OMS

Organization of MISO States

ORGANIZATION OF MISO STATES, INC.
Board of Directors Meeting
Conference Call
June 14, 2007

Approved July 12, 2007

The following board members or their proxies participated in the meeting:

John Norris, Iowa
Dan Ebert, Wisconsin
Greg Jergeson, Montana
Robert Lieberman, Illinois
Greg Server, Indiana
Jeff Johnson, proxy for Mark David Goss, Kentucky
Monica Martinez, Michigan
Burl Haar, proxy for Tom Pugh, Minnesota
Steve Gaw, Missouri
Tim Texel, proxy for Eugene Bade, Nebraska
Susan Wefald, North Dakota
Kim Wissman, proxy for Valerie Lemmie, Ohio
Kim Hafner, proxy for Kim Pizzingrilli, Pennsylvania
Greg Rislov, proxy for Gary Hanson, South Dakota

<u>Absent</u>
Manitoba

<u>Agency members participating</u>
Randy Rismiller - Illinois
Cathy Brewster, Bob Pauley – Indiana
Rick Bertelson, Jorge Valladares - Kentucky
Angie Butcher – Michigan
Mike Proctor - Missouri
Bryan Baldwin - Montana
Jerry Lein – North Dakota
Graham Edwards, Mike Holstein, Dave Hadley – Midwest ISO

Also Bill Smith - OMS Staff

The directors and proxies listed above established the necessary quorum for the meeting of at least eight directors being present.

Monica Martinez was introduced as the new Director from the State of Michigan, replacing Laura Chappelle who left office June 7, 2007

Approval of Minutes of the May 10th Board Meeting
Susan Wefald moved for approval of the May 10, 2007 OMS Board of Directors Meeting minutes as distributed to board members. Dan Ebert seconded the motion. The minutes were approved by a unanimous voice vote of the directors.

Review of the Executive Committee on May 24
Bill Smith highlighted the following items from the May 24th Executive Committee meeting.

1. **ASM.** The location of the ASM meetings. Midwest ISO staff spoke and said they were willing to schedule state specific meetings in addition to the three regional workshops already scheduled.
2. **RTO 101.**
3. **RSG.**

Treasurer's Report
Chairman Jergeson presented the Treasurer's Report. The Wells Fargo Savings Account May 1st balance was $57,182.72, the May 31st balance was $57,335.00. The Chase One Checking Account May 1st balance was $46,540.90 and the May 31st balance was $45,905.00. There were deposits of $40,109.00 and disbursements of $40,749.00 during May.

Greg Jergeson moved to accept the Treasurer's report as presented. The motion was seconded. A voice vote of the directors unanimously accepted the report.

President Norris asked about the audit report. Chairman Jergeson stated he wasn't sure if they needed a motion to accept the audit. Commissioner Wefald suggested the audit approval be handled by the Executive Committee.

MISO Report – KEMA Benefit Study – Graham Edwards & Midwest ISO Staff
Graham Edwards introduced Mike Holstein who gave an overview of the KEMA cost/benefit study.

- Graham Edwards asked for a technical review team from OMS to give MISO input on the study.
- Dan Ebert suggested the ICF group take on that responsibility.
- It was agreed that names of the ICF study group members would be given to Dave Hadley for coordination with MISO.

Executive Director's Administrative Update – Bill Smith
The monthly report for May is not yet completed, but will be out in a day or two. The three ASM regional workshops are set up. The RSG briefing was on Tuesday and Bill Bokram's notes were sent out. Susan Wefald asked about the location of the ASM workshops and some discussion ensued.

Business Item
1. MISO Advisory Committee Issues – John Norris
John Norris stated the main topic for the A/C meeting would be the State of the Market Report and the only voting item as the Governance Guide.

- Bill Smith summarized the RSG issues to be covered at the A/C meeting.
- It was decided that the OMS A/C member would present the position that OMS is very concerned about the RSG issues and intends to assign it to the Market Work Group for study.
- Randel Pilo asked for instruction on what to do if it was pushed to a vote. The Board decided that the OMS representatives would vote to delay voting.

2. National Interest Electric Transmission Corridors (NIETC)– Jerry Lein

Jerry Lein made a presentation on the TP&SWG's comments on the DOE's draft proposed corridors.

- Susan Wefald moved to approve the comments of the OMS on the NIETC designation. Monica Martinez seconded.
- Susan Wefald then requested the inclusion of new footnote on page 2 to express North Dakota and South Dakota's position.
- Steve Gaw asked about the single corridor issue in the Mid-Atlantic. The Board discussed the issue.
- Ohio stated they would abstain from voting because they felt the issue best fit under the Ohio Siting Board, which would be commenting on the DOE's draft separately.

A roll call vote was taken. The comments passed 10-0 with 4 abstentions and 1 not present. The states voting yes to approve the comments were: Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota and Wisconsin. The states abstaining were: Illinois, Nebraska, Ohio and Pennsylvania. Manitoba was not present.

Position changes can be made through July 5.

