly less than 3000 MW due to the Weston #3 delta-P limit. This study did not attempt to determine the maximum western interface transfer capability (with the 1000 MW southern "bias") of Plan 1c at which the Weston delta-P limit is reached.

CHAPTER 4 DYNAMIC STABILITY

4.1 INTRODUCTION

Dynamic stability is the measure of the system's ability to react to a major system disturbance such as a short circuit on a transmission line, the opening of a line, the loss of a large generator, or the switching of a major load. Dynamic stability evaluates the ability of the system's generation units to remain synchronized and to "recover" from a system disturbance.

Dynamic stability analysis was performed as part of the WIRES Phase 2 study in order to assess the short term, dynamic performance of each reinforcement plan in response to major system disturbances. The response to known severe disturbances as well as disturbances involving the new transmission facilities were addressed.

The primary study objectives were to:

1. Evaluate the dynamic stability performance of each reinforcement plan at the WUMS 2000 West, 1000 South import condition.
2. Assess the ability of each plan to eliminate Eau Claire – Arpin cross tripping.
3. Assess the impact of each plan on the MAPP ¼ Hertz mode of oscillation.
4. Define the dynamic reactive power requirements needed to meet stability criterion for each plan.
5. Determine the potential increase in the Minnesota - WUMS stability limit achievable with each plan.

4.2 RESULTS

4.2.1 STUDY PROCEDURE

Model Development

This study was performed using the dynamic stability portion of the PSS/E power system analysis software. Due to the fast track nature of the study and the limited availability of WUMS area stability models, the study group chose to use a MAPP dynamics model which has had extensive use within MAPP for analysis of stability limited interfaces such as North Dakota, Manitoba – U.S., and Twin Cities 345 kV.

An updated WUMS representation including generator dynamics data was added to the model to provide an accurate representation within the WUMS area. Power flow model development is discussed further in section 4.2.2.

Study Criteria

This study adhered primarily to the study criteria defined in Appendix G of the MAPP Operating Studies Manual prepared by the MAPP Operating Review Subcommittee Working Groups as well as those defined in the MAPP System Design Standards. These criteria include transient bus voltage limitations, generator rotor angle oscillation damping and out of step relay margin limitations.

Since the WUMS area has not developed specific criteria for dynamic stability analysis, the MAPP standard values were used. For transient bus voltage limitations, a minimum of 0.7 p.u. and a maximum of 1.2 p.u. following fault clearing was used.

For generator rotor angle damping, a minimum damping ratio criterion of 0.05 p.u. was established. This ratio is obtained using Prony analysis which calculates eigenvalues for each major mode of oscillation. The current MAPP operating study criteria is a minimum damping ratio of 0.00816 for disturbances with faults and 0.0168 for line trips. The 0.05 p.u. criterion was selected to be consistent with the proposed MAPP planning standard.

Selection of Critical Disturbances

The disturbances studied included 15 MAPP, 25 WUMS, and all combinations of new facility fault/trip scenarios. The MAPP disturbances included North Dakota, Manitoba – U.S. 500 kV, and Twin Cities 345 kV normal and delayed clearing breaker failure faults. In the WUMS areas, normal and delayed clearing faults in both the Weston – Rocky Run and Columbia areas were studied. The new facility faults included normal clearing 3 phase faults at each line terminal of each line segment and a limited number of proxy breaker failure scenarios.

Description of Data Output

The primary output from dynamic stability analysis is time versus amplitude data for a specified set of monitored parameters or channels. A subset of these channels, usually the most critical quantities, are graphically plotted on paper for visual inspection. For this study, a standard set of channels typically used for northern MAPP stability analysis were monitored and analyzed. Additional channels were added to monitor critical busses and generators in the WUMS area such as Weston, Rocky Run and Columbia.

The MAPP stability analysis package also has automated routines that scan all output channels and stability runs in progress and will identify any study criteria violations. These routines, in addition, produce detailed reports that summarize all system conditions and criteria violations encountered for each simulation. Another routine generates summary tables that are compatible with Excel spreadsheets. These tables, referred to as “Stability Summary Tables”, are included with this report and document every simulation performed during the course of the study.

Since this study involved a great deal of comparative analysis between plans, special overlay plots were produced that compare critical bus voltages and generator angles for key disturbances.

4.2.2 BASE CASE ASSUMPTIONS

A stability base case *(wb-sraa.uvj04Y4)* was developed from the MAPP 2002 summer off-peak model with high simultaneous export conditions of 1975 MW Manitoba (MHEX), 1950 MW North Dakota (NDEX), and 1350 MW Twin Cities 345 kV (TCEX). This model was based on the standard 1997 series MAPP models and was selected because the off-peak, high export condition has been determined to be the most stressed for dynamic stability.

Power flow cases for each of the seven WIREs plans studied were created from the stability base case using IDEVs developed for the WIREs AC analysis study path which were modified to match MAPP bus numbering conventions. Switched capacitors were added for each plan according to the levels determined by the AC analysis.

The WUMS 2000 MW west – 1000 MW south import condition was simulated by setting the WUMS region to 100% peak load, removing "fake" peaking generation, and reducing generation to approximately 85% of nominal. To cover the deficit WUMS generation, loads in Illinois (SIPC, EMO, IP, CILCO, CWLP, CIPS, and CI) were reduced proportionally. This biasing methodology yielded WUMS interface line loading flows that were comparable to those found in the base cases used by the other WIREs Phase 2 study paths.

Table 4.2.2-1, shown below, summarizes the power flow cases that were created for the various reinforcement plans.

Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
Base	Wb-sraa.uvj04Y4	1975	1950	1350
1c	1c-sraa.uvj04Y4	1975	1950	1328*
2e	2e-sraa.uvg04Y4	1975	1950	1020*
3j	3j-sraa.uvg04Y4	1975	1950	1005*
5a	5a-sraa.uvf04Y4	1975	1950	910*
5b	5b-sraa.uvh04Y4	1975	1950	1117*
9b	9b-sraa.uvk04Y4	1975	1950	1395*
10	10-sraa.uvg04Y4	1975	1950	959*
* - TCEX flow following addition of new facilities				

Table 4.2.2- 1

Table 4.2.2-2 provides a summary of the WUMS interface flows for each of the plans. In this table, the flows from the stability power flow for Plan 3j are compared with those from the WIREs 3j AC analysis model.

Additional power flow documentation is included in Appendix B1.

	WIRES + 3j	MAPP 1c Bias	MAPP 2e Bias	MAPP 3j Bias	MAPP 5a Bias	MAPP 5b Bias	MAPP 9b Bias	MAPP 10 Bias
Minn – WUMS								
Eau Claire - Arpin 345 kV	753	908	857	773	704	831	860	742
Mauston 69 – Hilltop 69	23	27	26	24	22	25	24	22
T Corners 115 – Wien 115	66	86	77	52	36	60	71	44
Oakdale 69 – Council Crk 69	5	9	10	6	4	7	9	5
T TC 69 - Council Crk 69	48	59	57	55	49	55	49	50
Ned 161 - Ned 138	3	96	113	130	123	136	101	129
Bell Center 69 – Hillside 69	13	13	12	13	12	12	11	13
Sub-total	911	1198	1152	1053	950	1126	1125	1005
Arrowhead – Highway 8	471			495				
Prairie Island – Columbia			532					
Apple River – Hiway 8 Tap					679	353		
Eau Claire – Weston								576
Total Minn – WUMS	1382	1198	1684	1548	1629	1479	1125	1581
WUMS – South								
Wempleton – Paddock 345	889	727	776	866	837	878	743	848
Zion - Arcadian 345	296	256	261	252	235	268	256	245
Zion - Pleasant Prairie 345	184	109	119	110	77	137	107	95
Salem – Fitchburg		490						
Genoa – Columbia							554	
Total WUMS – South	1369	1582	1156	1228	1149	1283	1660	1188
Total WUMS	2751	2780	2840	2776	2778	2762	2785	2769
Manitoba Export (MHEX)	1940	1975	1975	1975	1977	1976	1976	1976
North Dakota Export (NDEX)	1100	1950	1940	1950	1942	1942	1942	1941
Twin Cities 345 Export (TCEX)	864	1322*	1007	1048*	910*	1117*	1395	959*
Northern MAPP East Bias		267	288	304	293	282	267	283

Table 4.2.2-2 – Summary of WIRES Stability Powerflow Cases

4.2.3 DYNAMIC STABILITY STUDY RESULTS

MAPP Disturbances

As discussed above, several of the worst known North Dakota, Twin Cities, and Manitoba – U.S. 500 kV MAPP disturbances were studied to test the dynamic robustness of each of the WIRES plans.

The MAPP disturbances studied included:

AG1	4 cycle slgf @ Leland Olds 345 on Ft. Thompson line, Leland Olds breaker 2692 stuck. Clear @ 11 cycles by tripping faulted line.
EI2	Permanent bipole fault on the CUDC line. Both Coal Creek units tripped at 0.30 sec.
EJ2	Permanent bipole fault on the Square Butte dc line. No Young unit 2 tripping.
MQS	Single line to ground fault with breaker fail at Sherco with 8N28 stuck. Trip Sherco generator 3.
MSS	Single line to ground fault with breaker fail at Sherco with 8N32. Trip Sherco to Coon Creek 345 kV line.
MTS	Single line to ground fault with breaker fail at Monticello with 8N6 stuck. Trip Monticello to Elm Creek 345 kV.
NBS	Three-phase fault at Chisago on Chisago County-Forbes 500 kV line.
MAD	4 cycle 3 phase fault at Dorsey 500 kV. Clear the Dorsey - Forbes 500 kV line.
NAD	4 cycle 3 phase fault at Forbes 500 kV. Clear the Forbes - Dorsey 500 kV line.
MAT	Dorsey - Forbes line trip without a fault.
OAS	single line to ground fault with breaker fail at Dorsey with 602L stuck. Trip D602F.
PCS	Single line to ground fault with breaker fail at King with 8P6 stuck. Trip King - Eau Claire - Arpin 345 kV line and King to Chisago County 345 kV line.
PCT	Trip King - Eau Claire - Arpin 345 kV line and King to Chisago County 345 kV line without fault
PDS	Single line to ground fault with breaker fail at King with 8P6 stuck. Trip King - Eau Claire 345 kV line and King to Chisago County 345 kV line.
PDT	Trip King - Eau Claire 345 kV line without a fault
PET	Trip Eau Claire - Arpin 345 kV line without a fault
PYT	Trip of Prairie Island – Byron 345 kV without a fault
PYS	14 cycle SLG fault at Prairie Island 345 kV, trip Prairie Island-Byron 345 kV line.

In general, all plans met established transient voltage and rotor angle criteria.

The North Dakota disturbances tested, (AG1, EI2, EJ2), demonstrated that there was little impact from the WIREs facilities on critical North Dakota busses. The Groton 345 kV transient voltage was well above criterion and varied less than 1% between plans for these disturbances.

The Manitoba – U.S. 500 kV disturbances tested, (NBS, MAD, NAD, MAT, OAS), also met all criterion and did not indicate any degradation in Manitoba – U.S. transfer capability. Plan 3j does improve dynamic performance somewhat for the NBS disturbance by improving the transient voltage performance at the Whapeton 230 kV bus. The Arrowhead – Weston line provides an additional dynamic outlet from the MP system during the South 500 kV (Chisago – Forbes) to North 500 kV (Forbes – Dorsey) cross-tripping sequence.

The Twin Cities disturbances tested, (MQS, MSS, MTS, PCS, PCT, PYT, PYS), met criterion but demonstrated some differences in performance between the WIREs plans. The most pronounced differences were observed for disturbances involving a loss of either of the major Twin Cities 345 kV outlet facilities. For either a loss of the King – Eau Claire – Arpin (PCS) or the Prairie Island – Byron 345 kV (PYS) transmission lines, differences in transient voltage performance at MAPP and WUMS area busses and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode is currently a stability limiting condition for Twin Cities 345 kV export and is discussed further below. Following the PCS disturbance, voltages in the Weston/Rocky Run area are more transiently depressed for plans 3j, 5a, 5b and 10. All of these plans terminate in the Weston area and subject it to dynamic post-contingency loading following the loss of the King – Eau Claire – Arpin line.

Appendix B2 contains stability summary tables for all cases run and overlay comparison plots for selected disturbances.

<u>Eau Claire – Arpin Crosstrip Assessment</u>

Three Twin Cities disturbances (PDS, PDT, PET) were run to assess the impact eliminating the cross tripping between the King – Eau Claire and the Eau Claire – Arpin 345 kV lines. All plans performed acceptably with the exception of 5b which had minor voltage violations in western Wisconsin for the PDS disturbance. It was assumed that these violations could be mitigated with additional reactive support.

<u>¼ Hertz Mode Damping</u>

The ¼ Hertz mode has been observed in MAPP system stability analysis for many years and can be characterized as an oscillation where MAPP and MAIN are swinging together at approximately 0.25 Hertz against the eastern equivalent. It has traditionally been well behaved and positively damped. In recent years, however, as transfer levels have increased, it has become a primary consideration for establishing the Twin Cities 345 kV export stability limits under system intact and prior outage conditions. Damping of this mode has been found to be critical following a loss of the

King – Eau Claire – Arpin (PCS) or the Prairie Island – Byron 345 kV (PYS) transmission lines.

To assess modal damping, simulations are run out to 15 seconds to capture several cycles of oscillation. Mathematical analysis using Prony techniques is then performed on generator rotor angles to determine effective damping ratios. As discussed earlier a minimum damping ratio criterion of 0.05 p.u. was established for this study.

All reinforcement plans met the study criterion at the 2000 – 1000 WUMS import level for both the PCS and PYS disturbances. Table 4.2.3-1 below summarizes the damping ratios calculated for each plan. For this analysis, damping ratios for the NSP Sherco 3 generator and MH Dorsey synchronous condensers were averaged to obtain a final value.

Plan	PCS (p.u.)	PYS (p.u.)
1c	0.087	0.055
2e	0.099	0.106
3j	0.088	0.100
5a	0.115	0.103
5b	0.093	0.077
9b	0.083	0.068
10	0.138	0.095

Table 4.2.3- 1

Incremental Transfer Capability Assessment

Since the damping of the ¼ Hertz oscillation mode is also dependent on transfer levels, additional stability analysis was performed to determine an incremental transfer capability (ITC) level for each plan. This was defined as the level of incremental transfer at which each plan satisfies the 0.05 p.u. damping ratio criterion following a loss of either the King or Prairie Island 345 kV lines.

Two increased transfer level cases, +300 MW and +600 MW, were created for each plan by reducing load in North Dakota and Minnesota and proportionally increasing load in the eastern equivalent. This had the effect of increasing MAPP export while maintaining the 2000 – 1000 WUMS import condition. Due to parallel path flow effects, a significant portion of this flow appears on and further stresses the MAPP – WUMS interface. Tables 4.2.3–2 and 4.2.3-3 below summarize the power flow cases utilized for this analysis.

+ 300 MW MAPP to East Transfer				
Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
1c	1c-sraa.vvl04Y4	1975	1990	1457*
2e	2e-sraa.vvh04Y4	1975	1987	1211*
3j	3j-sraa.vvh04Y4	1975	1988	1112*
5a	5a-sraa.vvgf04Y4	1975	1988	999*
5b	5b-sraa.vvl04Y4	1975	1989	1244*
9b	9b-sraa.vvm04Y4	1975	1990	1171*
10	10-sraa.vvh04Y4	1975	1988	1076*
* - TCEX flow following addition of new facilities				

Table 4.2.3- 2

+ 600 MW MAPP to East Transfer				
Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
1c	1c-sraa.wvn04Y4	1975	2037	1581*
2e	2e-sraa.wvi04Y4	1975	2034	1246*
3j	3j-sraa.wvi04Y4	1975	2034	1237*
5a	5a-sraa.wvif04Y4	1975	2035	1028*
5b	5b-sraa.wvk04Y4	1975	2035	1367*
9b	9b-sraa.wvo04Y4	1975	2036	1662*
10	10-sraa.wvi04Y4	1975	2034	1194*
* - TCEX flow following addition of new facilities				

Table 4.2.3- 3

Fifteen (15) second PCS and PYS simulations were run on each powerflow case and prony analysis was used to calculate damping ratios at each incremental power flow level. Linear interpolation was then used to find the ITC at the 0.05 p.u. criterion. During the investigation, it was discovered that the frequency damping control on the Square Butte HVDC transmission system, which terminates at the Arrowhead 230 kV substation, had a negative impact on the damping for Plan 3j. Therefore the damping ratios reported for 3j were obtained with the control disabled. It is assumed that the control would be re-tuned if Plan 3j were constructed. Table 4.2.3-4, shown below, summarizes the results.

		Damping Ratios		ITC at Criterion Linear
Plan	**0 MW**	**+300 MW**	**+600 MW**	**Interpolation**
PCS:				
1c	0.087	0.061	0.029	396 MW
2e	0.099	0.076	0.062	753
3j	0.088	0.075	0.032	448
5a	0.115	0.099	0.066	812
5b	0.093	0.068	0.030	431
9b	0.083	0.060	0.028	374
10	0.138	0.098	0.068	738

PYS:

1c	0.055	0.010	-0.053	50 MW
2e	0.106	0.085	0.059	717
3j	0.100	0.080	0.048	596
5a	0.103	0.080	0.055	672
5b	0.077	0.042	0.001	222
9b	0.068	0.024	-0.027	121
10	0.095	0.068	0.038	477

Table 4.2.3- 4

The ITC for each reinforcement plan is assumed to be the lower of the two (PCS and PYS) interpolated values. The final ITC values rounded to the nearest 10 MW are summarized below.

Plan	1c	2e	3j	5a	5b	9b	10
MW Incremental Transfer	50	720	450	670	220	120	480

<u>WUMS area disturbances</u>

The WUMS stability analysis focused on known problematic locations, specifically, the Columbia and Weston areas.

The WUMS area disturbances studied included:

WAS 3 phase fault on Columbia – Rockdale 345 kV line

WBS 3 phase fault on Columbia – South Fond du Lac 345 kV line

WCS 3 phase fault on Columbia – North Madison 345 kV line

WDS 3 phase fault on Columbia 400 MVA 345/138 kV transformer

WES 3 phase fault on Columbia 2-200 MVA 345/138 kV transformer

WFS 3 phase fault on Columbia – South Fond du Lac 345 kV line, Columbia breaker stuck

WGS 3 phase fault on Columbia – Rockdale 345 kV line, Columbia breaker stuck

WHS 3 phase fault on Columbia – North Madison 345 kV line, Columbia breaker stuck

WIS 3 phase fault at North Appleton on Rocky Run – North Appleton 345 line

WJS 3 phase fault at North Appleton on Rocky Run – North Appleton 345 line, breaker failure at North Appleton

WKS 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line

WLS 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run (18 cycle clearing)

WLZ 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run (14 cycle clearing)

WMS 3 phase fault at Arpin on Arpin – Rocky Run 345 line

WNS 3 phase fault at Arpin on Arpin – Rocky Run 345 line, 424-S breaker failure at Arpin

WOS 3 phase fault at Arpin on Arpin – Rocky Run 345 line, 627-S breaker failure at Arpin

WPS 3 phase fault at Rocky Run on Arpin – Rocky Run 345 line

WQS 3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run (16 cycle clearing)

WQZ 3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run (14 cycle clearing)

WRS 3 phase fault at Rocky Run on Rocky Run – Weston 345 line

WSS 3 phase fault at Rocky Run on Rocky Run – Weston 345 line, V-4 breaker failure at Rocky Run

WTS 3 phase fault at Weston on Rocky Run – Weston 345 line

WUS 3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure on Weston East 115 kV bus

WVS 3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure on Weston West 115 kV bus

WWS 3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure for future system with new 345 kV line into Weston

For the WUMS disturbances tested, all plans met established transient voltage and rotor angle criteria.

In the Weston area, the most severe disturbances were found to be the WLS and WNS cases which are 3 phase stuck breaker scenarios at Rocky Run and Arpin, respectively. Due to the severe nature of the fault, the voltage recovery at the Rocky Run, Weston and Arpin 345 kV busses is slow in comparison to other disturbances analyzed. This phenomenon was not negatively or positively impacted by any of the WIREs plans and is therefore considered to be a local area concern.

The Columbia area disturbances were found to be relatively moderate and were not negatively impacted by any of the WIREs plans.

Appendix B2 contains stability summary tables for all cases run and overlay comparison plots for selected disturbances.

<u>Maximum Columbia & Weston Generation and Breaker Failure Performance</u>

Since the 2000 -1000 WUMS import bias of the models used for dynamic stability analysis was achieved through an overall 80% generation reduction within WUMS, it was deemed necessary to perform additional sensitivity analysis with maximum generation levels represented at both Columbia and Weston. Of particular concern was the slow voltage recovery in the Weston area observed following delayed clearing 3 phase faults.

In the Columbia area, the WGS and WHS disturbances were re-run and found to be slightly impacted by increased generation. The post-fault voltage recovery was found to be slower at Columbia with maximum generation. Also, the immediate post-fault voltage was just below the 0.7 p.u. criterion for plans 2e, 3j, 5a and 5b, but was considered acceptable since it was recovering.

Of the cases re-run in the Weston area, two were found to be unstable with maximum generation. For both the WLS (3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run with 18 cycle clearing) and the WQS (3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run with 16 cycle clearing) disturbances, the Weston units lost synchronism with the rest of the power system. A reduction in breaker failure clearing times to 14 cycles for both disturbances (WLZ and WQZ) was required to maintain Weston generator stability and meet criterion. The new clearing times were tested with all reinforcement plans and found to be acceptable.

New Facility Disturbances

A series of simulations were run to assess the dynamic performance of normal clearing 3 phase fault sequences on each line segment of the various reinforcement plans.

The following disturbances were studied for each respective plan**:**

Plan 1c
VA3 3 phase fault at Salem on Salem – Fitchburg 345 kV line
VA9 3 phase fault at Fitchburg on Salem – Fitchburg 345 kV line

Plan 2e
VE3 3 phase fault at Pr Islnd on Pr Islnd – LaCrosse 345 kV line
VE9 3 phase fault at LaCrosse on Pr Islnd – LaCrosse 345 kV line
VF3 3 phase fault at LaCrosse on Columbia – LaCrosse 345 kV line
VF9 3 phase fault at Columbia on Columbia – LaCrosse 345 kV line

Plan 3j
VI3 3 phase fault at Arrowhead on Arrowhead – Hiway 8 Tap 345 kV line
VJ3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 345 kV line
VJ9 3 phase fault at Weston on Weston – Hiway 8 Tap 345 kV line

Plan 5a
VM3 3 phase fault at Chisago on Chisago – Apple River 345 kV line
VM9 3 phase fault at Apple River on Chisago – Apple River 345 kV line
VN3 3 phase fault at Apple River on Hiway 8 Tap – Apple River 345 kV line
VN9 3 phase fault at Hiway 8 Tap on Hiway 8 Tap – Apple River 345 kV line
VO3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 345 kV line
VO9 3 phase fault at Weston on Weston – Hiway 8 Tap 345 kV line

Plan 5b
VQ3 3 phase fault at Chisago on Chisago – Apple River 230 kV line

VQ9 3 phase fault at Apple River on Chisago – Apple River 230 kV line
VR3 3 phase fault at Apple River on Hiway 8 Tap – Apple River 230 kV line
VR9 3 phase fault at Hiway 8 Tap on Hiway 8 Tap – Apple River 230 kV line
VS3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 230 kV line
VS9 3 phase fault at Weston on Weston – Hiway 8 Tap 230 kV line

Plan 9b
VU3 3 phase fault at Lakefield on Lakefield – Adams 345 kV line
VU9 3 phase fault at Adams on Lakefield – Adams 345 kV line
VV3 3 phase fault at Adams on Genoa – Adams 345 kV line
VV9 3 phase fault at Genoa on Genoa – Adams 345 kV line
VW3 3 phase fault at Genoa on Genoa – Columbia 345 kV line
VW9 3 phase fault at Columbia on Genoa – Columbia 345 kV line

Plan 10
VX3 3 phase fault at King on King – Eau Claire #2 345 kV line
VX9 3 phase fault at Eau Claire on King – Eau Claire #2 345 kV line
VY3 3 phase fault at Eau Claire on Weston – Eau Claire 345 kV line
VY9 3 phase fault at Weston on Weston – Eau Claire 345 kV line

The normal clearing 3 phase faults were all found to be relatively minor disturbances and did not produce any criteria violations.

Dynamic Reactive Support Requirements

Since all reinforcement plans met the established dynamic stability criteria for the cases studied, it can be assumed that no additional dynamic reactive support is required to meet the study objectives.

4.3 CONCLUSIONS

In general, all plans met established transient voltage and rotor angle criteria for the WUMS 2000 MW west – 1000 MW south import transfer condition. No additional reactive voltage support (VAr) requirements, over and above those identified through the power flow analyses, were identified.

The most pronounced difference between the reinforcement plans was observed for disturbances involving a loss of a major Twin Cities 345 kV outlet facility. For a loss of either the King – Eau Claire – Arpin 345 kV or the Prairie Island – Byron 345 kV transmission line, differences in transient voltage performance within MAPP and WUMS and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode of oscillation is currently a stability limiting condition for the Twin Cities export (TCEX) limitation. The performance of ¼ Hz mode was also used to assess the incremental transfer capability (ITC) of each plan.

Some generator stability problems were identified in the Rocky Run area for delayed clearing breaker failure cases studied with maximum generation at Weston. These were found to be problems inherent in the base case and can be corrected with reduced failed breaker clearing times.

Chapter 5 VOLTAGE STABILITY

5.1 VOLTAGE STABILITY ANALYSIS, AND ITS IMPORTANCE

The topic of voltage stability deals with the challenge of ensuring the electric power transmission system has adequate reactive power supply capability to maintain all bus voltages at adequate levels, under both system intact and contingency conditions. Adequate operating margins or reactive supply reserve must be provided such that failure of any transmission system element (line, transformer, or bus section) or trip-out of any reactive power source (generator or capacitor bank) does not result in uncontrolled progressive decline of system voltages, which can result in system separation, under-voltage load shedding, or regional blackout.

Reactive power is the key to voltage control. Reactive power is measured in Volt-Amperes Reactive (VARs). Transmitting VARs an appreciable distance requires/causes a significant voltage difference, while another impediment to VAR transfer is that significant incremental VAR losses occur due to the series inductive reactance of the transmission lines and transformers. Since VARs "don't travel well", reactive supply is usually a highly-localized matter.

It is a characteristic of heavily-loaded transmission systems that reactive power consumption increases significantly following trip-out of a transmission interconnection. This is because the increased loading impressed upon the remaining parallel transmission circuits causes increased reactive losses. Since each circuit's reactive power consumption is proportional to the square of the line current ($Q = I^2X$) the post-contingent condition during high transfers often requires hundreds of MVAR additional reactive supply to maintain acceptable bus voltages. As explained previously, maintaining a satisfactory system voltage profile requires that these incremental reactive supply requirements be satisfied locally.

5.2 HOW THE PLANS' VOLTAGE STABILITY PERFORMANCE WAS STUDIED

Prior to activation of the WIRE Study Phase 2 technical analysis effort, the MAPP Transmission Reliability Assessment Working Group (TRAWG) had initiated a voltage stability study of the MAPP bulk power system. This study was for the purpose of analyzing--for the planned Year 2002 system configuration--the pre- and post-contingency power system performance for many source/sink transfer pairs, thereby enabling a determination of estimated power transfer limits as constrained by any voltage stability-imposed limitations which may be revealed. The TRAWG had contracted with Power Technologies, Inc. (PTI) to perform the power system simulations required and to provide a report summarizing the results observed and conclusions reached.

Consultations between the WIRE and TRAWG entities confirmed the desirability and feasibility of a coordinated voltage stability analysis effort. These consultations culminated in the decision to expand the scope of the PTI voltage stability analysis effort to include evaluation of the WIRE Study's seven Phase 2 transmission plans.

Because the TRAWG voltage stability effort was already under way, it was necessary to utilize the transfer source/sink definitions previously specified by the TRAWG. Of specific note is that the west-east power transfers (across the MAPP-WUMS interface) simulated in the TRAWG-initiated PTI analysis are structured in terms of MAPP-->MAIN source/sink pairs, and therefore represent a flow through WUMS to the postulated (MAIN) sink, whereas the WIRE study analyses were based on MAPP-->WUMS transfers, with a simultaneous MAIN-->WUMS transfer.

Consequently, the west-east power transfer capability MW limits identified in the TRAWG-initiated PTI analysis are not fully comparable with the other WIRE Study Phase 2 analysis efforts' results, due to the MAIN-WUMS interface not being held at a fixed loading. Notwithstanding this difference in analysis technique, it is possible to determine MAPP-WUMS interface loading at which the seven WIRE Study Phase 2 options exhibit voltage-related power transfer limitations.

5.3 VOLTAGE STABILITY RESULTS

As expected, the transmission options' voltage stability performance with respect to the MAPP-WUMS interface is determined by the degree to which the new transmission line reduces loading on the existing tie lines, and the degree to which the new line facilitates the delivery of reactive supplies to the Eau Claire/LaCrosse region where the voltage collapse phenomenon is first experienced.

Results of PTI's voltage stability analysis are summarized in the following table; PTI's full report, *Comparison of WIREs Reinforcement Alternatives* (PTI Report R21-99) is available as a separate reference document.

Plan	Description	Approximate W-->E Transfer Capability, MW
1c	Salem-Fitchburg 345 kV	2615
2e	Prairie Island-Columbia 345 kV	3245
3j	Arrowhead-Weston 345 kV	2615
5a	Chisago-Weston 345 kV	2865
5b	Apple River-Weston 230 kV	2865
9b	Lakefield-Columbia 345 kV	3105
10	King-Weston 345 kV	2865

Table 5.3- 1

Figure 5.3-1, shown below, graphically demonstrates the approximate Twin Cities export (TCEX) limits based on voltage stability limitations.

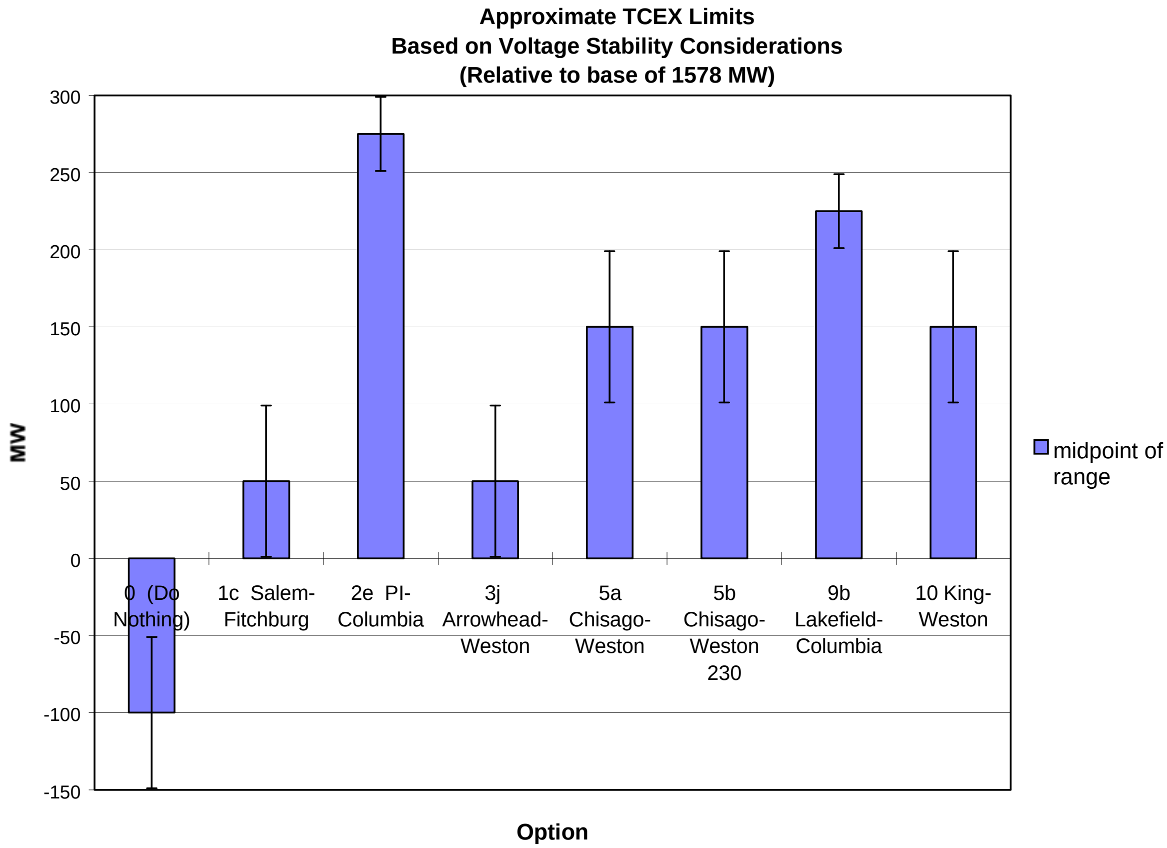

Figure 5.3- 1

5.4 Conclusions

All seven transmission reinforcement plans have adequate voltage stability performance with respect to the 2000 MW MAPP-->WUMS transfer capability criterion.

These voltage stability-constrained transfer limits are in all cases higher than the corresponding thermal or dynamic stability-imposed transfer limits associated with each transmission option. Consequently, although some transmission options appear to be more robust than others with respect to voltage stability performance, all options studied appear to be adequate to support a 2000 MW western interface transfer capability.

Chapter 6 MAPP FLOWGATE IMPACT

A flowgate is a set of one or more transmission lines common to a single interface. The MW flow on a flowgate allows a system operator to quickly determine the total flow across an interface. The total flow on a flowgate is the sum of the flow on each of the individual transmission lines that define the flowgate.

The WIREs study team evaluated the impact of each reinforcement plan on several flowgates defined for the MAPP region[2] by determining the flow on each flowgate with and without the reinforcement plan. Several other MAPP flowgates not significantly (>5% PTDF) impacted by imports into Wisconsin were not included in this analysis.

The change in flow on the flowgates were considered at the maximum simultaneous transfer level of 3000 MW (2000 MW western / 1000 MW southern). The results of the flowgate impact study are shown in the two tables below. The tables show the flow on each flowgate for the "base system" (without any reinforcements) and the flow with each reinforcement plan in service. The change in flow on each flowgate is expressed as a percent of the "base system" flow.

	COOPER_S		FT CAL_S		FT CAL_3459	
Reinforcement Plan	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)
Base System	378.9	0.0%	542.7	0.0%	470.2	0.0%
1c	348.8	-7.9%	534.8	-1.5%	466.2	-0.9%
2e	310.4	-18.1%	491.1	-9.5%	427.3	-9.1%
3j	323.2	-14.7%	500.5	-7.8%	432.9	-7.9%
5a	317.8	-16.1%	495.8	-8.6%	430.1	-8.5%
5b	334.8	-11.6%	512.4	-5.6%	445.3	-5.3%
9b	294.3	-22.3%	471.4	-13.1%	415.0	-11.7%
10	320.4	-15.4%	499.0	-8.1%	433.8	-7.7%

Table 6- 1

[2] Although MAIN defines a limited set of flowgates for coordination of ATCs with the MAPP and ECAR regions, the MAIN transmission system is typically thermally limited by single transmission elements.

	ECL-ARP		PRI-BYN		MN EX	
Reinforcement Plan	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)
Base System	929.6	0.0%	777.7	0.0%	2349.8	0.0%
1c	921.9	-0.8%	788.1	1.3%	2356.7	0.3%
2e	870.8	-6.3%	575.1	-26.1%	1935.8	-17.6%
3j	746.7	-19.7%	657.1	-15.5%	1951.5	-17.0%
5a	704.0	-24.3%	635.1	-18.3%	1865.2	-20.6%
5b	831.0	-10.6%	707.7	-9.0%	2191.9	-6.7%
9b	859.6	-7.5%	832.4	7.0%	2539.0	8.1%
10	742.0	-20.2%	649.2	-16.5%	1874.1	-20.2%

Table 6- 2

These tables show, that with few exceptions, the addition of a reinforcement plan to the system does not increase loading on the MAPP flowgates. Those flowgates which exhibit an increased flow due to the addition of a reinforcement plan are flowgates near the Twin Cities area whose definition would likely change if a new western interface transmission line is constructed. Therefore, these flowgates are not necessarily defined appropriately in a post-reinforcement scenario but are included here for demonstration purposes.

CHAPTER 7 LOSS EVALUATION

7.1 IMPACT OF LOSSES

Each alternative reinforcement plan considered in this analysis would introduce unique loss features into the transmission system. An analysis was done to quantify the relative cost of losses among the plans. The costs are summarized in the form of an equivalent capital investment adjustment to the initial capital construction cost for each alternative.

The process computes the lifetime costs for the installed generating capacity and associated energy to serve the losses that would prevail for each alternative. Transmission losses are included for the MAPP, MAIN, and SPP Regions. The total costs for each plan are illustrated, as well as a more meaningful cost adder. The cost adder is based on subtracting the life time costs of the lowest cost alternative, from the cost of all alternatives.

Three components of adjusted capital cost were computed. These are due to generation capacity to supply the losses, annual energy losses to serve load, and annual energy losses due to point-to-point transactions.

- **Capacity Cost** - Each plan causes the greatest demand for losses at some planned transfer level condition. In the cost evaluation, the maximum amount of loss caused by a plan is assigned a cost of 400 $/kW. The resulting cost represents the cost for installed generating capacity that would be required to serve the losses.

- **Energy Loss for Load** - Each plan has energy losses associated with the annual hourly loss that occurs as the load pattern is served. The annual energy lost as a consequence of serving load is priced out at 15 $/MWh. The resulting annual energy cost is equated to a levelized annual carrying charge. The annual carrying charge dollars are then converted to an equivalent capital investment, by dividing by 15 %.

- **Energy Loss for Transactions** - Each plan has energy losses that are required to support the various point-to-point transactions that are planned. After determining the annual energy associated with the point-to-point transactions, a capital investment is computed by dividing by 15 %.

7.2 SIMULATION OF POINT-TO-POINT TRANSACTION LEVELS MODELED IN POWER FLOW CASES

The loss analysis was accomplished by constructing AC power flow cases to represent various combinations of transactions. In all, eleven sets of various import and export combinations were developed to quantify the losses. From these cases, the incremental loss difference between plans is determined and economic loss values are applied to summarize the loss performance of each plan.

Base cases from each of the proposed WIRES study plans were used as a starting point. The imbedded transfers from the west (375 MW) and south (150 MW) were removed by adjusting generation in western MAPP, Illinois, ECAR and Wisconsin, so that the Wisconsin was zero. All known WIREs base case updates were included in the cases used to produce the loss information. This established the losses for each plan at the zero transfer level. This established one of the eleven sets of power flow base cases (also shown in Table 7.3-3).

The remaining Ten transfer cases for each plan were developed by utilizing generation changes to simulate power transfers relative to the zero transfer level. To avoid unrealistic flow patterns, generators were not increased beyond their maximum output levels. The assumption of 700 MW of new generation in the western MAPP region was carried forward from the earlier WIREs transfer simulations and used in the instances where 2000 MW of transfer was required from the western MAPP region. The only exception to utilizing generation to simulate transfers occurred when 1000 MW or 2000 MW was required from the west. In those instances there was not enough generation available so load was scaled down in MAPP to provide some of the transfer. For 1000 MW of transfer, 625 MW of load was scaled in Western MAPP. For 2000 MW transfer, 925 MW of load was scaled.

7.3 Loss Evaluation - Results

Table 7.3-1 illustrates the total up front costs to pay for the entire loss obligation of each plan over its useful life. Table 7.3-1 demonstrates the capital cost required to supply the capacity for “on-peak” losses, the annual energy loss to serve local area load, and the annual energy loss due to point-to-point transactions. The equivalent capital cost adders for each of the three loss components is shown in millions of dollars.