3. Report of ICF Study Group – Steve Gaw

- Steve reported that the group had completed its technical review and will be presenting the Board a final report in another week.
- The basic work of the study group is completed other than the report to the Board.

4. Subcontract to Provide Funding for MWDRI

Bill Smith introduced the OMS procedure for contracts and outlined the specific subcontract between Lawrence Berkley Labs and OMS.

- Robert Lieberman moved to recommend support for the contract to the Executive Committee. Susan Wefald seconded the motion.
- Ohio recommended that in the future OMS put out bids to make contracting an open process. John Norris explained that in this case, OMS was actually the bidder and discussion continued.
- A conversation with the DOE was requested for the next Board meeting.

A voice vote was taken on the motion to recommend support for the contract to the Executive Committee. The voice vote was unanimous.

Rich Sedano made a presentation on MWDRI to the Board.

- Rich Sedano requested the Board members facilitate the member states' completion of the MWDRI survey that was about to be distributed to the commissions.
- The survey was explained and questions were answered.

5. Amendment of OMS Bylaws

Bill Smith explained the bylaw change that the Executive Committee proposed.

By letter of May 18, 2007, the Nebraska Power Review Board outlined a change in Lincoln Electric System's membership status in the Midwest ISO. That change could disqualify the Power Review Board from membership in the OMS. The May 18 letter proposed a bylaw amendment that would enable the Power Review Board to continue its OMS membership. At the Executive Committee meeting on May 24, the proposed language was discussed and modified to address the Power Review Board's situation more precisely.

The following amendment to Article II of the OMS bylaws is proposed:

1. MEMBERSHIP. Membership shall be open to all state and provincial regulatory authorities that:

(a) regulate the retail electricity or distribution rates of transmission owning members or transmission-dependent utility members of the Midwest Independent System Operator (MISO), or

(b) are the primary regulatory authority responsible for siting electric transmission facilities in states or provinces where there are transmission-dependent load-serving utility members of the MISO or transmission-owning members of the MISO or independent transmission~~s~~ companies that own or operate transmission facilities associated with the MISO.

- Greg Jergeson moved to adopt the amendment to the OMS Bylaws. The motion was seconded.

A roll call vote was taken. The amendment passed 11-0 with 2 abstentions and 2 not present. The states voting yes to approve the comments were: Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, Ohio, South Dakota and Wisconsin. The state abstaining were: Nebraska and Pennsylvania. Illinois and Manitoba were not present.

6. Comments of "Free-Rider" Issue for Presentation to MISO Board in August

- Bill Smith explained there are two elements, one is technical – the issue of loop flows – and the other is designing a method to change cost causers for the effects of the loop flows. It was suggested the second element is more suited to the OMS skill set.
- There was discussion on which work group was in the best position to take on the task. It was suggested the Pricing Work Group was and it was further suggested that the final decision be made during the MISO Post Transition Pricing briefing on June 27th.

7. Post-Transition Pricing Briefing – Randy Rismiller

Randy Rismiller presented background information from the Pricing Work Group's briefing memo on post-transition pricing.

- Mike Proctor and Randel Pilo also gave information.
- It was decided that further discussion of the information in the memo would take place at the Special Board Meeting on June 20th.

The meeting adjourned at 4:15 p.m. CDT

OMS

Organization of MISO States
Report of the Treasurer
Greg Jergeson, Montana Public Service Commission to the
Board of Directors
June 14, 2007
Report for May 2007

CASH ON HAND

The beginning balance as of May 1 for the Wells Fargo Business Performance Savings Account was $57,182.72. Interest earned for this month was $153.18. The May 31, 2007 balance was $57,335.90.

The beginning balance as of May 1 for the Chase Bank One Checking account was $ 46,540.90. The total disbursements from the checking account for May 2007 were $40,749.94. Deposits, interest and adjustments were $40,109.09. As of May 31, 2007, the checking account bank balance was $45,900.05 and the book balance was $52,279.04 (with 11 checks outstanding).

The total savings and checking account balances as of April 30, 2007 is **$103,235.95.**

OMS

TREASURER'S REPORT
Organization of MISO States
May 31, 2007

Wells Fargo Business Performance Savings Account

Balance as of 5/1/07			$	57,182.72	
5/31/07	DEP	Interest on Savings	$	153.18	
Business Performance Savings Account Balance at 5/31/07					$ 57,335.90

Chase Bank One Commercial Checking with Interest

Balance as of 5/1/007			$	46,540.90
5/15/2007	DEP	MISO Remittance	$	40,000.00
5/25/2007	DEP	OM Reimbursement	$	76.71
5/31/07	DEP	Interest on Checking		32.38
		Total Deposits	$	40,109.09

Checks and Charges

Date	Check #	Descriptions		
5/9/2007	2322	IL Travel to PA PUC DR Conference	$	425.71
5/9/2007	2323	IL Travel to MISO Stakeholder Meeting	$	195.04
5/9/2007	2324	IA Travel to MISO Stakeholder Meeting	$	429.66
5/9/2007	2325	KY Travel to FERC Tech. Conf.	$	202.65
5/9/2007	2326	MN Travel to MISO Stakeholder Meeting	$	465.62
5/9/2007	2327	IA Travel to MISO Stakeholder Meeting	$	446.10
5/9/07	2328	ED Travel to GridWeek Conf.	$	37.00
5/10/2007	W/D	Paychex Fee	$	106.66
5/11/07	2329	Triplett Office Essentials	$	40.84
5/11/07	2330	IA Travel to MISO Stakeholder Meeting	$	327.60
5/11/07	2331	IA Travel to MISO Market Sub-Committee	$	634.55
5/11/07	2332	MI Travel to MWDRI	$	426.74
5/11/07	2333	MI Travel to MISO Stakeholder Meeting	$	211.41
5/11/07	2334	MI Travel to MWDRI	$	210.46
5/11/07	2335	ED Travel to MWDRI	$	4.00
5/16/07	2336	DWX Internet	$	35.00
5/16/07	2337	Intercall	$	2,576.52
5/16/07	2338	100 Court Investors	$	874.21
5/16/07	2339	Qwest	$	212.74
5/16/07	2340	Infomax Office Systems	$	172.31

5/16/07	2341	MARC Registration	$ 400.00		
5/16/07	2342	IL Travel to House Energy Committee	$ 856.93		
5/16/07	2343	IA Travel to DR FERC Tech. Conf.	$ 959.20		
5/16/07	2344	IA Travel to MISO Stakeholder Meeting	$ 338.36		
5/16/07	2345	MO Travel to GridWeek	$ 992.72		
5/16/07	2346	MO Travel to MISO Stakeholder Meeting	$ 46.40		
5/16/07	2347	MO Travel to MISO Stakeolder Meeting	$ 246.29		
5/16/07	2348	ND Travel to MISO Stakeholder Meeting	$ 47.00		
5/18/07	2349	OMS Visa	$ 7,914.34		
5/22/07	2350	IA Travel to MWDRI	$ 590.55		
5/22/07	2351	MI Travel to MRO/RFC Resource Adequacy Conf.	$ 205.26		
5/22/07	2352	MI Travel to MISO Advisory Committee	$ 356.49		
5/22/07	2353	WI Travel to MISO Stakeholder Meeting	$ 621.02		
5/22/07	2354	IA OCA Travel to MWDRI	$ 205.59		
5/22/07	2355	ED Travel to MISO Advisory Committee	$ 25.90		
5/24/07	2356	Ryun, Givens and Wenthe	$ 1,000.00		
5/24/07	2357	Triplett Office Essentials	$ 40.84		
5/25/07	2358	IA Travel to MWDRI	$ 607.30		
5/25/07	2359	IA Travel to MWDRI	$ 573.47		
5/25/07	2360	IA Travel to MISO Advisory Committee	$ 612.07		
5/25/07	2361	MI Travel to MRO/RFC Resource Adequacy Conf.	$ 7.00		
5/30/07	W/D	Paychex, Payroll	$ 8,397.23		
5/31/07	W/D	Paychex, Taxes	$ 4,704.49		
5/31/07	W/D	Oppenheimer Funds--ED	$ 2,166.67		
5/31/07	W/D	Oppenheimer Funds--OM	$ 800.00		
		Total Checks and Charges		$ 40,749.94	
CHECKING ACCOUNT BALANCE 5/31/07					$ 45,900.05

CERTIFICATES OF DEPOSIT, SAVINGS AND CHECKING ACCOUNT BALANCES AS OF 5/31/07 $ 103,235.95

CHASE CHECKING ACCOUNT RECONCILIATION

	Check #	Amount
Bank Balance 5/31/07		$ 52,279.04
Less: Checks O/S	W/D	$ 2,166.67
	W/D	$ 800.00
	2317	$ 235.10
	2333	$ 211.41
	2346	$ 46.40
	2347	$ 246.29
	2348	$ 47.00
	2351	$ 205.26
	2353	$ 621.02

2358	$	607.30
2359	$	573.47
2360	$	612.07
2361	$	7.00

Book Balance 5/31/07	$	45,900.05

CHASE OMS VISA PURCHASES

ED	Travel to Washington DC for GridWeek	1,922.82
ED	Travel to Washington DC for FERC Tech. Conf. on Market Monitoring	58.90
ED	MISO Annual Stakeholder Meeting	4,533.01
ED	Travel to MWDRI	600.79
ED	Travel To MISO Advisory Committee	259.60
ED	Personal Travel--Travel Agent mistakenly charged OMS Visa and is transferring the charges to ED's AMEX	360.60
OM	FEDEX Charge	7.78
OM	Personal Charged--Reimbursed on 5/23/07	76.71
OM	USPS--Stamps	13.33
OM	Best Buy	80.8
	Total Charges	$ 7,914.34

Background

- To date, RTO benefits associated with centralized unit commitment and dispatch quantified have been quantified by the Midwest ISO and other RTOs.
- RTOs provide economic benefits that exceed those associated with centralized unit commitment and dispatch.
- To date, these additional economic benefits have not been quantified[1].