	Loss Profile		**Equivalent Capital Cost Due to Losses [millions of $]**			
Plan Description	Peak Losses At Zero Transfer [MW]	Relative to Lowest Loss Plan (MW)	Capacity Cost	Energy Loss For Load	Energy Loss For Xacts	**Total (M$)**
Plan 1c Salem – Fitchberg 345 kV	3,975	24	$ 1,867	$ 1,045	$ 136	$ 3,047
Plan 2e Prairie Is – Columbia 345 kV	3,973	22	$ 1,852	$ 1,044	$ 128	$ 3,024
Plan 3j Arrowhead – Weston 345 kV	3,951	0	$ 1,836	$ 1,038	$ 123	$ 2,997
Plan 5a Chisago – Weston 345 kV	3,956	5	$ 1,836	$ 1,040	$ 122	$ 2,998
Plan 5b Apple River - Weston 230 kV	3,970	19	$ 1,860	$ 1,043	$ 132	$ 3,035
Plan 9b Lakefield – Columbia 345 kV	3,980	28	$ 1,851	$ 1,046	$ 128	$ 3,026
Plan 10 King – Weston 345 kV	3,968	17	$ 1,849	$ 1,043	$ 126	$ 3,017
Pre-plan System	4,002	50	$ 1,892	$ 1,052	$ 147	$ 3,091

Table 7.3- 1

Table 7.3-2 illustrates the differences among plans relative to the lowest cost plan for each of the three individual loss components. The net composite capital cost adder shown in the last column is the difference between the total capital cost of the least loss expense plan and the remaining plans. These results demonstrate that Plan 3j (Arrowhead – Weston 345 kV) creates the smallest economic burden from a loss perspective.

	Equivalent Capital Cost Adder Due to Losses [millions of $]				
Plan Description	Capacity Cost	Energy Loss For Load	Energy Loss For Xacts	Sum Of Difference	**Composite Net Adder (M$)**
Plan 1c Salem - Fitchberg 345 kV	$31.0	$6.3	$13.8	$51.1	$50.2
Plan 2e Prairie Is – Columbia 345 kV	$16.4	$5.7	$6.0	$28.1	$27.2
Plan 3j Arrowhead - Weston 345 kV	$0.0	$0.0	$0.9	$0.9	$0.0
Plan 5a Chisago - Weston 345 kV	$0.9	$1.3	$0.0	$2.3	$1.4
Plan 5b Apple River - Weston 230 kV	$24.1	$5.0	$10.5	$39.6	$38.7
Plan 9b Lakefield - Columbia 345 kV	$15.9	$7.5	$6.5	$29.9	$29.0
Plan 10 King – Weston 345 kV	$13.4	$4.4	$3.8	$21.7	$20.8
Pre-plan System	$56.7	$13.2	$25.2	$95.2	$94.3

Table 7.3- 2

The capital adjustment for point-to-point transactions in Table 7.3-1 depends on the load factor of the transactions. In other words, the energy to supply the losses depends on how long the transfers are sustained at various operating levels on an annual basis. Due to the varying degrees of point-to point transmission usage that can occur, the annual energy losses for transactions were computed for each plan over a range of potential operating conditions. Both Tables 7.3-1 and 7.3-2 use the weighting of point-to-point transactions as illustrated in Table 7.3-3. For example, 5% of the time a 2000 MW import into WUMS from the West and a 1000 MW import from the South is one operating point along with, 40% of the time at a 1000 MW West import and 0 South import, etc.

Scenario For P-to-P Loss Calculation
[% of Time at Transfer Condition]

		West Import Schedule		
		0	1000	2000
South Import Schedule	2000	0%	5%	N/A
	1000	0%	10%	5%
	0	35%	40%	5%
	-1000	N/A	0%	0%
	-2000	N/A	N/A	0%

SUM = 100 %

Table 7.3- 3

Similarly, the energy loss for load depends on how long the load is sustained at various operating levels. However, an annual load pattern is sufficiently predictable, so that the resulting cost for energy loss for load is a constant for each plan. The annual energy to serve load in each plan has been set at 30% of the energy that would be lost if the peak load occurred all hours in the year. Since the load is the same for all plans, it follows that the unique electrical characteristic for each transmission plan is the only factor affecting the energy lost to serve load.

Table 7.3-4 shows the effect of the capital cost loss adders for each region separately relative to the plan with the smallest equivalent capital cost adder for losses. Loss adders were calculated for each region separately (while ignoring the other two regions). Then the three regions (MAPP, MAIN, and SPP) are recombined in Table 7.3-4 to create the percent shares shown in the three right columns. The base combined dollar adder column in Table 7.3-4 (to which the percents apply) is identical to the right hand column in Table 7.3-2. A negative share indicates that losses are actually reduced in that region.

	Equivalent Capital Cost Adder Due to Losses [millions of $]			
Plan Description	Composite Net Adder (M$)	MAPP Share	MAIN Share	SPP Share
Plan 1c Salem - Fitchberg 345 kV	$50.2	125%	-28%	3%
Plan 2e Prairie Is – Columbia 345 kV	$27.2	105%	-6%	2%
Plan 3j Arrowhead - Weston 345 kV	$0.0	0%	0%	0%
Plan 5a Chisago - Weston 345 kV	$1.4	-732%	832%	0%
Plan 5b Apple River - Weston 230 kV	$38.7	70%	29%	1%
Plan 9b Lakefield - Columbia 345 kV	$29.0	114%	-16%	2%
Plan 10 King - Weston 345 kV	$20.8	53%	47%	0%

Table 7.3- 4

Chapter 8 CONSTRUCTION COST ESTIMATES

8.1 WIREs Cost Estimate Development Process

The cost estimates for the WIREs transmission project plans are made up of three parts, as shown in the WIREs Cost Estimate Summary sheets (***Appendix C1***). These three parts are Cost of New Transmission Lines, Cost of Substation Terminal Improvements, and Cost of Associated Projects and Upgrades. There is one summary sheet for each plan, with total costs listed at the bottom of each sheet.

There is one item to be noted regarding the summary sheet for Plan 5b. On the summary sheet plan 5b is titled “Apple River-Weston 230 kV” rather than “Chisago-Weston 230kV”, and has been cost estimated with new 230 kV line construction beginning at Apple River rather than Chisago. This has been done to accurately reflect the inclusion of the Chisago-Apple River 230 kV line project in the base case used for the WIREs analysis.

Cost of New Transmission Lines

The cost estimates for the new transmission lines were developed by Black & Veatch (B&V), a transmission consultant retained by WRAO for this purpose. The assumptions, clarifications, and methods used by B&V to develop the cost estimates are listed in ***Appendix C2***. B&V’s full report, titled *Wisconsin Interface Reliability Enhancement Study Cost Estimates,* is available upon request.

The transmission line cost estimates were developed based on the study areas defined for each plan by an environmental consultant, Resource Strategies Inc. (RSI), working with WRAO and the WIREs group on the study. RSI used desired line endpoint and midpoint information provided by the WIREs group to determine the most feasible high level study corridors, from an environmental perspective, for the new lines. For all plans except plan 9b, two distinct alternate study areas were identified for each plan.

Two estimates for each alternate study area were developed – one for single circuit construction and one for double circuit construction. The single circuit estimate assumed construction of a completely new line through the study area, utilizing corridor sharing with existing transmission or transportation corridors where feasible. The double circuit estimate assumed construction of new shared structures with existing transmission lines in the study area where feasible. B&V used cost per mile figures determined for the first alternate study area to calculate the costs for the second alternate study area for each plan. The calculation methodology is explained in ***Appendix C2***. An additional worksheet is included which illustrates more directly which figures were used to calculate the ultimate cost estimates for each transmission line plan (***Appendix C2a)***. A detailed component cost breakdown of each estimate is also included (***Appendix C2b)***.

Additionally, for plans 3j, 5a, and 5b the Alternate 1 study area enabled the inclusion of facilities (listed as Highway 8 Tap -- Highway 8 115 kV transmission line) to address local load serving needs. The cost estimate for this local load serving line addition was supplied by Wisconsin Public Service and is included in the total cost estimate for the Alternate 1 study area for those plans.

Cost of Substation Terminal Improvements

The cost estimates for the substation terminal additions and enhancements required for each WIRES plan were developed by the utilities whose service territories include the affected substations. B&V supplied standard substation component costs and assumptions (***Appendix C3***) which were used by each utility to determine the estimated cost for these improvements.

For plans 3j, 5a, and 5b, the additional substation facilities required to support the local load serving project as noted above are included in the total cost estimate for the Alternate 1 study area.

Cost of Associated Projects and Upgrades

The associated projects and upgrades are various system improvements necessary for the plan under consideration to achieve the required power transfer and performance goals. These projects and upgrades are in addition to the new transmission line(s) and must be constructed along with the line(s) to achieve the required performance levels. These projects and upgrades are not already included in the planning models as base case facilities; they are additions to the base case facilities and thus are specifically listed and estimated for each plan. The cost estimates for these projects were developed by the utilities whose service territories include the affected facilities.

Some associated projects and upgrades are common requirements for multiple plans, and some are unique to a single plan (***Appendix C4***). Two projects which are common to all plans, “Plano-Plano Tap 345 kV line (ComEd)” and “Convert Oak Creek-Arcadian to 345 kV operation (WE)”, were listed in the summary sheets but their costs were not included in the total cost estimates for each plan. The two projects are excluded from the construction cost estimates because the regulatory approval process is underway for each.

Chapter 9 Evaluated Cost Proxy

The reinforcements plans presented in this report are intended to ensure the adequacy and security of the regional transmission system. An ancillary benefit of a major transmission expansion plan is the ability to address local load serving needs as customer load continues to grow. Several of the reinforcement plans presented in this report have the ability to address local load serving requirements.

Reinforcement Plans 2e (Prairie Island – Columbia 345 kV), 3j (Arrowhead – Weston 345 kV), 5a (Chisago – Weston 345 kV), and 5b (Chisago – Weston 230 kV) all have the ability to address certain local area load serving needs. To account for this benefit, the avoided cost of the local area load serving facilities was determined. The following table demonstrates the local load serving benefits associated with each project based on the "study areas" identified by the environmental analysis team. The study areas are referred to as "Study Area 1" and "Study Area 2". Notice that the study area dictates a plan's ability to defer or eliminate a local area load serving project.

	Avoided Local Load Serving Projects (base case facilities) ($ M)					
Plan	Study Area 1			Study Area 2		
	Facility	Cost	Year	Facility	Cost	Year
1c	none			none		
2e	LaCrosse Area Reinf	$1.8	2002	LaCrosse Area Reinf	$1.8	2002
3j	Upperwest Area Reinf	$10.5	2002	none		
5a	Upperwest Area Reinf	$10.5	2002			
	Chisago Co.-Apple R	$47.0	2002	Chisago Co.-Apple R	$47.0	2002
5b	Upperwest Area Reinf	$10.5	2002	none		
9b	none			none		
10	none			none		

Table 9- 1

An indicative "evaluated cost proxy" was determined for each reinforcement plan by considering the net impact of the construction cost, the equivalent capital cost adder for system losses, and the savings from avoided local load serving projects. The arithmetic sum of these three factors is a "proxy" for a more detailed economic analysis that considers the time value of money, inflation, etc.

The evaluated cost proxy, shown below, is shown as a range of values to account for the multiple study areas for each reinforcement plan. The range of costs is indicative of the magnitude of uncertainty associated with the study areas.

Evaluated Cost Proxy

	Single Circuit Construction ($M)		Potential Double Circuit Construction ($M)	
Plan	Study Area 1	Study Area 2	Study Area 1	Study Area 2
1c	$166.0	$195.0	$208.0	$277.0
2e	$194.8	$201.8	$268.8	$290.8
3j	$199.0	$176.8	$299.0	$265.8
5a	$148.5	$126.4	$227.5	$194.4
5b	$172.5	$156.6	$236.5	$209.6
9b	$255.5	-	$423.5	-
10	$156.8	$159.8	$230.8	$282.8

Notes:
- Evaluated Cost Proxy = Construction Cost - Avoided Local Load Serving Facilities + Capital Cost Adder for Losses
- Evaluated cost proxy not a full economic evaluation.

Table 9- 2

APPENDIX A1

ACCC Comparison – Intact System

COMMENTS		Rate	Base	1c	2e	3j	5a	5b	9b	10
These lines tie the 161 kV @ Monroe County with the 138 kV @ Council Creek and participate in the transfers. They are overloaded in the transfer case without any contingencies. Under high transfers the Council Creek bus tie would open.	872 COC 69.0 - 67600*T TC 69.0	50.0	28.9	60.4	57.7	53.8	51.8	58.9	53.1	53.8
	67600 T TC 69.0 - 67602*TOMAH 69.0	47.0	34.2	65.0	62.3	58.5	56.4	63.4	57.7	58.4
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	47.0	35.8	66.6	63.9	60.0	58.0	64.9	59.3	59.9
	67603 SPARTA 69.0 - 69121*MONROCO869.0	47.0	37.9	70.0	67.1	62.8	60.7	68.1	62.1	62.7
These lines participate in the transfers. They have a very small participation factor (<30MW). However, they show up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	62329 NEAL 4 5 161 - 62351*MONONA 5 161	134.0	116.9	142.9	136.6	136.9	136.3	138.8	135.1	136.9
	62351*MONONA 5 161 - 62355 CARROLL5 161	113.0	94.3	120.2	114.3	114.6	114.2	116.5	113.0	114.7
This line goes from NW Ill. To SW Wis. and participates in the transfers. It has a very small participation factor(<15MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	67547*PILOT NB69.0 - 67811 GALENA8 69.0	48.0	39.5	45.2	50.9	53.1	52.9	54.3	50.6	53.3
This transformer feeds the 69 kV which forms a parallel path from Riverton to Millaca 230 kV. It has a very small participation factor (<10MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	61353*RIVERTN7 115 0- 66093 RIVTON 869.0	19.9	32.7	37.8	38.6	37.3	38.4	38.3	37.9	38.5
	66093*RIVTON 869.0 - 66096 OAKLWNTP69.0	24.0	21.6	26.2	26.9	23.7	26.0	26.5	26.3	26.8

These 69 kv lines are part of a parallel path to the Willmar to Crow River/Big Swan 115 kV. They have a very small participation factor (<10MW). However, they show up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	61519*WILLMAR869.0 - 66147 SVEATAP869.0	23.9	24.5	32.9	34.7	34.0	34.2	33.6	33.3	34.3
	66147*SVEATAP869.0 - 66199 LITCHTP869.0	20.0	21.6	29.9	31.8	31.0	31.3	30.6	30.3	31.4
This 69 kV line ties the 230 kV @ Millaca to Rush City. It has a very small participation factor (<5MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	66115*LONGSDG869.0 - 66118 MILACA 869.0	24.0	22.9	25.9	26.1	25.7	25.6	26.4	25.9	26.0
These 69 kV lines are part of a parallel path to the Elk River to Bunker 230 kV. They have a negligible participation factor. However, they show up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	61509 ELK RIV869.0 - 66053*RDFTAP 869.0	29.0	30.8	32.4	32.5	32.4	32.4	32.6	32.3	32.5
	61509*ELK RIV869.0 - 66188 TRLHVN 869.0	24.0	27.9	28.3	28.7	26.7	27.6	27.6	28.5	27.9
These 69 kV lines tie the Cedar Ck 230 kV to Rush City. They have a negligible participation factor. However, they show up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	66045*COOPER 869.0 - 66079 SDRVL SW69.0	24.0	25.7	25.4	25.1	27.8	25.3	26.2	25.4	24.8
	66079*SDRVL SW69.0 - 66082 CEDARCK869.0	24.0	31.0	32.2	32.2	33.8	31.9	33.0	32.2	32.0
This transformer feeds the 34.5 kV which is part of a parallel path to the 161 kV from Apple River to Barron. It has a negligible participation factor. However, it shows up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	67719 BALSM L869.0 - 67727*BLSM LK934.5	12.0	16.4	18.3	17.6	17.2	17.1	18.1	17.8	17.5

This line participates in the transfers. It exceeds it's 220 MVA RATEA rating and it shows up for many of the ComEd contingencies. The flow on this line is controlled by a phase-shifter which would eliminate these overloads	36648*CROSB; B 138 - 36866 JEFFE; B 138	220.0	177.5	233.5	233.6	234.1	233.7	238.1	233.1	234.4
This 69kV line is part of a parallel path to the 161kV around Ottumwa. It does not participate in the transfers. However, it shows up as overloaded in the transfer case without any contingencies. The none participation indicates this is local load problem.	62639 EICTAP 869.0 - 62641*EIC 869.0	41.0	48.8	46.2	46.7	46.7	46.7	46.5	46.8	46.6
This 161 kV line is south of St. Louis. It does not participate in the transfers. However, it shows up as overloaded in the transfer case without any contingencies. The none participation indicates this is local load problem.	31325 FRED TAP 161 - 58756*FREDTN 5 161	45.0	63.9	62.5	62.8	62.7	62.7	62.6	62.8	62.7
This transformer participates in the transfers. It has a very small participation factor (<25MW). However, it shows up as close to being overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	918*SGL 138 138 - 919 SGL 69 69.0	46.7	19.8	43.3	42.2	40.8	41.4	41.6	42.9	40.3
Radial	65813*LITCHFLD69.0 - 66199 LITCHTP869.0	18.0	21.6	21.6	21.6	21.6	21.6	21.6	21.6	21.6
	66201*HUTCH PT69.0 - 66203 HUTCHMUN69.0	30.0	39.5	39.4	39.5	39.5	39.5	39.5	39.5	39.5
	62542*WILMSBG7 115 - 62614 WILMSBG934.5	13.0	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
Increased VAR output to support the voltage	31125 CALAWY 1 345 - 31124*CAL G125.0	1245.0	1159.8	1160.2	1159.7	1159.6	1159.7	1159.5	1159.8	1159.7
	31598 MER 2&3 138 - 31596*MER 216.5	150.0	137.7	137.7	137.6	137.6	137.6	137.7	139.2	137.7
	60816 COYOTE 3 345 - 60815*COYOTE1G24.0	428.0	405.3	409.4	409.7	409.7	409.9	409.6	409.5	409.8
	62012 FOX LK 5 161 - 62016*FOXLK53G13.8	85.0	82.2	82.1	82.1	82.1	82.1	82.1	82.1	82.1
	62143 ALMA 5 161 - 62140*ALMA5 5G14.4	90.0	89.2	91.3	87.5	90.4	88.2	89.3	91.3	87.8
	62328 NEAL N 5 161 - 62341*NEAL 1G18.0	150.0	142.3	147.8	146.6	146.2	145.8	146.3	146.9	146.0

Area swing for OPPD it is overgenerating to cover losses PMAX=648	60285 NEBRCTY3 345 - 60284*NEBRC31G18.0	672.0	587.7	722.2	719.6	718.8	719.1	721.3	721.6	720.7
Area swing for NSP it is overgenerating to cover losses PMAX=735	61662 SHERCO 3 345 - 61682*SHERC32G24.0	800.0	710.7	830.3	819.4	757.8	775.3	811.1	821.6	793.3
Area swing for MEC it is overgenerating to cover losses PMAX=539.8	62330 RAUN 3 345 - 62343*NEAL 3G22.0	560.0	493.8	556.5	546.8	544.9	544.3	547.0	547.3	545.0

APPENDIX A2

ACCC Comparison – Selected Contingencies

CONTINGENCY		Rate	Base	1c	2e	3j	5a	5b	9b	10
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	441.4	782.3	820.3	923.6	909.6	968.4	814.5	907.0
	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.6	65.3	64.6	57.6	54.4	62.9	58.2	57.3
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	39.7	70.0	69.4	62.4	59.1	67.6	63.0	61.9
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.3	71.6	71.0	63.9	60.6	69.2	64.6	63.4
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.6	75.7	75.1	67.3	63.6	73.1	68.1	66.4
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	369.8	342.5	319.9	287.1	272.0	301.2	332.7	177.9
	538*COL 345 345 - 628 SFL 345 345	676.0	265.4	489.3	567.9	300.8	285.8	323.6	571.8	274.4
	750*GSS 138 138 - 753 RDR 138 138	72.0	31.6	46.4	50.1	16.1	12.7	23.9	50.3	8.5
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	46.8	73.4	115.9	128.3	126.2	137.0	123.1	119.3
	62103 CASVILL5 161 - 7 *NED 161	221.0	38.3	71.5	108.6	122.1	120.1	131.5	114.9	113.2
	7 *NED 161 - 62108 GRANGRAE	221.0	25.8	35.3	19.2	16.1	18.9	16.7	27.1	17.5
	7 NED 161 - 9 *NED 138	280.0	44.8	100.7	108.2	121.8	117.2	128.7	103.8	118.0
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	494.8	841.2	851.9	980.3	953.7	1033.9	851.1	950.5
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	56.5	91.7	83.6	79.2	72.5	85.4	81.6	71.4
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	61.1	96.3	88.7	84.0	77.4	90.2	86.5	76.3
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	62.6	98.4	90.8	85.8	79.2	92.2	88.4	78.1
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	65.7	109.5	99.6	92.5	84.8	100.8	96.3	83.4
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	276.9	199.3	162.2	161.6	156.8	188.2	199.8	134.3
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	318.2	633.1	728.3	371.3	352.0	419.7	729.6	341.2
	750*GSS 138 138 - 753 RDR 138 138	72.0	49.0	85.5	87.9	38.7	32.8	54.9	88.2	30.1
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	47.8	59.9	113.7	122.9	123.2	131.8	120.5	122.1
	62103 CASVILL5 161 - 7 *NED 161	221.0	41.0	57.3	106.8	118.0	118.0	127.2	112.4	116.3
	7 *NED 161 - 62108 GRANGRAE	221.0	26.8	71.1	31.7	31.7	25.0	34.6	32.6	24.4
	7 NED 161 - 9 *NED 138	280.0	61.9	118.6	119.8	138.8	132.0	147.2	115.7	130.7
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	503.2	849.6	855.4	990.1	962.1	1045.8	855.0	957.8
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	20.2	33.8	27.2	28.8	26.4	30.6	27.7	26.1
870 COC 69.000 - 872 COC 69 69.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	25.5	39.8	33.0	34.5	31.9	36.6	33.4	31.5
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	27.1	41.6	34.7	36.2	33.6	38.4	35.1	33.2
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	28.9	44.6	37.1	38.6	35.7	41.1	37.4	35.3
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	276.7	199.1	161.0	159.5	155.0	187.4	199.2	135.8
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	322.8	644.0	744.4	377.4	357.3	427.4	744.5	345.4
	750*GSS 138 138 - 753 RDR 138 138	72.0	54.4	95.1	97.9	45.6	38.9	63.5	97.8	36.0
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	42.9	50.1	107.8	116.0	116.9	124.2	114.9	116.0
	62103 CASVILL5 161 - 7 *NED 161	221.0	37.1	48.5	101.8	112.1	112.6	121.0	107.8	111.2
	7 *NED 161 - 62108 GRANGRAE	221.0	31	83.3	34.7	39.8	31.2	42.8	31.6	30.4
	7 NED 161 - 9 *NED 138	280.0	65.3	125.1	124.2	144.7	137.2	154.4	119.6	135.6
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	506.5	850.5	855.8	992.7	964.3	1048.8	855.2	960.1
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	17.1	28.2	21.5	24.1	22.1	25.2	22.7	21.8
870 COC 69.000 - 872 COC 69 69.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	22.3	34.0	27.1	29.6	27.5	31.0	28.2	27.2
859 HLT 69 69.000 - 67591 MAUSTON 69.000	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	23.9	35.8	28.8	31.3	29.1	32.7	29.8	28.8

	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	25.6	38.2	30.7	33.3	31.0	35.0	31.8	30.7
	61854 EAU CLA5 161 - 61870*WHEATON5 161{A}	294.0	276.6	199.1	160.6	159.2	154.2	186.9	199.1	136.1
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	326.1	653.1	754.5	383.1	362.8	434.8	754.2	350.2
	750*GSS 138 138 - 753 RDR 138 138	72.0	58.5	102.4	104.8	51.1	43.9	69.8	104.6	40.8
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	38.9	42.1	101.3	110.0	111.4	117.7	109.1	110.8
	62103 CASVILL5 161 - 7 *NED 161	221.0	34.1	41.6	96.3	107.0	107.9	115.4	102.7	106.7
	7 *NED 161 - 62108 GRANGRAE	221.0	33.7	90.8	37.7	45.5	36.7	48.7	31.4	35.5
	7 NED 161 - 9 *NED 138	280.0	66.7	128.4	127.1	147.9	139.7	157.7	121.7	138.1
930 ARP 345 345.00 - 2921 ROCKY RN345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	424.3	764.8	801.7	908.0	895.3	944.9	795.0	896.6
	67588*T HLB 69.0 - 67589 T UC 69.0	94.6	50.9	79.7	72.6	77.9	74.8	82.6	68.6	74.6
	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.9	68.5	62.1	58.5	54.9	63.9	59.0	55.3
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	40.0	73.6	67.0	63.4	59.7	68.8	63.9	60.0
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.5	75.5	68.7	65.1	61.3	70.5	65.6	61.5
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.8	81.0	72.7	68.7	64.4	74.7	69.4	64.6
	61861*MONROCO5 161 - 69121 MONROCO869.0	91.0	60.3	85.9	78.5	76.0	72.9	80.2	76.2	72.7
	904 SAR 138 138 - 911*POE 138 138	143.0	104.2	205.1	185.7	147.3	133.5	166.8	194.1	119.4
	907 RUT 69 69.0 - 919*SGL 69 69.0	48.0	17.7	56.3	53.4	46.5	42.6	51.0	54.4	39.0
	911*POE 138 138 - 912 POE 69 69.0	46.7	14.5	45.7	47.1	41.1	37.0	43.2	46.8	34.7
	911 POE 138 138 - 928*LPV 138 138	287.0	201.5	324.5	293.3	287.0	271.4	305.7	303.3	251.7
	918*SGL 138 138 - 919 SGL 69 69.0	46.7	39.1	81.6	77.1	70.2	65.4	75.3	79.1	61.2
	918*SGL 138 138 - 928 LPV 138 138	286.0	209.3	333.1	304.7	297.7	280.9	317.3	313.8	260.6
	918*SGL 138 138 - 931 ARP 138 138	287.0	247.1	411.6	380.5	366.3	344.9	390.9	390.7	320.8
	930*ARP 345 345 - 931 ARP 138 138	395.0	330.9	538.6	497.2	450.6	418.3	490.5	509.9	388.8
	2988 BAKER 115 - 2990*SARATOGA 115	138.0	77.7	227.9	206.6	142.6	126.3	170.3	211.2	113.6
	2988*BAKER 115 - 2992 COYNE 115	239.0	67.7	210.9	188.8	129.9	117.4	154.6	193.9	107.5
930 ARP 345 345.00 - 2921 ROCKY RN345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	472.2	823.0	835.5	965.2	942.5	1011.7	833.3	929.0
911 POE 138 138.00 - 802 SAL 138 138.00	67588*T HLB 69.0 - 67589 T UC 69.0	94.6	61.4	91.0	82.2	89.6	85.3	94.4	78.3	82.1
911 POE 138 138.00 - 904 SAR 138 138.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	54.4	92.8	84.0	80.1	74.0	86.5	82.9	69.3
4002 WWR 25 46.000 - 3460 WATER QU46.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	59.0	97.1	89.0	84.9	78.8	91.2	87.5	74.1
932 ARP 115 115.00 - 2752 HUME 115.00	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	60.5	99.1	90.9	86.7	80.6	93.1	89.3	75.8
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	63.3	110.0	99.1	93.4	86.3	101.7	96.7	80.6
	61861*MONROCO5 161 - 69121 MONROCO869.0	91.0	71.3	101.7	95.5	92.2	88.3	96.9	92.7	83.8
192 PAD 345 345.00 - 36406 WEMPL; B345.00	387 SPG 69 69.0 - 393*ARE 69 69.0	36.0	25.0	22.9	36.7	42.2	41.8	43.6	37.1	42.3
1883 WHITWATR138.00 - 1445 LKHD TP 138.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.5	66.2	60.7	64.9	62.4	69.3	57.6	64.0
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	39.6	70.9	65.5	69.9	67.2	74.3	62.4	68.8
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.2	72.6	67.1	71.6	68.8	76.1	64.0	70.5
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.4	76.8	70.8	76.1	72.8	81.2	67.4	74.7
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	75.2	90.4	176.5	194.3	192.8	201.3	178.6	193.6
	62103 CASVILL5 161 - 7 *NED 161	221.0	66.2	90.3	169.6	190.5	188.5	198.6	170.4	189.5
	7 *NED 161 - 62108 GRANGRAE	221.0	24.1	38.1	14.9	9.5	6.0	8.8	25.9	6.5
	7 NED 161 - 9 *NED 138	280.0	68.7	126.9	156.7	191.6	186.4	199.7	148.3	189.1
	67547*PILOT NB69.0 - 67811 GALENA8 69.0	52.8	46.8	53.2	65.2	71.8	70.9	73.4	64.3	71.2
9 NED 138 138.00 - 33 POT 138 138.00	67547*PILOT NB69.0 67811 - GALENA8 69.0	52.8	50.2	58.9	65.9	68.9	68.5	70.5	65.0	69.0

2950 WHITNG A115.00 - 2970 HOOVER 115.00	941*WHB 69 - 69.0 943 RTP 69	36.0	35.1	35.8	33.8	47.4	48.3	45.3	34.2	46.2
61325 BLCKBRY4 230 - 61326 BOSWELL4 230 1	61325 BLCKBRY4 230 - 61326*BOSWELL4 230 2	503.0	607.0	596.1	595.6	630.1	589.7	595.4	597.0	593.9
62330 RAUN 3345.00 - 62367 LEHIGH 3345.00	62329 NEAL 4 5 161 - 62351*MONONA 5 161	131.0	138.0	172.6	164.2	164.7	163.8	167.2	161.5	164.6
	62351*MONONA 5 161 - 62355 CARROLL5 161	113.0	112.4	144.8	137.4	137.9	137.2	140.1	135.2	137.9
NOTES: {A} Presently this line is limited by CT's.										

APPENDIX B

The full text for Appendix B is contained in a separate document.

Reference File: WIREs_Appen_B.PDF

Appendix

C1

Plan 1c (Salem-Fitchburg 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: Salem-Fitchburg 1-N Madison-Rockdale	$ 88,000	$ 130,000
Alternate 2: Salem-Fitchburg 2-N Madison-Rockdale	$ 117,000	$ 199,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Salem SS	ALTE	$ 1,569
Fitchburg SS	MGE	$ 6,331
N. Madison SS	MGE	$ 2,251
Rockdale SS	MGE	$ 1,846
TOTAL		**$ 11,997**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Wheaton 161 kV busses tied together	NSP	$ 4,000
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Uprate Elk Mound-Barron to 212F operating temp	NSP	$ 759
Reconductor Wien-T-Corners with SSAC	WPS	$ 1,200
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction- Highway V 138 kV line to 275 deg	WE	$ 215
Upgrade Quad Cities-Rock Creek terminal equipmnt CT	ALTW	$ 75
Install 373 Mvars Capacitors	WIRES	$ 5,595
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 15,823**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 1C ALTERNATE 1 COST (000)	**$ 115,820**	**$ 157,820**
TOTAL OPTION 1C ALTERNATE 2 COST (000)	**$ 144,820**	**$ 226,820**

Plan 2e (Prairie Island – Columbia 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: Prairie Island-LaCrosse 1-Columbia	$ 146,000	$ 220,000
Alternate 2: Prairie Island-LaCrosse 2-Columbia	$ 153,000	$ 242,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Prairie Island SS	NSP	$ 1,500
LaCrosse SS	NSP	$ 6,688
Columbia SS	ALTE	$ 1,493
TOTAL		**$ 9,681**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Upgrade Blackhawk-Colley Rd terminal equipment	WPL	$ 200
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Replace ss limiters on Columbia-S FDL 345 kV line	WPL	$ 300
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Rockdale Transformer	ALTE	$ 4,000
Upgrade Green Lake-Roeder terminal equipment	ALTE	$ 25
Install 333 Mvars Capacitors	WIRES	$ 4,995
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 13,764**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 2E ALTERNATE 1 COST (000)	**$ 169,445**	**$ 243,445**
TOTAL OPTION 2E ALTERNATE 2 COST (000)	**$ 176,445**	**$ 265,445**

Plan 3j (Arrowhead – Weston 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
*Alternate 1: Arrowhead-Ladysmith-Weston 1	$ 161,000	$ 261,000
Highway 8 Tap-Highway 8 115 kV	$ 6,000	$ 6,000
**Alternate 2: Arrowhead-Ladysmith-Weston 2	$ 142,000	$ 231,000

SUBSTATION TERMINAL IMPROVEMENTS			
SUBSTATION	**UTILITY**	**COST (000)**	
		Alternate 1	**Alternate 2**
Arrowhead SS	MP	$ 6,100	$ 6,100
Highway 8 Tap-New SS	WPS	$ 7,403	
Highway 8 SS	WPS	$ 220	
Weston 345 kV SS	WPS	$ 3,084	$ 3,084
TOTAL		**$ 16,807**	**$ 9,184**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$ 200
Install 578 Mvars Capacitors	WIRES	$ 8,670
Convert Oak Creek-Arcadian to 345 kV operation ***	WE	
Plano-Plano Tap 345 kV line***	COMED	
TOTAL		**$ 25,650**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 3J ALTERNATE 1 COST (000)	**$ 209,457**	**$ 309,457**
TOTAL OPTION 3J ALTERNATE 2 COST (000)	**$ 176,834**	**$ 265,834**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2 -Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 5a (Chisago – Weston 345 kV)

NEW TRANSMISSION LINE(S)				
LINES	**COST (000)**			
	SINGLE CKT		**DOUBLE CKT**	
*Alternate 1: Chisago-Apple River-Ladysmith-Weston 1	$	148,000	$	227,000
Highway 8 Tap-Highway 8 115 kV	$	6,000	$	6,000
**Alternate 2: Chisago-Apple River-Ladysmith-Weston 2	$	129,000	$	197,000

SUBSTATION TERMINAL IMPROVEMENTS					
SUBSTATION	**UTILITY**	**COST (000)**			
		Alternate 1		**Alternate 2**	
Chisago SS	NSP	$	1,500	$	1,500
Apple River SS	NSP	$	9,773	$	9,773
Lawrence Creek- New SS	NSP	$	6,482	$	6,482
Highway 8 Tap- New SS	WPS	$	7,403		
Weston 345 kV SS	WPS	$	3,084	$	3,084
Highway 8 SS	WPS	$	220		
TOTAL		**$**	**28,462**	**$**	**20,839**

ASSOCIATED PROJECTS AND UPGRADES			
ITEM	**UTILITY**	**COST (000)**	
Reconductor Eau Claire-Weaton	NSP	$	387
Upgrade Barron-Apple River terminal equipment	NSP	$	10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$	10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$	1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$	1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$	1,000
Reconductor Wheaton-Wheaton Tap	NSP	$	198
Relocate Des Plaines transformer on new bus	COMED	$	50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$	300
Upgrade Weston 345/115 to 500 MVA	WPS	$	2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$	4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$	-
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$	215
Improve Goodings-Lockport Red/Blue line sag	COMED	$	50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$	50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$	10
Rockdale transformer	ALTE	$	4,000
Weston-Northpoint	WPS	$	2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$	200
Install 343 Mvars Capacitors	WIRES	$	5,145
Convert Oak Creek-Arcadian to 345 kV operation ***	WE		
Plano-Plano Tap 345 kV line***	COMED		
TOTAL		**$**	**22,125**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 5A ALTERNATE 1 COST (000)	**$ 204,587**	**$ 283,587**
TOTAL OPTION 5A ALTERNATE 2 COST (000)	**$ 171,964**	**$ 239,964**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2-Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 5b (Apple River – Weston 230 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
*Alternate 1: Apple River-Ladysmith-Weston 1	$ 94,000	$ 158,000
Highway 8 Tap-Highway 8 115 kV	$ 6,000	$ 6,000
**Alternate 2: Apple River-Ladysmith-Weston 2	$ 80,000	$ 133,000

SUBSTATION TERMINAL IMPROVEMENTS			
SUBSTATION	**UTILITY**	**COST (000)**	
		Alternate 1	**Alternate 2**
Apple River SS	NSP	$ 1,161	$ 1,161
Highway 8 Tap- New SS	WPS	$ 6,241	
Weston 230/345 kV SS	WPS	$ 13,128	$ 13,128
Highway 8 SS	WPS	$ 220	
TOTAL		**$ 20,750**	**$ 14,289**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Install 453 Mvars Capacitors	WIRES	$ 6,795
Convert Oak Creek-Arcadian to 345 kV operation ***	WE	
Plano-Plano Tap 345 kV line***	COMED	
TOTAL		**$ 23,575**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 5B ALTERNATE 1 COST (000)	**$ 144,325**	**$ 208,325**
TOTAL OPTION 5B ALTERNATE 2 COST (000)	**$ 117,864**	**$ 170,864**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2-Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 9b (Lakefield – Columbia 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Lakefield-Adams-Genoa-Columbia	$ 197,000	$ 365,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Lakefield SS	NSP	$ 801
Adams SS	NSP	$ 2,301
Genoa SS	DPC	$ 6,085
Columbia SS	ALTE	$ 1,493
TOTAL		**$ 10,680**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Wheaton 161 kV busses tied together	NSP	$ 4,000
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Uprate Elk Mound-Barron to 212 F operating temp	NSP	$ 759
Reconductor Wien-T-Corners with SSAC	WPS	$ 1,200
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Upgrade Blackhawk-Colley Rd terminal equipment	WPL	$ 200
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Rockdale Transformer	ALTE	$ 4,000
Upgrade Green Lake-Roeder terminal equipment	ALTE	$ 25
Install 293 Mvars Capacitors	WIRES	$ 4,395
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 18,823**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 9B COST (000)	**$ 226,503**	**$ 394,503**

Plan 10 (King – Weston 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: King-Eau Claire 1-Weston	$ 109,000	$ 183,000
Alternate 2: King-Eau Claire 2-Weston	$ 112,000	$ 235,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
King SS	NSP	$ 2,198
Eau Claire SS	NSP	$ 2,301
Weston SS	WSP	$ 3,084
TOTAL		**$ 7,583**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale Transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$ 200
Install 163 Mvars Capacitors	WIRES	$ 2,445
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 19,425**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 10 ALTERNATE 1 COST (000)	**$ 136,008**	**$ 210,008**
TOTAL OPTION 10 ALTERNATE 2 COST (000)	**$ 139,008**	**$ 262,008**

Appendix
C2

WISCONSIN INTERFACE RELIABILITY ENHANCEMENT STUDY
CONCEPTUAL COST ESTIMATE SUMMARY

The Wisconsin Reliability Assessment Organization (WRAO) is performing a Wisconsin Interface Reliability Enhancement Study (WIREs) to identify possible regional transmission improvements that could increase the transfer capability between eastern Wisconsin and adjoining regions. This document contains conceptual cost estimates of line route options for this study. This section includes the following information.

- Summary table of costs for each line route option
- A description of the line routes
- Costs for the segments within line routes 3j, 5a and 5b
- Assumptions and clarifications for the estimates
- Sketches of the structure configurations

Included in section 2.0 are the detailed conceptual cost estimates for the new 345 kV single circuit transmission line routes (1 route is also estimated as 230 kV).

Included in section 3.0 are the detailed conceptual cost estimates for 345 kV double circuit transmission lines (1 is also estimated as 230 kV) for the same routes as sections 2.0. These estimates assume the new double circuit line erected in the existing right-of-way will replace an existing single circuit transmission line. The actual single circuit/double circuit cost estimates in the summary table contain portions of the line as double circuit and the rest as single circuit based on an estimated length of sharing right-of-way of existing lines in the individual corridors. The estimates in sections 3.0 were used to obtain the costs for the double circuit options as shown in the following example.

Route 1c
(Single circuit miles Route 1c) x (SC cost/mile Route 1c) + (double circuit miles Route 1c) x (DC cost/mile Route 1c) = cost of SC/DC cost Route 1c

(69 miles SC) x ($715,000/mile) + (54 miles DC) x ($1,496,000/mile) = $130,000,000 (rounded)

A second alternate route was identified for each option and was estimated as a single circuit and double circuit. These estimates were done using the cost/mile from the first alternate route as shown in the following example.