1. See November 2006 article in The Electricity Journal, "*Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies: A Review of Recent Benefit-Cost Studies of RTOs.*"

Background

- RTOs manage system reliability and congestion across a wide region using state-of-the-art information systems
  - Midwest ISO state estimator with 34,000 buses
  - Midwest ISO contingency analysis of 17,000 contingencies updated every five (5) minutes
  - Market-based dispatch instructions updated every five (5) minutes to over 120,000 MW of generation
- RTO information systems provide RTO Reliability Coordinators with better information updated more frequently than non-RTO counter-parts and better tools for managing congestion faster.

Additional RTO Benefits: Economic Efficiency

- RTO information systems allow **more efficient use of existing transmission assets** due to their superior view of the bulk power system (e.g., 34,000 buses) and five-minute re-dispatch capabilities.
- More efficient use of existing transmission assets is reflected in transmission line operating limits that are higher after RTO formation than before RTO formation.
  - Pre-RTO operating limits were less than full rating in order to address potential contingencies.
  - Post-RTO operating limits are higher given state estimator, contingency analysis and five-minute re-dispatch to relieve congestion.
- Higher operating limits translate into lower production costs, a benefit that can be quantified using production cost simulation models[1].

1. ICF Study performed for Midwest ISO modeled higher operating limits for the Midwest ISO scenarios.

Midwest ISO
We manage power.

Additional RTO Benefits: Economic Efficiency

- RTO information systems also provide opportunity for longer term **economic efficiency benefits** in the form of reduced generation planning reserve requirements.
  - Generation reserves are required to reliably meet demand for electricity given uncertainties associated with both the future demand for electricity and the future availability of generation.
  - Generation availability is uncertain due to plant outages, fuel supply interruptions, weather conditions and other contingencies.
  - Reserves are analogous to maintaining inventory to meet demand.
- Reduced generation planning reserve requirements translate into lower costs due to the need for fewer new power plants or other resources to meet demand.

Midwest ISO
We manage power.

Additional RTO Benefits: Economic Efficiency

- Regional planning by RTOs results in the identification of targeted transmission investment that pays for itself through reduction in production costs achieved by relieving congestion[1].
  - Congestion occurs when the demand for lower cost power exceeds the transfer capability of the transmission system.
  - Congestion is managed by re-dispatching generation to reduce flows to transfer capability.
  - The resultant production cost is higher than it would have been had the transfer capability not limited the flow of the lower cost power.
- Regional planning by RTOs results in investment that makes **more economic efficient use** of both generation and transmission assets.

1. Reduced congestion also results in greater system reliability.

Midwest ISO
We manage power.

Additional RTO Benefits: Economic Efficiency

- Economic Efficiency Benefits made possible by RTOs include:
  - Centralized unit commitment and dispatch resulting in lower production costs.
  - Higher transmission operating limits resulting in lower production costs.
  - Reductions in generation planning reserve requirements resulting in lower costs due to the need for fewer new power plants.
  - Regional planning that identifies targeted transmission investment to relieve congestion resulting in more efficient use of low cost generation and therefore lower production costs.

- Midwest ISO retained KEMA to develop a tool to analyze and quantify all of the benefits listed above on a prospective basis over a ten to twenty year planning horizon.

Stakeholder Review of KEMA Tool

- KEMA tool has been applied to hypothetical system with characteristics similar to the Midwest ISO region.
  - Demand for electricity similar in scope
  - Generation mix (nuclear, coal, gas) has similar composition
  - Transmission system transfer capabilities are similar
- KEMA tool simulated generation dispatch and selected resource additions over twenty (20) year period.
  - Computes production costs with and without RTO
  - Selects resource additions to meet growing demand over time
  - Selects transmission investment that pays for itself by relieving congestion
- Midwest ISO now seeks stakeholder review of KEMA tool – methodology and results for hypothetical system.
- Tool can also be applied to analyzing renewable portfolio mandates and demand responsive resources.
- Tool can also be applied to analyzing policy decisions related to Resource Adequacy.

Technical Assistance on Electric System Regional Planning: Midwest Demand Resources Initiative

Scope of Work, June 2007
Organization of MISO States

PO# XXXX

The Organization of MISO States (OMS) and its members and associate members, with support of the Midwest ISO (MISO) and the U.S. Department of Energy, have established the Midwest Demand Resources Initiative (MWDRI) to develop state and regional policies and market-enabling activities to support demand response in the Midwest region. MWDRI is intended to create a more favorable market environment for demand response and to highlight ways the states and MISO can make that happen.

MWDRI will complement the demand response work group of OMS and will be managed by a steering committee of OMS members. MWDRI will call meetings of stakeholders to discuss its agenda, and will also convene more focused working groups to develop understanding and solutions to address particular opportunities for or barriers to demand response. MWDRI will also provide interface with the MISO's efforts to increase demand response opportunities in the MISO wholesale market.

The initial focus areas for MWDRI will seek to expand existing ways by which customers' electric use can respond to wholesale system conditions (more easily described as "putting slope in the demand curve") and may include initiatives in the areas of retail rate design, advanced meter deployment, measurement and verification procedures, demand response program design (including transitioning existing and legacy load management programs), and system level planning. MWDRI will also explore connections between retail and wholesale markets that may require complementary FERC and state action.

Task #1: Technical Support to the Midwest Demand Resources Initiative

Subcontractor (OMS) will provide project management and technical support services to MWDRI. Subcontractor will develop and manage a website that will facilitate dialogue among the MWDRI stakeholders, arrange meetings, provide teleconferencing capabilities for meetings, disseminate and summarize information on meetings of the MWDRI stakeholders and working groups, provide assistance on agendas, meeting support, and travel arrangements. The contractor will develop and maintain a web site to support all MWDRI Steering Committee and Working Groups, including posting meeting materials in a timely fashion (e.g. preferably before meetings if materials are provided at least 3 business days in advance and within one week after meetings).

OMS will provide technical support to the MWDRI stakeholder group, steering committee, and subgroups as needed. Technical assistance may include identification of existing retail demand response provisions, analysis of opportunities to extend those provisions to additional customer groups and to improve their financial attractiveness, and consideration of retail measures to integrate retail provisions into MISO wholesale energy markets.

Deliverables:
OMS will prepare a progress and summary report on the project management and technical assistance services provided to MWDRI in furtherance of the scope of work in this task.

> **Milestone 1 ($30,000)**
> Due September 30, 2007
> Progress Report.
>
> **Milestone 2 ($25,568)**
> Due December 20, 2007
> Summary Report.

2007 Budget:

The budget for this technical assistance includes funding for three in-person meetings of the steering committee, two teleconference meetings of the steering committee, six in-person working group meetings, and six working group meetings by teleconference. The amount estimated for steering committee meetings is $24,100 (rounded) and the amount for working group meetings is $25,600 (rounded). Total expenses estimated are $55,568. The basis for these estimates is shown on the attached worksheet.

MWDRI
Meeting Expenses
July - December 2007

Meetings anticipated		Number travelling:	Average airfare/ mileage	Hotels	Meals, taxi, parking	Total travel expense	Conference call:	Location expense:	
				(half of travellers, $150/ night)	($60 each)				
Steering Committee:							4 hour calls		
July		0	320	0	0	0	600		
August		0	320	0	0	0	600		
September		12	320	900	720	5460	312	800	
October		0	320	0	0	0	600		
November		15	320	1125	900	6825	240	800	
December		15	320	1125	900	6825	240	800	
									24102
Work Groups:							90 minute calls		
July	in person	8	320	600	480	3640	105	500	
	phone only	0					225		
August	in person	8	320	600	480	3640	105	100	
	phone only	0					225		
September	in person	8	320	600	480	3640	105	500	
	phone only	0					225		
October	in person	8	320	600	480	3640	105	100	
	phone only	0					225		
November	in person	8	320	600	480	3640	105	500	
	phone only	0					225		
December	in person	8	320	600	480	3640	105	100	
	phone only	0					225		
Total for Meetings:						40950	4572	4200	

		25620
Project management and oversight		
10 hours / month @ 56.00	3360	
Website maintenance		
15 hours / month @ 27.62	2485.8	5845.8
Total through Dec 30	**$55,568**	

June 5, 2007

OMS ICF Study Group's Technical Analysis of ICF's Response to OMS Comments

Summary

At the outset, the OMS ICF Study Group wants to express its appreciation to ICF for the additional effort it has put forth in response to the OMS comments, questions and suggestions. However, the OMS ICF Study Group's analysis of ICF's response to date indicates that this response has not provided significant progress in answering the original OMS comments.

First, with respect to escalating hurdle rates with the index of spot-market natural gas prices, the OMS ICF Study Group did not find sufficient justification in ICF's response to warrant the use of this modeling procedure. While it is true that escalating hurdle rates from their calibrated levels in 2004 will decrease the ability of the Day 1 model to substitute lower cost coal-fired generation for natural gas-fired generation, the OMS ICF Study Group already indicated that it understood this concept in its initial comments and was looking for a possible explanation of why applying such an approach could possibly result in a correct estimate for transactions that would be expected in a Day 1 (bilateral) market environment. Unfortunately, in its response to the OMS comments, ICF did not provide such an explanation, but instead attempted to justify the use of the natural gas price indexing of hurdle rates based on results from applying this approach to a period when the Day 1 market was no longer the primary market structure. Because the Day 1 market was not the dominant market structure during the application period, looking at the results of that same application period cannot provide empirical verification for the approach. The OMS ICF Study Group does not believe it is good modeling practice to implement an approach that changes the specifications of the calibrated portion of a model that is based on empirical verification. Instead, in this application, the OMS ICF Study Group maintains that this issue could and should have been avoided had ICF used spot-market rather than delivered prices for coal in its models.