Route 1c
(Single circuit miles for Route 1c, alternate 2) x (single circuit cost/mile for Route 1c, alternate 1) = cost for Route 1c, alternate 2

(164 miles) x ($715,000/mile) = $117,000,000 (rounded)

Similarly the segment costs for line routes 3j, 5a and 5b were done using the cost/mile values for those line routes.

These cost estimates were completed without performing structure studies, conductor studies and specific line route studies. Structures, foundations, conductors and other items were estimated based on an acceptable, economical type for construction of a 345 kV or 230 kV line. Studies should be completed for the final selected route to determine the best economical choice for that line route.

ASSUMPTIONS AND CLARIFICATIONS

1. The quantities of materials and labor shown are those estimated to be actually required for the design and construction of the line. Costs for bonds have not been included.

2. Although these transmission line options will not be constructed entirely in the State of Wisconsin, the vast majority will be. For simplicity of estimating, Wisconsin state sales and use tax has been included in all estimates. The tax rate is 5.6 percent, and is applied to material and labor, excluding labor associated with foundation installation.

3. The assumed design loading conditions are the following.

   - NESC Heavy
   - Extreme Wind: 21 psf high wind
   - Extreme Ice: 1.5 inches of ice with 4 psf wind, 0ºF
   - -20ºF
   - 200ºF

   The overload factors used are in accordance with the NESC for the NESC load case, 1.25 for the extreme wind load case and 1.0 for the extreme ice load case. Clearance requirements are in accordance with the NESC, and Wisconsin code.

4. These 345 kV lines are designed for bundled 2-795 kcmil, 26/7 ACSR “Drake” conductor with two 134.6 kcmil 12/7 ACSR “Leghorn” shield wires. The 230 kV lines are designed for 1033.5 kcmil 54/7 ACSR “Curlew” conductor and two 134.6 kcmil 12/7 ACSR “Leghorn” shield wires. All wire quantities are the exact line footage.

5. No restrictions were used on placement of structures in swamps and wetlands.

6. All single circuit tangent structures are steel H-frames. All single circuit angle structures are steel H-frames and are similar to the tangent structures. All single circuit deadend structures are steel lattice towers. For double circuit structures, all

tangents are single poles, all angle and deadend structures are lattice towers.

7. The 345kV suspension structures have 18-20 kip insulators per string and the deadends have 2 strings of 18-30 kip insulators per string. The 230 kV suspension structures have 14-20 kip insulators per string and the deadends have s strings of 16-30 kip insulators per string.

8. The average 345 kV single circuit structure height is 85' with an average span of 950'. The average 345 kV double circuit structure height is 125' with an average span of 850'. The average 230 kV single circuit structure height is 80' with an average span of 950'. The average 230 kV double circuit structure height is 120' with an average span of 850'. Ground clearance used for 345 kV is 27' and for 230 kV is 25'.

9. Structure types were based on the following distribution.

Line Route	% Tangents	% Angles	% Deadends
1c	80	16	4
2e	70	24	6
3j	80	16	4
5a/5b	80	17	3
9b	80	17	3
10	80	17	3

10. A rock adder has been included to account for increases in foundation cost due to rock coring. A percentage of structures were given this adder based on general geographic characteristics of the State of Wisconsin extrapolated from USGS map "Depth to Bedrock in Wisconsin" 1973. The estimates include a percentage of the line requiring the bottom 5 feet of the foundations in rock. The percentages per segment used are as follows.

Line Route	Percentage of Line Considered in Rock
1c	50%
2e	25%
3j	5%
5a/5b	15%
9b	25%
10	30%

11. Wetland matting is assumed to be required for 10 percent of the wetland areas listed in the report for the line routes.

12. The soil type assumed for the foundation design is good soil (sand, gravel, or stiff clay).

    Foundations are assumed to be drilled piers for all structure types except the single circuit H-frame structures. The single circuit H-frame structures are assumed to be direct embedded 10 percent of the pole length plus four feet.

13. Construction will be performed during the time of year when the line route is driveable. Minimal access roads to the right-of-way are included in the right-of-way clearing expense.

14. The clearing of land is split into three categories based on the report. These categories are average, forested or wetlands. Average clearing costs are used for all areas not specifically designated forested and wetlands in the report.

15. For the estimate, we have assumed one soil boring at every angle and deadend and one additional boring per mile.

16. No mitigation costs are included for the wetland areas, wildlife or scenic areas or Indian reservations. No mitigation costs are included for induced voltages on railroad tracks, pipelines or adjacent communication or signal wires. It is assumed the 10% contingency will cover these potential costs.

17. The ground survey work is assumed to be performed by the same surveyor who will do the aerial survey for the line route. The surveyor will provide digitized plan and profile sheets for the cost included for the design survey work. The survey work is split into two costs, one for forested areas and one for the rest of the line.

18. Deadends are included in the estimate at a minimum of one every ten miles.

19. All costs are in 1999 dollars, then escalated by adding 3 percent per year for the assumed in-service date of 2002.

20. The engineering and construction management costs per segment have been estimated at 7 and 3 percent of the material and labor cost respectively.

21. The right-of-way is assumed to be 150’ for new 345 kV single circuit lines and 100’ for new 230 kV single circuit lines. The right-of-way is assumed to be an additional 50’ for new 345kV double circuit lines and 25’ for 230kV double circuit lines.

22. For line segments along an existing transmission line, the double circuit cost estimates assume the existing line is the same voltage as the new line. An additional cost of $200,000 is assumed, $150,000 for removal of the existing line and $50,000 for working with and near an energized line. No salvage value is assumed during removal of the existing line.

23. No costs for the design or construction of substations are included in this estimate.

Appendix C2a

Option		Length (miles)	Cost/Mile ($M)	S-C Cost ($M)	Length (miles)	Cost/Mile ($M)	Cost ($M)	S-C/D-C Cost ($M)
1c Alternate 1: 123 miles								
Single Circuit	SC	123	0.715102	**$88**	69	0.715102	49.3	
Double Circuit	DC				54	1.496119	80.8	**$130**
1c Alternate 2: 164 miles								
	SC	164	0.715102	**$117**	59	0.715102	42.2	
	DC				105	1.496119	157.1	**$199**
2e Alternate 1: 195 miles								
	SC	195	0.747197	**$146**	109	0.747197	81.4	
	DC				86	1.605531	138.1	**$220**
2e Alternate 2: 205 miles								
	SC	205	0.747197	**$153**	102	0.747197	76.2	
	DC				103	1.605531	165.4	**$242**
3j Alternate 1: 228 miles								
	SC	228	0.703695	**$160**	103	0.703695	72.5	
	DC				125	1.509201	188.7	**$261**
3j Alternate 2: 201 miles								
	SC	201	0.703695	**$141**	90	0.703695	63.3	
	DC				111	1.509201	167.5	**$231**
5a Alternate 1: 214 miles								
	SC	214	0.689653	**$148**	116	0.689653	80.0	
	DC				98	1.501430	147.1	**$227**
5a Alternate 2: 187 miles								
	SC	187	0.689653	**$129**	103	0.689653	71.0	
	DC				84	1.501430	126.1	**$197**
5b Alternate 1: 214 miles								
	SC	214	0.528274	**$113**	116	0.528274	61.3	
	DC				98	1.290428	126.5	**$188**
5b Alternate 2: 187 miles								
	SC	187	0.528274	**$99**	103	0.528274	54.4	
	DC				84	1.290428	108.4	**$163**
9b: 292 miles								
	SC	292	0.673196	**$197**	87	0.673196	58.6	
	DC				205	1.495523	306.6	**$365**
10 Alternate 1: 156 miles								
	SC	156	0.69742	**$109**	63	0.697420	43.9	
	DC				93	1.492920	138.8	**$183**
10 Alternate 2: 160 miles								
	SC	160	0.69742	**$112**	5	0.697420	3.5	
	DC				155	1.492920	231.4	**$235**

Appendix C2b

	OPTION 1C	OPTION 2E	OPTION 3J	OPTION 5A	OPTION 5B	OPTION 9B	OPTION 10
LAND AND LAND RIGHTS	$16,308,057	$25,444,960	$25,846,080	$24,416,000	$20,380,548	$34,736,120	$20,008,040
TOWERS AND FIXTURES							
Land and Crop Damage	$87,146	$138,158	$161,538	$151,619	$151,619	$206,882	$110,526
Structures - Materials	$12,131,700	$20,170,450	$22,116,100	$20,542,140	$15,897,650	$27,838,600	$15,115,030
Structures - Labor	$5,791,992	$10,111,579	$11,069,114	$9,856,164	$8,058,394	$12,831,617	$7,051,264
Install Tower Footings							
Materials	$1,630,640	$2,841,630	$2,941,910	$2,663,960	$2,146,755	$3,619,890	$1,963,962
Installation	$10,197,244	$16,670,053	$16,108,236	$15,010,748	$12,261,190	$20,696,721	$11,537,706
Engineering	$2,082,610	$3,485,560	$3,656,475	$3,365,111	$2,685,479	$4,549,078	$2,496,757
Soil Borings	$573,340	$1,133,600	$1,052,940	$981,000	$981,000	$1,345,060	$721,580
Construction Management	$892,547	$1,493,811	$1,567,061	$1,442,190	$1,150,920	$1,949,605	$1,070,039
Sundries 5% of Labor	$976,887	$1,644,730	$1,672,691	$1,532,761	$1,256,849	$2,068,604	$1,143,867
State Tax (5.6% M&L) Excluding Fnd Labor)	$1,348,464	$2,289,356	$2,468,272	$2,261,466	$1,801,915	$3,035,337	$1,655,500
OVERHEAD CONDUCTORS AND DEVICES							
Land and Crop Damage	$87,146	$138,158	$161,538	$151,619	$151,619	$206,882	$110,526
Line Survey	$1,039,154	$1,865,699	$2,389,553	$2,105,499	$2,105,499	$2,454,299	$1,377,324
Clearing	$5,690,131	$10,936,664	$14,620,269	$12,511,416	$8,340,944	$13,402,045	$7,739,396
Conductors and Accessories							
Material	$6,380,072	$10,113,536	$11,824,564	$11,098,995	$7,293,312	$15,142,366	$8,091,782
Installation	$7,274,345	$11,528,675	$13,478,130	$12,652,103	$7,639,070	$17,257,133	$9,225,946
Insulators							
Material	$1,667,700	$2,719,550	$3,030,200	$2,792,580	$2,532,942	$3,782,300	$2,054,650
Installation	$1,133,817	$1,840,485	$2,062,509	$1,906,071	$1,906,071	$2,580,950	$1,402,128
Engineering	$1,622,965	$2,730,323	$3,318,366	$3,014,667	$2,087,249	$3,823,337	$2,092,386
Construction Management	$695,557	$1,170,138	$1,422,157	$1,292,000	$894,535	$1,638,573	$896,737
Sundries (5% of Labor)	$872,798	$1,503,599	$1,864,549	$1,674,088	$1,148,668	$2,057,817	$1,136,696
State Tax (5.6% M&L)	$1,477,086	$2,486,885	$3,024,577	$2,746,655	$1,901,104	$3,479,774	$1,904,955
10% CONTINGENCY	7,996,139	13,245,759	14,585,682	13,416,885	10,277,333	17,870,298	9,890,679
TOTAL	**87,957,538**	**145,703,357**	**160,442,512**	**147,585,738**	**113,050,664**	**196,573,288**	**108,797,477**
per mile	715,101	747,196	703,695	689,652	528,274	673,196	697,419

Appendix

C3

SUBSTATION TERMINAL COMPONENT COSTS
(information supplied by Black & Veatch)

Clarifications and Assumptions	
1	1999 Dollars.
2	No contingency has been included. Recommend 15% be used.
3	No taxes have been included.
4	It is assumed the existing control room and station service is adequate for addition of the equipment. If a control building addition is needed, use $150/square foot for prefab building, foundation, lights, raceway and HVAC.
5	Foundation are assumed to be drilled pier in firm soil. No rock encountered.
6	No real estate costs are included.
7	No cost for permitting or environmental considerations have been included.

345 kV "Component Costs" for the addition of a typical 345kV line position at an existing substation.:

345kV		
COMPONENT	MATERIAL COST	LABOR COST
345Kv Breaker, 2000A, 40ka, dead tank, 3-ph	$220,000	$15,000
345kV Breaker foundation	$8,000	$12,000
345kV Dead-end Structure	$40,000	$8,000
345kV DE Structure foundation	$10,000	$20,000
345kV Disconnect Switch and structural support	$25,000	$6,000
345kV Disconnect Switch foundation	$2,000	$2,000
345kV line relaying panel	$45,000	$1,000
345kV breaker control panel	$25,000	$1,000
345kV CCVT and support, 1-ph	$8,000	$1,000
345kV PT and support, 1-ph	$18,000	$1,000
Control and Power Cable per Breaker	$6,000	$6,000
345kV low profile bus, insulators, fittings and structures (Line position tapping into a ring bus)	$50,000	$30,000
345kV bus support foundations	$6,000	$10,000
Minor Site Grading, grounding, raceway and fencing	$10,000	$20,000
345/138kV, 300/400/500 MVA Transformer	$2,200,000	$60,000
345/138kV, 300/400/500 MVA Transformer w/LTC	$2,900,000	$65,000
345/138kV,300/400/500 MVA Transformer & misc Transformer relay panel	$15,000 $25,000	$20,000 $1,000
Engineering and construction management-use 15% of total material and labor		

230 kV "Component Costs" for the addition of a typical 230kV line position at an existing substation.:

230kV		
COMPONENT	**MATERIAL COST**	**LABOR COST**
230kV Breaker, 2000A, 40ka, dead-tank, 3-ph	$100,000	$7,000
230kV Breaker foundation	$4,000	$6,000
230kV Dead-end Structure	$32,000	$6,000
230kV DE Structure foundation	$9,000	$14,000
230kV Disconnect Switch and Structural support	$14,000	$5,000
230kV Disconnect Switch foundation	$1,500	$1,500
230kV line relaying panel	$40,000	$1,000
230kV breaker control panel	$25,000	$1,000
230kV CCVT and support, 1-ph	$6,000	$1,000
230kV PT and support, 1-ph	$14,000	$1,000
Control and Power Cable per Breaker	$5,000	$5,000
230kV low profile bus, insulators, fittings and structures (Line position tapping into a ring bus)	$40,000	$24,000
230kV bus support foundations	$5,000	$7,000
Minor Site Grading, grounding, raceway, and fencing	$8,000	$18,000
230/138kV, 300/400/500 MVA Transformer	$2,000,000	$55,000
230/138kV, 300/400/500 MVA Transformer w/LTC	$2,700,000	$60,000
230/138kV, 300/400/500 MVA & misc Transformer relay panel	$12,000 $25,000	$16,000 $1,000
Engineering and construction management-use 15% of total material and labor		

161 kV "Component Costs" for the addition of a typical 161kV line position at an existing substation.:

161kV		
COMPONENT	MATERIAL COST	LABOR COST
161kV circuit switcher with support	$55,000	$5,000
161kV circuit switcher foundation	$2,000	$2,000
345/161kV 300/400/500 MVA Transformer	$2,300,000	$60,000
345/161kV 300/400/500 MVA Transformer w/LTC	$3,000,000	$65,000
345/161kV 300/400/500 MVA Transformer Foundation w/ Oil Cont	$15,000	$20,000

Appendix C4

Item	Project	1c	2e	3j	5a	5b	9b	10	Owner / Cost
1	Reconductor Eau Claire - Wheaton	1	1	1	1	1	1	1	NSP $387
2	Upgrade Barron - Apple River terminal	1	1	1	1	1	1	1	NSP $10
3	Reconductor portion of Itasca - Lombard R	1	1	1	1	1	1	1	COMED $10
4	Upgrade Itasca - Lombard B 345 kV breaker	1	1	1	1	1	1	1	COMED $1,000
5	Upgrade Itasca - Lombard R 345 kV breaker	1	1	1	1	1	1	1	COMED $1,000
6	Schaumburg Breaker's/Swap red & blue	1	1	1	1	1	1	1	COMED $1,000
7	Reconductor Wheaton - Wheaton Tap	1	1	1	1	1	1	1	NSP $198
	Convert Oak Creek-Arcadian to 345 kV	1	1	1	1	1	1	1	WE $12,127
	Plano-Plano Tap 345 kV line	1	1	1	1	1	1	1	COMED $35,000
8	Wheaton 161 kV busses tied together	1					1		NSP $4,000
9	Relocate Des Plaines transformer on new bus	1	1	1	1	1	1	1	COMED $50
10	Upgrade Weston - Rocky Run 345 kV			1	1	1		1	WPS $300
11	Reconductor Wheaton - Elk Mound	1	1				1		NSP $324
12	Upgrade Weston 345/115 to 500 MVA			1	1	1		1	WPS $2,000
13	Rebuild Kelly-Whitcomb (24 mi) 115 kV line			1	1	1		1	WPS $4,100
14	Uprate Elk Mound - Barron to 212 F operating	1					1		NSP $759
15	Reconductor Wien - T-Corners with SSAC	1					1		WPS $1,200
16	Upgrade Goodings Grove 345 kV bus tie	1	1	1	1	1	1	1	COMED $0
17	Upgrade Blackhawk - Colley Rd terminal		1				1		WPL $200
18	Inc Forest Junction-Highway V 138kV to 275	1	1	1	1	1	1	1	WE $215
19	Replace ss limiters on Columbia-S FDL 345		1						WPL $300
20	Improve Goodings-Lockport Red/Blue line		1	1	1	1	1	1	COMED $50
21	Upgrade Sand Lake-Port Edwards terminal			1	1	1		1	WPL $50
22	Upgrade Pulliam 138/115 kV terminal eq.			1	1	1		1	WPS $10
23	Rockdale transformer		1	1	1	1	1	1	ALTE $4,000
24	Weston-Northpoint			1	1	1		1	WPS - $2,400
25	Reconductor Rocky Run-Whiting Ave SSAC			1	1			1	WPS - $200
26	Upgrade Green Lake-Roeder term equip		1				1		ALLIANT $25
27	Upgrade Quad Cities-Rock Ck term equip CT	1							ALTW $75
28	Install 373 Mvars	1							WIREs $15/KVAR $5,595
29	Install 333 Mvars		1						WIREs $15/KVAR $4,995
30	Install 578 Mvars			1					WIREs $15/KVAR $8,670
31	Install 343 Mvars				1				WIREs $15/KVAR $5,145
32	Install 453 Mvars					1			WIREs $15/KVAR $6,795
33	Install 293 Mvars						1		WIREs $15/KVAR $4,395
34	Install 163 Mvars							1	WIREs $15/KVAR $2,445

Exhibit G

Merger Stipulation December 15, 1999

PUC Docket PA-99-1031

MINNESOTANS FOR AN ENERGY-EFFICIENT ECONOMY'S
Sustainable **Minnesota**

UTILITY MERGER INFORMATION

A Chronological Listing of What's New at Sustainable Minnesota

Environmental Coalition Agreement with Northern States Power Company in the Matter of NSP and New Centures Energy's Proposed Merger

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STIPULATION AGREEMENT

MN PUC Docket E,G002/PA-99-1031

This Stipulation Agreement made this 15th day of December, 1999, by and between Northern States Power Company (Minnesota) ("NSP"), on behalf of itself and its public utility subsidiaries, Izaak Walton League of America, Minnesotans for an Energy Efficient Economy and Environmental Law and Policy Center of the Midwest (referred to as the Environmental Coalition), and hereinafter referred to as the "Parties."

WHEREAS, the Environmental Coalition has a membership which includes customers of NSP; and

WHEREAS, NSP has proposed to merge with New Century Energies, Inc. ("NCE") ;and

WHEREAS, the Environmental Coalition believes that NSP's decision to merge with NCE may adversely impact the effectiveness of Minnesota regulatory process to protect the public interest; and

NOW THEREFORE, It is agreed that:

1. NSP agrees to study the technical feasibility and economic impact of conversion of first its High Bridge plant (units 3 and 4) and then its Riverside (units 7 and 8) generating facility to natural gas. The studies will conducted in a time frame that allows NSP to gain information from its current Black Dog Repowering effort, but is not contingent on the outcome of the Blackdog Certificate of Need process, and in any event not later than July 1, 2001. NSP agrees to provide information regarding how it will conduct the feasibility study to the Environmental Coalition. The feasibility criteria used by NSP will be based on factors aimed at measuring the potential profitability of the converted facilities based on the assumed revenue stream and the cost, taking into consideration: environmental externality values set by the Minnesota Public Utilities Commission; the current cost of producing electricity at these units where applicable; the estimated cost of producing or purchasing electricity from an alternative facility or supplier; the value of any net additional generating capacity; the value of new generating capacity with load following capability; an analysis of market

conditions at the time of the studies. NSP agrees to include the results of the studies in its resource plan following the completion of the studies as a potential resource option.

2. NSP agrees that it will conduct an evaluation of both demand-side and supply-side non-nuclear resource options to its Prairie Island nuclear generating units in the event of a pre-license expiration shutdown and file it with the Commission in its upcoming resource plan.

3. NSP agrees that its new public utility subsidiary of Xcel, Inc. will be subject to applicable Minnesota Statutes including but not limited to provisions related to conservation and renewable energy. NSP further agrees that its control over output, the economic life of the plant and the budget make it a "public utility that operates a nuclear generating facility" for purposes of Minnesota statutes, rules and orders of the applicable regulatory agencies and that the transfer of NSP's licenses to operate nuclear facilities issued by the Nuclear Regulatory Commission to the Nuclear Management Company will in no way affect this interpretation or the applicability of rules and orders adopted pursuant to such Minnesota statutes.

4. NSP agrees to undertake the necessary transmission studies with respect to upgrades needed to move additional increments of up to a total of 825 MW of wind generation from within the State of Minnesota, subject to the requirements and procedures of FERC Order 888/889. Upon review of the most feasible transmission alternatives, NSP agrees that it will seek all necessary regulatory approvals, including regional transmission planning approvals, and will file for a Certificate of Need and/or Environmental Impact Statement, as required by law, by July, 2001, unless the requirements for filing have not been satisfied, such that a filing made on this date would not satisfy the Minnesota Public Utilities Commission's requirements for Certificate of Need filings, in which case the filing shall be made within a reasonable period thereafter. In the event that wind resources are not procured in an all-source bidding scheduled for 2000 or 2001, NSP agrees to provide an assessment of the impediments to wind in an all-source bidding process in its July 1, 2002 resource plan. The Parties agree to work together to remove the identified impediments to wind energy with the intention of improving its performance in subsequent all-source bidding processes. Efforts to remove the identified impediments may include, but are not limited to, legislative initiatives to lower costs, initiatives to improve wind accreditation, identification of preferred sites for wind developments, and improvements to wind forecasting to address operational issues. Nothing in this provision waives either Parties' right to argue their position regarding wind procurement before the MPUC in future Resource Plan proceedings.

5. NSP agrees to study the potential for distributed generation technologies on its system in its July 2000 resource plan. This study shall include analysis of opportunities and economics of distributed wind, fuel cell, microturbine, and industrial cogeneration technologies up to 5000 kilowatts in size. Unless otherwise agreed to by the Parties, within one year after a Commission order approving the merger, NSP will file a distributed generation tariff to facilitate low-cost, safe and standardized interconnection for dispersed generation on its system. NSP agrees to consult with the Coalition in the design of the study and the proposed tariff.

6. New NSP Utility agrees to continue to seek approval of affiliated interest agreements as required by Minn. Stat. 216B.48 and that it will not raise federal preemption as a defense to Minnesota Public Utilities Commission's decisions with respect to Resource Planning. Further, NSP commits to not claim that federal preemption precludes the Commission from evaluating and disallowing recovery of costs allocated to New NSP Utility on the basis of imprudence, including costs allocated to New NSP Utility under an affiliated interest agreement or the Joint Operating Agreement, and agrees to hold ratepayers harmless from any decision overruling the Commission's decision in the event that another party successfully challenges an MPUC Order by raising federal preemption under these circumstances where NSP has waived such right.

7. This Stipulation Agreement resolves all issues among the parties in MPUC Docket E,G002/PA-99-1031 related to approval and consummation of the merger including the intervention filed by the Environmental Coalition on November 1, 1999. The Environmental Coalition agrees not to either directly or indirectly through third parties, oppose, delay or otherwise seek to place further conditions on NSP and NCE's proposed merger in any state or federal regulatory or other legal proceeding.

8. This Stipulation Agreement applies to each of the Parties and shall be binding on the successors and assigns of the Parties and any subsequent owner of a material portion of the transmission assets of NSP. This Stipulation Agreement shall not be deemed to constitute an admission by any Party that any allegation or contention is true and valid except as to the terms provided for in the Stipulation Agreement, and shall establish no principles or precedents.

9. NSP will perform the commitments described in this Stipulation Agreement regardless of whether the merger is consummated.

10. This Agreement may be executed in identical counterparts with the same effect as if a single copy were executed.

Signed by:

Northern States Power Company

Izaak Walton League of America and

The Environmental Law and Policy Center of the Midwest

Minnesotans for an Energy-Efficient Economy

Dated: December 15, 1999

Exhibit H

TRANSLink Settlement Agreement

PUC Dockets 02-2151 and 02-2219

MICHAEL BEST & FRIEDRICH LLP
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June 23, 2003

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Re: Northern States Power Company d/b/a Xcel Energy
Docket No. E002,PT6205/PA-02-2152

Interstate Power & Light Company
Docket No. E001/PA-02-2219

Dear Mr. Haar:

Enclosed for filing are the original and 15 copies of the Settlement Agreement in the above-entitled docket between TRANSLink Development Management Corporation ("TRANSLink") and several of the environmental intervenors, including Minnesota Center for Environmental Advocacy, Izaak Walton League of America – Midwest Office, Minnesotans for an Energy Efficient Economy, and North American Water Office (jointly, "the Intervenors") (collectively with TRANSLink, the Settling Parties). The Settlement Agreement exemplifies TRANSLink's commitment to conduct business in Minnesota and throughout TRANSLink's proposed footprint in a way that recognizes and integrates the interests of all stakeholders in the planning process, including those who advance the development of wind energy.

As the Settlement Agreement indicates at ¶ 8, the Settlement Agreement "addresses all of the concerns Intervenors raised in these proceedings." As a result, and as also indicated in ¶ 8, the Intervenors withdraw their objections to the requested approvals relating to TRANSLink and have no further objections to the Commission's approval of the Petitions in this proceeding. For its part, TRANSLink has agreed to be bound by the terms of the Settlement Agreement as a condition of a Commission order granting the approvals requested in this proceeding.

MICHAEL BEST
&FRIEDRICH LLP
Attorneys at Law

Service

TRANSLink Development will arrange to serve a copy of these initial comments on all parties to the Commission service list for this proceeding. A certificate of service and service list are attached.

Sincerely,

MICHAEL BEST & FRIEDRICH LLP

Jordan J. Hemaidan

JJH:jjh
Enclosures

Q:\CLIENT\091474\0004\A0592644.1

STATE OF WISCONSIN	)	**AFFIDAVIT OF SERVICE**
	) ss.	**MPUC Docket Nos. E002, PT6205/PA-02-2152**
COUNTY OF DANE	)	**E001, PT6205/PA-02-2219**

Susan Bunge of the City of Madison, County of Dane, State of Wisconsin, says that on the 23rd day of June, 2003, she served the Settlement Agreement in the above-entitled dockets between TRANSLink Development Management Corporation and Minnesota Center for Environmental Advocacy, Izaak Walton League of America – Midwest Office, Minnesotans for an Energy Efficient Economy, and North American Water Office upon the people listed upon the attached service list via FedEx, except for Dr. Burl Haar, Kathy Aslakson and Curt Nelson. Dr. Haar, Ms. Aslakson and Curt Nelson will have been served via messenger on the 24th day of June, 2003.

Susan Bunge

Susan Bunge

Subscribed and sworn to before me this
23rd day of June, 2003.

Suzanne K. Trotter

Notary Public
My Commission: expires 7/24/05

IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR APPROVAL OF TRANSFER OF FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES TO TRANSLINK TRANSMISSION COMPANY LLC AND FOR RELATED RELIEF

DOCKET NO. E002, PT6205/PA-02-2152

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In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of Transfer of Functional Control of Transmission Facilities to TRANSLink Transmission Company LLC and for Related Relief

Docket No. E002, PT6205/PA-02-2152

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IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY PETITION FOR APPROVAL OF TRANSFER OF FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES TO TRANSLINK TRANSMISSION COMPANY LLC AND FOR RELATED RELIEF

DOCKET NO. E002, PT6205/PA-02-2219

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IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY PETITION FOR APPROVAL OF TRANSFER OF FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES TO TRANSLINK TRANSMISSION COMPANY LLC AND FOR RELATED RELIEF

DOCKET NO. E002, PT6205/PA-02-2219

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Leroy Koppendrayer	Chair
Ellen Gavin	Commissioner
Marshall Johnson	Commissioner
Gregory Scott	Commissioner
Phyllis Reha	Commissioner

Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the Transfer of Functional Control of Transmission Facilities to TRANSLink Transmission Company LLC and for Related Relief

Docket No. E002, PT6025/PA-02-2152

and

Petition of Interstate Power and Light Company For Approval of the Transfer of Functional Control of Transmission Facilities To TRANSLink Transmission Company LLC And For Related Relief

Docket No. E001, PT6205/PA-02-2219

SETTLEMENT AGREEMENT

This Settlement Agreement ("Settlement Agreement") is made and entered into this 20th day of June, 2003, by and between TRANSLink Management Development Corporation ("TRANSLink Development") for itself and on behalf of its successor TRANSLink Management Corporation, and the Minnesota Center for Environmental Advocacy, Izaak Walton League of America – Midwest Office and Minnesotans for an Energy Efficient Economy and North American Water Office (jointly, "the Intervenors") collectively referred to as the "Parties."

WITNESSETH:

WHEREAS, On December 16, 2002, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy") petitioned the Minnesota Public Utilities Commission ("Commission") for an Order authorizing the transfer of functional control of its transmission facilities in the State of Minnesota to TRANSLink Transmission Company LLC ("TRANSLink") and transfer of ownership of Xcel Energy's Energy Management System ("EMS") software pursuant to Minn. Stat. 216B.50 (the "Xcel Energy Petition");

WHEREAS, On December 30, 2002, Interstate Power and Light Company ("IPL") petitioned the Commission for an Order authorizing the transfer of control and ownership of its transmission facilities in the State of Minnesota to TRANSLink (the "IPL Petition");

WHEREAS, the Xcel Energy Petition and the IPL Petition are collectively referred to herein as "the Petitions;"

WHEREAS, On or about March 24, 2003 the Intervenors submitted initial comments on the Petitions to the Commission and expressed concerns relating to the TRANSLink transmission planning process and TRANSLink's ability to satisfy certificate of need ("CON") information requirements.

WHEREAS, at least one of the Intervenors petitioned the Commission for intervention as a party pursuant to Minnesota Rule 7829.0800 and more than 15 days have elapsed without an objection to that petition being filed;

WHEREAS, On April 14, 2003, the Intervenors submitted reply comments wherein Intervenors requested that the Commission require Xcel Energy to provide satisfactory mechanisms to ensure formal and meaningful stakeholder participation in the TRANSLink transmission planning process and to ensure that TRANSLink will satisfy the content requirements for resource planning and CON filings TRANSLink may submit proposing to construct transmission facilities in Minnesota;

WHEREAS, the Intervenors also expressed concerns in comments regarding the ability of the Commission to require TRANSLink to take actions to modify its transmission planning process because TRANSLink was not a petitioner in this proceeding;

WHEREAS, On April 14, 2003, TRANSLink Development, the predecessor entity to TRANSLink Management Corporation, filed reply comments and petitioned the Commission for intervention as a party pursuant to Minnesota Rule 7829.0800 and more than 15 days have elapsed without an objection to that petition being filed;

WHEREAS, TRANSLink Development and Intervenors is each a party to the above captioned proceeding by operation of Minnesota Rule 7829.0800, Subpart 5;

WHEREAS, After these filings, representatives from Intervenors met with TRANSLink Development and discussed the concerns of Intervenors;

WHEREAS, TRANSLink Development and Intervenors have agreed to make certain commitments to each other, which commitments would fully satisfy Intervenors' concerns about the Xcel Energy petition and the proposed transfers to TRANSLink;

WHEREAS, TRANSLink and Intervenors recognize the rapidly expanding legislative, regulatory, and market support for continued strong growth of wind power in the TRANSLink footprint, and agree that it is reasonable to expect that at least 7500 megawatts (MW) of new wind power will be operational in the TRANSLink footprint by 2015;

WHEREAS, The Parties wish to memorialize these commitments in this Settlement Agreement to fully and finally settle all of Intervenors' concerns in this proceeding about the Xcel Energy petition and the proposed transfers to TRANSLink;

NOW, THEREFORE, in consideration of the foregoing and of the mutual promises and undertakings set forth herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. To the extent reasonable and practicable, TRANSLink shall avoid filing exemption requests when it files CON applications for future transmission facilities in Minnesota, including when it makes transmission project filings under the statewide biennial transmission planning process. TRANSLink shall not file exemption requests on the grounds that TRANSLink neither owns or controls, or manages electric generation or electric distribution facilities. TRANSLink commits to work with all of its Participants in Minnesota to gather the information required for a CON application. If TRANSLink files a request to be exempt from any Minnesota CON filing requirement because neither TRANSLink nor its Participants can gather the required data, TRANSLink will identify in such exemption request the steps TRANSLink has taken to obtain the data and explain why neither TRANSLink nor its Participants could provide the data.

2. Once TRANSLink begins operations and provides service under its rate schedules, the Intervenors and TRANSLink shall jointly undertake to create a coalition of organizations that support the development in TRANSLink's footprint of small-scale community-based and large-scale wind generation (the "Wind Coalition"). The purpose of the Wind Coalition will be to work with TRANSLink to develop the infrastructure, operations, and tariffs needed to serve wind generation throughout the TRANSLink footprint. The Wind Coalition shall compile and submit to TRANSLink Wind Development Plan(s) for use in determining what transmission infrastructure development, operational solutions, and tariff changes may be needed to serve forecast wind generation development within TRANSLink's

footprint. To address seams issues, the Wind Development Plan(s) may also consider forecast wind generation development in states or other areas adjacent to the TRANSLink footprint.

3. TRANSLink Development will develop the TRANSLink Planning Process, a working draft of which is attached hereto as Exhibit A, in a way that affords the Wind Coalition a level of participation in the TRANSLink regional planning process at least as great as Intervenors may have in the MISO super-regional and Mid-Continent Area Power Pool ("MAPP") regional planning processes. The Intervenors' level of participation in the TRANSLink Planning Process shall never be less than that currently afforded to Intervenors under the MISO and MAPP planning processes except where such participation is, through no effort of TRANSLink, limited by any court or administrative agency of competent jurisdiction. For example, the Wind Coalition may participate in the scenario planning process and participate in and comment on TRANSLink study scopes, problem identification, solution development, solution testing and solution evaluations. Consistent with the nature of its participation at MAPP and MISO, the Wind Coalition will provide assumptions relating to wind generation for use in planning scenarios and assist TRANSLink in identifying potential non-transmission solutions where appropriate. Non-transmission solutions may include, but are not limited to, control strategies, distribution or generation solutions, demand side management, operational solutions, or tariff modifications.

4. As part of the Wind Coalition's participation in the TRANSLink Planning Process, the Wind Coalition will:

(a) Annually prepare and submit a forecast (the "Wind Development Plan") of the quantity of wind generation expected to be installed in the TRANSLink region, where that wind generation is likely to be located and when the generation is expected to come on-line.

(b) TRANSLink shall integrate the Wind Development Plan into the TRANSLink Planning Process, including but not limited to TRANSLink "scenario" planning initiatives. As part of the TRANSLink Planning Process, TRANSLink shall work with the Wind Coalition to analyze and identify the transmission infrastructure requirements, operational modifications, and tariff changes that may be needed to serve the forecasted wind generation (the "Wind Response Plan"). TRANSLink shall provide the Wind Response Plan to the Wind Coalition for review and comment in accordance with established review procedures within the TRANSLink Planning Process.

(c) The Wind Coalition shall evaluate and make recommendations to TRANSLink on the Wind Response Plan. TRANSLink shall thereafter implement the Wind Response Plan in a fashion consistent with the Wind Coalition's recommendations to the extent that such recommendations are technically feasible and consistent with good utility practice, electric reliability and security. TRANSLink is not required to implement the Wind Coalition's recommendations where the costs associated with implementing and sustaining such recommendations are not reasonable or where TRANSLink reasonably believes that such costs would not be recoverable in TRANSLink's rates.

5. The Wind Coalition will prepare and submit to TRANSLink list(s) of any transmission-related issues within the TRANSLink footprint that the Wind Coalition believes TRANSLink needs to address to facilitate the development of wind generation (a "Wind Issues

List(s)"). The Wind Issues List(s) need not be prepared and submitted within the context of the TRANSLink Planning Process. The Wind Issues List(s) may recommend transmission solutions or non-transmission solutions (examples of which area listed in paragraph 3 of this Settlement Agreement) to the issues raised. Within 120 days of receiving the Wind Issues List(s), TRANSLink shall evaluate the issues and shall provide the Wind Coalition with a response identifying the actions TRANSLink agrees to implement or alternative solutions TRANSLink proposes to implement to address the issues on the Wind Issues List(s) (a "Wind Issues Response Plan(s)"). The Wind Coalition shall review the Wind Issues Response Plan(s) and make recommendations to TRANSLink. TRANSLink shall thereafter implement the Wind Issues Response Plan(s) in a fashion consistent with the Wind Coalition's recommendations to the extent that such recommendations are technically feasible, consistent with good utility practice, and consistent with electric reliability and security. TRANSLink is not required to implement the Wind Coalition's recommendations where the costs associated with implementing and sustaining such recommendations are unreasonable or where TRANSLink reasonably believes that such costs would not be recoverable in TRANSLink's rates.

6. TRANSLink recognizes that the process of obtaining rights-of-way within its footprint has the potential to generate significant public controversy. TRANSLink shall work with the Wind Coalition to investigate and implement creative solutions or alternatives for the procurement of and landowner compensation for transmission rights of way. To the extent that TRANSLink and the Wind Coalition agree to implement any particular alternative, the Intervenors shall not object to TRANSLink's recovery of associated reasonable costs in TRANSLink's rates.

7. Within 180 days after TRANSLink commences operations, TRANSLink and the Wind Coalition shall jointly identify and evaluate any federal and/or state regulatory impediments to 1) the efficient development and execution of infrastructure development plans necessary to accommodate planned wind generation, and 2) the provision of ancillary services for wind generation facilities. TRANSLink and the Wind Coalition shall thereafter work together with the goal of jointly developing any federal and/or state regulatory filings that may be appropriate and necessary to achieve the elimination or minimization of such regulatory impediments. Any rate schedule amendments to reduce or eliminate such impediments are subject to FERC approval. This paragraph is not intended to limit the Parties' right to express independent views on issues that are or may in the future be pending before any federal and/or state regulatory agency(ies).

8. As a result of the commitments that TRANSLink Development makes in this Settlement Agreement, Intervenors agree that Commission approval of TRANSLink will bring about beneficial opportunities for stakeholder involvement in expanding the transmission infrastructure, operations, and tariffs that support significant wind power expansion in the TRANSLink footprint. Intervenors agree that this Settlement Agreement addresses all of the concerns Intervenors raised in these proceedings, and hereby withdraw their opposition to the Petitions, having no further objections to Commission approval of the Petitions.

9. Intervenors will not propose any conditions to the Commission other than those to which TRANSLink Development has agreed in this Settlement Agreement, nor will Intervenors advocate for any conditions that have been or in the future may be proposed by other parties and commenters in this proceeding, other than those conditions set forth in this Settlement

Agreement. Intervenors may advocate for conditions contained in other Settlement Agreements TRANSLink submits to the Commission in this proceeding.

10. TRANSLink hereby agrees to the MPUC's imposition of the requirements of this Settlement Agreement on TRANSLink as a condition of any order approving the Petitions.