Second, with respect to Achieved benefits exceeding Achievable benefits, ICF reran its models for the months of January, February and March of 2006 using lower levels of spinning reserves based on monthly peak demands rather than the annual peak demand. At first glance, the results of the rerun months did result in moving Achieved benefits from being $25 million higher than Achievable benefits to being $21 million lower. However, digging deeper into the results, the OMS ICF Study Group compared differences in benefits for all three cases

(Maximum - Day 2 optimal; Achievable - Day 2 no ASM and Achieved - Day 2 Actual). In this comparison of the impact of lower spinning reserves on production cost savings, the OMS Study Group found that while the Day 2 optimal case demonstrated less savings in production costs than the Day 1 case (an expected result), the Day 2 no ASM case demonstrated greater savings in production costs than the Day 1 case (an unexpected result). Given the nature of the models used, there may be an explanation for this result, but without such an explanation, the OMS ICF Study Group is concerned that there may have been a modeling error in either the original or the revised runs of the Day 2 no ASM models.

Third, with respect to the measure of negative benefits in September through December of 2005, ICF found that in actual MISO dispatch of the market, gas-fired generation was being dispatched more than what its model indicated for even Day 1 operations. It appears that some of this unexpected gas-fired generation came from reliability issues related to committing these units because they were needed either to have adequate capacity for the market or to meet more local reliability issues on the power grid. In regard to this issue, ICF stated its intention to evaluate the offer curve for coal-fired generation actually experienced by MISO compared to the offer curve that resulted in the ICF modeling of the market. The OMS ICF Study Group will state no conclusions on this issue until it completes its analysis of the information received from MISO on the afternoon of June 4.

Finally, these are the technical comments of the OMS ICF Study group and are not intended to represent a position of the OMS Board or individual Commissioners who serve on that Board. Instead, these comments are meant in the spirit of providing feedback to MISO and ICF on technical issues related to ICF's modeling of benefits. In this respect, nothing in these comments is intended to be a request by OMS for ICF to perform additional modeling runs that would result in additional expense to MISO.

Item1. Escalation Assumptions for Hurdle Rates Based on Indexing to Spot-Market Natural Gas Prices

ICF's response is to compare resource variable costs for combined cycle generation to coal generation in the months of June and December. ICF's comparisons show that that using delivered cost for coal prices the average cost of combined cycle generation increased from \$53.4/MWh to \$94.0/MWh (76% increase), while coal-fired generation increased from

$24.5/MWh to $28/6/MWh (17% increase). ICF argues that the hurdle rate would have to more than double to get a dispatch of coal-fired generation equivalent to that of the "actual market."[1]

The OMS ICF Study Group agrees with ICF that in a market where there is an increasing divergence between natural gas prices and coal prices there will also be increasing opportunities for transactions to take place in a bilateral market, and that escalating hurdle rates reduces those opportunities. However the OMS ICF Study Group respectfully disagrees with ICF that escalating hurdle rates by an index of natural gas prices is a proper modeling procedure.

First, in its initial comments the OMS ICF Study Group pointed out that the use of delivered coal prices is likely to be the major flaw that results in the type of results that shows natural gas prices increasing by 76% relative to coal prices increasing at 17%. The modeling assumption being used in this approach is that coal-fired generation is bid into the market based on contracts for delivered coal that are used to hedge against spot-market prices for coal. Contract prices for coal should be treated as fixed costs, just as if an entity had purchased the coal in the futures market and has the ability to buy more coal or sell contracted coal in the spot market. The OMS ICF Study Group's position in its comments is that had ICF used spot-market prices for coal in its modeling, this issue of escalating hurdle rates by a natural gas price index would not have occurred. ICF has the data base to compare the delivered coal prices it used to the spot prices for coal, and the OMS ICF Study Group is disappointed that it did not see that comparison in ICF's response. At this time, the OMS ICF Study Group can only conclude that since ICF did not address this aspect of the OMS ICF Study Group's concern that its initial comments were on target.

Second, with respect to future applications where one fuel price increases relative to another, there is a methodological question as to how hurdle rates designed to capture market inefficiencies during a period where the fuel prices were at a given ratio (in this case 2004) should be treated when the fuel price ratio changes in a future period (in this case June 2005 through August 2006).

Within MISO hurdle rates are designed as a method of reflecting the inefficiencies of not having a centralized spot market for electricity. Those inefficiencies are the result of

[1] The OMS ICF Study Group does not understand how ICF could know the "actual market" for Day 1 operations when MISO is operating a Day 2 market during this time frame. This statement by ICF should have referred to its "expectations of Day 1 market operations" of coal units rather than to "actual market" operation of coal units.

a. MISO having a more conservative position on granting transmission rights needed to implement bilateral transactions of electricity (e.g., treatment of unused purchased transmission rights and counterflows from used transmission service) than it has in the centralized dispatch of bid-based offers;
b. First-come / first-served allocation of transmission rights versus economic dispatch based on bids from resources;
c. Congestion management based on an inefficient system of prorated reductions in transmission service versus redispatch of resources based on bids; and
d. The differences between 5 minute dispatch versus 60 minute scheduling of generation.

ICF's response failed to relate any part of its explanation as to how increasing natural gas prices relative to coal prices would impact any of these above four components. The best that the OMS Study Group can discern from ICF's response is that when natural gas prices increase relative to coal prices, at a fixed hurdle rate the MAPS model will result in more transactions in Day 1 MISO operations. But there were no reasons given in ICF's response as to why such higher levels of trade would not take place in a Day 1 MISO market under the stated fuel market conditions.

While there are several assertions by ICF that by escalating its hurdle rates by a natural gas price index it obtains an accurate simulation of Day 1 MISO operations, there is no economic reasoning provided by ICF for its assertion. Moreover, the fact that the model would have produced more transactions without the inclusion of escalated hurdle rates does not constitute an explanation of why escalating hurdle rates produces accurate results. It is merely an explanation that with higher hurdle rates there are fewer transactions. However, if this were a valid explanation of getting to accurate results, then the OMS Study Group's assertion that using spot-market prices for coal would also produce accurate results. How can two competing methodologies that produce different results both be accurate? Clearly these are two different approaches to the same issue. The OMS Study Group's explanation is supported by economic reasoning, while the ICF approach is not.

In complete fairness to the issue, the OMS Study Group points out that the inefficiencies of the MISO Day 1 market can be characterized as limitations associated with using a system of physical transmission rights, and may be thought of as physical limitations. Then the question can be asked, when natural gas prices are low relative to coal prices, if physical limitations restrict the transactions, won't those same physical limitations exist and restrict transactions to approximately the same levels when natural gas prices increase relative to coal prices? If the answer to this question is “yes,” then having a fixed hurdle rate (an economic limit rather than a physical limit) will not produce that result in a model that simply relies on hurdle rates to represent MISO’s Day 1 market. In a model that does not put physical restrictions on flows (such as decreasing flowgate capacities) for the MISO Day 1 market, it would be necessary to increase the hurdle rates in order to model what in reality are physical restrictions on transactions. However, in the ICF study it did reduce the capacities of the Midwest ISO flowgates as indicated in Exhibit 3.20 on page 69 of its report.

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

Region	Day-1	Day-2
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%

Given the physical restrictions placed on flowgates in the ICF model, the question remains as to whether escalating hurdle rates based on a natural gas price index is necessary in order to perform an accurate modeling of physical restrictions caused by Day 1 inefficiencies when fuel prices indicate a higher level of transactions than were occurring during the period used to calibrate the model.

In summary, the OMS ICF Study Group is disappointed that ICF did not consider using spot market prices for coal in its determination of dispatch prices; for if spot coal prices were escalating at rates equal to or greater than natural gas price during the September through December months of 2005, then it does not appear that escalating the hurdle rates would have been necessary. In this regard, the OMS ICF Study Group is currently evaluating the additional information recently supplied regarding “actual generation offer data from December for a comparison to model offer assumptions for the same period to determine if differences between modeled and actual offers at coal units provide further explanation of the difference between potential and realized benefits.”

Item 2. Months Showing Achieved Benefits Exceeding Achievable Benefits

In response to OMS ICF Study Group comments, ICF reran the months of January through March of 2006 with spinning reserves varying with the level of monthly peak demands. The bottom line from these reruns is that for these months, lowering the level of operating reserves had the modeling results shown in the following table taken from the ICF response. This table measures benefits and demonstrates that with spinning reserves varying with the monthly system peak, Actual benefits dropped below Achievable benefit for the three month period, but remained slightly higher for the month of January 2006.

Comparing Benefits for Annual vs. Monthly Spinning Reserves: Achievable - Actual

	Annual Spinning Reserve			Monthly Spinning Reserves			Change		
	Achievable	Actual	Difference	Achievable	Actual	Difference	Achievable	Actual	Difference
JAN '06	21	34	-13	24	27	-3	3	-7	10
FEB '06	14	27	-13	23	20	3	9	-7	16
MAR '06	15	14	1	29	8	21	14	-6	20
Total	**50**	**75**	**-25**	**76**	**55**	**21**	**26**	**-20**	**46**

The basic concept involved is that with a reduction in the level of spinning reserves, the production cost of the Day 2 no ASM ("Achievable") would decrease, while the Day 2 Actual ("Achieved") production costs would not change. The reason for the lower Day 2 no ASM production costs is that with lower spinning reserves, additional lower cost generation becomes available for dispatch in the Day 2 energy markets. However, it is interesting to note that this change of $46 million dollars (from Actual being $25 million higher than Achievable to being $21 million lower) has two components: 1) an increase of $26 million in Achievable benefits; and 2) a decrease of $20 million in Actual benefits.