11. Upon TRANSLink's request, Intervenors shall submit to agency(ies) in other states before which application(s) for the transfer of control of transmission facilities to TRANSLink are pending written comments or correspondence expressing their support for such application(s) on the basis of the application's(s') beneficial opportunities for wind power development, so long as TRANSLink agrees to conditions consistent with this Settlement Agreement in such other states. Intervenors shall not be required to make such submissions where they have objections to pending applications on issues that were not implicated by the Petitions in these proceedings.

12. This Settlement Agreement shall be binding upon and inure to the benefit of the successors and assigns of TRANSLink Development and Intervenors whether by way of merger, consolidation, operation of law, assignment, purchase or other acquisition. If the proposed transfer of functional control of Xcel Energy's and IPL's transmission facilities to TRANSLink is not effectuated for any reason, this Settlement Agreement shall be of no force and effect.

13. In entering into this Settlement Agreement, the Parties represent that they have relied upon the advice of their attorneys, that each party's attorney is the attorney of the party's own choice, that they have read the terms of this Settlement Agreement, that the terms of this Settlement Agreement have been completely read and explained to them by their attorney, and that the terms are fully understood and voluntarily accepted by them. Each party agrees and

represents that neither party is relying on any representations or statement(s) made by the other party or anyone representing the other party or by any person employed by the other party.

14. It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, the Settlement Agreement shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Settlement Agreement shall not in any respect constitute a determination by the Parties as to the merits of any specific allegations or contentions made by the Parties.

15. This Settlement Agreement constitutes the entire agreement and understanding between the Parties pertaining to the resolution of issues in this proceeding and the other matters specified herein, and supersedes and replaces all prior negotiations and proposed agreements, written or oral.

16. Any modification to this Settlement Agreement shall not be binding on the Parties unless consented to in writing by TRANSLink Development and Intervenors.

17. This Settlement Agreement may be executed in counterparts with the same force and effect as if a single original had been executed by the Parties hereto. A facsimile signature will be considered as an original.

TRANSLink Management Development Corp.

by Audrey Zabelman, its Chief Executive Officer
for itself on and behalf of its successor
TRANSLink Management Corporation

Izaak Walton League of America – Midwest Office

by William Grant, its Associate Executive Director

Minnesotans for an Energy Efficient Economy

by Michael Noble, its Executive Director

Minnesota Center for Environmental Advocacy

by Martha Brand, its Executive Director

North American Water Office

by George Crocker, its Executive Director

TRANSLink Management Development Corp.

by Audrey Zibelman, its Chief Executive Officer
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for itself on and behalf of its successor
TRANSLink Management Corporation

Izaak Walton League of America – Midwest Office

by William Grant, its Associate Executive Director

Minnesotans for an Energy Efficient Economy

Michael Noble 6/23/03

by Michael Noble, its Executive Director

Minnesota Center for Environmental Advocacy

by Martha Brand, its Executive Director

North American Water Office

by George Crocker, its Executive Director

TRANSLink Management Development Corp.

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Exhibit A

WORKING DRAFT FOR DISCUSSION PURPOSES ONLY.

TRANSLink℠
Transmission Company

TRANSLink Planning Process Overview

June 5, 2003

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1.0 Appendix I

On November 22, 2002, the Appendix I Agreement between TRANSLink Development Company, LLC and the Midwest Independent Transmission System Operator, Inc. (MISO) was filed with the Federal Energy Regulatory Commission (FERC). Contained in the Appendix I Agreement is Schedule 5 which describes the TRANSLink Planning Procedures.

The purpose of Schedule 5 is to describe a framework within which TRANSLink will develop a TRANSLink transmission system expansion plan. The attributes of Schedule 5 include the concepts of "coordinated planning through an open and fair process", environmentally sensitive and least-cost planning, development of 10 Year Plan (updated annually) and the use of planning committees. The following is meant to add further detail to the TRANSLink Planning Process and add clarity to the various relationships with stakeholders that are necessary for developing the appropriate TRANSLink transmission plan. This document is marked as draft because it is a work in progress, as TRANSLink has not yet had the benefit of stakeholder input.

The TRANSLink planning process is designed to enable various stakeholders to participate at all stages, including problem/opportunity identification, scenario development, solution alternative identification, and result presentation. The objective of the process is to develop plans that have wide stakeholder and regulatory understanding and support to permit smooth implementation.

2.0 Glossary of Terms

2.1 RSPG

Regional Stakeholder Planning Group: The RSPG will identify and coordinate regional planning issues and coordinate sub-regional initiatives. Membership will be open to all stakeholders including transmission owners, load serving entities, environmental groups, generation developers, other public interest groups, the Midwest ISO and regulatory agencies.

2.2 RPC

Reliability Planning Committee: The RPC is defined in Schedule 5 to the Appendix I agreement between TRANSLink Development LLC and MISO to consist of those entities with an "obligation to serve" (TRANSLink, TRANSLink Participants, and Load Serving Entities, plus representatives of regulatory agencies and MISO). The RPC will be a subset of the RSPG and will provide a forum for the discussion of RSPG issues that are subject to the FERC Standards of Conduct and Commercial Confidentiality Requirements. Accordingly, RPC membership will be limited to those who agree to comply with these standards.

2.3 TPWS

Ten Year Plan Working Subcommittee (TPWS): The TPWS will be another subset of the RSPG and will be open to all RSPG members. It will be responsible for coordinating the 10-year TRANSLink enhancement plan process and drafting the 10-year TRANSLink enhancement plan.

2.4 SPGs

Stakeholder Planning Groups: The SPGs are designed to focus on local-level planning issues and solutions. Membership will be open to all stakeholders including transmission owners, load serving entities, environmental groups, generation developers, other public interest groups, and regulatory agencies.

2.5 WSCs

Working Subcommittees: WSCs will be part of the RSPG and the SPGs. The WSCs will undertake the studies and other tasks within each group. WSC members are expected to complete study work in a thorough and timely manner.

2.6 MTEP

MISO Transmission Expansion Plan: MTEP is the name of the Midwest ISO long-range expansion plan. The first such plan is referred to as MTEP-03.

2.7 Planning Scenario

Planning Scenario: refers to the multitude of expectations, assumptions and goals upon which the transmission system can be planned. These scenarios, for example, can take into account various inputs in load growth patterns, wind development, conservation, load management, distributed generation, locations of energy markets, etc.

3.0 Planning Committees

TRANSLink's objective is to establish an open and fair planning process to foster input from all interested parties and stakeholders. To accomplish this, a stakeholder committee structure has been developed as an integral part of the planning process. The committee structure will augment the planning structure of TRANSLink and perform tasks through the use of working subcommittees. Throughout the process, TRANSLink staff will be available upon request to attend various stakeholder meetings to receive comment and to answer questions. (Refer to Diagram 1 on page 8)

3.1 Regional Stakeholder Planning Group

The Regional Stakeholder Planning Group (RSPG) will coordinate the identification of regional planning issues and sub-regional initiatives. It is envisioned that the RSPG will maintain the "big picture" with respect to planning in the TRANSLink footprint. It will be the responsibility of the RSPG to: 1) ensure effective communications between the RSPG, SPGs and TRANSLink, 2) ensure coordination and minimize duplication of efforts between and among the SPGs and 3) perform work that is "regional" in nature. The following are key attributes of the RSPG:

- The RSPG will be chaired by TRANSLink staff.
- Membership will be open to all stakeholders and consist of transmission owners, load serving entities, environmental groups, generation developers, other public interest groups, the Midwest ISO and regulatory agencies.
- RSPG activities will be coordinated with the Midwest ISO through TRANSLink.
- The RSPG and the SPGs will perform functions through the use of Working Sub-Committees (WSCs):
    - TRANSLink staff will chair the WSCs.
    - The WSCs will be open to all stakeholders.
    - Members of the WSCs will be expected to perform study work in a thorough and timely manner.
    - Each WSC will have a clearly defined scope of work approved by the RSPG.
    - Work performed by the WSCs is to be presented for review by the SPGs and the RSPG.
    - In the event that the scope of a WSC is subject to the FERC Standards of Conduct, the WSC will have membership closed to those not bound by the Standards of Conduct. Accordingly,

such a WSC would report directly to the Reliability Planning Committee that similarly is subject to confidentiality rules.

3.2 Reliability Planning Committee

A subset of the RSPG is the Reliability Planning Committee (RPC). The RPC is defined in Schedule 5 to consist of those entities with an "obligation to serve" within the TRANSLink transmission system(TRANSLink, TRANSLink Participants, and Load Serving Entities, plus representatives of regulatory agencies and MISO). The purpose of the RPC will be to provide a forum for the discussion of RSPG issues that are subject to the FERC Standards of Conduct. The following are the key points of the RPC:

- Will be chaired by TRANSLink staff.
- The FERC Standards of Conduct will limit participation.
- The intent of the RPC is not to be separate from the RSPG, but rather a "stakeholder" sub-group of the RSPG.
- RPC meetings will be held only as needed for discussion of FERC Standards of Conduct issues and held in conjunction with RSPG meetings whenever possible.
- RPC meeting dates and locations will be considered public information for all stakeholders.
- Specific meeting discussion items will be made available to the RSPG when the information is ready for release to the public domain as determined by either by the FERC Standards of Conduct or other confidentiality terms.

3.3 Sub-Regional Stakeholder Planning Groups

The Sub-Regional Stakeholder Planning Groups will be established for the purpose of addressing local (sub-regional) planning issues and undertaking other efforts as directed by the RSPG. Within the historic MAPP area, there will be three such groups:

- Iowa Stakeholder Planning Group (ISPG)
- Nebraska Stakeholder Planning Group (NSPG)
- Northern MAPP Stakeholder Planning Group (NMSPG)

The sub-regional SPGs are similar to the RSPG, but their focus is on sub-regional planning issues. The following are the key points of the SPGs:

- Membership will be open to all stakeholders and consist of transmission owners, load serving entities, environmental groups, generation developers, other public interest groups, and regulatory agencies.

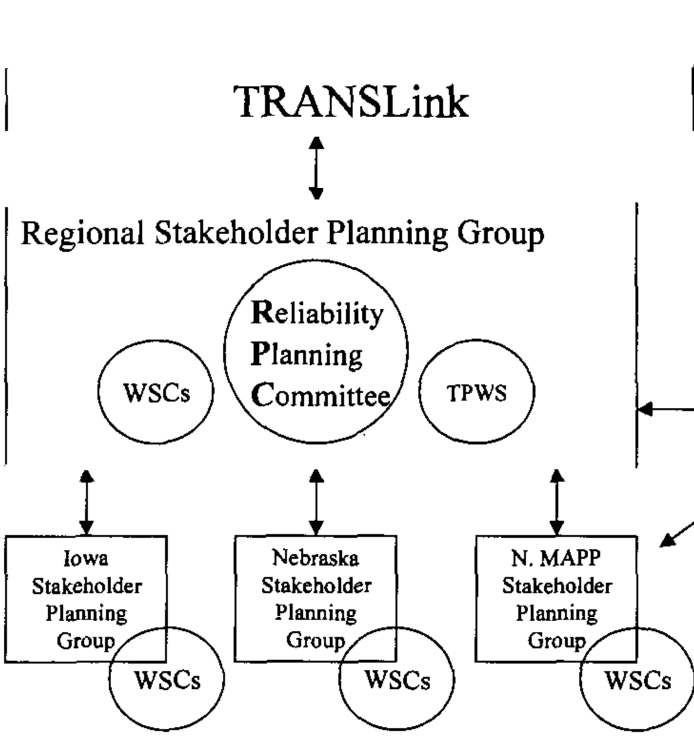
- SPGs will perform functions through the use of WSCs:
    - These groups will be open to all members of the SPGs.
    - The role of the WSCs will be local in nature (e.g. load service planning).
    - Each WSC will have a clearly defined scope of work approved by the RSPG.
    - Members of the WSCs will be expected to perform study work in a thorough and timely manner.
    - Work performed by the WSCs will be presented for review to the RSPG.
    - In the event that the scope of a WCS is subject to the FERC Standards of Conduct, the WCS will be coordinated by the RPC.

3.4 RSPG and SPG Coordination

The coordination effort between the RSPG and SPGs is envisioned to be a layered structure. The RSPG will maintain a "regional" perspective of the transmission system while the SPGs will have the "local" perspective. The RSPG will coordinate the efforts of the SPGs in order to eliminate duplication of efforts between the RSPG and SPGs and between the SPGs themselves.

Diagram 1

TRANSLink 10 Year Planning Structure (North System)



The **Reliability Planning Committee (RPC)** consists of entities with an "Obligation To Serve" and is subject to FERC Standards of Conduct and Commercial Confidentiality Requirements. See body of document for additional explanation of planning structure.

Parallel processes are used in the SPP and WECC regions

TRANSLink Transmission Company

4.0 Long Term Transmission Planning

4.1 Midwest ISO Transmission Expansion Planning Cycle

The Midwest ISO will be publishing its first long-range expansion plan, referred to as MTEP-03, in May-June of 2003. The Midwest ISO intends to publish its 2004 expansion plan in April of 2004 as part of its annual cycle. The on-going annual expansion plan cycle at the Midwest ISO is as follows:

- Perform necessary study work throughout the year
- Draft report writing in November/December
- Draft report sent to various Midwest ISO committees for comments and approval, requiring approximately 3 months (Jan-Mar)
- Final approved MTEP report published in April
- Next annual expansion plan cycle starts

4.2 TRANSLink System Enhancement Planning Cycle

The title above was selected specifically to convey the TRANSLink philosophy that a wide variety of options should be considered during plan development. The process is designed to encourage stakeholders to identify solutions ranging from traditional transmission additions, to implementation of new technologies, to dispersed generation.

Given that the annual TRANSLink System Enhancement Plan will be incorporated into the annual MTEP, the TRANSLink schedule below is meant to coincide with the Midwest ISO cycle (also see Diagram 2 on page 12). To the extent that the Midwest ISO adjusts its expansion plan cycle, TRANSLink will adjust as well. The envisioned details of the TRANSLink planning cycle are: (refer to Section 3.0 for a description of groups/committees)

<u>1st Quarter</u>

- Regional Stakeholder Planning Group (RSPG) meets and establishes the Ten Year Plan Working Subcommittee (TPWS). This subcommittee will be chaired by TRANSLink staff. Its membership will consist of RSPG member representatives, regulatory representatives, and other stakeholder representatives. As this is viewed as a "working subcommittee" the size of the subcommittee must be kept at a functional size.
- TPWS compiles all existing study work and proposed projects since the last published TRANSLink System Enhancement plan including

load service plans, generator interconnection plans, regional transmission plans, IRP results etc.

- Stakeholder Planning Groups (SPGs) and the TPWS identify deficient study areas and other study needs.
- TPWS develops priorities, scopes and schedules that are then presented to the RSPG and SPGs for comment on priorities and scopes.
- RSPG, TPWS and SPGs establish necessary Working Subcommittees (WSCs) to complete the study scopes. Membership in WSCs will be drawn from a list of all stakeholders registered with SPGs or the RSPG.
- To the extent possible, the WSCs begin study work.

2nd Quarter

- WSCs perform adequacy assessment on study areas (NERC 1A Standards) and identify system enhancement needs.
- WSCs present adequacy assessment to SPGs and use this open forum to develop alternatives to be studied to address deficiencies.
- SPGs analyze alternatives and evaluate enhancement options.
- SPGs share evaluations with RSPG for comments, ideas, and other input.

3rd Quarter

- WSCs complete study work and present results to RSPG and SPGs.
- TPWS coordinates the 10 Year System Enhancement Plan report writing effort with the RSPG and SPGs.
- New plans developed during the year (e.g. generator interconnection results) are added to the draft report.

4th Quarter

- TPWS presents draft report to RSPG for review and comment by all members and participant observers.
- RSPG formally accepts plan.
- The Draft 10 Year System Enhancement Plan Report is forwarded to TRANSLink Management for approval.
- Upon TRANSLink Management approval, the report will become Final and sent to the Midwest ISO for incorporation into the Midwest ISO MTEP Report. Should any stakeholders continue to have concerns about any aspect of the plan, they can raise these concerns by petitioning MISO.

4.3 Planning Scenarios

TRANSLink's goal is to propose system expansion options to accommodate not only the "obligation to serve" requirements, but also market, public interest and environmental initiatives and requirements as well. TRANSLink is establishing its planning process to provide an opportunity for all stakeholders to actively participate. To achieve these objectives, TRANSLink will rely on the development and analysis of planning "scenarios" as a key component of the TRANSLink Ten Year System Enhancement Plan.

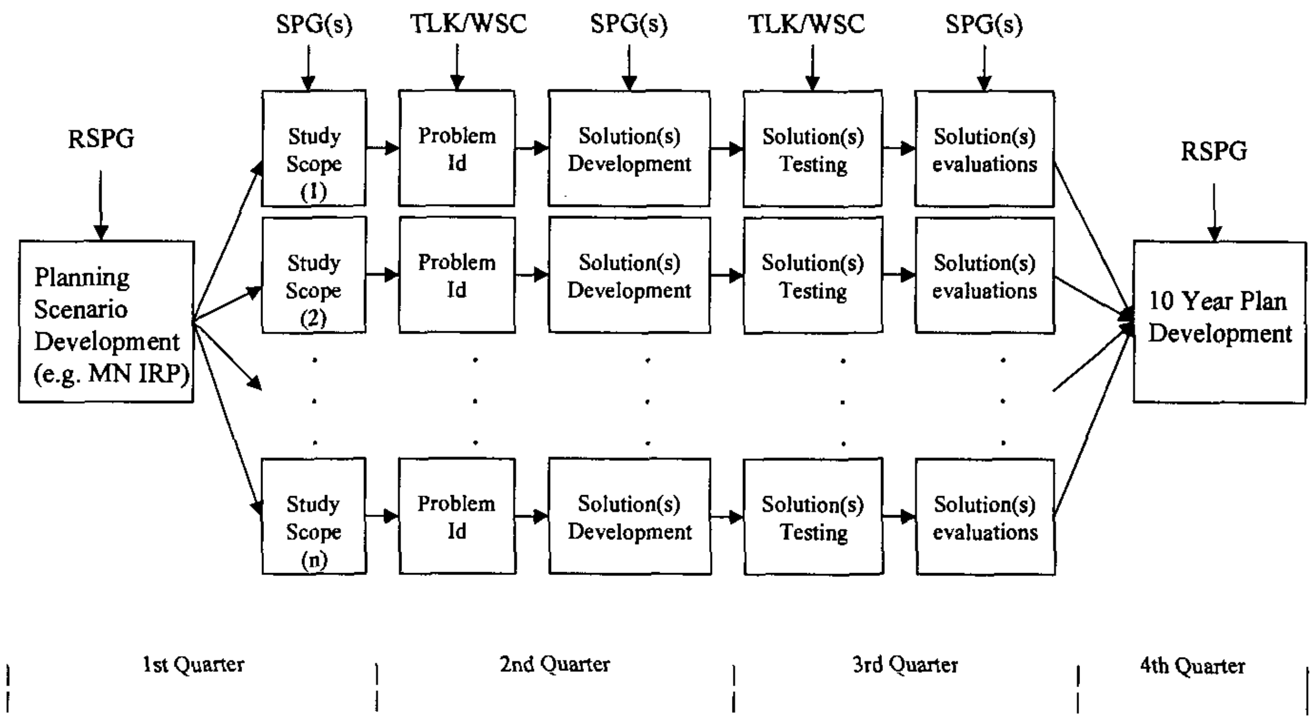
Planning scenarios will provide direction(s) for optional transmission expansion initiatives incorporating "traditional" planning and "vision" planning. Traditional planning concerns consist of the "obligation to serve" demands that must be accommodated such as reliability, load growth and interconnections. Vision planning concerns include energy policy, conservation and market economics. In Minnesota, for example, vision planning drives the utility integrated resource plan (IRP) process. TRANSLink expects that these plans will play an integral role in the development of scenarios relating to the transmission needs of load serving entities and the market (also see Diagram 2 on page 12). Other vision issues include:

- Load Growth Assumptions (demand side management and other)
- Energy Source Options
- Market Needs (wholesale, flowgates)
- Generator Assumptions
- Economic Activity
- New Technologies

Developing vision scenarios will require significant input from all stakeholders, particularly market participants (such as the wind energy industry), environmental groups, public interest advocates and regulatory agencies. TRANSLink will be asking for and strongly encouraging direct and purposeful involvement from stakeholders to incorporate vision planning in the process. The RSPG will be the main body for achieving this result.

Diagram 2

TRANSLink 10 Year Transmission Plan



TRANSLink Transmission Company

4.4 Plan Implementation and Dissemination

The implementation of the accepted plan will be the responsibility of TRANSLink and subject to the permitting and siting rules of the various jurisdictions within which TRANSLink operates. To facilitate implementation, TRANSLink will schedule periodic meetings with state regulatory agencies to keep the agencies informed of developments. These meetings will also provide another forum outside the planning process for the agencies to express comments/concerns to TRANSLink.

5.0 TRANSLink Planning Functions

TRANSLink will be the transmission owner and operator for a significant portion of the eastern interconnection. TRANSLink will have the ultimate responsibility for numerous planning related functions such as facilitating interconnections, maintaining NERC compliance and developing a long-term enhancement plan. Below is a listing of some of these functions and important aspects of each.

5.1 Ten Year System Enhancement Plan

- The RSPG or a WSC of the RSPG will develop the 10 Year Plan.
- The Plan will be updated on an annual basis.
- The Plan will be compiled utilizing all study work to date from each of the TRANSLink planning functions carried out by TRANSLink, the RSPG, the SPGs and MISO.
- The TRANSLink Asset Management group will have the final approval of all proposed facilities within the TRANSLink footprint.
- The 10 Year Plan will be coordinated with the SPGs for input.
- The 10 Year Plan will be provided to the Midwest ISO through its Expansion Plan process.
- The Midwest ISO will have final authority over those projects deemed to have "material affect" on facilities outside of the TRANSLink footprint.
- Non-TRANSLink participant utilities will have the opportunity to add their long-range transmission plans to the TRANSLink plan for submission to the Midwest ISO.

5.2 Model Building

- The RPC will develop a model building process for TRANSLink.
- SPG and RSPG members within the TRANSLink footprint will gather data for the model building process.
- Other entities with model building responsibilities wishing to participate in the TRANSLink model building process will be welcomed and encouraged.
- The intent of the TRANSLink model building process will be to create a regional model.
- The model building process will be coordinated with the Midwest ISO and all data gathered will be supplied to the Midwest ISO as part of its model building process(s).

5.3 NERC Compliance

- The RPC will develop NERC compliance requirements for TRANSLink.
- The RPC will determine what data is needed and what study work is required for NERC compliance.
- The RPC will coordinate NERC compliance needs with the SPGs to ensure the appropriate information is available and study work completed.
- Through the use of WSCs, the RSPG will perform study work on a regional basis; the SPGs will perform study work on a sub-regional basis.
- WSCs will be created as necessary.

5.4 Load Service Planning

- Load Service Planning and other local planning initiatives will be conducted by the SPGs.
- To ensure the proper coordination with other SPGs and RSPG efforts, each study effort will have a clearly defined scope of work approved by the RSPG.
- All study work efforts shall be provided to the RSPG for review and final approval.
- Where the study effort is outside of the TRANSLink footprint, the study work will be shared with the RSPG.

5.5 Generator Interconnection and Transmission Service Analysis

- Due to the FERC Standards of Conduct and proprietary nature of Generator Interconnection and Transmission Service Analysis study work, these two processes will be conducted internally within TRANSLink.
- TRANSLink will utilize a WSC format encompassing necessary stakeholders under the FERC Standards of Conduct.
- As necessary and when permissible, information will be shared with the RPC and RSPG.
- Information will be shared with the SPGs once public involvement is permitted.

5.6 Facility Interconnections

- The Facility Interconnection process will be conducted internally within TRANSLink due to potential FERC Standards of Conduct issues.
- The Facility Interconnection process will utilize a WSC format encompassing necessary stakeholders under the FERC Standards of Conduct as needed.
- As allowable by the FERC Standards of Conduct, facility interconnection study work will be conducted and coordinated within the SPGs via the RPC and RSPG.
- Only those projects or requests that are not already part of the normal load service planning process, 10 Year Plan or other study processes will be required to be studied separately under a facility interconnection process.

Exhibit I

Wind on the Wires $4.5 million and $8.1 million grants

May 1, 2001 - $4.5 million

June 26, 2003 - $8.1 million
(3 days after TRANSLink Agreement filed in PUC Dockets)

McKnight Foundation 600 TCF Tower
121 South 8th Street
Minneapolis, MN 55402

May 1, 2001

For Immediate Release

Contact: Tom Kelly (612) 309-3303

$4.5 MIL. RENEWABLE ENERGY INITIATIVE LAUNCHED IN MINNEAPOLIS; "WIND ON THE WIRES" WILL BOOST ECONOMIC DEVELOPMENT IN RURAL MINNESOTA

"Wind on the Wires" will help build the "Road to Market" for wind energy, a new cash crop"

Download this document in PDF format

Minneapolis, Minn. - "Wind on the Wires," the centerpiece of a $4.5 million, two-year project to develop renewable energy resources, was unveiled today during the National Wind Coordinating Committee Upper Midwest Transmission Workshop at the Embassy Suites Hotel in Minneapolis. The McKnight Foundation and the San Francisco-based Energy Foundation are the primary sponsors of the project, which is a partnership of the business community, local leaders, clean energy advocates and wind energy experts.

"We are proud to support "Wind on the Wires," said Rip Rapson, McKnight Foundation President. "Wind power is a reliable, affordable and pollution-free source of energy. It promises to be a high-growth business that offers opportunities to further diversify our rural economy. Wind on the Wires is dedicated to realizing these opportunities, so Minnesota can be a world leader in developing this resource, " Rapson added.

"Wind power is the fastest growing source of electricity in the world, and the Upper Midwest has been a focus for new development in recent years," said Eric Heitz, Executive Vice-President of the Energy Foundation. "This region is rich in wind resources with five of the top ten windiest states in the country in the Upper Midwest. Tapping this potential could mean billions of dollars of investment in the region," Heitz added.

"Wind on the Wires" will help build a road to market for wind power in the Upper Midwest. The roads for electricity are transmission wires connecting windy areas to power consumers. Opening up these roads to market will be the primary focus of this project. "Wind on the Wires" will focus on overcoming two main hurdles that currently limit large-scale development: bottlenecks in the power grid and old rules of the road for transmission systems.

"We are poised to expand markets for wind power and build a thriving industry in Minnesota and the Dakotas," said Paul White, Midwest Project Manager for enXco, a wind energy development company. "To move wind power to large markets such as the Twin Cities, Chicago, Des Moines and St. Louis, our top priority must be to remove the physical bottlenecks of the current power grid and upgrade the system. These upgrades will also improve the reliability of the system for consumers," White emphasized.

White also explained that the current rules of the road for transmission systems have worked well for conventional technology, but as technology has advanced, the rules also need to be updated. "Wind on the Wires will help by working to update government rules so that wind power has fair access to the market," White concluded.

Wind on the Wires partners will work with transmission planners and the grid operators to solve technical issues and to overcome regulatory hurdles. In addition, the Wind on the Wires partners will work with economic development officials to enlist their support for transmission improvements and wind development, and educate state, local, and federal officials on the benefits of wind power for the region.

For additional information on the "Wind on the Wires" project visit the website at: www.windonthewires.org.

ABOUT THE MCKNIGHT FOUNDATION - Founded in 1953 and endowed by William L. McKnight and Maude L. McKnight, the Foundation has assets of approximately $2 billion and granted about $94 million in 2000. Mr. McKnight was one of the early leaders of the 3M Company, although the Foundation is independent of 3M.

ABOUT THE ENERGY FOUNDATION - The Energy Foundation is a partnership of major foundations interested in energy efficiency and renewable power. Sponsors include: The McKnight Foundation, the John D. and Catherine T. MacArthur Foundation, the Pew Charitable Trusts, the Rockefeller Foundation, the Joyce Mertz-Gilmore Foundation, and the David and Lucille Packard Foundation.

FACT SHEET

- 1999 was a record year for worldwide wind turbine sales and Minnesota and Iowa captured almost 15% ($450 mil.) of the wind energy investment market.
- Electricity generated from wind energy is the fastest growing segment of energy production in the world, with an overall growth rate of 36% in 1999.
- According to the American Wind Energy Association, installed wind energy capacity in the US totaled 2,550 megawatts in 2000, and generated enough power for over 500,000 homes.
- The United States will increase wind-generated power output by 2000 megawatts in 2001.
- The US Department of Energy estimates that wind energy in Minnesota could supply more than the current energy needs of the state and could generate about 14% of the nation's electric power.
- Minnesota could develop 1,600 megawatts of new wind by 2010, and 4,500 megawatts by 2020, according to www.repowermidwest.org
- LM Glasfiber, a Danish firm that manufactures wind turbine blades recently opened a plant in Grand Forks, North Dakota that created 120 new jobs.
- NEG Micon, the world's second largest turbine manufacturer, has a plant in Champaign, Illinois.
- DMI Industries of Fargo, North Dakota recently switched from manufacturing farm implements for the sugar beet industry to building towers for wind turbines. They employ 130 people.
- Iowa wind farms generate $2 million a year in tax revenue to local governments, and $650,000 in payments to landowners
- Wind-generated energy supplies about 2% of Iowa's electricity needs, offsetting the need for coal imported from Wyoming and Montana.
- Wind farms produce $710,000 in property tax revenues in Lincoln County, Minnesota.

# # #

MCKNIGHT FOUNDATION TO INVEST MORE THAN $8 MILLION IN UPPER MIDWEST RENEWABLE ENERGY

June 26, 2003 - McKnight continues 10-year partnership with San Francisco's Energy Foundation.

The McKnight Foundation announced today it will devote $8.1 million over three years to a renewable energy program ”primarily wind energy” in seven Upper Midwest states: Minnesota, Wisconsin, Illinois, Iowa, Nebraska, North Dakota and South Dakota.

McKnight will work with The Energy Foundation, a San Francisco-based national renewable energy leader, to administer the program. McKnight has had a 10-year partnership with The Energy Foundation.

McKnight's investment seeks to capitalize on, and promote, the Upper Midwest's leadership role in national energy policy. It builds on the three-year-old McKnight/Energy Foundation program "Wind on the Wires," which is designed to bring wind energy to market by improving and expanding the current power grid infrastructure. And it seeks to reinforce the economic development potential of alternative energy investments in hard-hit rural areas.

"We believe this investment will help the renewable energy message cross over from the environmental community to a broader audience," said Rip Rapson, president of The McKnight Foundation. "There is such tremendous potential waiting to be tapped. For example, wind power can be a potent form of economic development and income diversification for those in rural communities. The McKnight Foundation is proud to be leading an initiative that will both broaden the nation's energy mix and diversify our regional economy."

"The Energy Foundation has long advocated for reliable, affordable, and pollution-free energy," said Eric Heitz, the organization's president. "We see the potential for the Upper Midwest to become a world leader in this industry in the 21st century. We have already seen almost a billion dollars invested in wind power in the region, with hundreds of skilled jobs created and millions of dollars put into the hands of struggling farmers and counties."

Existing wind energy projects in the Midwest create enough power for 250,000 homes in the region, pay more than $2 million per year in royalties to farmers, and eliminate almost 3 million tons of carbon dioxide from coal-fired power plants, equivalent to taking 469,000 cars off the road.

Since 1993 The Energy Foundation and The McKnight Foundation have worked together to promote public policies to encourage development of renewable power and more efficient use of energy. This partnership was formalized in 1997 when McKnight made a three-year, $3 million grant to the Energy Foundation to implement the Upper Midwest Clean Energy Initiative, a jointly developed strategy to encourage wind power development and stimulate businesses that help people use energy more efficiently in Minnesota and the Midwest. This support was renewed in 2000 with a two-year, $2.5 million grant that focused on policy incentives for renewable energy development and the promotion of public policies that support transmission of wind-generated electricity.

ABOUT THE MCKNIGHT FOUNDATION
Founded in 1953 and endowed by William L. McKnight and Maude L. McKnight, the Foundation has assets of approximately $1.6 billion and granted about $87 million in 2002. Mr. McKnight was one of the early leaders of the 3M Company, although the Foundation is independent of 3M.

ABOUT THE ENERGY FOUNDATION
The Energy Foundation is a private foundation whose mission is to promote energy efficiency and renewable energy as clean energy options. It is a partnership of major foundations including The William and Flora Hewlett Foundation, John D. and Catherine T. MacArthur Foundation, The McKnight Foundation, The Mertz-Gilmore Foundation, The David and Lucile Packard Foundation, and The Pew Charitable Trusts. The Energy Foundation has an annual budget of $20 million and offices in San Francisco and Beijing, China.

Related links

Factsheet: Upper Midwest Wind Energy
Energy Foundation
Wind on the Wires

Exhibit J

Minnesota Session Laws Chapter 97, SF 1368

Minnesota Session Laws

Search

Key: (1) ~~language to be deleted~~ (2) new language

2005, Regular Session

CHAPTER 97-S.F.No. 1368

An act relating to energy; providing for expedited cost recovery for certain transmission investments; authorizing and regulating transmission companies; permitting the transfer of transmission assets and operation to transmission companies; providing for expedited regulatory approval of transmission projects related to renewable generation; providing new criteria to analyze the need for transmission projects; establishing the framework for a wind energy tariff related to community development; requiring a wind integration study; transferring generation plant siting and transmission line routing authority from the Minnesota Environmental Quality Board to the Public Utilities Commission; providing for technical corrections to the energy assistance program; providing for a sustainably managed woody biomass generation project to satisfy the biomass mandate; providing for an electronic mail filing system at the Public Utilities Commission and Department of Commerce; making changes to the conservation investment program recommended by the legislative auditor; authorizing the creation of energy quality zones; regulating eligibility of biogas projects for the renewable energy production incentive; providing for the recovery of certain infrastructure investments by gas utilities; requiring a study of compensation of landowners for transmission easements; promoting the use of soy-diesel; providing for the adjustment of power purchase agreements to account for production tax payments; promoting the use of hydrogen as an energy source; requiring study of using biodiesel fuel to heat homes; expanding authority of city of Alexandria to enter into telecommunications-related joint ventures; appropriating money; amending Minnesota Statutes 2004, sections 13.681, by adding a subdivision; 116C.52, subdivisions 2, 4; 116C.53, subdivision 2; 116C.57, subdivisions 1, 2c, by adding a subdivision; 116C.575, subdivision 5; 116C.577; 116C.58; 116C.61, subdivision 3; 116C.69, subdivisions 2, 2a; 119A.15, subdivision 5a; 216B.02, by adding a subdivision; 216B.16, subdivision 6d, by adding subdivisions; 216B.1645, subdivision 1; 216B.2421, subdivision 2; 216B.2424, subdivisions 1, 2, 5a, 6, 8, by adding a subdivision; 216B.2425, subdivisions 2, 7; 216B.243, subdivisions 3, 4, 5, 6, 7, 8; 216B.50, subdivision 1; 216B.62, subdivision 5, by adding a subdivision; 216B.79; 216C.052; 216C.09; 216C.41, subdivision 1; 462A.05, subdivisions 21, 23; Laws 2002, chapter 329, section 5; proposing coding for new law in Minnesota Statutes, chapters 216B; 216C.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF MINNESOTA:

ARTICLE 1

TRANSMISSION COMPANIES

Section 1. Minnesota Statutes 2004, section 216B.02, is amended by adding a subdivision to read:

Subd. 10. [TRANSMISSION COMPANY.] "Transmission company" means persons, corporations, or other legal entities and their lessees, trustees, and receivers, engaged in the business of owning, operating, maintaining, or controlling in this state equipment or facilities for furnishing electric transmission service in Minnesota, but does not include public utilities, municipal electric utilities, municipal power agencies, cooperative electric associations, or generation and transmission cooperative power associations.

Sec. 2. Minnesota Statutes 2004, section 216B.16, is amended by adding a subdivision to read:

Subd. 7b. [TRANSMISSION COST ADJUSTMENT.] (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs of new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject or modify, after notice and comment, a tariff that:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425;

(2) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(3) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(4) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(5) allocates project costs appropriately between wholesale and retail customers;

(6) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(7) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;

(2) a schedule for implementation of applicable projects;

(3) the utility's costs for these projects;

(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

Sec. 3. Minnesota Statutes 2004, section 216B.16, is amended by adding a subdivision to read:

Subd. 7c. [TRANSMISSION ASSETS TRANSFER.] (a) Public utility owners of transmission facilities may, subject to Public Utilities Commission approval, transfer operational control or ownership of those transmission assets to a transmission company subject to Federal Energy Regulatory Commission jurisdiction. For transmission asset transfers by a public utility, the Public Utilities Commission must review the request to transfer either in the context of a general rate case under this section or by initiating other proceedings it determines provide adequate review of the transmission asset transfer. The Public Utilities Commission may limit, in whole or in part, the transfer of transmission assets or the timing of those transfers by a public utility if it finds the limitation in the public interest. The commission may only approve a transfer if it finds that the transfer is consistent with the public interest.

In assessing the public interest, the commission shall evaluate, among other things, whether the transfer:

(1) facilitates the development of transmission infrastructure necessary to ensure reliability, encourages the development of renewable resources, and accommodates energy transfers within and between states;

(2) protects Minnesota ratepayers against the subsidization of wholesale transactions through retail rates;

(3) ensures, in the case of operational control of transmission assets, that the state retains jurisdiction over the transferring utility for all aspects of service under chapter 216B;

(4) impacts Minnesota retail rates; and

(5) protects Minnesota ratepayers from paying capital costs for transmission assets that have already been recovered.

(b) A transfer of operational control or ownership of transmission assets by a public utility under this subdivision is subject to section 216B.50. The relationship between a public utility transferring operational control of transmission assets to another entity under this subdivision is subject to the provisions of section 216B.48. If a public utility transfers ownership of its transmission assets to a transmission provider subject to the jurisdiction of the Federal Energy Regulatory Commission, the Public Utilities Commission may permit the utility to file a rate schedule providing for the automatic adjustment of charges to recover the cost of transmission services purchased under tariff rates approved by the Federal Energy Regulatory Commission.

(c) A municipal utility, a municipal power agency, or a joint venture pursuant to section 452.25 may transfer operational control or ownership of transmission assets to a transmission company, or make investments in a transmission company, if the governing body of the municipal utility, municipal power agency, or joint venture finds that the transfer or investment is consistent with the public interest and will facilitate the development of infrastructure necessary to ensure reliability.

[EFFECTIVE DATE.] This section is effective August 1, 2005, and applies to petitions for approval of transfer of transmission assets filed on or after that date and does not apply to proceedings pending before the Public Utilities Commission before that date.

Sec. 4. Minnesota Statutes 2004, section 216B.2421, subdivision 2, is amended to read:

Subd. 2. [LARGE ENERGY FACILITY.] "Large energy facility" means:

(1) any electric power generating plant or combination of plants at a single site with a combined capacity of 50,000 kilowatts or more and transmission lines directly associated with the plant that are necessary to interconnect the plant to the transmission system;

(2) any high-voltage transmission line with a capacity of 200 kilovolts or more and greater than 1,500 feet in length;

(3) any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line;

(4) any pipeline greater than six inches in diameter and having more than 50 miles of its length in Minnesota used for the transportation of coal, crude petroleum or petroleum fuels or oil, or their derivatives;

(5) any pipeline for transporting natural or synthetic gas at pressures in excess of 200 pounds per square inch with more than 50 miles of its length in Minnesota;

(6) any facility designed for or capable of storing on a single site more than 100,000 gallons of liquefied natural gas or synthetic gas;

(7) any underground gas storage facility requiring a permit pursuant to section 103I.681;

(8) any nuclear fuel processing or nuclear waste storage or disposal facility; and

(9) any facility intended to convert any material into any other combustible fuel and having the capacity to process in excess of 75 tons of the material per hour.

Sec. 5. Minnesota Statutes 2004, section 216B.243, subdivision 3, is amended to read:

Subd. 3. [SHOWING REQUIRED FOR CONSTRUCTION.] No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:

(1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

(2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

(3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;

(4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments; ~~and~~

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.

Sec. 6. Minnesota Statutes 2004, section 216B.243, subdivision 6, is amended to read:

Subd. 6. [APPLICATION FEES; RULES.] Any application for a certificate of need shall be accompanied by the application fee required pursuant to this subdivision. The application fee is to be applied toward the total costs reasonably necessary to complete the evaluation of need for the proposed facility. The maximum application fee shall be $50,000, except for an application for an electric power generating plant as defined in section 216B.2421, subdivision 2, clause (1), or a high-voltage transmission line as defined in section 216B.2421, subdivision 2, clause (2), for which the maximum application fee shall be

$100,000. ~~The commission may require an additional fee to recover the costs of any rehearing. The fee for a rehearing shall not be greater than the actual cost of the rehearing or the maximum fee specified above, whichever is less.~~ Costs exceeding the application fee and reasonably necessary to complete the evaluation of need for the proposed facility shall be recovered from the applicant. If the applicant is a public utility, a cooperative electric association, a generation and transmission cooperative electric association, a municipal power agency, a municipal electric utility, or a transmission company, the recovery shall be done pursuant to section 216B.62. The commission shall establish by rule pursuant to chapter 14 and sections 216C.05 to 216C.30 and this section, a schedule of fees based on the output or capacity of the facility and the difficulty of assessment of need. Money collected in this manner shall be credited to the general fund of the state treasury.

Sec. 7. Minnesota Statutes 2004, section 216B.2425, subdivision 2, is amended to read:

Subd. 2. [LIST DEVELOPMENT; TRANSMISSION PROJECTS REPORT.] (a) By November 1 of each odd-numbered year, ~~each~~ a transmission projects report must be submitted to the commission by each utility, organization, or company that:

(1) is a public utility, a municipal utility, ~~and~~ a cooperative electric association, ~~or~~ the generation and transmission organization that serves each utility or association, ~~that~~ or a transmission company; and

(2) owns or operates electric transmission lines in Minnesota ~~shall~~.

(b) The report may be submitted jointly or individually ~~submit a transmission projects report~~ to the commission.

(c) The report must:

(1) list specific present and reasonably foreseeable future inadequacies in the transmission system in Minnesota;

(2) identify alternative means of addressing each inadequacy listed;

(3) identify general economic, environmental, and social issues associated with each alternative; and

(4) provide a summary of public input ~~the utilities and associations have gathered~~ related to the list of inadequacies and the role of local government officials and other interested persons in assisting to develop the list and analyze alternatives.

~~(b)~~ (d) To meet the requirements of this subdivision, ~~entities~~ reporting parties may rely on available information and analysis developed by a regional transmission organization or any subgroup of a regional transmission organization and may develop and include additional information as necessary.

Sec. 8. Minnesota Statutes 2004, section 216B.50, subdivision 1, is amended to read:

Subdivision 1. [COMMISSION APPROVAL REQUIRED.] No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000, or merge or consolidate with another public utility or transmission company operating in this state, without first being authorized so to do by the commission. Upon the filing of an application for the approval and consent of the commission ~~thereto~~, the commission shall investigate, with or without public hearing~~, and in case of~~. The commission shall hold a public hearing, upon such notice as the commission may require~~, and if it shall find~~. If the commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval by order in writing. In reaching its determination, the commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of, or merged and consolidated. ~~The provisions of~~

This section ~~shall~~ does not ~~be construed as applicable~~ apply to the purchase of ~~units of~~ property ~~for replacement or to the addition~~ to replace or add to the plant of the public utility by construction.

Sec. 9. Minnesota Statutes 2004, section 216B.62, subdivision 5, is amended to read:

Subd. 5. [ASSESSING COOPERATIVES AND MUNICIPALS.] The commission and department may charge cooperative electric associations, generation and transmission cooperative electric associations, municipal power agencies, and municipal electric utilities their proportionate share of the expenses incurred in the review and disposition of resource plans, adjudication of service area disputes, proceedings under section 216B.1691, 216B.2425, or 216B.243, and the costs incurred in the adjudication of complaints over service standards, practices, and rates. Cooperative electric associations electing to become subject to rate regulation by the commission pursuant to section 216B.026, subdivision 4, are also subject to this section. Neither a cooperative electric association nor a municipal electric utility is liable for costs and expenses in a calendar year in excess of the limitation on costs that may be assessed against public utilities under subdivision 2. A cooperative electric association, generation and transmission cooperative electric association, municipal power agency, or municipal electric utility may object to and appeal bills of the commission and department as provided in subdivision 4.

The department shall assess cooperatives and municipalities for the costs of alternative energy engineering activities under section 216C.261. Each cooperative and municipality shall be assessed in proportion that its gross operating revenues for the sale of gas and electric service within the state for the last calendar year bears to the total of those revenues for all public utilities, cooperatives, and municipalities.

Sec. 10. Minnesota Statutes 2004, section 216B.62, is amended by adding a subdivision to read:

Subd. 5a. [ASSESSING TRANSMISSION COMPANIES.] The commission and department may charge transmission companies their proportionate share of the expenses incurred in the review and disposition of proceedings under sections 216B.2425, 216B.243, 216B.48, 216B.50, and 216B.79. A transmission company is not liable for costs and expenses in a calendar year in excess of the limitation on costs that may be assessed against public utilities under subdivision 2. A transmission company may object to and appeal bills of the commission and department as provided in subdivision 4.

Sec. 11. Minnesota Statutes 2004, section 216B.79, is amended to read:

216B.79 [PREVENTATIVE MAINTENANCE.]

The commission may order public utilities to make adequate infrastructure investments and undertake sufficient preventative maintenance with regard to generation, transmission, and distribution facilities. The commission's authority under this section also applies to any transmission company that owns or operates electric transmission lines in Minnesota.

Sec. 12. [STAKEHOLDER PROCESS AND REPORT.]

Subdivision 1. [MEMBERSHIP.] By June 15, 2005, the Legislative Electric Energy Task Force shall convene a stakeholder group consisting of one representative from each of the following groups: transmission-owning investor-owned utilities, electric cooperatives, municipal power agencies, energy consumer advocates, business energy consumer advocates, residential energy consumer advocates, environmental organizations, the Minnesota Department of Commerce, and the Minnesota Public Utilities Commission. The task force, in its sole discretion, may add other representatives to the stakeholder group.

Subd. 2. [CHARGE.] (a) The stakeholder group shall explore whether increased efficiencies and effectiveness can be obtained through modifying current state statutes and administrative processes to certify and route high-voltage transmission lines, including modifications to section 216B.243.

(b) In developing its recommendations, the stakeholder group shall consider:

(1) whether the certification process established under section 216B.2425, subdivision 3, can be modified to encourage

utilities to apply for certification under that section;
(2) whether alternative certification processes are feasible for different types of transmission facilities; and
(3) whether additional cooperation between state agencies is needed to enhance the efficiency of the certification and routing processes, and whether modifications to those processes are appropriate.
Subd. 3. [REPORT.] By January 15, 2006, the task force shall submit a report to the legislature summarizing the stakeholder group findings and any recommended changes to the certification and routing processes for high-voltage transmission lines.

ARTICLE 2

C-BED AND RENEWABLE TRANSMISSION

Section 1. [216B.1612] [COMMUNITY-BASED ENERGY DEVELOPMENT; TARIFF.]
Subdivision 1. [TARIFF ESTABLISHMENT.] A tariff shall be established to optimize local, regional, and state benefits from wind energy development, and to facilitate widespread development of community-based wind energy projects throughout Minnesota.
Subd. 2. [DEFINITIONS.] (a) The terms used in this section have the meanings given them in this subdivision.
(b) "C-BED tariff" or "tariff" means a community-based energy development tariff.
(c) "Qualifying owner" means:
(1) a Minnesota resident;
(2) a limited liability corporation that is organized under the laws of this state and that is made up of members who are Minnesota residents;
(3) a Minnesota nonprofit organization organized under chapter 317A;
(4) a Minnesota cooperative association organized under chapter 308A or 308B, other than a rural electric cooperative association or a generation and transmission cooperative;
(5) a Minnesota political subdivision or local government other than a municipal electric utility or municipal power agency, including, but not limited to, a county, statutory or home rule charter city, town, school district, or public or private higher education institution or any other local or regional governmental organization such as a board, commission, or association; or
(6) a tribal council.
(d) "Net present value rate" means a rate equal to the net present value of the nominal payments to a project divided by the total expected energy production of the project over the life of its power purchase agreement.
(e) "Standard reliability criteria" means:
(1) can be safely integrated into and operated within the utility's grid without causing any adverse or unsafe consequences; and
(2) is consistent with the utility's resource needs as identified in its most recent resource plan submitted under section 216B.2422.
(f) "Community-based energy project" or "C-BED project" means a new wind energy project that:
(1) has no single qualifying owner owning more than 15 percent of a C-BED project that consists of more than two turbines; or
(2) for C-BED projects of one or two turbines, is owned entirely by one or more qualifying owners, with at least 51 percent of the total financial benefits over the life of the project flowing to qualifying owners; and
(3) has a resolution of support adopted by the county board of each county in which the project is to be located, or in the case of a project located within the boundaries of a reservation, the tribal council for that reservation.
Subd. 3. [TARIFF RATE.] (a) The tariff described in subdivision 4 must have a rate schedule that allows for a rate up to a 2.7 cents per kilowatt hour net present value rate over

the 20-year life of the power purchase agreement. The tariff must provide for a rate that is higher in the first ten years of the power purchase agreement than in the last ten years. The discount rate required to calculate the net present value must be the utility's normal discount rate used for its other business purposes.

(b) The commission shall consider mechanisms to encourage the aggregation of C-BED projects.

(c) The commission shall require that qualifying owners provide sufficient security to secure performance under the power purchase agreement, and shall prohibit the transfer of the C-BED project to a nonqualifying owner during the initial 20 years of the contract.

Subd. 4. [UTILITIES TO OFFER TARIFF.] By December 1, 2005, each public utility providing electric service at retail shall file for commission approval a community-based energy development tariff consistent with subdivision 3. Within 90 days of the first commission approval order under this subdivision, each municipal power agency and generation and transmission cooperative electric association shall adopt a community-based energy development tariff as consistent as possible with subdivision 3.

Subd. 5. [PRIORITY FOR C-BED PROJECTS.] (a) A utility subject to section 216B.1691 that needs to construct new generation, or purchase the output from new generation, as part of its plan to satisfy its good faith objective under that section should take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements, applying standard reliability criteria, to fulfill some or all of the identified need at minimal impact to customer rates.

Nothing in this section shall be construed to obligate a utility to enter into a power purchase agreement under a C-BED tariff developed under this section.

(b) Each utility shall include in its resource plan submitted under section 216B.2422 a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.

(c) The commission shall consider the efforts and activities of a utility to purchase energy from C-BED projects when evaluating its good faith effort towards meeting the renewable energy objective under section 216B.1691.

Subd. 6. [PROPERTY OWNER PARTICIPATION.] To the extent feasible, a developer of a C-BED project must provide, in writing, an opportunity to invest in the C-BED project to each property owner on whose property a high voltage transmission line is constructed that will transmit the energy generated by the C-BED project to market. This subdivision applies if the property is located and the owner resides in the county where the C-BED project is located.

[EFFECTIVE DATE.] This subdivision is effective July 1, 2005, and applies to transmission line construction beginning on or after that date.

Subd. 7. [OTHER C-BED TARIFF ISSUES.] (a) A community-based project developer and a utility shall negotiate the rate and power purchase agreement terms consistent with the tariff established under subdivision 4.

(b) At the discretion of the developer, a community-based project developer and a utility may negotiate a power purchase agreement with terms different from the tariff established under subdivision 4.

(c) A qualifying owner, or any combination of qualifying owners, may develop a joint venture project with a nonqualifying wind energy project developer. However, the terms of the C-BED tariff may only apply to the portion of the energy production of the total project that is directly proportional to the equity share of the project owned by the qualifying owners.

(d) A project that is operating under a power purchase agreement under a C-BED tariff is not eligible for net energy billing under section 216B.164, subdivision 3, or for production incentives under section 216C.41.

(e) A public utility must receive commission approval of a power purchase agreement for a C-BED tariffed project. The commission shall provide the utility's ratepayers an opportunity to address the reasonableness of the proposed power purchase agreement. Unless a party objects to a contract within 30 days of submission of the contract to the commission the contract is deemed approved.

Sec. 2. Minnesota Statutes 2004, section 216B.1645, subdivision 1, is amended to read:

Subdivision 1. [COMMISSION AUTHORITY.] Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives set forth in section 216B.1691, including reasonable investments and expenditures made to:

(1) transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, ~~or to~~ including studies necessary to identify new transmission facilities needed to transmit electricity to Minnesota retail customers from generating facilities constructed to satisfy the renewable energy objectives, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425 for the new transmission facilities identified in the studies; or

(2) develop renewable energy sources from the account required in section 116C.779.

Sec. 3. Minnesota Statutes 2004, section 216B.2425, subdivision 7, is amended to read:

Subd. 7. [TRANSMISSION NEEDED TO SUPPORT RENEWABLE RESOURCES.] (a) Each entity subject to this section shall determine necessary transmission upgrades to support development of renewable energy resources required to meet objectives under section 216B.1691 and shall include those upgrades in its report under subdivision 2.

(b) Transmission projects determined by the commission to be necessary to support a utility's plan under section 216B.1691 to meet its obligations under that section must be certified as a priority electric transmission project, satisfying the requirements of section 216B.243. In determining that a proposed transmission project is necessary to support a utility's plan under section 216B.1691, the commission must find that the applicant has met the following factors:

(1) that the transmission facility is necessary to allow the delivery of power from renewable sources of energy to retail customers in Minnesota;

(2) that the applicant has signed or will sign power purchase agreements, subject to commission approval, for resources to meet the renewable energy objective that are dependent upon or will use the capacity of the transmission facility to serve retail customers in Minnesota;

(3) that the installation and commercial operation date of the renewable resources to satisfy the renewable energy objective will match the planned in-service date of the transmission facility; and

(4) that the proposed transmission facility is consistent with a least cost solution to the utility's need for additional electricity.

Sec. 4. Minnesota Statutes 2004, section 216B.243, subdivision 8, is amended to read:

Subd. 8. [EXEMPTIONS.] This section does not apply to:

(1) cogeneration or small power production facilities as defined in the Federal Power Act, United States Code, title 16, section 796, paragraph (17), subparagraph (A), and paragraph (18), subparagraph (A), and having a combined capacity at a single site of less than 80,000 kilowatts ~~or to~~; plants or facilities for the production of ethanol or fuel alcohol ~~nor in~~;

or any case where the commission ~~shall determine~~ has determined after being advised by the attorney general that its application has been preempted by federal law;

(2) a high-voltage transmission line proposed primarily to distribute electricity to serve the demand of a single customer at a single location, unless the applicant opts to request that the commission determine need under this section or section 216B.2425;

(3) the upgrade to a higher voltage of an existing transmission line that serves the demand of a single customer that primarily uses existing rights-of-way, unless the applicant opts to request that the commission determine need under this section or section 216B.2425;

(4) a high-voltage transmission line of one mile or less required to connect a new or upgraded substation to an existing, new, or upgraded high-voltage transmission line;

(5) conversion of the fuel source of an existing electric generating plant to using natural gas; ~~or~~

(6) the modification of an existing electric generating plant to increase efficiency, as long as the capacity of the plant is not increased more than ten percent or more than 100 megawatts, whichever is greater; or

(7) a large energy facility that (i) generates electricity from wind energy conversion systems, (ii) will serve retail customers in Minnesota, (iii) is specifically intended to be used to meet the renewable energy objective under section 216B.1691 or addresses a resource need identified in a current commission-approved or commission-reviewed resource plan under section 216B.2422; and (iv) derives at least 10 percent of the total nameplate capacity of the proposed project from one or more C-BED projects, as defined under section 216B.1612, subdivision 2, paragraph (f).

Sec. 5. [216C.053] [RENEWABLE ENERGY DEVELOPMENT.]

The commissioner of commerce must engage in activities to encourage deployment of cost effective renewable energy developments within the state. The commissioner shall compile and maintain information concerning existing and potential renewable energy developments and resources in the state. The commissioner shall provide, as appropriate, this information in proceedings for the determination of need for large energy facilities and for the review of a utility's integrated resource plan. To the extent practicable, and in addition to any other obligation of an electric utility to furnish information, an electric utility seeking to add generation to its supply portfolio to serve Minnesota consumers shall provide the commissioner with notice of its intention.

Sec. 6. [WIND INTEGRATION STUDY.]

The commission shall order all electric utilities, as defined in Minnesota Statutes, section 216B.1691, subdivision 1, paragraph (b), to participate in a statewide wind integration study. Utilities subject to Minnesota Statutes, section 216B.1691, shall jointly contract with an independent firm selected by the reliability administrator to conduct an engineering study of the impacts on reliability and costs associated with increasing wind capacity to 20 percent of Minnesota retail electric energy sales by the year 2020, and to identify and develop options for utilities to use to manage the intermittent nature of wind resources. The contracting utilities shall cooperate with the firm conducting the study by providing data requested. The reliability administrator shall manage the study process and shall appoint a group of stakeholders with experience in engineering and expertise in power systems or wind energy to review the study's proposed methods and assumptions and preliminary data. The study must be completed by November 30, 2006. Using the study results, the contracting utilities shall provide the commissioner of commerce with estimates of the impact on their electric rates of increasing wind capacity to 20 percent, assuming no reduction in reliability. Electric utilities shall incorporate the study's findings into their utility integrated resource plans prepared under Minnesota Statutes, section 216B.2422. The costs of the study are recoverable under Minnesota Statutes, section 216C.052, subdivision 2, paragraph (c), clause (2).

Sec. 7. [EXPIRATION.]

Section 3, paragraph (b), expires on January 1, 2010.

ARTICLE 3

ROUTING AND SITING AUTHORITY TRANSFER

Section 1. Minnesota Statutes 2004, section 116C.52, subdivision 2, is amended to read:

Subd. 2. [~~BOARD~~ COMMISSION.] ~~"Board" shall mean the Minnesota Environmental Quality Board~~ "Commission" means the Public Utilities Commission.

Sec. 2. Minnesota Statutes 2004, section 116C.52, subdivision 4, is amended to read:

Subd. 4. [HIGH VOLTAGE TRANSMISSION LINE.] "High voltage transmission line" means a conductor of electric energy and associated facilities designed for and capable of operation at a nominal voltage of 100 kilovolts or more and is greater than 1,500 feet in length.

Sec. 3. Minnesota Statutes 2004, section 116C.53, subdivision 2, is amended to read:

Subd. 2. [JURISDICTION.] The ~~board~~ commission is hereby given the authority to provide for site and route selection for large electric power facilities. The ~~board~~ commission shall issue permits for large electric power facilities in a timely fashion~~. When the Public Utilities Commission has determined the~~ and in a manner consistent with the overall determination of need for the project under section 216B.243 or 216B.2425~~,~~. Questions of need, including size, type, and timing; alternative system configurations; and voltage ~~are not within the board's siting and routing authority and~~ must not be included in the scope of environmental review conducted under sections 116C.51 to 116C.69.

Sec. 4. Minnesota Statutes 2004, section 116C.57, subdivision 1, is amended to read:

Subdivision 1. [SITE PERMIT.] No person may construct a large electric generating plant without a site permit from the ~~board~~ commission. A large electric generating plant may be constructed only on a site approved by the ~~board~~ commission. The ~~board~~ commission must incorporate into one proceeding the route selection for a high voltage transmission line that is directly associated with and necessary to interconnect the large electric generating plant to the transmission system and whose need is certified ~~as part of the generating plant project by the Public Utilities Commission~~ under section 216B.243.

Sec. 5. Minnesota Statutes 2004, section 116C.57, subdivision 2c, is amended to read:

Subd. 2c. [ENVIRONMENTAL REVIEW.] The ~~board~~ commissioner of the Department of Commerce shall prepare for the commission an environmental impact statement on each proposed large electric generating plant or high voltage transmission line for which a complete application has been submitted. ~~For any project that has obtained a certificate of need from the Public Utilities Commission, the board~~ The commissioner shall not consider whether or not the project is needed. No other state environmental review documents shall be required. The ~~board~~ commissioner shall study and evaluate any site or route proposed by an applicant and any other site or route the ~~board~~ commission deems necessary that was proposed in a manner consistent with rules ~~adopted by the board~~ concerning the form, content, and timeliness of proposals for alternate sites or routes.

Sec. 6. Minnesota Statutes 2004, section 116C.57, is amended by adding a subdivision to read:

Subd. 9. [DEPARTMENT OF COMMERCE TO PROVIDE TECHNICAL EXPERTISE AND OTHER ASSISTANCE.] The commissioner of the Department of Commerce shall consult with other state agencies and provide technical expertise and other assistance to the commission or to individual members of the commission for activities and proceedings under this section, sections 116C.51 to 116C.697, and chapter 116I. This assistance shall include the sharing of power plant siting and routing staff and other resources as necessary. The commissioner shall periodically report to the commission concerning the Department of Commerce's costs of providing assistance. The report shall conform to the schedule and include the required contents specified by the commission. The commission shall include the costs of the assistance in assessments for activities and proceedings under those sections and reimburse the special revenue fund for those costs. If either the commissioner or the commission deems it necessary, the department and the commission shall enter into an interagency agreement establishing terms and conditions for the provision of assistance and sharing of resources under this subdivision.

Sec. 7. Minnesota Statutes 2004, section 116C.575, subdivision 5, is amended to read:

Subd. 5. [ENVIRONMENTAL REVIEW.] For the projects identified in subdivision 2 and following these procedures, the ~~board~~ commissioner of the Department of Commerce shall prepare for the commission an environmental assessment. The environmental assessment shall contain information on the human and environmental impacts of the proposed project and other sites or routes identified by the ~~board~~ commission and shall address mitigating measures for all of the sites or routes considered. The environmental assessment shall be the only state environmental review document required to be prepared on the project.

Sec. 8. Minnesota Statutes 2004, section 116C.577, is amended to read:

116C.577 [EMERGENCY PERMIT.]

(a) Any utility whose electric power system requires the immediate construction of a large electric power generating plant or high voltage transmission line due to a major unforeseen event may apply to the ~~board~~ commission for an emergency permit ~~after providing~~. The application shall provide notice in writing ~~to the Public Utilities Commission~~ of the major unforeseen event and the need for immediate construction. The permit must be issued in a timely manner, no later than 195 days after the ~~board's~~ commission's acceptance of the application and upon a finding by the ~~board~~ commission that (1) a demonstrable emergency exists, (2) the emergency requires immediate construction, and (3) adherence to the procedures and time schedules specified in section 116C.57 would jeopardize the utility's electric power system or would jeopardize the utility's ability to meet the electric needs of its customers in an orderly and timely manner.

(b) A public hearing to determine if an emergency exists must be held within 90 days of the application. The ~~board~~ commission, after notice and hearing, shall adopt rules specifying the criteria for emergency certification.

Sec. 9. Minnesota Statutes 2004, section 116C.58, is amended to read:

116C.58 [ANNUAL HEARING.]

The ~~board~~ commission shall hold an annual public hearing at a time and place prescribed by rule in order to afford interested persons an opportunity to be heard regarding any matters relating to the siting of large electric generating power plants and routing of high voltage transmission lines. At the meeting, the ~~board~~ commission shall advise the public of the permits issued by the ~~board~~ commission in the past year. The ~~board~~ commission shall provide at least ten days but no more than 45 days' notice of the annual meeting by mailing notice to those persons who have requested notice and by publication in the EQB Monitor and the commission's weekly calendar.

Sec. 10. Minnesota Statutes 2004, section 116C.61, subdivision 3, is amended to read:

Subd. 3. [STATE AGENCY PARTICIPATION.] (a) State agencies authorized to issue permits required for construction or operation of large electric power generating plants or high voltage transmission lines shall participate during routing and siting at public hearings and all other activities of the board on specific site or route designations and design considerations of the board, and shall clearly state whether the site or route being considered for designation or permit and other design matters under consideration for approval will be in compliance with state agency standards, rules, or policies.

(b) An applicant for a permit under this section or under chapter 116I shall notify the commissioner of agriculture if the proposed project will impact cultivated agricultural land, as that term is defined in section 116I.01, subdivision 4. The commissioner may participate and advise the commission as to whether to grant a permit for the project and the best options for mitigating adverse impacts to agricultural lands if the permit is granted. The Department of Agriculture shall be the lead agency on the development of any agricultural mitigation plan required for the project.

Sec. 11. Minnesota Statutes 2004, section 116C.69, subdivision 2, is amended to read:

Subd. 2. [SITE APPLICATION FEE.] Every applicant for a site permit shall pay to the ~~board~~ commissioner of commerce a fee ~~in an amount equal to $500 for each $1,000,000 of production plant investment in the proposed installation as defined in the Federal Power Commission Uniform System of Accounts. The board shall specify the time and manner of payment of the fee. If any single payment requested by the board is in excess of 25 percent of the total estimated fee, the board shall show that the excess is reasonably necessary. The applicant shall pay within 30 days of notification any additional fees reasonably necessary for completion of the site evaluation and designation process by the board. In no event shall the total fees required of the applicant under this subdivision exceed an amount equal to 0.001 of said production plant investment ($1,000 for each $1,000,000)~~ to cover the necessary and reasonable costs incurred by the commission in acting on the permit application and carrying out the requirements of sections 116C.51 to 116C.69. The commission may adopt rules providing for the payment of the fee. Section 16A.1283 does not apply to establishment of this fee. All money received pursuant to this subdivision shall be deposited in a special account. Money in the account is appropriated to the ~~board~~ commissioner of commerce to pay expenses incurred in processing applications for site permits in accordance with sections 116C.51 to 116C.69 and in the event the expenses are less than the fee paid, to refund the excess to the applicant.

Sec. 12. Minnesota Statutes 2004, section 116C.69, subdivision 2a, is amended to read:

Subd. 2a. [ROUTE APPLICATION FEE.] Every applicant for a transmission line route permit shall pay to the ~~board~~ commissioner of commerce a ~~base fee of $35,000 plus a fee in an amount equal to $1,000 per mile length of the longest proposed route. The board shall specify the time and manner of payment of the fee. If any single payment requested by the board is in excess of 25 percent of the total estimated fee, the board shall show that the excess is reasonably necessary. In the event the actual cost of processing an application up to the board's final decision to designate a route exceeds the above fee schedule, the board may assess the applicant any additional fees necessary to cover the actual costs, not to exceed an amount equal to $500 per mile length of the longest proposed route~~ fee to cover the necessary and reasonable costs incurred by the commission in acting on the permit application and carrying out the requirements of sections 116C.51 to 116C.69. The commission may adopt rules providing for the payment of the fee. Section 16A.1283 does not apply to the establishment of this fee. All money received pursuant to this subdivision shall be deposited in a special account. Money in the account is appropriated to the ~~board~~ commissioner of commerce to pay expenses incurred in processing applications for route permits in accordance with sections 116C.51 to 116C.69 and in the event the expenses are less than the fee paid, to refund the excess to the applicant.

Sec. 13. Minnesota Statutes 2004, section 216B.243, subdivision 4, is amended to read:

Subd. 4. [APPLICATION FOR CERTIFICATE; HEARING.] Any person proposing to construct a large energy facility shall apply for a certificate of need ~~prior to applying~~ and for a site or route permit under sections 116C.51 to 116C.69 ~~or~~ prior to construction of the facility. The application shall be on forms and in a manner established by the commission. In reviewing each application the commission shall hold at least one public hearing pursuant to chapter 14. The public hearing shall be held at a location and hour reasonably calculated to be convenient for the public. An objective of the public hearing shall be to obtain public opinion on the necessity of granting a certificate of need and, if a joint hearing is held, a site or route permit. The commission shall designate a commission employee whose duty shall be to facilitate citizen participation in the hearing process. ~~If~~ Unless the commission ~~and the Environmental Quality Board determine~~ determines that a joint hearing on siting and need under this subdivision and section 116C.57, subdivision 2d, is not feasible~~,~~ or more efficient, ~~and may further~~ or otherwise not in the public interest, a joint hearing under those subdivisions ~~may~~ shall be held.

Sec. 14. Minnesota Statutes 2004, section 216B.243, subdivision 5, is amended to read:

Subd. 5. [APPROVAL, DENIAL, OR MODIFICATION.] Within ~~six~~ 12 months of the submission of an application, the commission shall approve or deny a certificate of need for the facility. Approval or denial of the certificate shall be accompanied by a statement of the reasons for the decision. Issuance of the certificate may be made contingent upon modifications required by the commission. If the commission has not issued an order on the application within the 12 months provided, the commission may extend the time period upon receiving the consent of the parties or on its own motion, for good cause, by issuing an order explaining the good cause justification for extension.

Sec. 15. Minnesota Statutes 2004, section 216B.243, subdivision 7, is amended to read:

Subd. 7. [PARTICIPATION BY OTHER AGENCY OR POLITICAL SUBDIVISION.] (a) Other state agencies authorized to issue permits for siting, construction or operation of large energy facilities, and those state agencies authorized to participate in matters before the commission involving utility rates and adequacy of utility services, shall present their position regarding need and participate in the public hearing process prior to the issuance or denial of a certificate of need. Issuance or denial of certificates of need shall be the sole and exclusive prerogative of the commission and these determinations and certificates shall be binding upon other state departments and agencies, regional, county, and local governments and special purpose government districts except as provided in sections 116C.01 to 116C.08 and 116D.04, subdivision 9.

(b) An applicant for a certificate of need shall notify the commissioner of agriculture if the proposed project will impact cultivated agricultural land, as that term is defined in section 116I.01, subdivision 4. The commissioner may participate in any proceeding on the application and advise the commission as to whether to grant the certificate of need, and the best options for mitigating adverse impacts to agricultural lands if the certificate is granted. The Department of Agriculture shall be the lead agency on the development of any agricultural mitigation plan required for the project.

Sec. 16. Minnesota Statutes 2004, section 216C.052, is amended to read:

216C.052 [RELIABILITY ADMINISTRATOR.]

Subdivision 1. [RESPONSIBILITIES.] (a) There is established the position of reliability administrator in the ~~Department of Commerce~~ Public Utilities Commission. The administrator shall act as a source of independent expertise and a technical advisor to ~~the commissioner,~~ the commission~~,~~ and the public~~, and the Legislative Electric Energy Task Force~~ on issues related to the reliability of the electric system. In conducting its work, the administrator shall provide assistance to the commission in administering and implementing the commission's duties under sections 116C.51 to 116C.69; 116C.691 to 116C.697; 216B.2422; 216B.2425; 216B.243; chapter 116I; and rules associated with those sections. Subject to resource constraints, the reliability administrator may also:

(1) model and monitor the use and operation of the energy infrastructure in the state, including generation facilities, transmission lines, natural gas pipelines, and other energy infrastructure;

(2) develop and present to the commission and parties technical analyses of proposed infrastructure projects, and provide technical advice to the commission;

(3) present independent, factual, expert, and technical information on infrastructure proposals and reliability issues at public meetings hosted by the task force, the Environmental Quality Board, the department, or the commission.

(b) Upon request and subject to resource constraints, the administrator shall provide technical assistance regarding matters unrelated to applications for infrastructure improvements to the task force, the department, or the commission.

(c) The administrator may not advocate for any particular outcome in a commission proceeding, but may give technical advice to the commission as to the impact on the reliability of the energy system of a particular project or projects. ~~The administrator must not be considered a party or a participant in any proceeding before the commission.~~

Subd. 2. [ADMINISTRATIVE ISSUES.] (a) The ~~commissioner~~ commission may select the administrator who shall serve for a four-year term. The administrator may not have been a party or a participant in a commission energy proceeding for at least one year prior to selection by the ~~commissioner~~ commission. The ~~commissioner~~ commission shall oversee and direct the work of the administrator, annually review the expenses of the administrator, and annually approve the budget of the administrator. Pursuant to commission approval, the administrator may hire staff and may contract for technical expertise in performing duties when existing state resources are required for other state responsibilities or when special expertise is required. The salary of the administrator is governed by section 15A.0815, subdivision 2.

(b) Costs relating to a specific proceeding, analysis, or project are not general administrative costs. For purposes of this section, "energy utility" means public utilities, generation and transmission cooperative electric associations, and municipal power agencies providing natural gas or electric service in the state.

(c) The ~~Department of Commerce~~ commission shall pay:

(1) the general administrative costs of the administrator, not to exceed $1,000,000 in a fiscal year, and shall assess energy utilities for those administrative costs. These costs must be consistent with the budget approved by the ~~commissioner~~ commission under paragraph (a). The ~~department~~ commission shall apportion the costs among all energy utilities in proportion to their respective gross operating revenues from sales of gas or electric service within the state during the last calendar year, and shall then render a bill to each utility on a regular basis; and

(2) costs relating to a specific proceeding analysis or project and shall render a bill to the specific energy utility or utilities participating in the proceeding, analysis, or project directly, either at the conclusion of a particular proceeding, analysis, or project, or from time to time during the course of the proceeding, analysis, or project.

(d) For purposes of administrative efficiency, the ~~department~~ commission shall assess energy utilities and issue bills in accordance with the billing and assessment procedures provided in section 216B.62, to the extent that these procedures do not conflict with this subdivision. The amount of the bills rendered by the ~~department~~ commission under paragraph (c) must be paid by the energy utility into an account in the special revenue fund in the state treasury within 30 days from the date of billing and is appropriated to the ~~commissioner~~ commission for the purposes provided in this section. The commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover amounts paid by utilities under this section. All amounts assessed under this section are in addition to amounts appropriated to the commission ~~and the department~~ by other law.

Subd. 3. [ASSESSMENT AND APPROPRIATION.] In addition to the amount noted in subdivision 2, the ~~commissioner~~ commission may assess utilities, using the mechanism specified in that subdivision, up to an additional $500,000 annually through June 30, 2006. The amounts assessed under this subdivision are appropriated to the ~~commissioner~~ commission, and some or all of the amounts assessed may be transferred to the commissioner of administration, for the purposes specified in section 16B.325 and Laws 2001, chapter 212, article 1, section 3, as needed to implement those sections.

Subd. 4. [EXPIRATION.] This section expires June 30, ~~2006~~ 2007.

Sec. 17. [TRANSFERRING POWER PLANT SITING RESPONSIBILITIES.]

To ensure greater public participation in energy infrastructure approval proceedings and to better integrate and align state energy and environmental policy goals with economic decisions involving large energy infrastructure, all responsibilities, as defined in Minnesota Statutes, section 15.039, subdivision 1, held by the Environmental Quality Board relating to power plant siting and routing under Minnesota Statutes, sections 116C.51 to 116C.69; wind energy conversion systems under Minnesota Statutes, sections 116C.691 to 116C.697; pipelines under Minnesota Statutes, chapter 116I; and rules associated with those sections are transferred to the Public Utilities Commission under Minnesota Statutes, section 15.039, except that the responsibilities of the Environmental Quality Board under Minnesota Statutes, section 116C.83, subdivision 6, and Minnesota Rules, parts 4400.1700, 4400.2750, and 4410.7010 to 4410.7070, are transferred to the commissioner of the Department of Commerce. The power plant siting staff of the Environmental Quality Board are transferred to the Department of Commerce. The department's budget shall be adjusted to reflect the transfer.

The Department of Commerce and the Public Utilities Commission shall carry out these duties in accordance with the provisions of Minnesota Statutes, section 116D.03.

Sec. 18. [TRANSFERRING RELIABILITY ADMINISTRATOR RESPONSIBILITIES.]

All responsibilities, as defined in Minnesota Statutes 2004, section 15.039, subdivision 1, held by the Minnesota Department of Commerce relating to the reliability administrator under Minnesota Statutes, section 216C.052, are transferred to the Minnesota Public Utilities Commission under Minnesota Statutes, section 15.039.

Sec. 19. [REVISOR'S INSTRUCTION.]

(a) The revisor of statutes shall change the words "Environmental Quality Board," "board," "chair of the board," "chair," "board's," and similar terms, when they refer to the Environmental Quality Board or chair of the Environmental Quality Board, to the term "Public Utilities Commission," "commission," or "commission's," as appropriate, where they appear in Minnesota Statutes, sections 13.741, subdivision 3, 116C.51 to 116C.697, and chapter 116I. The revisor shall also make those changes in Minnesota Rules, chapters 4400, 4401, and 4415, except as specified in paragraph (b).

(b) The revisor of statutes shall change the words "Environmental Quality Board," "board," "chair of the board," "chair," "board's," and similar terms, when they refer to the Environmental Quality Board or chair of the Environmental Quality Board, to the term "commissioner of the Department of Commerce," "commissioner," or "commissioner's," as appropriate, where they appear in Minnesota Statutes, section 116C.83, subdivision 6; and Minnesota Rules, parts 4400.1700, subparts 1 to 9, 11, and 12; 4400.2750; and 4410.7010 to 4410.7070.

Sec. 20. [EFFECTIVE DATE.]

Sections 1 to 18 are effective July 1, 2005.

ARTICLE 4

ENERGY ASSISTANCE TECHNICAL CORRECTIONS

Section 1. Minnesota Statutes 2004, section 13.681, is amended by adding a subdivision to read:

Subd. 5. [ENERGY PROGRAMS.] Treatment of data on individuals applying for benefits or services under energy programs is governed by section 216C.266.

Sec. 2. Minnesota Statutes 2004, section 119A.15, subdivision 5a, is amended to read:

Subd. 5a. [EXCLUDED PROGRAMS.] Programs transferred to the Department of Education from the Department of Employment and Economic Development may not be included in the consolidated funding account and are ineligible for local consolidation. The commissioner may not apply for federal waivers to include these programs in funding consolidation initiatives. The programs include the following:

(1) programs for the homeless under sections 116L.365 and 119A.43;

(2) emergency energy assistance and energy conservation programs under sections ~~119A.40 and 119A.42~~ 216C.263 and 216C.265;

(3) weatherization programs under section ~~119A.41~~ 216C.264;

(4) foodshelf programs under section 119A.44 and the emergency food assistance program; and

(5) lead abatement programs under section 119A.45.

Sec. 3. Minnesota Statutes 2004, section 216C.09, is amended to read:

216C.09 [COMMISSIONER DUTIES.]

(a) The commissioner shall:

(1) manage the department as the central repository within the state government for the collection of data on energy;

(2) prepare and adopt an emergency allocation plan specifying actions to be taken in the event of an impending serious shortage of energy, or a threat to public health, safety, or welfare;

(3) undertake a continuing assessment of trends in the consumption of all forms of energy and analyze the social, economic, and environmental consequences of these trends;

(4) carry out energy conservation measures as specified by the legislature and recommend to the governor and the legislature additional energy policies and conservation measures as required to meet the objectives of sections 216C.05 to 216C.30;

(5) collect and analyze data relating to present and future demands and resources for all sources of energy;

(6) evaluate policies governing the establishment of rates and prices for energy as related to energy conservation, and other goals and policies of sections 216C.05 to 216C.30, and make recommendations for changes in energy pricing policies and rate schedules;

(7) study the impact and relationship of the state energy policies to international, national, and regional energy policies;

(8) design and implement a state program for the conservation of energy; this program shall include but not be limited to, general commercial, industrial, and residential, and transportation areas; such program shall also provide for the evaluation of energy systems as they relate to lighting, heating, refrigeration, air conditioning, building design and operation, and appliance manufacturing and operation;

(9) inform and educate the public about the sources and uses of energy and the ways in which persons can conserve energy;

(10) dispense funds made available for the purpose of research studies and projects of professional and civic orientation, which are related to either energy conservation, resource recovery, or the development of alternative energy technologies which conserve nonrenewable energy resources while creating minimum environmental impact;

(11) charge other governmental departments and agencies involved in energy-related activities with specific information gathering goals and require that those goals be met;

(12) design a comprehensive program for the development of indigenous energy resources. The program shall include, but not be limited to, providing technical, informational, educational, and financial services and materials to persons, businesses, municipalities, and organizations involved in the development of solar, wind, hydropower, peat, fiber fuels, biomass, and other alternative energy resources. The program shall be evaluated by the alternative energy technical activity; and

(13) dispense loans, grants, or other financial aid from money received from litigation or settlement of alleged violations of federal petroleum-pricing regulations made available to the department for that purpose. The commissioner shall adopt rules under chapter 14 for this purpose. ~~Money dispersed under this clause must not include money received as a result of the settlement of the parties and order of the United States District Court for the District of Kansas in the case of In Re Department of Energy Stripper Well Exemption Litigation, 578 F. Supp. 586 (D.Kan. 1983) and all money received after August 1, 1988, by the governor, the commissioner of finance, or any other state agency resulting from overcharges by oil companies in violation of federal law.~~

(b) Further, the commissioner may participate fully in hearings before the Public Utilities Commission on matters pertaining to rate design, cost allocation, efficient resource utilization, utility conservation investments, small power production, cogeneration, and other rate issues. The commissioner shall support the policies stated in section 216C.05 and shall prepare and defend testimony proposed to encourage energy conservation improvements as defined in section 216B.241.

Sec. 4. Minnesota Statutes 2004, section 462A.05, subdivision 21, is amended to read:

Subd. 21. [RENTAL PROPERTY LOANS.] The agency may make or purchase loans to owners of rental property that is occupied or intended for occupancy primarily by low- and moderate-income tenants and which does not comply with the standards established in section ~~216C.27~~ <u>16B.61</u>, subdivision ~~3~~ <u>1</u>, for the purpose of energy improvements necessary to bring the property into full or partial compliance with these standards. For property which meets the other requirements of this subdivision, a loan may also be used for moderate rehabilitation of the property. The authority granted in this subdivision is in addition to and not in limitation of any other authority granted to the agency in this chapter. The limitations on eligible mortgagors contained in section 462A.03, subdivision 13, do not apply to loans under this subdivision. Loans for the improvement of rental property pursuant to this subdivision may contain provisions that repayment is not required in whole or in part subject to terms and conditions determined by the agency to be necessary and desirable to encourage owners to maximize rehabilitation of properties.

Sec. 5. Minnesota Statutes 2004, section 462A.05, subdivision 23, is amended to read:

Subd. 23. [INSURING FINANCIAL INSTITUTION LOANS.] The agency may participate in loans or establish a fund to insure loans, or portions of loans, that are made by any banking institution, savings association, or other lender approved by the agency, organized under the laws of this or any other state or of the United States having an office in this state, to owners of renter occupied homes or apartments that do not comply with standards set forth in section ~~216C.27~~ <u>16B.61</u>, subdivision ~~3~~ <u>1</u>, without limitations relating to the maximum incomes of the owners or tenants. The proceeds of the insured portion of the loan must be used to pay the costs of improvements, including all related structural and other improvements, that will reduce energy consumption.

Sec. 6. [RECODIFICATION.]

<u>Minnesota Statutes 2004, sections 119A.40; 119A.41;</u>

119A.42; 119A.425; and 216C.27, subdivision 8, are recodified as sections 216C.263; 216C.264; 216C.265; 216C.266; and 16B.61, subdivision 8, respectively.

ARTICLE 5

WOODY BIOMASS MANDATE PROJECT

Section 1. Minnesota Statutes 2004, section 216B.2424, subdivision 1, is amended to read:

Subdivision 1. [FARM-GROWN CLOSED-LOOP BIOMASS.] (a) For the purposes of this section, "farm-grown closed-loop biomass" means biomass, as defined in section 216C.051, subdivision 7, that:

(1) is intentionally cultivated, harvested, and prepared for use, in whole or in part, as a fuel for the generation of electricity;

(2) when combusted, releases an amount of carbon dioxide that is less than or approximately equal to the carbon dioxide absorbed by the biomass fuel during its growing cycle; and

(3) is fired in a new or substantially retrofitted electric generating facility that is:

(i) located within 400 miles of the site of the biomass production; and

(ii) designed to use biomass to meet at least 75 percent of its fuel requirements.

(b) The legislature finds that the negative environmental impacts within 400 miles of the facility resulting from transporting and combusting the biomass are offset in that region by the environmental benefits to air, soil, and water of the biomass production.

(c) Among the biomass fuel sources that meet the requirements of paragraph (a), ~~clause~~ clauses (1) and (2) are poplar, aspen, willow, switch grass, sorghum, alfalfa, ~~and~~ cultivated prairie grass and sustainably managed woody biomass.

(d) For the purpose of this section, "sustainably managed woody biomass" means:

(1) brush, trees, and other biomass harvested from within designated utility, railroad, and road rights-of-way;

(2) upland and lowland brush harvested from lands incorporated into brushland habitat management activities of the Minnesota Department of Natural Resources;

(3) upland and lowland brush harvested from lands managed in accordance with Minnesota Department of Natural Resources "Best Management Practices for Managing Brushlands";

(4) logging slash or waste wood that is created by harvest, precommercial timber stand improvement to meet silvicultural objectives, or by fire, disease, or insect control treatments, and that is managed in compliance with the Minnesota Forest Resources Council's "Sustaining Minnesota Forest Resources: Voluntary Site-Level Forest Management Guidelines for Landowners, Loggers and Resource Managers" as modified by the requirement of this subdivision; and

(5) trees or parts of trees that do not meet the utilization standards for pulpwood, posts, bolts, or sawtimber as described in the Minnesota Department of Natural Resources Division of Forestry Timber Sales Manual, 1998, as amended as of May 1, 2005, and the Minnesota Department of Natural Resources Timber Scaling Manual, 1981, as amended as of May 1, 2005, except as provided in paragraph (a), clause (1), and this paragraph, clauses (1) to (3).

Sec. 2. Minnesota Statutes 2004, section 216B.2424, is amended by adding a subdivision to read:

Subd. 1a. [MUNICIPAL WASTE-TO-ENERGY PROJECT.] (a) This subdivision applies only to a biomass project owned or controlled, directly or indirectly, by two municipal utilities as described in subdivision 5a, paragraph (b).

(b) Woody biomass from state-owned land must be harvested in compliance with an adopted management plan and a program of ecologically based third-party certification.

(c) The project must prepare a fuel plan on an annual basis after commercial operation of the project as described in the power contract between the project and the public utility, and must also prepare annually certificates reflecting the types of fuel used in the preceding year by the project, as described in the power contract. The fuel plans and certificates shall also be filed with the Minnesota Department of Natural Resources and the Minnesota Department of Commerce within 30 days after being provided to the public utility, as provided by the power contract. Any person who believes the fuel plans, as amended, and certificates show that the project does not or will not comply with the fuel requirements of this subdivision may file a petition with the commission seeking such a determination.

(d) The wood procurement process must utilize third-party audit certification systems to verify that applicable best management practices were utilized in the procurement of the sustainably managed biomass. If there is a failure to so verify in any two consecutive years during the original contract term, the farm-grown closed-loop biomass requirements of subdivision 2 must be increased to 50 percent for the remaining contract term period; however, if in two consecutive subsequent years after the increase has been implemented, it is verified that the conditions in this subdivision have been met, then for the remaining original contract term the closed-loop biomass mandate reverts to 25 percent. If there is a subsequent failure to verify in a year after the first failure and implementation of the 50 percent requirement, then the closed-loop percentage shall remain at 50 percent for each remaining year of the contract term.

(e) In the closed-loop plantation, no transgenic plants may be used.

(f) No wood may be harvested from any lands identified by the final or preliminary Minnesota County Biological Survey as having statewide significance as native plant communities, large populations or concentrations of rare species, or critical animal habitat.

(g) A wood procurement plan must be prepared every five years and public meetings must be held and written comments taken on the plan and documentation must be provided on why or why not the public inputs were used.

(h) Guidelines or best management practices for sustainably managed woody biomass must be adopted by:

(1) the Minnesota Department of Natural Resources for managing and maintaining brushland and open land habitat on public and private lands, including, but not limited to, provisions of sections 84.941, 84.942, and 97A.125; and

(2) the Minnesota Forest Resources Council for logging slash, using the most recent available scientific information regarding the removal of woody biomass from forest lands, to sustain the management of forest resources as defined by section 89.001, subdivisions 8 and 9, with particular attention to soil productivity, biological diversity as defined by section 89A.01, subdivision 3, and wildlife habitat.

These guidelines must be completed by July 1, 2007, and the process of developing them must incorporate public notification and comment.

(i) The University of Minnesota Initiative for Renewable Energy and the Environment is encouraged to solicit and fund high-quality research projects to develop and consolidate scientific information regarding the removal of woody biomass from forest and brush lands, with particular attention to the environmental impacts on soil productivity, biological diversity, and sequestration of carbon. The results of this research shall be made available to the public.

(j) The two utilities owning or controlling, directly or indirectly, the biomass project described in subdivision 5a, paragraph (b), shall fund or obtain funding from nonstate sources of up to $150,000 to complete the guidelines or best management practices described in paragraph (h). The expenditures to be funded under this paragraph do not include any of the expenditures to be funded under paragraph (i).

Sec. 3. Minnesota Statutes 2004, section 216B.2424, subdivision 2, is amended to read:

Subd. 2. [INTERIM EXEMPTION.] (a) A biomass project proposing to use, as its primary fuel over the life of the project, short-rotation woody crops, may use as an interim fuel agricultural waste and other biomass which is not farm-grown closed-loop biomass for up to six years after the project's electric generating facility becomes operational; provided, the project developer demonstrates the project will use the designated short-rotation woody crops as its primary fuel after the interim period and provided the location of the interim fuel production meets the requirements of subdivision 1, paragraph (a), clause (3).

(b) A biomass project proposing to use, as its primary fuel over the life of the project, short-rotation woody crops, may use as an interim fuel agricultural waste and other biomass which is not farm-grown closed-loop biomass for up to three years after the project's electric generating facility becomes operational; provided, the project developer demonstrates the project will use the designated short-rotation woody crops as its primary fuel after the interim period.

(c) A biomass project that uses an interim fuel under the terms of paragraph (b) may, in addition, use an interim fuel under the terms of paragraph (a) for six years less the number of years that an interim fuel was used under paragraph (b).

(d) A project developer proposing to use an exempt interim fuel under paragraphs (a) and (b) must demonstrate to the public utility that the project will have an adequate supply of short-rotation woody crops which meet the requirements of subdivision 1 to fuel the project after the interim period.

(e) If a biomass project using an interim fuel under this subdivision is or becomes owned or controlled, directly or indirectly, by two municipal utilities as described in subdivision 5a, paragraph (b), the project is deemed to comply with the requirement under this subdivision to use as its primary fuel farm-grown closed-loop biomass if farm-grown closed-loop biomass comprises no less than 25 percent of the fuel used over the life of the project. For purposes of this subdivision, "life of the project" means 20 years from the date the project becomes operational or the term of the applicable power purchase agreement between the project owner and the public utility, whichever is longer.

Sec. 4. Minnesota Statutes 2004, section 216B.2424, subdivision 5a, is amended to read:

Subd. 5a. [REDUCTION OF BIOMASS MANDATE.] (a) Notwithstanding subdivision 5, the biomass electric energy mandate ~~shall~~ must be reduced from 125 megawatts to 110 megawatts.

(b) The Public Utilities Commission shall approve a request pending before the ~~Public Utilities~~ commission as of May 15, 2003, for ~~an amendment~~ amendments to and assignment of a ~~contract for power from~~ power purchase agreement with the owner of a facility that uses short-rotation, woody crops as its primary fuel previously approved to satisfy a portion of the biomass mandate if the ~~developer~~ owner of the project agrees to reduce the size of its project from 50 megawatts to 35 megawatts, while maintaining ~~a~~ an average price for energy ~~at or below the current contract price.~~ in nominal dollars measured over the term of the power purchase agreement at or below $104 per megawatt-hour, exclusive of any price adjustments that may take effect subsequent to commission approval of the power purchase agreement, as amended. The commission shall also approve, as necessary, any subsequent assignment or sale of the power purchase agreement or ownership of the project to an entity owned or controlled, directly or indirectly, by two municipal utilities located north of Constitutional Route No. 8, as described in section 161.114, which currently own electric and steam generation facilities using coal as a fuel and which propose to retrofit their existing municipal electrical generating facilities to utilize biomass fuels in order to perform the power purchase agreement.

(c) If the power purchase agreement described in paragraph (b) is assigned to an entity that is, or becomes, owned or controlled, directly or indirectly, by two municipal entities as described in paragraph (b), and the power purchase agreement meets the price requirements of paragraph (b), the commission shall approve any amendments to the power purchase agreement necessary to reflect the changes in project location and ownership and any other amendments made necessary by those changes. The commission shall also specifically find that:

(1) the power purchase agreement complies with and fully satisfies the provisions of this section to the full extent of its 35-megawatt capacity;

(2) all costs incurred by the public utility and all amounts to be paid by the public utility to the project owner under the terms of the power purchase agreement are fully recoverable pursuant to section 216B.1645;

(3) subject to prudency review by the commission, the public utility may recover from its Minnesota retail customers the Minnesota jurisdictional portion of the amounts that may be incurred and paid by the public utility during the full term of the power purchase agreement; and

(4) if the purchase power agreement meets the requirements of this subdivision, it is reasonable and in the public interest.

(d) The commission shall specifically approve recovery by the public utility of any and all Minnesota jurisdictional costs incurred by the public utility to improve, construct, install, or upgrade transmission, distribution, or other electrical facilities owned by the public utility or other persons in order to permit interconnection of the retrofitted biomass-fueled generating facilities or to obtain transmission service for the energy provided by the facilities to the public utility pursuant to section 216B.1645, and shall disapprove any provision in the power purchase agreement that requires the developer or owner of the project to pay the jurisdictional costs or that permit the public utility to terminate the power purchase agreement as a result of the existence of those costs or the public utility's obligation to pay any or all of those costs.

Sec. 5. Minnesota Statutes 2004, section 216B.2424, subdivision 6, is amended to read:

Subd. 6. [REMAINING MEGAWATT COMPLIANCE PROCESS.] (a) If there remain megawatts of biomass power generating capacity to fulfill the mandate in subdivision 5 after the commission has taken final action on all contracts filed by September 1, 2000, by a public utility, as amended and assigned, this subdivision governs final compliance with the biomass energy mandate in subdivision 5 subject to the requirements of subdivisions 7 and 8.

(b) To the extent not inconsistent with this subdivision, the provisions of subdivisions 2, 3, 4, and 5 apply to proposals subject to this subdivision.

(c) A public utility must submit proposals to the commission to complete the biomass mandate. The commission shall require a public utility subject to this section to issue a request for competitive proposals for projects for electric generation utilizing biomass as defined in paragraph (f) of this subdivision to provide the remaining megawatts of the mandate. The commission shall set an expedited schedule for submission of proposals to the utility, selection by the utility of proposals or projects, negotiation of contracts, and review by the commission of the contracts or projects submitted by the utility to the commission.

(d) Notwithstanding the provisions of subdivisions 1 to 5 but subject to the provisions of subdivisions 7 and 8, a new or existing facility proposed under this subdivision that is fueled either by biomass or by co-firing biomass with nonbiomass may satisfy the mandate in this section. Such a facility need not use biomass that complies with the definition in subdivision 1 if it uses biomass as defined in paragraph (f) of this subdivision. Generating capacity produced by co-firing of biomass that is operational as of April 25, 2000, does not meet the requirements of the mandate, except that additional co-firing capacity added at an existing facility after April 25, 2000, may be used to satisfy this mandate. Only the number of megawatts of capacity at a facility which co-fires biomass that are directly attributable to the biomass and that become operational after April 25, 2000, count toward meeting the biomass mandate in this section.

(e) Nothing in this subdivision precludes a facility proposed and approved under this subdivision from using fuel sources that are not biomass in compliance with subdivision 3.

(f) Notwithstanding the provisions of subdivision 1, for proposals subject to this subdivision, "biomass" includes farm-grown closed-loop biomass; agricultural wastes, including animal, poultry, and plant wastes; and waste wood, including chipped wood, bark, brush, residue wood, and sawdust.

(g) Nothing in this subdivision affects in any way contracts entered into as of April 25, 2000, to satisfy the mandate in subdivision 5.

(h) Nothing in this subdivision requires a public utility to retrofit its own power plants for the purpose of co-firing biomass fuel, nor is a utility prohibited from retrofitting its own power plants for the purpose of co-firing biomass fuel to meet the requirements of this subdivision.

Sec. 6. Minnesota Statutes 2004, section 216B.2424, subdivision 8, is amended to read:

Subd. 8. [AGRICULTURAL BIOMASS REQUIREMENT.] Of the 125 megawatts mandated in subdivision 5, or 110 megawatts mandated in subdivision 5a, at least 75 megawatts of the generating capacity must be generated by facilities that use agricultural biomass as the principal fuel source. For purposes of this subdivision, agricultural biomass includes only farm-grown closed-loop biomass and agricultural waste, including animal, poultry, and plant wastes. For purposes of this subdivision, "principal fuel source" means a fuel source that satisfies at least 75 percent of the fuel requirements of an electric power generating facility. Nothing in this subdivision is intended to expand the fuel source requirements of subdivision 5.

ARTICLE 6
E-FILING

Section 1. [ESTABLISHMENT OF FUND.]

The Department of Commerce's e-filing account is established. The commissioner of commerce shall make a onetime assessment of no more than $300,000 to cover the actual cost of implementing this section. The funds assessed must be deposited in the account. Any excess funds in the account upon completion must be refunded to the utilities proportionately to the amount assessed. Each public utility, generation and transmission cooperative electric association, municipal power agency, telephone company, and telecommunications carrier must be assessed in proportion to its respective gross jurisdictional operating revenues for sales of gas, electric, or telecommunications service in the state in the last calendar year. Revenue in the account is appropriated to the commissioner of commerce for the costs associated with establishing an e-filing system that allows documents filed with the Public Utilities Commission to be filed and retrieved via the Internet. Revenue in the account remains available until expended.

Sec. 2. [COMPLETION DATE.]

The e-filing system described in section 1 must be operational by July 1, 2006.

Sec. 3. [EFFECTIVE DATE.]

Sections 1 and 2 are effective the day following final enactment.

ARTICLE 7
CIP TECHNICAL CORRECTIONS

Section 1. Minnesota Statutes 2004, section 216B.241, subdivision 1b, is amended to read:

Subd. 1b. [CONSERVATION IMPROVEMENT BY COOPERATIVE ASSOCIATION OR MUNICIPALITY.] (a) This subdivision applies to:

(1) a cooperative electric association that provides retail service to its members;

(2) a municipality that provides electric service to retail

customers; and

(3) a municipality with gross operating revenues in excess of $5,000,000 from sales of natural gas to retail customers.

(b) Each cooperative electric association and municipality subject to this subdivision shall spend and invest for energy conservation improvements under this subdivision the following amounts:

(1) for a municipality, 0.5 percent of its gross operating revenues from the sale of gas and 1.5 percent of its gross operating revenues from the sale of electricity, excluding gross operating revenues from electric and gas service provided in the state to large electric customer facilities; and

(2) for a cooperative electric association, 1.5 percent of its gross operating revenues from service provided in the state, excluding gross operating revenues from service provided in the state to large electric customer facilities indirectly through a distribution cooperative electric association.

(c) Each municipality and cooperative electric association subject to this subdivision shall identify and implement energy conservation improvement spending and investments that are appropriate for the municipality or association, except that a municipality or association may not spend or invest for energy conservation improvements that directly benefit a large electric customer facility for which the commissioner has issued an exemption under subdivision 1a, paragraph (b).

(d) Each municipality and cooperative electric association subject to this subdivision may spend and invest annually up to ten percent of the total amount required to be spent and invested on energy conservation improvements under this subdivision on research and development projects that meet the definition of energy conservation improvement in subdivision 1 and that are funded directly by the municipality or cooperative electric association.

(e) Load-management activities that do not reduce energy use but that increase the efficiency of the electric system may be used to meet ~~the following percentage~~ 50 percent of the conservation investment and spending requirements of this subdivision~~:~~

~~(1) 2002 - 90 percent;~~

~~(2) 2003 - 80 percent;~~

~~(3) 2004 - 65 percent; and~~

~~(4) 2005 and thereafter - 50 percent~~.

(f) A generation and transmission cooperative electric association that provides energy services to cooperative electric associations that provide electric service at retail to consumers may invest in energy conservation improvements on behalf of the associations it serves and may fulfill the conservation, spending, reporting, and energy savings goals on an aggregate basis. A municipal power agency or other not-for-profit entity that provides energy service to municipal utilities that provide electric service at retail may invest in energy conservation improvements on behalf of the municipal utilities it serves and may fulfill the conservation, spending, reporting, and energy savings goals on an aggregate basis, under an agreement between the municipal power agency or not-for-profit entity and each municipal utility for funding the investments.

(g) At least every ~~two~~ four years, on a schedule determined by the commissioner, each municipality or cooperative shall file an overview of its conservation improvement plan with the commissioner. With this overview, the municipality or cooperative shall also provide an evaluation to the commissioner detailing its energy conservation improvement spending and investments for the previous period. The evaluation must briefly describe each conservation program and must specify the energy savings or increased efficiency in the use of energy within the service territory of the utility or association that is the result of the spending and investments. The evaluation must analyze the cost-effectiveness of the utility's or association's conservation programs, using a list of baseline energy and capacity savings assumptions developed in consultation with the department. The commissioner shall review each evaluation and make recommendations, where appropriate, to the municipality or association to increase the effectiveness of conservation improvement activities. Up to three percent of a utility's conservation spending obligation under this section may be used for program pre-evaluation, testing, and monitoring and program evaluation. The overview and evaluation filed by a municipality with less than 60,000,000 kilowatt hours in annual retail sales of electric service may consist of a letter from the governing board of the municipal utility to the department providing the amount of annual conservation spending required of that municipality and certifying that the required amount has been spent on conservation programs pursuant to this subdivision.

(h) The commissioner shall also review each evaluation for whether a portion of the money spent on residential conservation improvement programs is devoted to programs that directly address the needs of renters and low-income persons unless an insufficient number of appropriate programs are available. For the purposes of this subdivision and subdivision 2, "low-income" means an income at or below 50 percent of the state median income.

(i) As part of its spending for conservation improvement, a municipality or association may contribute to the energy and conservation account. A municipality or association may propose to the commissioner to designate that all or a portion of funds contributed to the account be used for research and development projects that can best be implemented on a statewide basis. Any amount contributed must be remitted to the commissioner by February 1 of each year.

(j) A municipality may spend up to 50 percent of its required spending under this section to refurbish an existing district heating or cooling system. This paragraph expires July 1, 2007.

Sec. 2. Minnesota Statutes 2004, section 216B.241, subdivision 2, is amended to read:

Subd. 2. [PROGRAMS.] (a) The commissioner may require public utilities to make investments and expenditures in energy conservation improvements, explicitly setting forth the interest rates, prices, and terms under which the improvements must be offered to the customers. The required programs must cover no more than a ~~two-year~~ four-year period. Public utilities shall file conservation improvement plans by June 1, on a schedule determined by order of the commissioner, but at least every four years. Plans received by a public utility by June 1 must be approved or approved as modified by the commissioner by December 1 of that same year. The commissioner shall give special consideration and encouragement to programs that bring about significant net savings through the use of energy-efficient lighting. The commissioner shall evaluate the program on the basis of cost-effectiveness and the reliability of technologies employed. The commissioner's order must provide to the extent practicable for a free choice, by consumers participating in the program, of the device, method, material, or project constituting the energy conservation improvement and for a free choice of the seller, installer, or contractor of the energy conservation improvement, provided that the device, method, material, or project seller, installer, or contractor is duly licensed, certified, approved, or qualified, including under the residential conservation services program, where applicable.

(b) The commissioner may require a utility to make an energy conservation improvement investment or expenditure whenever the commissioner finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of new supply of energy. The commissioner shall nevertheless ensure that every public utility operate one or more programs under periodic review by the department.

(c) Each public utility subject to subdivision 1a may spend and invest annually up to ten percent of the total amount required to be spent and invested on energy conservation improvements under this section by the utility on research and development projects that meet the definition of energy conservation improvement in subdivision 1 and that are funded directly by the public utility.

(d) A public utility may not spend for or invest in energy conservation improvements that directly benefit a large electric customer facility for which the commissioner has issued an exemption pursuant to subdivision 1a, paragraph (b). The commissioner shall consider and may require a utility to undertake a program suggested by an outside source, including a political subdivision or a nonprofit or community organization.

(e) The commissioner may, by order, establish a list of programs that may be offered as energy conservation improvements by a public utility, municipal utility, cooperative electric association, or other entity providing conservation services pursuant to this section. The list of programs may include rebates for high-efficiency appliances, rebates or subsidies for high-efficiency lamps, small business energy audits, and building recommissioning. The commissioner may, by order, change this list to add or subtract programs as the commissioner determines is necessary to promote efficient and effective conservation programs.

(f) The commissioner shall ensure that a portion of the money spent on residential conservation improvement programs is devoted to programs that directly address the needs of renters and low-income persons, in proportion to the amount the utility has historically spent on such programs based on the most recent three-year average relative to the utility's total conservation spending under this section, unless an insufficient number of appropriate programs are available.

(g) A utility, a political subdivision, or a nonprofit or community organization that has suggested a program, the attorney general acting on behalf of consumers and small business interests, or a utility customer that has suggested a program and is not represented by the attorney general under section 8.33 may petition the commission to modify or revoke a department decision under this section, and the commission may do so if it determines that the program is not cost-effective, does not adequately address the residential conservation improvement needs of low-income persons, has a long-range negative effect on one or more classes of customers, or is otherwise not in the public interest. The commission shall reject a petition that, on its face, fails to make a reasonable argument that a program is not in the public interest.

(h) The commissioner may order a public utility to include, with the filing of the utility's proposed conservation improvement plan under paragraph (a), the results of an independent audit of the utility's conservation improvement programs and expenditures performed by the department or an auditor with experience in the provision of energy conservation and energy efficiency services approved by the commissioner and chosen by the utility. The audit must specify the energy savings or increased efficiency in the use of energy within the service territory of the utility that is the result of the spending and investments. The audit must evaluate the cost-effectiveness of the utility's conservation programs.

(i) Up to three percent of a utility's conservation spending obligation under this section may be used for program pre-evaluation, testing, and monitoring and program audit and evaluation.

ARTICLE 8

POWER QUALITY ZONES

Section 1. [216B.2426] [OPPORTUNITIES FOR DISTRIBUTED GENERATION.]

The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

Sec. 2. [216B.82] [LOCAL POWER QUALITY ZONES.]

(a) Upon joint petition of a public utility as defined in section 216B.02, subdivision 4, and any customer located within the utility's service territory, the commission may establish a zone within that utility's service territory where the utility will install additional, redundant or upgraded components of the electric distribution infrastructure that are designed to decrease the risk of power outages, provided the utility and all of its customers located within the proposed zone have approved the installation of the components and the financial recovery plan prior to the creation of the zone. Prior to commission approval, the utility must notify each customer within the proposed zone of the total costs of the installation, an estimate of the customer's share of those costs, and the potential benefits of the local power quality zone to the customer.

(b) The commission shall authorize the utility to collect all costs of the installation of any components under this section, including initial investment, operation and maintenance costs and taxes from all customers within the zone, through tariffs and surcharges for service in a zone that appropriately reflect the cost of service to those customers, provided the customers agree to pay all costs for a predetermined period, including costs of component removal, if appropriate.

(c) Nothing in this section limits the ability of the utility and any customer to enter into customer-specific agreements pursuant to applicable statutory, rule, or tariff provisions.

Nothing in this section shall be construed to permit the quality of service outside a designated zone to decline.

ARTICLE 9

BIOGAS INCENTIVE PAYMENTS

Section 1. Minnesota Statutes 2004, section 216C.41, subdivision 1, is amended to read:

Subdivision 1. [DEFINITIONS.] (a) The definitions in this subdivision apply to this section.

(b) "Qualified hydroelectric facility" means a hydroelectric generating facility in this state that:

(1) is located at the site of a dam, if the dam was in existence as of March 31, 1994; and

(2) begins generating electricity after July 1, 1994, or generates electricity after substantial refurbishing of a facility that begins after July 1, 2001.

(c) "Qualified wind energy conversion facility" means a wind energy conversion system in this state that:

(1) produces two megawatts or less of electricity as measured by nameplate rating and begins generating electricity after December 31, 1996, and before July 1, 1999;

(2) begins generating electricity after June 30, 1999, produces two megawatts or less of electricity as measured by nameplate rating, and is:

(i) owned by a resident of Minnesota or an entity that is organized under the laws of this state, is not prohibited from owning agricultural land under section 500.24, and owns the land where the facility is sited;

(ii) owned by a Minnesota small business as defined in section 645.445;

(iii) owned by a Minnesota nonprofit organization;

(iv) owned by a tribal council if the facility is located within the boundaries of the reservation;

(v) owned by a Minnesota municipal utility or a Minnesota cooperative electric association; or

(vi) owned by a Minnesota political subdivision or local government, including, but not limited to, a county, statutory or home rule charter city, town, school district, or any other local or regional governmental organization such as a board, commission, or association; or

(3) begins generating electricity after June 30, 1999, produces seven megawatts or less of electricity as measured by nameplate rating, and:

(i) is owned by a cooperative organized under chapter 308A other than a Minnesota cooperative electric association; and

(ii) all shares and membership in the cooperative are held by an entity that is not prohibited from owning agricultural land under section 500.24.

(d) "Qualified on-farm biogas recovery facility" means an anaerobic digester system that:

(1) is located at the site of an agricultural operation; and

(2) is owned by an entity that is not prohibited from owning agricultural land under section 500.24 and that owns or rents the land where the facility is located~~; and~~

~~(3) begins generating electricity after July 1, 2001~~.

(e) "Anaerobic digester system" means a system of components that processes animal waste based on the absence of oxygen and produces gas used to generate electricity.

ARTICLE 10

GAS INFRASTRUCTURE COST

Section 1. [216B.1635] [RECOVERY OF ELIGIBLE INFRASTRUCTURE REPLACEMENT COSTS BY GAS UTILITIES.]

Subdivision 1. [DEFINITIONS.] (a) "Gas utility" means a public utility as defined in section 216B.02, subdivision 4, that furnishes natural gas service to retail customers.

(b) "Gas utility infrastructure costs" or "GUIC" means gas utility projects that:

(1) do not serve to increase revenues by directly connecting the infrastructure replacement to new customers;

(2) are in service but were not included in the gas utility's rate base in its most recent general rate case; and

(3) replace or modify existing infrastructure if the replacement or modification does not constitute a betterment, unless the betterment is required by a political subdivision, as evidenced by specific documentation from the government entity requiring the replacement or modification of infrastructure.

(c) "Gas utility projects" means relocation and replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the State of Minnesota, or a political subdivision.

Subd. 2. [FILING.] (a) The commission may approve a gas utility's petition for a rate schedule to recover GUIC under this section. A gas utility may petition the commission to recover a rate of return, income taxes on the rate of return, incremental property taxes, plus incremental depreciation expense associated with GUIC.

(b) The filing is subject to the following:

(1) a gas utility may submit a filing under this section no more than once per year;

(2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC or be subject to denial by the commission. The information includes, but is not limited to:

(i) the government entity ordering the gas utility project and the purpose for which the project is undertaken;

(ii) the location, description, and costs associated with the project;

(iii) a description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;

(iv) the proposed rate design and an explanation of why the proposed rate design is in the public interest;

(v) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;

(vi) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges;

(vii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case;

(viii) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case; and

(ix) documentation supporting the calculation of the GUIC.

Subd. 3. [COMMISSION AUTHORITY.] The commission may issue orders and adopt rules necessary to implement and administer this section.

[EFFECTIVE DATE.] This section is effective the day following final enactment.

Sec. 2. [REPORT TO LEGISLATURE.]

The Department of Commerce shall review the operation and impact of the GUIC recovery mechanism established under Minnesota Statutes, section 216B.1635, on ratepayers and the utility and submit a report of its findings and recommendations to the legislature four years after the effective date of this section.

Sec. 3. [SUNSET.]

Sections 1 and 2 shall expire on June 30, 2015.

ARTICLE 11

EMINENT DOMAIN LANDOWNER COMPENSATION

Section. 1. [LANDOWNER PAYMENTS WORKING GROUP.]

Subdivision 1. [MEMBERSHIP.] By June 15, 2005, the Legislative Electric Energy Task Force shall convene a landowner payments working group consisting of up to 12 members, including representatives from each of the following groups: transmission-owning investor-owned utilities, electric cooperatives, municipal power agencies, Farm Bureau, Farmers Union, county commissioners, real estate appraisers and others with an interest and expertise in landowner rights and the market value of rural property.

Subd. 2. [APPOINTMENT.] The chairs of the Legislative Electric Energy Task Force and the chairs of the senate and house committees with primary jurisdiction over energy policy shall jointly appoint the working group members.

Subd. 3. [CHARGE.] (a) The landowner payments working group shall research alternative methods of remunerating landowners on whose land high voltage transmission lines have been constructed.

(b) In developing its recommendations, the working group shall:

(1) examine different methods of landowner payments that operate in other states and countries;

(2) consider innovative alternatives to lump-sum payments that extend payments over the life of the transmission line and that run with the land if the land is conveyed to another owner;

(3) consider alternative ways of structuring payments that are equitable to landowners and utilities.

Subd. 4. [EXPENSES.] Members of the working group shall be reimbursed for expenses as provided in Minnesota Statutes, section 15.059, subdivision 6. Expenses of the landowner payments working group shall not exceed $10,000 without the approval of the chairs of the Legislative Electric Energy Task Force.

Subd. 5. [REPORT.] The landowner payments working group shall present its findings and recommendations, including legislative recommendations and model legislation, if any, in a report to the Legislative Electric Energy Task Force by January 15, 2006.

ARTICLE 12

TECHNICAL CORRECTION

Section 1. Minnesota Statutes 2004, section 216B.16, subdivision 6d, is amended to read:

Subd. 6d. [WIND ENERGY; PROPERTY TAX.] An owner of a wind energy conversion facility which is required to pay property taxes under section 272.02, subdivision 22, or production taxes under section 272.029, and any related or successor provisions, or a public utility regulated by the Public Utilities Commission which purchases the wind generated electricity may petition the commission to include in any power purchase agreement between the owner of the facility and the public utility the amount of property taxes and production taxes paid by the owner of the facility. The Public Utilities Commission shall require the public utility to amend the power purchase agreement to include the property taxes and production taxes paid by the owner of the facility in the price paid by the utility for wind generated electricity if the commission finds:

(1) the owner of the facility has paid the property taxes or production taxes required by this subdivision;

(2) the power purchase agreement between the public utility and the owner does not already require the utility to pay the amount of property taxes or production taxes the owner has paid under this subdivision, or, in the case of a power purchase agreement entered into prior to 1997, the amount of property or production taxes paid by the owner in any year of the power purchase agreement exceeds the amount of such property or production taxes included in the price paid by the utility to the owner, as reflected in the owner's bid documents; and

(3) the commission has approved a rate schedule containing provisions for the automatic adjustment of charges for utility service in direct relation to the charges ordered by the commission under section 272.02, subdivision 22, or section 272.029.

ARTICLE 13

HYDROGEN

Section 1. [216B.811] [DEFINITIONS.]

Subdivision 1. [SCOPE.] For purposes of sections 216B.811 to 216B.815, the terms defined in this section have the meanings given them.

Subd. 2. [FUEL CELL.] "Fuel cell" means an electrochemical device that produces useful electricity, heat, and water vapor, and operates as long as it is provided fuel.

Subd. 3. [HYDROGEN.] "Hydrogen" means hydrogen produced using native energy sources.

Subd. 4. [RELATED TECHNOLOGIES.] "Related technologies" means balance of plant components necessary to make hydrogen and fuel cell systems function; turbines, reciprocating, and other combustion engines capable of operating on hydrogen; and electrolyzers, reformers, and other equipment and processes necessary to produce, purify, store, distribute, and use hydrogen for energy.

Sec. 2. [216B.812] [FOSTERING THE TRANSITION TOWARD ENERGY SECURITY.]

Subdivision 1. [EARLY PURCHASE AND DEPLOYMENT OF HYDROGEN, FUEL CELLS, AND RELATED TECHNOLOGIES BY THE STATE.] The Department of Administration shall identify opportunities for demonstrating the use of hydrogen fuel cells within state-owned facilities, vehicle fleets, and operations.

The department shall purchase and demonstrate hydrogen, fuel cells, and related technologies in ways that strategically contribute to realizing Minnesota's hydrogen economy goal as set forth in section 216B.013, and which contribute to the following nonexclusive list of objectives:

(1) provide needed performance data to the marketplace;

(2) identify code and regulatory issues to be resolved;

(3) advance or validate a critical area of research;

(4) foster economic development and job creation in the state;

(5) raise public awareness of hydrogen, fuel cells, and related technologies; or

(6) reduce emissions of carbon dioxide and other pollutants.

Subd. 2. [SUPPORT FOR STRATEGIC DEMONSTRATION PROJECTS THAT ACCELERATE THE COMMERCIALIZATION OF HYDROGEN, FUEL CELLS, AND RELATED TECHNOLOGIES.] (a) In consultation with appropriate representatives from state agencies, local governments, universities, businesses, and other interested parties, the Department of Commerce shall report back to the legislature by November 1, 2005, and every two years thereafter, with a slate of proposed pilot projects that contribute to realizing Minnesota's hydrogen economy goal as set forth in section

216B.013. The Department of Commerce must consider the following nonexclusive list of priorities in developing the proposed slate of pilot projects:

(1) demonstrate "bridge" technologies such as hybrid-electric, off-road, and fleet vehicles running on hydrogen or fuels blended with hydrogen;

(2) develop cost-competitive, on-site hydrogen production technologies;

(3) demonstrate nonvehicle applications for hydrogen;

(4) improve the cost and efficiency of hydrogen from renewable energy sources; and

(5) improve the cost and efficiency of hydrogen production using direct solar energy without electricity generation as an intermediate step.

(b) For all demonstrations, individual system components of the technology must meet commercial performance standards and systems modeling must be completed to predict commercial performance, risk, and synergies. In addition, the proposed pilots should meet as many of the following criteria as possible:

(1) advance energy security;

(2) capitalize on the state's native resources;

(3) result in economically competitive infrastructure being put in place;

(4) be located where it will link well with existing and related projects and be accessible to the public, now or in the future;

(5) demonstrate multiple, integrated aspects of hydrogen infrastructure;

(6) include an explicit public education and awareness component;

(7) be scalable to respond to changing circumstances and market demands;

(8) draw on firms and expertise within the state where possible;

(9) include an assessment of its economic, environmental, and social impact; and

(10) serve other needs beyond hydrogen development.

Subd. 3. [ESTABLISHING INITIAL, MULTIFUEL TRANSITION INFRASTRUCTURE FOR HYDROGEN VEHICLES.] The commissioner of commerce may accept federal funds, expend funds, and participate in projects to design, site, and construct multifuel hydrogen fueling stations that eventually link urban centers along key trade corridors across the jurisdictions of Manitoba, the Dakotas, Minnesota, Iowa, and Wisconsin.

These energy stations must serve the priorities listed in subdivision 2 and, as transition infrastructure, should accommodate a wide variety of vehicle technologies and fueling platforms, including hybrid, flexible-fuel, and fuel cell vehicles. They may offer, but not be limited to, gasoline, diesel, ethanol (E-85), biodiesel, and hydrogen, and may simultaneously test the integration of on-site combined heat and power technologies with the existing energy infrastructure.

The hydrogen portion of the stations may initially serve local, dedicated on or off-road vehicles, but should eventually support long-haul transport.

Sec. 3. [216B.815] [AUTHORIZE AND ENCOURAGE THE STATE'S PUBLIC RESEARCH INSTITUTIONS TO COORDINATE AND LEVERAGE THEIR STRENGTHS THROUGH A REGIONAL ENERGY RESEARCH AND EDUCATION PARTNERSHIP.]

The state's public research and higher education institutions should work with one another and with similar institutions in the region to establish Minnesota and the Upper Midwest as a center of research, education, outreach, and technology transfer for the production of renewable energy and products, including hydrogen, fuel cells, and related technologies. The partnership should be designed to create a critical mass of research and education capability that can compete effectively for federal and private investment in these areas.

The partnership must include an advisory committee comprised of government, industry, academic, and nonprofit representatives to help focus its research and education efforts on the most critical issues. Initiatives undertaken by the partnership may include:

(1) collaborative and interdisciplinary research, demonstration projects, and commercialization of market-ready technologies;

(2) creation of undergraduate and graduate course offerings and eventually degreed and vocational programs with reciprocity;

(3) establishment of fellows programs at the region's institutes of higher learning that provide financial incentives for relevant study, research, and exchange; and

(4) development and field-testing of relevant curricula, teacher kits for all educational levels, and widespread teacher training, in collaboration with state energy offices, teachers, nonprofits, businesses, the United States Department of Energy, and other interested parties.

Sec. 4. [HYDROGEN REFUELING STATIONS; GRANTS.]

The commissioner of commerce shall make assessments under Minnesota Statutes, section 216C.052, of $300,000 in fiscal year 2006 and $300,000 in fiscal year 2007 for the purpose of matching federal and private investments in three multifuel hydrogen refueling stations in Moorhead, Alexandria, and the Twin Cities respectively. The assessments are subject to the assessment caps specified in Minnesota Statutes, section 216C.052. Sums assessed under this section are appropriated to the commissioner of commerce for the purpose of this section. The assessments and grants are contingent upon securing the balance of the total project costs from nonstate sources.

Sec. 5. [FUEL CELL CURRICULUM DEVELOPMENT PILOT.]

The Board of Trustees of the Minnesota State Colleges and Universities is encouraged to work with the Upper Midwest Hydrogen Initiative and other interested parties to develop and implement hydrogen and fuel cell curricula and training programs that can be incorporated into existing relevant courses and disciplines affected by these technologies. These disciplines include, but are not limited to, chemical, electrical, and mechanical engineering, including lab technicians; fuel cell production, installation, and maintenance; fuel cell and internal combustion vehicles, including hybrids, running on hydrogen or biofuels; and the construction, installation, and maintenance of facilities that will produce, use, or serve hydrogen. The curricula should also be useful to secondary educational institutions and should include, but not be limited to, the production, purification, distribution, and use of hydrogen in portable, stationary, and mobile applications and in fuel cells, turbines, and reciprocating engines.

ARTICLE 14

SOY-DIESEL

Section 1. [ALLOCATION; RENEWABLE DEVELOPMENT GRANT.]

Notwithstanding any contrary provision of Minnesota Statutes, section 116C.779, $150,000 is allocated in fiscal year 2006 to the Agricultural Utilization Research Institute from available funds in the renewable development account established under Minnesota Statutes, section 116C.779. The institute shall disburse the money over three fiscal years as grants to an applicant meeting the requirements of Minnesota Statutes, section 216C.41, subdivision 1, paragraph (c), clause (2), item (i), for a project that uses a soy-diesel generator to provide backup power for a wind energy conversion system of one megawatt or less of nameplate capacity. The institute shall disburse $50,000 of the grant in three consecutive fiscal years beginning July 1, 2005.

For the purpose of this section, "soy-diesel" means a renewable, biodegradable, mono alkyl ester combustible liquid fuel derived from agricultural plant oils that meets American Society for Testing and Materials Specification D6751-02 for Biodiesel Fuel (B100) Blend Stock for Distillate Fuels. This section only applies if the entity receives qualifying applications.

ARTICLE 15

BIODIESEL FUEL FOR HOME HEATING

Section 1. [STUDY; BIODIESEL FUEL FOR HOME HEATING.]

(a) From the money available to the commissioner of commerce for purposes of studies and technical assistance by the reliability administrator under Minnesota Statutes, section 216C.052, and in conformity with the goals and directives of Minnesota Statutes, section 16B.325, the reliability administrator shall perform a comprehensive technical and economic analysis of the benefits to be derived from using biodiesel fuel as defined in Minnesota Statutes, section 239.77, subdivision 1, or biodiesel fuel blends, as a home heating fuel. The analysis must consider blends ranging from B2 to B100. No more than $25,000 may be expended for the analysis.

(b) Not later than March 15, 2007, the reliability administrator shall report the results of the study and analysis to the appropriate standing committees of the Minnesota senate and house of representatives.

ARTICLE 16

CITY OF ALEXANDRIA JOINT VENTURE AUTHORITY

Section 1. Laws 2002, chapter 329, section 5, is amended to read:

Sec. 5. [JOINT VENTURE AUTHORITY.]

(a) The city of Alexandria may enter into a joint venture or joint ventures with one, two, or three of the entities known as Runestone Telephone Association ~~and~~, Runestone Electric Association, and Gardonville Telephone Cooperative for the purpose of providing local niche service, including internet services, and point to point transmission of digital information.

(b) For purposes of this section, with respect to the services described in paragraph (a), the city of Alexandria and a joint venture to which it is a party shall have the rights and authority granted by, and be subject to, Minnesota Statutes 2001 Supplement, section 452.25, except for the provisions of that section which relate specifically and only to electric utilities.

(c) For the purposes of this section, "local niche service" refers to point-to-point connections between end-user locations within a service area and any telecommunications services under the public utilities commission's jurisdiction under Minnesota Statutes, chapter 237 that do not fall within the definition of local service or the definition of interexchange service.

(d) If the city of Alexandria obtains authority to provide local service or interexchange service under chapter 237, it may enter into a joint venture with the entities identified in paragraph (a) for those purposes.

[**EFFECTIVE DATE; LOCAL APPROVAL.**] This section is effective as to the city of Alexandria the day after the city of Alexandria's governing body and its chief clerical officer timely complete compliance with Minnesota Statutes, section 645.021, subdivisions 2 and 3.

Presented to the governor May 21, 2005

Signed by the governor May 25, 2005, 1:10 p.m.

Exhibit K

Testimony of Will Kaul, GRE V.P. of Transmission

June 17, 2008

Before the U.S. Senate Energy and Natural Resource Committee
June 17, 2008

William Kaul, Chair, CapX 2020
President, WIRES
Transmission Vice President, Great River Energy

Mr. Chairman, members of the Committee, my name is William Kaul. I serve as the transmission vice president at Great River Energy, a generation and transmission cooperative located in Maple Grove, Minnesota with operations in North Dakota, Minnesota and Wisconsin. I am a founder and chairman of CapX 2020, a collaboration of 10 utilities including Xcel Energy, Minnesota Power, Otter Tail Power, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Wisconsin Public Power Incorporated, Dairyland Power Cooperative and the Rochester Public Utilities. I am also the president of WIRES, a national coalition of transmission providers and customers. Today I will talk about the work of both CapX 2020 and WIRES aimed at the necessary expansion of electric transmission infrastructure.

CapX 2020 collaboration. CapX 2020 was formed in 2004 in recognition of the need for a coordinated vision for grid expansion in the greater Minnesota area. CapX 2020 is a "joint ownership" initiative that involves cooperative, investor-owned and municipal utilities in the planning, financing and ownership of new transmission. A package of materials further describing CapX 2020 and its proposed projects is included with this testimony.

CapX 2020 took a two-pronged approach to planning and implementing a vision for grid expansion by: 1) establishing a coordinated and comprehensive planning process, a "vision study", for grid expansion in our collective service territories, and 2) seeking a workable regulatory environment that will enable that vision to be realized.

Vision study. CapX 2020 set a planning horizon of 15 years, projected load growth during that period and ran scenario analyses of different generation mixes, assuming a 10% renewable energy component. The result was a conceptual plan, a vision for grid expansion, with transmission line projects prioritized in groups.

Regulatory environment. Regulatory reforms were needed to reduce project risks, ensure cost recovery and make the permitting process more predictable and efficient. We collaborated with stakeholder groups including regulators, environmental groups and others on a legislative initiative that resulted in formula rates for the investor-owned utilities, ensuring predictable revenue recovery and cash flow, streamlined permitting of need and siting, recognition of transmission as regional infrastructure and the ability to transfer assets into a transmission-only company if deemed in the public interest by the Minnesota Public Utilities Commission.

Group 1 project status. CapX 2020 Group 1 projects are currently pending state regulatory review and approval. Group 1 projects include four transmission lines, three at 345 kilovolts (kV) and one at 230 kV, totaling 700 miles in length and projected to cost $1.7 billion. The 345 kV projects have been grouped into a single certificate of need filing and are supported by all major stakeholders, including the Minnesota Office of Energy Security, the environmental coalition and the Midwest ISO. With this support, the environmental coalition and the Office of Energy Security are recommending these 345 kV projects either be upgraded to a higher capacity or built to support future double circuit capability. The 230 kV project has no interveners in its certificate of need filing.

Minnesota Renewable Energy Standard and Group 2. In 2007, the Minnesota Legislature passed a law (MN RES) requiring all utilities to generate at least 25% of their electricity from renewable sources by the year 2025, with Xcel Energy required to meet a 30% requirement by 2020 – 25% in the portfolio needs to be sourced from wind power. Included in the law is a requirement that utilities develop a transmission plan enabling compliance with the MN RES. This dramatically changed the planning assumptions from the original CapX 2020 Vision Study. CapX 2020 is now in the process of developing another group of 345 kV projects similar in scope to Group 1 that are intended to achieve renewable energy milestones through 2016. CapX 2020 expects to invest more than $3 billion in the first two groups of projects by 2016.

Bridging beyond the 2016 timeframe and Minnesota's geography. Our planning horizon is now in the 2016 to 2025 timeframe. We realize that the excellent wind resources located in the Upper Midwest can and should be developed for a much broader market. While it is expected that 6000 MW of wind will be developed just to meet the MN RES, the market potential for Midwest states is much greater and we are now shifting our focus beyond the greater Minnesota region.

As the demand for renewable energy in regional markets evolves, the Upper Midwest states will develop renewable energy resources that will need transmission for exporting renewable energy to distant markets. Accomplishing that feat will require an extraordinary level of cooperation among utilities, state regulators and legislators, renewable energy developers and other stakeholders. While CapX 2020 has been a very successful initiative, *it was achieved under very favorable circumstances*: one primary political jurisdiction, a clear state energy policy, an organized energy market and tariffs (MISO), the prospect of significant economic development from wind generation and the support of environmental groups. The challenges of developing major inter-regional transmission infrastructure increase exponentially with additional political jurisdictions, multiple transmission providers, conflicting energy policies, differential economic benefits, etc

New initiatives to address new challenges. Several parallel efforts are underway to address these challenges:

1. **Midwest ISO.** The Midwest ISO has begun an initiative, the Regional Generation Outlet Study (RGO study), that brings together planners from across the MISO footprint to develop an expansion plan for renewable resources that

meets the needs of the MISO market. In addition, MISO is conducting a joint planning effort with PJM, Tennessee Valley Authority and Southwest Power Pool to evaluate needed transmission under a 20% wind energy mandate for the Eastern Interconnection.

2. **Organization of MISO States.** This is a group of public utility commissioners, one from each state within MISO, that is closely monitoring the activities of MISO and utilities within MISO. The attention of this group to grid expansion planning is critical since it is the public utility commissions who certify the need for new transmission projects, site the lines and rule on cost recover at retail.
3. **The Midwest Governor's Association.** The Midwest Governor's Association held an environmental summit last fall. Its stated objectives were to improve energy efficiencies, deploy lower-carbon renewable and fossil fuels and implement geologic CO2 storage and terrestrial carbon sequestrations. The MGA identified the development of transmission for renewable energy as a key strategy for goal achievement. The MGA has working groups now addressing the carbon reduction and transmission expansion issues.
4. **CapX 2020 future strategy.** The CapX 2020 utilities are developing a strategy on how to plan and partner with other transmission developers in the region such as International Transmission Company (ITC), American Transmission Company (ATCo), Western Area Power Administration (WAPA), Basin Electric Power Cooperative and others, with an objective to develop needed transmission projects to maintain reliability and satisfy the various renewable requirements within the Midwest. Just last week, CapX 2020 convened a forum for transmission system planners from these companies to initiate broader regional transmission plans. CapX 2020 also is actively participating in the MISO RGO study and the MGA working groups.

WIRES. Working at a national level, CapX 2020 is a founding member of WIRES, which was formed in 2006 and is the nation's only pure transmission advocacy group. WIRES membership includes CapX 2020, ITC, Trans-Elect, National Grid, ONCOR, Xcel Energy, FPL Energy, Quanta Services and Northeast Utilities.

WIRES believes that policy issues must be addressed in order to achieve necessary transmission expansion. In 2006, WIRES convened a Blue Ribbon Panel on cost allocation consisting of nationally and internationally recognized economists, engineers and public policy experts. I am providing the Committee with copies of their report submitted with my testimony. One of the critical barriers to transmission expansion is cost allocation – and resolution is paramount in order for large scale transmission grid expansion.

WIRES has just commissioned an additional study to evaluate various proposals for integration of wind and remote clean energy resources into the existing transmission grid. In addition to proposals introduced as legislation in Congress, a number of states, including Texas, California and Colorado have developed and implemented renewable energy zone concepts and related transmission expansion and upgrade policies. WIRES will examine these initiatives with an eye out for what can be learned from the experience so far and to identify “best practices”. The study is scheduled to be completed this fall and WIRES would be pleased to be able to share the results with the Committee.

On behalf of the CapX 2020 consortium, WIRES and Great River Energy, thank you for inviting us to participate in this hearing. I look forward to answering any questions you may have.

Exhibit L

RE-AMP Funding – Grantees and Amounts

FUNDER	RECIPIENT	DATE	AMOUNT	PURPOSE
Carolyn Foundation				
	Community Wind Project (consortium)	2004	$ 100,000	Initiative including North American Water Office, Minnesotans for an Energy-Efficient Economy, Minnesota Project & Windustry
	Community Wind Project (consortium)	2005	$ 75,000	Initiative including North American Water Office, Minnesotans for an Energy-Efficient Economy, Minnesota Project & Windustry
	Environment Minnesota	2011	$ 30,000	MN Solar Works Campaign: Ten percent solar electricity by 2030
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2003	$ 97,500	Advancing community wind projects
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2005	$ 75,000	Better energy option business plan for large-scale wind project
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2006	$ 150,000	Second phase of developing business plan for large-scale wind transmission in MN, SD, IA & WI
	Great Plains Institute for Sustainable Development	2009	$ 15,000	Green Step Cities program
	Great Plains Institute for Sustainable Development	2010	$ 15,000	Green Step Cities program
	Green Institute	2004	$ 15,000	General operating support
	Green Institute	2009	$ 25,000	Clean Energy Resource Teams (CERT) in Twin Cities
	Honor the Earth	2009	$ 15,000	Energy justice initiative
	Institute for Agriculture and Trade Policy	2003	$ 35,000	Renewable energy, working landscapes and watershed protection work
	Institute for Agriculture and Trade Policy	2007	$ 35,000	Promoting sustainable renewable energy project
	Institute for Agriculture and Trade Policy	2011	$ 20,000	Promote public health title in federal farm bill to protect human health and the environment
	Institute for Local Self-Reliance	2007	$ 20,000	New Rules Project for work on renewable energy and distributed energy development
	Institute for Local Self-Reliance	2010	$ 17,295	New Rules Project for work on renewable energy and distributed energy development
	Minnesota Council of Non-Profits	2005	$ 15,000	General operating support
	Minnesota Center for Environmental Advocacy	2007	$ 20,000	Dialogue w/Xcel Energy re: re-education of carbon dioxide emissions
	Minnesota Environmental Partnership	2007	$ 15,000	Clean Energy MN Collaborative
	Minnesota Project	2003	$ 45,000	CERTS building renewable energy project in MN
	Minnesota Project	2004	$ 35,000	Hearland food initiative
	Minnesota Public Interest Research Group	2007	$ 15,000	Renewable energy & campus sustainability campaign
	North American Water Office	2003	$ 15,000	Organizing local and community-based ownership of wind generation in SW MN
	North American Water Office	2007	$ 50,000	Community based energy
	REnew Northfield	2005	$ 18,000	General operating support
	Sierra Club Foundation	2003	$ 40,000	MN air toxics campaign
	Sierra Club Foundation	2005	$ 40,000	MN clean air campaign
	Windustry	2010	$ 30,000	Community Options for Renewable Energy (CORE)
	Total (28 grants)		**$ 1,077,795**	

FUNDER	RECIPIENT	DATE	AMOUNT	PURPOSE
Energy Foundation of San Francisco				
	Blue Green Alliance Foundation	2010	$ 250,000	To assess the job impacts of EPA regulation of greenhouse gases, and convene stakeholders to discuss potential regulations.
	Blue Green Alliance Foundation	2009	$ 80,000	To design and get support for improvements to the Manufacturing Extension Partnership program, and for media outreach on renewable energy.
	Blue Green Alliance Foundation	2008	$ 100,000	To promote policies and incentives for the creation of new jobs in renewable energy equipment manufacturing.
	Blue Green Alliance Foundation	2007	$ 185,000	To help build support for a federal RPS campaign in Midwestern states.
	Blue Green Alliance Foundation	2010	$ 135,000	To support the Clean Energy Manufacturing Center initiative.
	Blue Green Alliance Foundation	2010	$ 100,000	To support education and stakeholder engagement of the pulp and paper and biomass industries on issues related to a federal renewable electricity standard.
	Blue Green Alliance Foundation	2009	$ 100,000	To support the development of a Green Manufacturing Center, which would help manufacturers, economic development agencies, and government promote the renewable energy supply chain.
	Blue Green Alliance Foundation	2008	$ 350,000	To hire labor organizers in the Midwest to educate labor leaders on climate.
	Blue Green Alliance Foundation	2009	$ 300,000	To provide general operating support.
	Blue Green Alliance Foundation	2010	$ 190,000	To provide general operating support.
	Blue Green Alliance Foundation	2010	$ 105,000	To provide general operating support.
	Blue Green Alliance Foundation	2010	$ 150,000	To engage labor voices in heavy duty rule making efforts
	Blue Green Alliance Foundation	2010	$ 250,000	To support automotive and oil industry task forces and related outreach and analysis
	Clean Up the River Environment	2008	$ 25,000	To oppose the Big Stone II coal plant in South Dakota
	Clean Up the River Environment	2008	$ 20,000	To oppose new conventional coal-fired power plants in the Midwest
	Clean Up the River Environment	2006	$ 20,000	To resist permits for new conventional coal plants in the Midwest
	Clean Water Fund	2008	$ 15,000	To support oposition to new coal-fired power plants in South Dakota
	Clean Water Fund	2006	$ 10,000	To resist permits for new conventional coal plants in the Midwest
	Farmer's Legal Action Group	2005	$ 20,000	To develop a farmers' legal guide on wind power, and to analyze state policies encouraging community-owned wind power
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2003	$ 275,000	To support clean energy advocacy in Minnesota
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2004	$ 550,000	to promote clean energy projects in MN and the midwest
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2006	$ 275,000	To continue promoting renewable energy policies in Minnesota through the support of the Minnesota SEED Coalition
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2003	$ 260,000	To support the Community Wind project, promoting policies that encourage locally-owned wind power projects in MinnesotaCommuunity wind MN
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2004	$ 550,000	To promote renewable energy and energy efficiency policies in Minnesota.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 15,000	To inform businesses in Minnesota of the benefits of energy efficiency.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 225,000	To support a Clean Energy Program that will advance clean energy in Minnesota, regionally in the Midwest, and at the federal level
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 15,000	To conduct business outreach on federal energy efficiency policy in Minnesota and North Dakota
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$ 125,000	To advocate for a carbon cap in Minnesota
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$ 31,250	To support global warming policy development in the Midwest
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$ 93,000	To develop and advocate for cap-and-trade policy in Minnesota and the upper Midwest
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 75,000	To educate opinion leaders and policymakers in Minnesota on the elements of a carbon cap and trade system
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 100,000	To support outreach and education on climate regulation options in Minnesota.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 50,000	To work on building code adoption in Minnesota
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 250,000	To advance clean cars in Minnesota
	Great Plains Institute for Sustainable Development	2011	$ 35,000	To educate policymakers, climate advocates, and industry stakeholders about carbon capture and storage (CCS) and enhanced oil recovery (EOR) and promote sound and protective CCS-EOR policies.
	Great Plains Institute for Sustainable Development	2008	$ 80,000	To support state policy development and education on federal climate policy opportunities
	Great Plains Institute for Sustainable Development	2010	$ 200,000	To develop a pathway toward low carbon fuels for the Midwest
	Great Plains Institute for Sustainable Development	2009	$ 365,000	To advance low-carbon fuels and renewable power in the Midwest
	Great Plains Institute for Sustainable Development	2009	$ 25,000	To advance low-carbon fuels in the Midwest
	Great Plains Institute for Sustainable Development	2008	$ 189,000	To provide regional outreach and to organize farm groups in support of policies to encourage farm-based energy production
	Great Plains Institute for Sustainable Development	2008	$ 100,000	To provide support for the North Central Bioeconomy Consortium.
	Great Plains Institute for Sustainable Development	2007	$ 40,000	To develop and promote policies around advanced and cellulosic biofuels in the Midwest
	Great Plains Institute for Sustainable Development	2007	$ 100,000	To establish the North Central Bioeconomy Consortium, with Midwestern secretaries of agriculture, ag extension, and ag experiement stations
	Great Plains Institute for Sustainable Development	2006	$ 75,000	To convene stakeholders in the Upper Midwest to develop a package of policies promoting advanced biofuels
	Institute for Agriculture and Trade Policy	2009	$ 80,000	To promote low-carbon fuels in Minnesota
	Institute for Agriculture and Trade Policy	2008	$ 300,000	To promote policies for cellulosic and low-carbon biofuels in Minnesota.
	Institute for Agriculture and Trade Policy	2007	$ 100,000	To develop and implement standards for the sustainable production of biofuels feedstocks
	Institute for Agriculture and Trade Policy	2007	$ 50,000	To research and develop policy encouraging the use of advanced biofuels
	Institute for Agriculture and Trade Policy	2006	$ 100,000	To develop sustainable cropping standards for the most promising biomass crops and materials that will be the feedstocks for the emerging cellulosic biofuel sector
	International Alliance for Sustainability	2007	$ 15,000	To support Congregations Caring for Creation to develop a strategic Plan for its global warming work with faith communities in Minnesota
	Izaak Walton League of America Midwest Office	2003	$ 100,000	To study the integration of windpower with midwestern hydro resources, compare the environmental and economic impacts of transmission options, and to promote pro-wind transmission policies
	Izaak Walton League of America Midwest Office	2004	$ 150,000	To support a second year of work to promote renewable energy, energy efficiency, and clean distributed generation in Minnesota.
	Izaak Walton League of America Midwest Office	2008	$ 300,000	To promote clean energy policies in Minnesota.
	Izaak Walton League of America Midwest Office	2008	$ 55,000	To oppose new coal-fired power plants in the upper Midwest.

Izaak Walton League of America Midwest Office	2007	$ 50,000	To promote energy efficiency and renewable energy policies in Minnesota
Izaak Walton League of America Midwest Office	2007	$ 55,000	To defeat proposals to expand power generation from conventional coal-fired power plants in the Midwest
Izaak Walton League of America Midwest Office	2006	$ 31,000	To resist permits for new conventional coal plants in the Midwest
Izaak Walton League of America Midwest Office	2006	$ 300,000	To promote energy efficiency and renewable energy policies in Minnesota
Izaak Walton League of America Midwest Office	2005	$ 75,000	To support advocacy efforts to promote renewable energy, and to fight power generation derived from pulverized coal in South Dakota.
Izaak Walton League of America Midwest Office	2004	$ 330,000	To promote renewable energy, energy efficiency, and clean distributed generation in Minnesota
Izaak Walton League of America Midwest Office	2010	$ 150,000	To support work on clean energy policies in Minnesota and the upper midwest.
Izaak Walton League of America Midwest Office	2010	$ 80,000	To support energy efficiency programs and accelerate the retirement of coal-fired power plants in Minnesota
Izaak Walton League of America Midwest Office	2003	$ 600,000	To provide research and advocacy to overcome the physical, policy, and pricing barriers to transmission for wind power in the Upper Midwest
Izaak Walton League of America Midwest Office	2009	$ 65,000	To transition the Midwest away from reliance on conventional coal plants in the Upper Midwest and build support for federal energy efficiency policies
Izaak Walton League of America Midwest Office	2011	$ 50,000	To advance low carbon fuels in Minnesota and more broadly in the Midwest
Izaak Walton League of America Midwest Office	2009	$ 80,000	To promote low-carbon fuels in Minnesota
Izaak Walton League of America Midwest Office	2008	$ 160,000	To advance a low carbon fuel standard in Minnesota
Izaak Walton League of America Midwest Office	2008	$ 35,000	To study and promote Minnesota-oriented low carbon fuels standard.
Izaak Walton League of America Midwest Office	2008	$ 100,000	To advance a low carbon fuel standard in Minnesota
Minnesota Center for Enivronmental Advocacy	2006	$ 25,000	To support efforts to discourage permitting of the 600-megawatt Big Stone II pulverized coal plant.
Minnesota Center for Enivronmental Advocacy	2004	$ 10,000	To advocate that Minnesota utilities must procure new renewables generation under the Minnesota Renewable Energy Objective
Minnesota Center for Enivronmental Advocacy	2004	$ 35,000	To support legal advocacy in the implementation of the Minnesota Renewable Energy Obligation, and in transmission planning around renewable energy.
Minnesota Center for Enivronmental Advocacy	2010	$ 150,000	To accelerate the retirement of coal-fired power plants in Minnesota
Minnesota Center for Enivronmental Advocacy	2009	$ 48,000	To oppose existing coal in Minnesota
Minnesota Environmental Partnership	2009	$ 30,000	To engage the ag sector in advancing clean cars in Minnesota
Minnesota Project	2007	$ 200,000	To promote community ownership of wind generation through public policy
Minnesota Project	2006	$ 100,000	To support community wind development in state and federal policies
Minnesota Project	2005	$ 100,000	To advance community wind efforts in Minnesota, the Upper Midwest and Great Plains by expanding policy developments and advocacy efforts.
Minnesota Project	2005	$ 42,500	To support the Midwest Agriculture Energy Network
Minnesota Project	2004	$ 32,500	To support the establishment of a Midwestern network of groups promoting agricultural energy sources, like wind and bioenerg
Minnesota Project	2005	$ 45,000	To host an ag energy conference for advancing renewable energy and the use of advanced biofuels.
Minnesota Project	2007	$ 100,000	To promote sustainable cellulosic bioenergy production and ensure a rapid transition to perennial energy crop
Minnesota Project	2007	$ 75,000	To provide regional outreach and organizing of farm groups in support of policies to encourage farm-based energy production
Minnesota Project	2006	$ 75,000	To provide regional outreach and organizing of farm groups in support of policies to encourage farm-based energy production
Minnesota Project	2006	$ 25,000	To support education and outreach on clean energy opportunities in federal farm policy
Plains Justice	2009	$ 18,459	To defeat new coal-fired power plants in North Dakota, South Dakota, and Minnesota
Rural Minnesota Energy Taskforce	2003	$ 30,000	To support the work of the Rural Minnesota Energy Task Force, a collaboration of 11 county commissions in Southwest Minnesota to promote wind power
Southwest Minnesota Initiative Foundation	2003	$ 45,000	To host an innovation forum and to hire a consultant to help with renewable energy business development in Southwest Minnesota
University of Minnesota Foundation	2008	$ 40,000	To analyze the potential for a low-carbon fuels standard in Minnesota
Wind on the Wires	2006	$ 275,000	wind for midwest
Wind on the Wires	2006	$ 300,000	overcome wind barriers midwaes
Wind on the Wires	2009	$ 500,000	wind transportation midwest
Windustry	2008	$ 30,000	To support the Community Wind Energy 2008 conference in New York
Windustry	2005	$ 30,000	To convene a conference on farm-based renewable energy production in Iowa
Windustry	2005	$ 10,000	o develop a farmers' legal guide on wind power, and to analyze state policies encouraging community-owned wind power
Windustry	2010	$ 80,000	To educate the public about community owned wind power.
Windustry	2009	$ 100,000	To develop and promote public policies that advance community owned renewable energy projects.
Windustry	2003	$ 25,000	To develop support in rural communities for new wind energy projects and policies in Illinois, and to support a national
Windustry	2003	$ 25,000	To develop support in rural communities for new wind energy projects and policies in Illinois
Total (99 grants)		**$ 12,515,709**	

Garfield Foundation				
	Clean Water Fund	2006	$ 30,000	Boosted grassroots efforts to halt construction of the proposed Big Stone II coal plant in South Dakota
	Common Assets Defense Fund/Tomales Bay Institute	2008	$ 20,000	A contribution toward its 2008 Climate Program in the upper Midwest to promote the Cap and Dividend model as an equitable and sustainable method of reducing greenhouse gas emissions at the state, regional and national levels.
	Fresh Energy (formerly Minnnesotans for an Energy-Efficient Economy)	2003	$ 275,000	No details
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2004	$ 550,000	No details
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2005	$ 275,000	Assisted Fresh Energy's efforts to lead the Reducing Demand for New Dirty Energy Working Group through its strategic planning phase. Also supported
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2005	$ 260,000	Enabled Fresh Energy to assume management of the RE-AMP on-line Communications Commons and improve the existing infrastructure by adding functions to speed communication, facilitate alignment, and create a dynamic learning community.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2005	$ 550,000	Establishment of a Media Center to influence public discourse on energy by reframing it to translate existing public preference for clean, efficient energy into effective policy action.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2006	$ 15,000	Support to significantly revamp the RE-AMP on-line Communication Commons, increasing the number of "high value" postings, and making the Commons a transparent hub for tracking the progress of RE-AMP.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2006	$ 225,000	Enabled the Clean Energy Working Group to become more structured and dynamic,
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$ 15,000	Continue to manage and further develop the RE-AMP on-line communication Commons
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$ 125,000	Continue to manage the RE-AMP Media Center, designed to influence the public discourse on energy by reframing it
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$ 31,250	Supports the ongoing activities of the RE-AMP Media Center, designed to refine the RE-AMP message (keeping it as up-to-date and effective as possible), while helping RE-AMP organizations stay on message and training them to be as effective as possible in their media outreach. The Media Center cultivates and trains new media messengers, and coordinates rapid response to emerging media opportunities.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$ 93,000	Continued support to manage and further develop the RE-AMP on-line communication Commons.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$ 75,000	Support to design a round-table dialogue between environmental and social justice advocates to address the issues involved in cap & trade policy.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 100,000	For ongoing activities such as developing and refining the RE-AMP media and public outreach message.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 50,000	Funds the launch of an updated and easier to navigate Internet-based Commons
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 250,000	Supports on-going leadership role in RE-AMP and the Global Warming Strategic Action Fund
	Izaak Walton League of America Midwest Office	2003	$ 50,000	No details
	Izaak Walton League of America Midwest Office	2005	$ 50,000	Support to lead the Retirement of Dirty Energy Generation Working Group through its strategic planning phase. Also supported coordination and cross-checking among all four RE-AMP working groups.
	Minnesota Center for Enivronmental Advocacy	2007	$ 25,000	Allows the Center to demonstrate to Minnesota state regulators the financial and regulatory risks associated with constructing the Big Stone II coal plant in South Dakota. The Center will use advanced modeling software endorsed by the Minnesota Department of Commerce.
	Minnesota Project	2003	$ 50,000	No details
	Minnesota Project	2004	$ 115,000	No details
	Minnesota Project	2005	$ 50,000	Support to lead the Energy Efficiency Working Group through the strategic planning phase. Also supported coordination and cross-checking among all four RE-AMP working groups.
	Minnesota Project	2006	$ 200,000	Supported the RE-AMP Energy-Efficiency Working Group's Midwest Energy-Efficiency Initiative
	Minnesota Project	2006	$ 15,000	Supports the continued efforts of the
	Minnesota Project	2007	$ 100,000	RE-AMP Energy Efficiency Working Group while strengthening its ability to attract additional financial resources and carry out implementation phase work.
	Minnesota Project	2007	$ 15,000	Working Group's Midwest Energy-Efficiency Initiative
	Will Steger Foundation	2007	$ 2,000	No details
	Will Steger Foundation	2008	$ 2,800	No details

Total (29 grants)		$	3,614,050	

Joyce Foundation					
	Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)	2003	$	175,000	Promote changes in state energy, transportation and tax policies
	Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)	2004	$	350,000	To advance policies for renewable energy and energy efficiency in Minnesota.
	Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)	2007	$	300,000	To establish a media center to provide communications tools and services to regional and national organizations working
	Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)	2009	$	300,000	To support the work of the REAMP media center.
	Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)	2011	$	120,000	RE-AMP media center
	Great Plains Institute for Sustainable Development	2006	$	437,500	Coal gassification working group
	Great Plains Institute for Sustainable Development	2007	$	99,400	To brief Midwest lawmakers and regulators about how advanced coal technologies are currently deployed in Europe and encourage their support for similar adoption here.
	Great Plains Institute for Sustainable Development	2008	$	600,000	For ongoing work to accelerate adoption of advanced coal technologies with carbon capture and storage, building on regional agreements of Midwestern governors.
	Great Plains Institute for Sustainable Development	2010	$	411,000	For implementation of key elements of the Midwestern Governors Association's Energy Roadmap and related accords.
	Great Plains Institute for Sustainable Development	2011	$	282,184	Accelerate CCS via Enhanced Oil Recovery; test New Models for Energy Efficiency Financing; and increase uptake of energy efficiency by industry and cities
	Izaak Walton League of America Midwest Office	2004	$	300,000	To assist state regulators and electric suppliers in designing a renewable energy credit trading system for the upper Midwest and the Dakotas.
	Izaak Walton League of America Midwest Office	2006	$	300,000	To support intervention in the licensing hearings for the Big Stone II power plant in SD and MN
	Izaak Walton League of America Midwest Office	2007	$	350,000	To encourage the deployment of advanced coal generation in MN and to promote policies that encourage and enable carbon capture and storage
	Izaak Walton League of America Midwest Office	2009	$	350,000	To continue its efforts to develop policies that drive a transition away from conventional coal-fired electricity and promote low emissions alternatives
	Izaak Walton League of America Midwest Office	2011	$	172,202	To affect clean energy policy adoption in Minnesota and surrounding Upper Midwest states.
	Minnesota Center for Enivronmental Advocacy	2003	$	97,360	Transportation policy work
	Minnesota Center for Enivronmental Advocacy	2004	$	217,077	To build business support for a new funding mechanism for public transit projects in Minnesota
	Minnesota Center for Enivronmental Advocacy	2008	$	150,000	To fund a second energy attorney to the staff, provide more administrative and research support for the energy team, and provide compensation for critical expert testimony.
	Transit for Livable Communities	2003	$	75,000	Continued analysis of tansportation planning and spending in MN and to educate the media and public.
	Transit for Livable Communities	2004	$	150,000	To advocate for new public transportation policies in Minnesota to support new transit projects, such as the proposed Northstar
	Total (20 grants)		$	5,236,723	

Kendeda Sustainability Fund / Kendeda Fund					
	Minnesota Public Radio/American Public Media	2005	$	2,100,000	American Public Media sustainability initiative
	Minnesota Public Radio/American Public Media	2008	$	1,000,000	Continued Global Sustainability News Coverage and Programming
	Minnesota Public Radio/American Public Media	2009	$	1,000,000	Continued Global Sustainability News Coverage and Programming
	Minnesota Public Radio/American Public Media	2010	$	1,000,000	Continued Global Sustainability News Coverage and Programming
	Total (4 grants)		$	5,100,000	

Kresge Foundation					
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$	350,000	Support current and expanded services of the RE-AMP media center
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$	150,000	Support current and expanded services of the RE-AMP media center
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$	100,000	Expand project-planning and policy-making process for development and deployment of clean energy transmission
	Institute for Agriculture and Trade Policy	2010	$	225,000	Analysis of the food system and impact on people's health and the environment.
	Institute for Local Self-Reliance	2010	$	50,000	New Rules initiative support.
	Great Plains Institute for Sustainable Development	2010	$	150,000	Support to participate in policy, planning and development efforts for clean energy transmission
	Wind on the Wires	2010	$	350,000	Provide general operating support and efforts to move forward with energy infrastructure development
	Wind on the Wires	2009	$	100,000	General operating support and help advance efforts to educate individuals, advocacy groups and decision makers on wind
	Windustry	2010	$	75,000	Support for wind energy projects and efforts to educate landowners and residents.
	Total (9 grants)		$	1,550,000	

Leighty Foundation					
	Great Plains Institute for Sustainable Development	2007	$	10,000	Upper Midwest hydrogen initiative
	Great Plains Institute for Sustainable Development	2009	$	2,000	Earth protection
	Windustry	2009	$	2,000	Earth protection
	Total (3 grants)		$	14,000	

Rockefeller Family Fund					
	Center for Energy and Environment	2008	$	48,000	RE-AMP climate change initiatives
	Common Assets Defense Fund	2007	$	30,000	To develop a commons-based approach to climate stability.
	Conservation Minnesota	2007	$	100,000	General support.
	Conservation Minnesota	2009	$	175,000	Fair Share Fund
	Creation Care Fund	2009	$	22,400	RE-AMP climate change initiatives
	Foundation for Environmental Research	2008	$	50,000	Changing Horizons Fund
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$	20,000	Support for RE-AMP project, clean energy working group.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$	100,000	Work on energy efficiency and renewables.
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$	55,000	RE-AMP climate change initiatives
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2008	$	115,000	RE-AMP climate change initiatives
	Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$	237,500	RE-AMP climate change initiatives
	Great Plains Institute for Sustainable Development	2008	$	99,000	RE-AMP climate change initiatives
	Institute for Local Self Reliance	2007	$	45,000	RE-AMP climate change initiatives
	Izaak Walton League of America Midwest Office	2007	$	40,000	RE-AMP climate change initiatives
	Izaak Walton League of America Midwest Office	2008	$	70,000	RE-AMP climate change initiatives
	Izaak Walton League of America Midwest Office	2009	$	50,000	RE-AMP climate change initiatives
	Luthern Coalition for Public Policy in Minnesota	2009	$	149,000	RE-AMP climate change initiatives
	Minnesota Environmental Partnership	2007	$	125,000	RE-AMP climate change initiatives
	Minnesota Environmental Partnership	2009	$	160,000	RE-AMP climate change initiatives
	Minnesota Project	2007	$	5,000	Support for RE-AMP project, energy efficiency working group.
	On the Commons	2009	$	75,000	A grant to undertake analyses to examine the economic and climate benefits of a Cap & Dividend policy and to engage in
	Will Steger Foundation	2007	$	25,000	RE-AMP climate change initiatives
	Will Steger Foundation	2009	$	50,000	RE-AMP climate change initiatives
	Windustry	2007	$	35,000	Work on promoting wind energy in MN and the Midwest.
	Total (24 grants)		$	1,880,900	

The McKnight Foundaton					
	Alliance for Metropolitan Stability	2004	$	480,000	Smart Growth Organization Project
	Alliance for Metropolitan Stability	2003	$	200,000	Smart Growth Organization Project
	Alliance for Metropolitan Stability	2006	$	400,000	For general operations and to support the Equitable Development project
	Alliance for Metropolitan Stability	2009	$	300,000	For general operations and to support the Equitable Development project
	Alliance for Metropolitan Stability	2011	$	350,000	For general operations and to support the Equitable Development project
	Center for Energy and Environment	2010	$	350,000	support overall Climate Works Network

City of Minneapolis	2011	$ 75,000	to partner with the City of Minneapolis, Hennepin County, and Metro Transit to build Transit-Oriented Development capacity within existing public-private partnerships
City of Ramsey	2006	$ 50,000	To support planning and community engagement activities aimed at producing a comprehensive plan informed by smart growth principles to guide future development
Conservation Minnesota	2011	$ 75,000	to build capacity for Conservation Minnesota and other Minnesota-based environmental nonprofits to engage their constituents
Conservation Minnesota	2009	$ 100,000	to strengthen the outreach capacity of advocacy organizations
Conservation Minnesota	2004	$ 15,000	For an organization that works to connect and support Minnesota's environmental community
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2011	$ 225,000	General operating support
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2011	$ 20,000	To host and document a civic engagement forum based on The New Metropolis films
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2010	$ 25,000	Twin Cities delegations for the 2011 New Partners for Smart Growth Conference; community resource center; growth management project
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2009	$ 925,000	Project to pormote growth management and thoughtful community planning
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2007	$ 1,500,000	Project to pormote growth management and thoughtful community planning
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2007	$ 75,000	To build a community resource center that democratizes the use of public data for local planning purposes
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2006	$ 260,000	for general operating and program support
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2005	$ 25,000	to opperate and maintain open space website and newsletter
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2005	$ 60,000	To provide community planning assistance to the cities of Independence and Dayton related to The Edge project
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2003	$ 25,000	Capacity-building activities
Envision Minnesota (formerly 1,000 Friends of Minnesota)	2003	$ 10,000	Sponsor a smart growth conference
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2011	$ 50,000	To support collaboration on Minnestoa energy policy communications
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2010	$ 230,000	To support the Transportation Connections program
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2009	$ 100,000	To support research and advocacy for policies to affect transportation and transit policy
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2007	$ 280,000	To build capacity to affect trans. and transit policy
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2005	$ 150,000	To support research, constitutency building and advocacy to promote energy policies that support smart growth development
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2011	$ 50,000	to support collaboration on Minnesota energy policy communications
Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy)	2003	$ 100,000	To support policy and fiscal analysis projects related to the Smart Growth Organizing Project
Funders' Network for Smart Growth and Livable Communities	2011	$ 65,000	To support the success of the Central Corridor Light Rail project and improve transportation policy and practice in the Twin Cities and at the federal level
Funders' Network for Smart Growth and Livable Communities	2010	$ 75,000	To advance sustainable community by transforming transportation poilicy and practices in twin cities region and at federal level
Funders' Network for Smart Growth and Livable Communities	2008	$ 60,000	to align and advance philanthropic leadership on growth and development issues in the greater twin cities region
Funders' Network for Smart Growth and Livable Communities	2007	$ 75,000	to align and advance philanthropic leadership on growth and development issues in the greater twin cities region
Funders' Network for Smart Growth and Livable Communities	2004	$ 15,000	To sponsor the Twin Cities delegation to the second national summit on regional equity and smart growth
Great Plains Institute for Sustainable Development	2011	$ 70,000	To ramp up GreenStep Cities program to promote cities' adoption of sustainable community goals and standards
Green Institute	2003	$ 15,000	Rainwater infiltration (sic) rooftop garden Phillips Eco-Enterprise Center
Growth & Justice	2011	$ 25,000	To support the Smart Investments in Transportation for Minnesota project
Growth & Justice	2009	$ 50,000	To support the Smart Investments in Transportation for Minnesota project
Growth & Justice	2007	$ 165,000	Invest for Real Prosperity project and organizational assessment
ISAIAH	2003	$ 25,000	For a membership mapping and analysis project involving multiple organizations working on smart growth issues.
Living Cities, Inc.	2007	$ 1,200,000	To support a national funders' collaborative committed to improving the vitality of cities and urban neighborhoods with opportunities and implications for sustainable community development in the Twin Cities
Local Initiatives Support Corporation	2011	$ 50,000	To reduce the interest rate on loans made from partners involved in the Living Cities Local Integration Initiative to developers working to preserve and develop affordable housing units within Twin Cities transit corridors
Local Initiatives Support Corporation	2011	$ 1,800,000	to support implementation, integration, and knowledge sharing efforts to build sustainable communities throughout the Twin Cities region
Minnesota Center for Enivronmental Advocacy	2010	$ 675,000	To support public policy advocacy for transportation and transit choice
Minnesota Center for Enivronmental Advocacy	2008	$ 680,000	To reduce the impact of regional growth by promoting balanced transportation and to protect/restore Mississippi river system in MN
Minnesota Center for Enivronmental Advocacy	2007	$ 15,000	Regional public opinion poll on transportation funding
Minnesota Center for Enivronmental Advocacy	2006	$ 655,000	To reduce the impact of regional growth by promoting balanced transportation and to protect/restore Mississippi river system in MN
Minnesota Center for Enivronmental Advocacy	2004	$ 776,798	To reduce impact on regional growth, support the Embrace Open Space campaign to protect/restore Mississippi river system in MN
Minnesota Center for Enivronmental Advocacy	2004	$ 150,000	To support the Embrace Open Space campaign's communications effort
Minnesota Center for Enivronmental Advocacy	2003	$ 65,000	To support the Embrace Open Space campaign's communications effort
Minnesota Council of Non-Profits	2008	$ 25,000	General operating support
Minnesota Environmental Partnership	2003	$ 50,000	To provide communications assistance to environmental and conservation organizations
Minnesota Environmental Partnership	2008	$ 250,000	General operating support
Minnesota Environmental Partnership	2008	$ 220,000	To strengthen communications and outreach about environmental and conservation issues
Minnesota League of Conservation Voters Education Fund	2003	$ 15,000	For an organization that works to connect and support Minnesota's environmental community
Reconnecting America	2010	$ 250,000	Support for Center for Transit-Oriented Development for work in the Twin Cities region
Reconnecting America	2007	$ 525,000	Support for Center for Transit-Oriented Development for work in the Twin Cities region
Reconnecting America	2004	$ 25,000	Support for Center for Transit-Oriented Development for work in the Twin Cities region
Reconnecting America	2004	$ 600,000	Support for Center for Transit-Oriented Development for work in the Twin Cities region
Sierra Club Foundation	2010	$ 140,000	To support the Land Use and Transportation Organizing project, which educates and involves Twin Cities metro residents in local land-use planning processes
Sierra Club Foundation	2008	$ 167,929	To support the Land Use and Transportation Organizing project, which educates and involves Twin Cities metro residents in local land-use planning processes
Sierra Club Foundation	2006	$ 180,000	To support the Land Use and Transportation Organizing project, which educates and involves Twin Cities metro residents in local land-use planning processes
Smart Growth America	2010	$ 97,000	To support comprehensive transportation reform at the federal level through investment of an considering its impact on the Twin Cities region, and for the next steps in implementing the Regional Sustainability Indicator work (not re-amp)
Smart Growth America	2008	$ 75,000	To support compreto support comprehensive transportation reform at the federal level to impact the Twin Cities region
Transit for Livable Communities	2009	$ 250,000	For an organization that encourages improvement in transit and other transportation systems in the Twin Cities
Transit for Livable Communities	2007	$ 275,000	For an organization that encourages improvement in transit and other transportation systems in the Twin Cities
Transit for Livable Communities	2005	$ 235,000	For an organization that encourages improvement in transit and other transportation systems in the Twin Cities
Transit for Livable Communities	2011	$ 250,000	for general operating support
Transit for Livable Communities	2003	$ 150,000	For an organization that encourages improvement in transit and other transportation systems in the Twin Cities
Total (69 grants)		**$ 16,991,727**	
TOTAL (285 grants)		**$ 47,980,904**	

REPORT OF THE WISCONSIN RELIABILITY ASSESSMENT ORGANIZATION ON TRANSMISSION SYSTEM REINFORCEMENT IN WISCONSIN

June 14, 1999

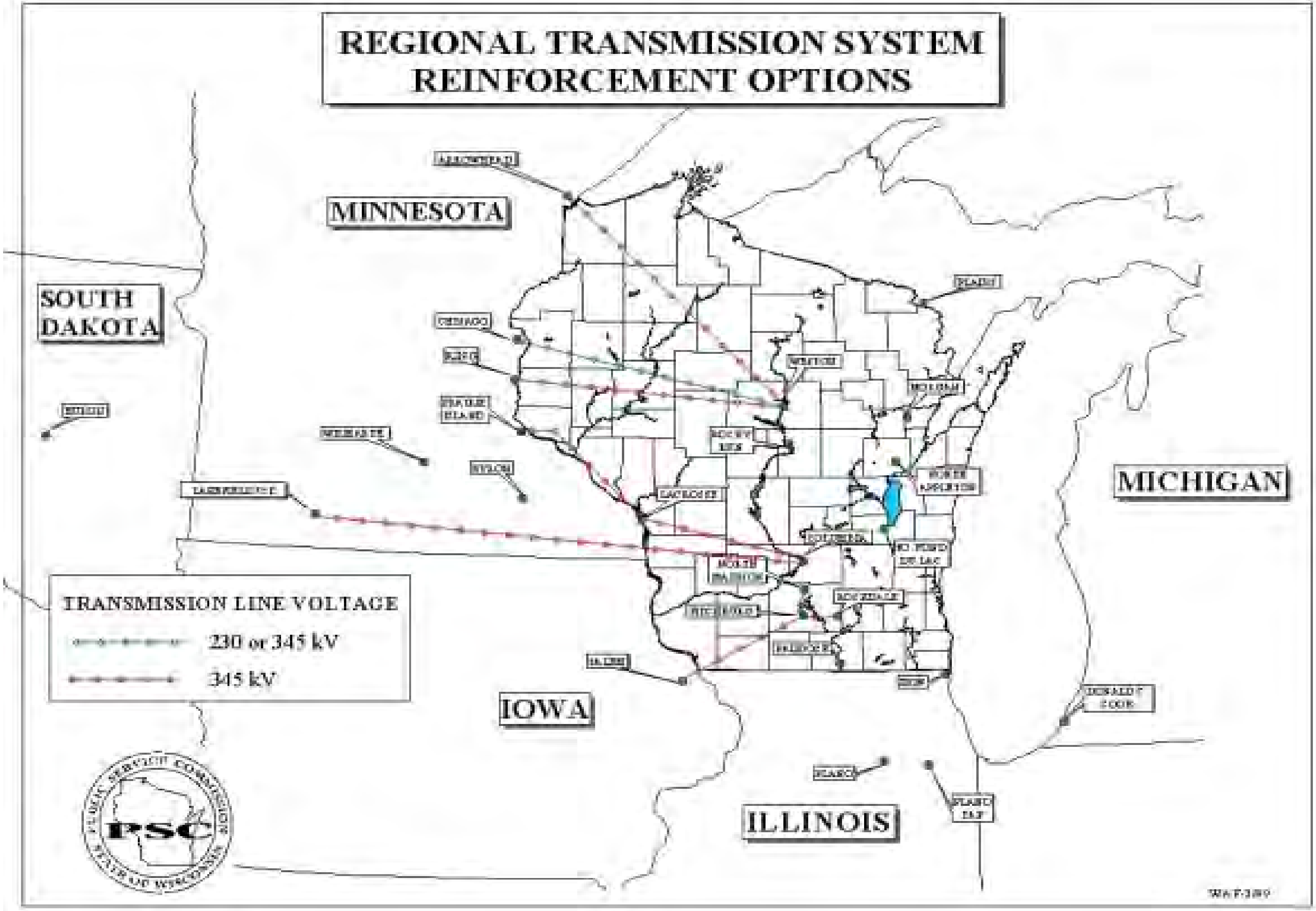

REGIONAL TRANSMISSION SYSTEM
REINFORCEMENT OPTIONS
MINNESOTA
SOUTH
DAKOTA
MICHIGAN
IOWA
ILLINOIS
TRANSMISSION LINE VOLTAGE
230 or 345 kV
345 kV
PSC

Exhibit N

Comment to DOE – Recommendation of NEITC Corridor

Wind on the Wires, AWEA, et al.

March 6, 2006

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE–20,
Attention: EPAct 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H–050
1000 Independence Avenue, SW.
Washington, DC 20585

Re: Comments of the American Wind Energy Association, Wind on the Wires, Interwest Energy Alliance, The Wind Coalition, the Center for Energy Efficiency and Renewable Technologies, and The Renewable Northwest Project on the Department of Energy's "Considerations for transmission congestion study and designation of National Interest Electric Transmission Corridors"

The American Wind Energy Association (AWEA), Wind on the Wires (WOW), Interwest Energy Alliance, The Wind Coalition, the Center for Energy Efficiency and Renewable Technologies, and The Renewable Northwest Project appreciate this opportunity to respond to the Department of Energy's Notice of Inquiry[1] concerning its plans for a congestion study and possible designation of National Interest Electric Transmission Corridors (NIETCs). We believe that with high and volatile fuel prices, climate change and air quality concerns, water conservation needs, and threats to security from importing fuel, our Nation's vast resources of wind in the middle of the country can and should be tapped. As President Bush stated recently on his Advanced Energy Initiative tour, "areas with good wind resources have the potential to supply up to 20 percent of the electricity consumption of the United States." In this comment we address the proposed criteria for corridors in response to questions in the Department's inquiry, describe studies to add to the list of relevant studies in Appendix A of the notice, and identify specific corridors from the set of relevant studies that we believe will qualify as NIETCs.

I. WHO WE ARE

AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA's 780 members include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, renewable energy supporters, utilities, marketers, customers and their advocates. Many of AWEA's members are interested in developing wind projects in wind-rich areas but are currently prohibited from doing so because of a lack of transmission.

Wind on the Wires works on solving the technical (transmission) and regulatory barriers to interconnecting and delivering new wind power to market in the Upper Midwest. WOW

[1] Department of Energy, Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, Federal Register notice Vol. 71, No. 22, February 2, 2006, page 5660.

members include nationally prominent wind developers and wind turbine manufacturers, AWEA, non-profit sustainable energy advocacy organizations, and other stakeholders. WOW has been actively involved in transmission planning with utilities and the Midwest Independent System Operator since 2001. WOW members have a substantial interest in the resolution and advancement of the issues in DOE's Notice of Inquiry.

The Renewable Northwest Project is a non-profit renewable energy advocacy organization whose members include environmental and consumer groups, and energy companies. RNP works in Oregon, Washington, Idaho and Montana to increase the development of clean renewable energy resources.

West Wind Wires is a wind industry advocacy program under the auspices of Western Resource Advocates that represents wind in transmission planning and operational forums throughout the Western Electricity Coordinating Council region.

The Wind Coalition is a non-profit corporation advocating for the expansion of wind energy use in Texas and the Southwest Power Pool. The Wind Coalition's members are: AES; Babcock & Brown, LP; Gamesa Energia Southwest; GE Energy, LLC; Horizon Wind Energy; PPM Energy; Renewable Energy Systems (USA); Siemens; Superior Renewable Energy; Trinity Structural Towers, Inc.; Vestas-Americas, Inc.; Environmental Defense; Public Citizen; Texas Renewable Energy Industries Association; and AWEA.

The Interwest Energy Alliance is a trade association that brings the nation's wind energy industry together with the West's advocacy community. The Alliance's members support state-level public policies that harness the West's abundant renewable energy and energy efficiency resources in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

The Center for Energy Efficiency and Renewable Technologies is a not for profit public-benefit organization founded in 1990 in Sacramento. CEERT's board and host of affiliates is comprised of concerned scientists, environmentalists, public interest advocates and individuals involved in developing innovative energy technologies that share a vision to benefit the environment with sustainable solutions to California's growing appetite for energy.

II. A "CORRIDOR" SHOULD BE BROADLY DEFINED

The first question raised in the notice is essentially "what is a corridor?" AWEA agrees with the Department that corridors should be identified as "generalized electricity paths between two (or more) locations, as opposed to specific routes for transmission facilities."[2] We believe this generalized approach is consistent with standard transmission planning practice and with the intent of the law. The approach avoids the obviously unworkable approach of finding that a specific route is of national interest while other routes connecting two areas are not. Congress and the Administration presumably chose the term "corridor" over other terms like "route" for a reason and we believe it was with this consideration in mind.

[2] DOE Federal Register notice, page 5661.

Specifically we believe that a corridor should be defined as follows: "a corridor connects two geographic areas, defined as utility service territories, control areas, resource production areas, or points on the electric transmission system which are separated by transmission limitations."

III. CRITERIA FOR CORRIDOR IDENTIFICATION

AWEA generally supports the proposed criteria but respectfully submits that they do not sufficiently address the criteria required by EPAct §1221. We suggest specific modifications below. We do not advocate wind-specific provisions but rather generally applicable provisions that we believe are required by the law.

Draft Criterion 1: Action is needed to maintain high reliability.

AWEA supports this criterion and notes that there are reliability benefits of accessing wind generators. The smaller unit sizes of individual wind turbines make them more reliable than a single large generator. Many types of failures can and do take large generators off line. Aggregations of wind machines do not suffer from a similar vulnerability. Reliability is composed of security and adequacy. Transmission corridors that access generation fueled by domestic resources, especially domestic renewable resources, should be recognized as improving both security and adequacy and enhancing the reliability of the overall power system. We suggest adding the following provision: "an area that would lead to supply from greater numbers of geographically dispersed small generating units that are less vulnerable to large sudden outages due to plant failure, natural disasters or malicious acts than large generating stations."

Draft Criterion 2: Action is needed to achieve economic benefits for consumers.

AWEA supports this criterion as far as it goes. However it does not address the statement in EPAct § (B)(i) that "economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy." Economic growth can be enhanced by the rural economic development associated with wind farms in the many regions of the country. We suggest the following clarification: "an area that promotes rural economic development through generation development in rural areas such as on farms and ranches." This provision of the act should be included in Criterion 2 or as an additional criterion.

Draft Criterion 3: Actions are needed to ease electricity supply limitations in end markets served by a corridor, and diversify sources.

We suggest that this criterion be clarified to specifically state that supply diversification both at the local level (power used to serve load in a particular area) and national level are covered by the criterion. In other words, a corridor to an area that would increase national consumption of wind even if the particular state or region already has significant wind usage, would qualify given the low percentage of wind currently in the national electricity portfolio. We note that the criterion as written does not address the criterion in EPAct (B)(ii), "a diversification of supply is warranted." Supply diversification should be clarified in this criterion or added as another criterion.

Draft Criterion 4: Targeted actions in the area would enhance the energy independence of the United States.

AWEA supports this provision and finds it to be consistent with EPAct criterion (C), "the energy independence of the United States would be served by the designation." We agree with the specific metrics of fuel diversity, improved domestic fuel independence, and reduced dependence on energy imports.

Draft Criterion 5: Targeted actions in the area would further national energy policy.

We support this criterion and find it to be consistent with EPAct criterion (D) "the designation would be in the interest of national energy policy." However we note that the notice provides no clarifying language or metrics for this criterion unlike all of the other criteria. The Department should not and cannot shy away from implementing this provision of the law.

Metrics for this criterion should be based on the Advanced Energy Initiative in the President's State of the Union speech,[3] the Western Governors Association's (WGA) unanimous clean energy resolution,[4] the Midwestern Governors' Association (MGA) Regional Electric Transmission Protocol[5], and any other recent multi-state or national law or policy statement on energy policy. Together the State of the Union speech and the governors' associations resolutions provide clear criteria that are consistent with initiatives in states across the country and with initiatives in Congress.

The President's Advanced Energy Initiative includes the following: "replacing more than 75 percent of our oil imports from the Middle East by 2025," reducing demand for natural gas, diversifying energy sources, developing "cleaner," "cheaper," and "more reliable alternative energy sources."[6]

The WGA resolution states "To ensure that newer, clean energy sources play an important role in meeting this goal [of a clean, secure energy future], this resolution is specifically concerned with identifying ways to increase the contribution of renewable energy, energy efficiency, and clean energy technologies within the context of the overall energy needs of the West." It further states "the Western Governors will examine the feasibility of and actions that would be needed to achieve a goal to develop 30,000 MW of clean energy in the West by 2015 from resources such as energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies." The resolution identifies wind in particular: "Western Governors also believe there is long term wind energy potential in the western plains and mountain states but that a more aggressive effort to develop this energy resource is needed. Western Governors believe that a comprehensive study of the development and transmission of the West's wind energy resources is necessary. This study should build on the numerous subregional plans

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[3] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html
[4] http://www.westgov.org/wga/policy/04/clean-energy.pdf
[5] http://www.midwestgovernors.org/issues/Protocol.pdf
[6] http://www.whitehouse.gov/news/releases/2006/01/20060131-6.html

underway, such as the Rocky Mountain Area Transmission Study, but should emphasize policies that can facilitate wind development throughout the region."[7]

The Midwestern Governors' Association Regional Electric Transmission Protocol recognizes that additional investment in transmission is needed. The Protocol also states that the Midwest could become a substantial provider of wind-generated electricity, but the power needs to be moved to where it is needed. The Protocol also acknowledges that the benefits of additional infrastructure include more reliability, access to low-cost generation, diversity of supply, and economic development opportunities.

To derive metrics from the policy statements of the President, the MGA and the WGA, AWEA proposes that the following features from each be used. From the President's initiative metrics should include increasing supplies of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio. The WGA initiative includes these same metrics plus the development of "energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies." The MGA statement includes "low cost," "more diverse supplies leading to lower cost," "environmental benefits from improved access to renewable generation," "economic and job growth," and an "expanded tax base." Together, AWEA suggests that DOE adopt the following metrics for Criterion 5: "an area that allows for the development of clean, low cost, reliable, and domestic energy that diversifies the nation's energy portfolio including a demonstration that a corridor will increase the use of some or all of the following: energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies."

Draft Criterion 6: Targeted actions in the area are needed to enhance the reliability of electricity supplies to critical loads and facilities and reduce vulnerability of such critical loads or the electricity infrastructure to natural disasters or malicious acts.

AWEA suggests the following metric for this criterion as well as Criterion 1: "an area that would lead to supply from greater numbers of geographically dispersed small generating facilities that are less vulnerable to large sudden outages due to plant failure natural disasters or malicious acts than large generating stations."

Draft Criterion 7: The area's projected need (or needs) is not unduly contingent on uncertainties associated with analytic assumptions, e.g., assumptions about future prices for generation fuels, demand growth in load centers, the location of new generation facilities, or the cost of new generation technologies.

AWEA notes that this criterion is not identified in EPAct. The demonstration of whether corridors meet the other criteria should consider the issue identified here so this proposed criterion is at best redundant. Moreover, the undefined term "unduly contingent" provides little or no real guidance in selecting corridors.

Draft Criterion 8: The alternative means of mitigating the need in question have been addressed sufficiently.

[7] http://www.westgov.org/wga/policy/04/clean-energy.pdf

AWEA supports this criterion but emphasizes that the *option* of transmission should be preserved through corridor status while other options are considered. Therefore we suggest a criterion that more closely tracks the language of EPAct.§ 1221: "Any reasonable alternatives presented by interested parties have been addressed sufficiently to warrant preserving the transmission option, recognizing that alternatives to transmission facilities must be considered for approval of any specific project."

IV. CONGESTION MODELING MUST ADDRESS NEW RESOURCES

The notice indicates that the initial electric transmission congestion study required by Federal Power Act subsection 216(a)(1) will be based on existing studies and congestion modeling of the Eastern and Western Interconnections. AWEA believes the study required by law must include the lack of transmission between supply resources like wind and electric load. Typical power system load flow and economic dispatch models take existing generators and load as given and therefore do not address this issue unless it is explicitly added. The Department's modeling should include not only existing generators but new supply sources like pockets of wind.

V. RELEVANT TRANSMISSION PLANNING STUDIES

The Department's notice indicates that it will publish its congestion study by August 8, 2006 and at that time it will invite interested parties to provide comments and recommendations concerning its needs assessments and potential corridors to address identified needs. Appendix A to the notice includes the list of transmission plans and studies the Department currently has under review for its congestion study. AWEA respectfully proposes the following five additional studies for use in the Department's congestion study.

These five additional studies are:

- Southwest Power Pool's (SPP) *Kansas/Panhandle Sub-Regional Transmission Study,* http://sppoasis.spp.org/documents/swpp/transmission/studies.cfm, January 26, 2006;
- *Report of the BPA Infrastructure Technical Review Committee* 2001 – 2004, http://www.transmission.bpa.gov/planproj/ITRC.cfm?page=ITRC;
- *Report of the Tehachapi Collaborative Study Group*, March 16, 2005, www.cpuc.ca.gov/Published/Graphics/48819.pdf;
- the *Report of the Imperial Valley Study Group*, September 30, 2005, www.energy.ca.gov/ivsg/; and
- Southwestern Area Transmission group planning for southeastern Colorado, http://www.azpower.org/swat/meetings/pdf/aug2005/maps.ppt.

The existing transmission studies, both those noticed by the Department and those studies suggested above, show Draft Criteria met with transmission expansions that serve large additions of wind. Below is a description of the studies that have specifically examined the potential to bring benefits to consumers through large amounts of wind development, or identified wind-rich regions and begun the planning for the development of the wind resource.

Southern Plains

The Southwest Power Pool *Kansas/Panhandle Sub-Regional Transmission Study*, also known as the “X-Plan” because of the shape of the new lines crossing from the Nebraska border through western Kansas and into Oklahoma and the Texas Panhandle, is an important study for the Department to include because it would diversify electricity supply by accessing an extraordinarily wind-rich region. This study was driven by requests from the developers of 2,500 MW of new wind generation currently seeking interconnection to transmission. SPP prepared this study during 2004 and revised it in 2005, showing $80 million of production cost savings annually in the Southwest Power Pool, and annual total fixed charges costs of $74 million.[8] The plan uses new 345 kV line segments: Spearville-Mooreland-Potter-Tolk-Tuco, Spearville-Knoll-Pauline, and connections from Mooreland to the Northwest substation and to Wichita. These segments would allow new wind generation from western Kansas, southwestern Nebraska, western Oklahoma and the Texas panhandle to supply Kansas, Missouri, Arkansas and eastern Oklahoma immediately, and, with added transmission, Louisiana and Mississippi.

Desert Southwest

Several studies of proposed new transmission in Arizona, southern Nevada and Southern California detail congestion reduction and renewable energy development opportunities associated with the proposed facilities. These include the *Report of the Imperial Valley Study Group (*for export of 2,200 MW of renewable resources from California’s Imperial Valley); CAISO studies of the Palo Verde—Devers #2 project (to bring Southwestern resources to Southern California); the Report of the Phase III Study of the Central Arizona Transmission System; and the San Diego Gas & Electric Transmission Comparison Study (to provide a new 500 kV connection from the Southwest to San Diego County and Southern California). This collection of studies by regional utility companies, completed using WECC protocols, address reliability, congestion relief and new conventional and renewable generation supply for the region.

Central California

The *Report of the Tehachapi Collaborative Study Group* is a result of work directed under a California Public Utility Commission (“CPUC”) order.[9] The report details a plan to connect 4,500 MW of wind generation in the Tehachapi region to the state 500 kV grid. The study was led by a stakeholder collaborative that included the CPUC, the California ISO, the California Energy Commission, Southern California Edison, Pacific Gas & Electric, wind developers, and the Center for Energy Efficiency and Renewable Technologies. The Tehachapi conceptual development plan allows wind generation potential in the Tehachapi region to meet state renewable resource goals. Lack of transmission capacity has prevented the development of renewable generation supply in this region to serve the state’s well-known need for energy.

Pacific Northwest

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[8] Costs include underlying lower-voltage upgrades, and 15% cost of capital. Fuel cost assumed in 2005 study was $5/ MMBtu natural gas at the burner. *Addendum to the Kansas/Panhandle Sub-Regional Transmission Study* November 4, 2005. Higher natural gas prices would increase the plan’s net benefits.

[9] CPUC Decision 04-06-010 identified 4,060 MW of wind resource in Tehachapi in proceedings related to the implementation of the Renewable Portfolio Standard required by California law.

The Pacific Northwest has several wind-rich areas. Transmission planning in the region has focused on moving power from east of the Cascades to the coast, and from Montana to the Northwest more generally. Transmission planning to move wind power to load centers on the coast has emphasized the shorter distance transmission from the Columbia Gorge region than from Montana. These transmission reports are not included in the Department notice. The 2001 *Report of the BPA Infrastructure Technical Review Committee*, written by representatives of investor-owned utilities and publicly-owned utilities, highlight regional transmission needs. Annual updates of this inventory of unsolved congestion can be found at the BPA website http://www.transmission.bpa.gov/planproj/ITRC.cfm?page=ITRC.

There are three congestion bottlenecks identified in these reports that are most relevant to move wind resources from east of the Cascades to the load centers of Western Oregon and Washington: 1) McNary-John Day; 2) Paul-Allston and Allston-Keeler path; and 3) the Cross-Cascades North and South paths.

The Department notice also includes the *Montana-Pacific Upgrade Study*. This recent study by the Northwest Power Pool examined the addition of 750 MW of generation in eastern Montana, or the alternative of wind development closer to load, in western Montana near Great Falls, to serve the Puget Sound and Portland areas. The transmission options to incorporate significant new generation in Montana include one or more 500 kV circuits.

Intermountain West

In September 2003, Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt created the Rocky Mountain Area Transmission Study (RMATS) as a multi-state effort to reduce congestion and increase transmission. This work recommended two priority transmission upgrade projects in the region: the Bridger Expansion Project, and the Tot 3 Upgrade Project. RMATS also explored transmission export options. The Bridger Expansion Project adds transmission from the Jim Bridger switchyard/coal plant in southwest Wyoming East to the wind resources in central Wyoming; southwest to Salt Lake City; and West to southern Idaho. Initially, these additions would support 1,375 MW of new wind generation in southwest/south central Wyoming. Larger additions for export to Nevada and the West Coast are also described. The Tot 3 Upgrade Project would add new 345 kV facilities to export supply resources from eastern Wyoming to the Colorado Front Range load center, including export of 1,200 MW of wind generation from excellent wind resources in eastern Wyoming to Denver. The RMATS study also outlined alternatives for exporting as much as 10,000 MW of Rocky Mountain generating resources to the Pacific Northwest, Nevada and California.

Significant additional wind development in southeastern Colorado for Denver and for export via the Bridger Expansion Project will rely on transmission from the southeastern part of the state. This added transmission has been discussed in the Southwest Area Transmission regional planning effort. The reports in this effort have not been noticed by the Department. See the maps for southeastern Colorado at the website:
http://www.azpower.org/swat/meetings/pdf/aug2005/maps.ppt.

Midwest

The Midwest ISO prepared a 2003 Transmission Expansion Plan (MTEP) and the MTEP 2005 with the knowledge that this ISO serves a region with over 700,000 MW of "proven reserves" of wind power in its nine state region.[10] MTEP 2003 and 2005 are listed in Appendix A of the Department's notice. The economic analysis in the MTPEP 2003 study found transmission investments could reduce annual energy costs between $304 million and $1.6 billion when coupled with high amounts of wind, depending on natural gas price projections. 2003 MTEP includes an Exploratory Plan for Iowa and southern Minnesota for transmitting wind energy from this area (including the eastern edge of the Dakotas) to Minneapolis- St. Paul. When the study was performed, a gas price of $3.24-$3.85/mmBtu Natural Gas was the base case assumption, resulting in an annual benefit of $304 Million.[11] In MTEP 2005, the Exploratory Plans are refined, with 3,500 MW of wind generation for Iowa and Southern Minnesota, as well a Northwest Exploratory Plan for the Eastern Dakotas and Western Minnesota providing 1,500 MW of new wind generation.

VII. PROPOSED CORRIDORS

Using the information and analyses from the studies the Department has noticed and the additional studies suggested in these comments, we believe the Department will find that the corridors identified below satisfy the criteria for National Interest Electric Transmission Corridors. We are not requesting early designation per the opportunity provided in the Department's notice; rather we provide these as preliminary suggestions on corridors that we believe should be considered in the Department's study.

1. Northern New Mexico to San Diego as a group identified in the *Report of the Imperial Valley Study Group*, Documents on the Palo Verde—Devers #2 project, and the *Report of the Phase III Study of the Central Arizona Transmission System*;
2. Eastern Oregon/ Washington to Portland/Seattle as identified in the *Report of the BPA Infrastructure Technical Review Committee*;
3. Tehachapi to Vincent Substation, identified in *Report of the Tehachapi Collaborative Study Group*;
4. Southern Wyoming to Denver, as identified in RMATS Recommendation 1;
5. Southern Wyoming to Las Vegas, as identified in RMATS Recommendation 2;
6. Eastern Colorado to Denver, as identified in RMATS Recommendation 2;
7. Western Kansas and Oklahoma to Kansas City, identified in SPP's *Kansas/Panhandle Sub-Regional Transmission Study*;
8. Eastern North Dakota to Minneapolis, identified in Midwest ISO's *MTEP 03*; and
9. South Dakota to Minneapolis, identified in Midwest ISO's *MTEP 03*.

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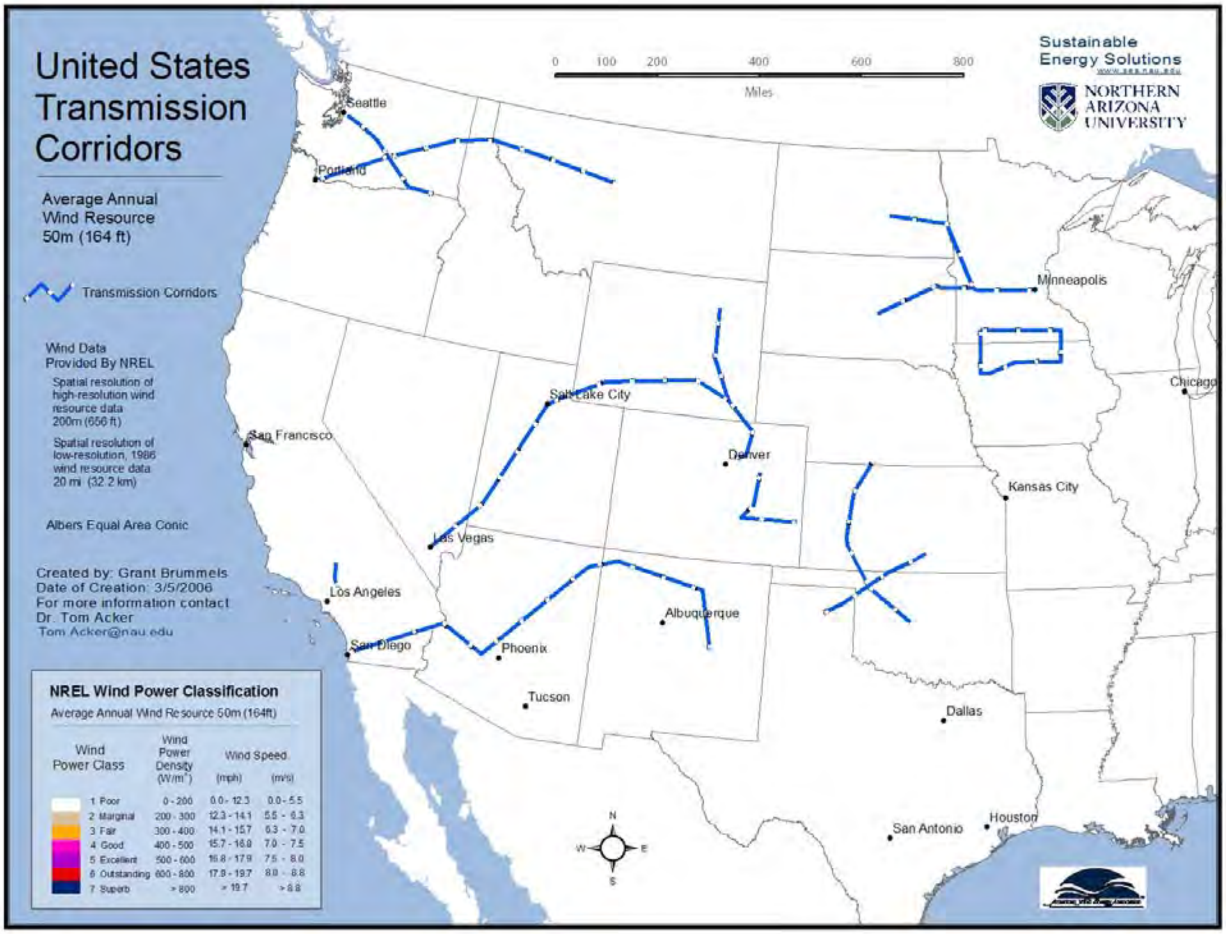
[10] See *An Assessment of Windy Land Area and Wind Energy Potential, Pacific Northwest Laboratory*, 1991.
[11] Greater savings to consumers are shown for higher gas prices.



United States Transmission Corridors
Average Annual Wind Resource 50m (164 ft)
Transmission Corridors
Wind Data Provided By NREL
Spatial resolution of high-resolution wind resource data 200m (656 ft)
Spatial resolution of low-resolution, 1986 wind resource data 20 mi (32.2 km)
Albers Equal Area Conic
Created by: Grant Brummels
Date of Creation: 3/5/2006
For more information contact
Dr. Tom Acker
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NREL Wind Power Classification
Average Annual Wind Resource 50m (164ft)
Wind Power Class
Wind Power Density (W/m²)
Wind Speed (mph) (m/s)
1 Poor 0 - 200 0.0 - 12.3 0.0 - 5.5
2 Marginal 200 - 300 12.3 - 14.1 5.5 - 6.3
3 Fair 300 - 400 14.1 - 15.7 6.3 - 7.0
4 Good 400 - 500 15.7 - 16.8 7.0 - 7.5
5 Excellent 500 - 600 16.8 - 17.9 7.5 - 8.0
6 Outstanding 600 - 800 17.9 - 19.7 8.0 - 8.8
7 Superb > 800 > 19.7 > 8.8
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Seattle
Portland
San Francisco
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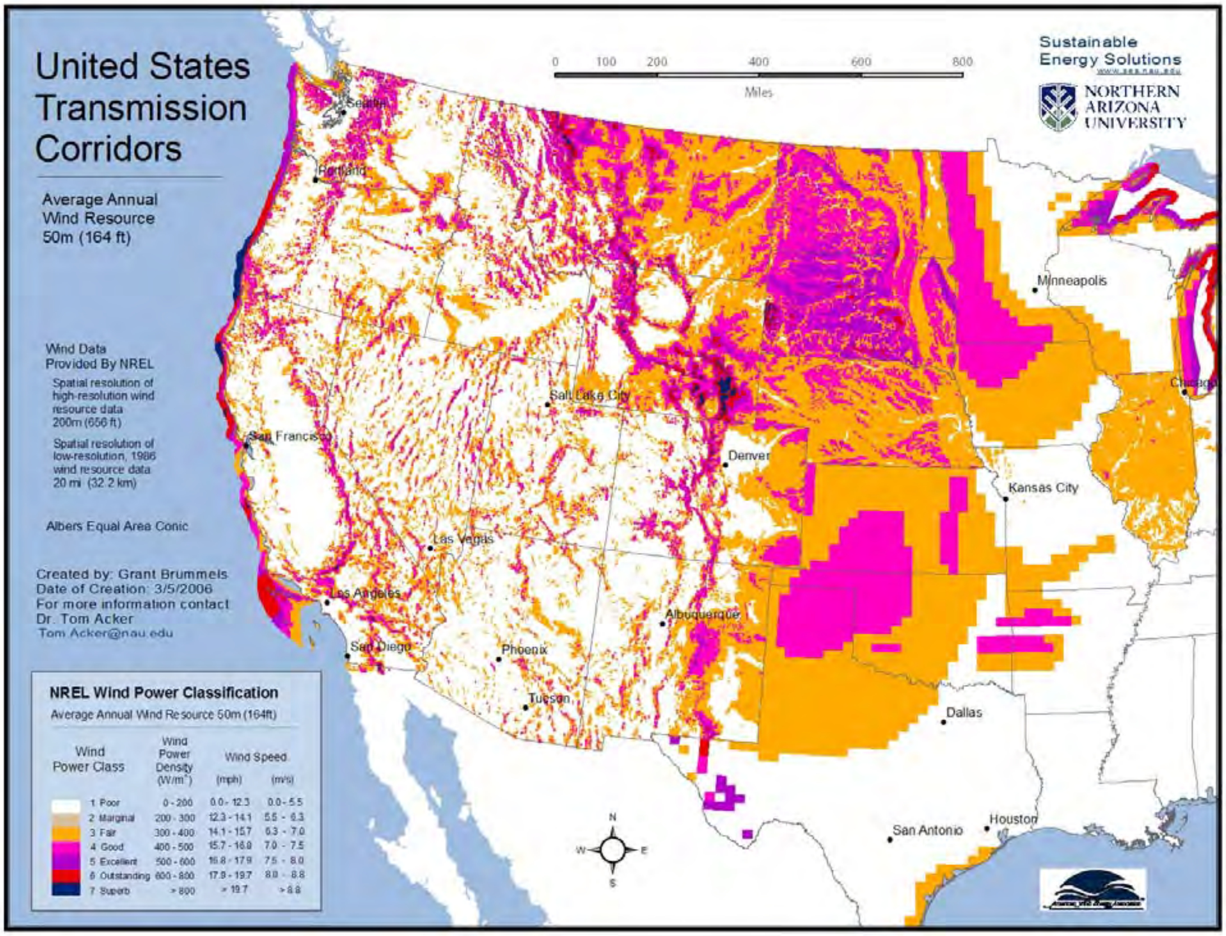

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