In order to understand this result it is important to keep in mind that for the ICF model runs the level of spinning reserves for the Day 1, Day 2 no ASM and Day 2 optimal cases are all the same. The difference is that in the Day 1 case these spinning reserves are assigned to the various balancing authorities and trades to achieve the requirement to meet load plus spinning reserves are severely limited by high commitment hurdle rates, while in the Day 2 optimal case the spinning reserves are optimized over the entire region and not subject to commitment hurdle rates or to reduced flowgate capacities. In the Day 2 no ASM case, ICF optimized 700 MWs of the 3,652 MWs of spinning reserves as representative of the spinning reserves being devoted to regulation.[2]

[2] While the ICF report did state that 700 MW of the 3.652 represented regulation, it did not directly state the reason for optimizing these 700 MW over the MISO footprint. The OMS ICF Study Group assumes that this represents the benefits from consolidation of balancing authorities, and if this assumption is true, it is not clear why this would be considered achievable during a period where there were multiple balancing authorities in MISO.

It follows that reducing the level of spinning reserves will decrease production costs for Day 1, Day 2 no ASM and Day 2 optimal model results. Day 1 costs will decrease, having an impact on benefit measures for Day 2 Actual, Day 2 optimal and Day 2 no ASM. The results for each of these three cases are shown in the following table.

Comparing Benefit for Annual vs. Monthly Spinning Reserves: Difference

	Annual Spinning Reserve			Monthly Spinning Reserve			Differences		
	Maximum	Actual	Achievable	Maximum	Actual	Achievable	Maximum	Actual	Achievable
JAN '06	38	34	21	33	27	24	-5	-7	3
FEB '06	32	27	14	28	20	23	-4	-7	9
MAR '06	29	14	15	25	8	29	-4	-6	14
Total	**99**	**75**	**50**	**86**	**55**	**76**	**-13**	**-20**	**26**

a. Since Day 2 Actual production cost levels change very little if at all,[3] with decreasing Day 1 production costs from reduced spinning reserves, the benefits from Actual operations (Day 1 production costs – Day 2 Actual production costs) will decrease; i.e., the gap between Day 1 production costs and Day 2 Actual production costs will become smaller. This is confirmed in the above table by the $20 million decrease in Actual benefits.

b. Production costs for Day 2 optimal will also decrease, but with the optimization of the lower level of spinning reserves, the decrease in Day 2 optimal production cost are likely to be smaller than the decrease in Day 1 production costs[4]. This is confirmed by a $13 million decrease in Maximum benefits that is smaller than the decrease in Actual benefits, where the change in production costs for Day 2 optimal is equal to the difference in benefits between Actual and Maximum; i.e., (-$20 – (-$13)) = -$7 million, which is less than the $20 million decrease in production costs for Day 1.

c. If the expectations for the decrease in Day 2 optimal are correct, the impact of decreased spinning reserves on productions costs for Day 2 no ASM is likely to be a reduction that is somewhere between the impact on production costs for Day 1 and Day 2 optimal; i.e., a higher reduction than Day 2 optimal costs (-$7 million), but a lower reduction than Day 1 costs (-$20 million). This would result in the Achievable benefits (from Day 2 no ASM) decreasing by more than the Theoretical Maximum benefits (from Day 2 optimal)

[3] ICF states: "The Day 2 Actual cost will reduce to the extent that the cost of imports depends on the Day 1 cost. However, the reduction in Day 2 Actual cost will be far less than that in the Day 1 and No ASM cases." Thus, there may be some "minor" level of reduction in Day 2 Actual production costs associated with the manner in which ICF determined the price of imports for the Day 2 Actual case.

[4] In the Day 1 case the opportunity cost of holding spinning reserves is expected to be higher than in the Day 2 optimal case. Thus a reduction in the opportunity cost of holding spinning reserves from lowering the spinning reserve level should be greater in the Day 1 case than in the Day 2 optimal case. However, the OMS Study Group notes that because of the non-linearity in the model related particularly to unit commitment, lower spinning reserves in the Day 1 case could result in a cheaper unit being "freed" from providing spinning reserves, but that unit not being dispatched to serve energy because of the hurdle rates. This situation cannot occur in the Day 2 optimal case where hurdle rates are set to zero.

> but less than Achievable benefits (from Day 2 Actual). If this were the case, the change in benefits for the Day 2 no ASM case should have been between -$20 million and -$13 million. However the change in benefits was actually positive, indicating a greater decrease in production costs for the Day 2 no ASM case than occurred in the Day 1 case.

For ICF to have found an increase in Achievable benefits, the decrease in production costs for Day 2 no ASM would have to be significantly larger than the decrease in Day 1 production costs. Since this does not appear to be likely from simply reducing the level of spinning reserves, it appears that the model found production cost savings for the Day 2 no ASM case related to factors other than simply decreasing the level of spinning reserves. There are three possible explanations for this result.

<u>Explanation 1</u>: The conclusion of OMS ICF Study Group analysis that the decrease in production costs for Day 2 no ASM resulting from lower spinning reserves should have been smaller than the decrease in production costs for Day 1 is not correct. Because of the non-linear optimization used in the modeling of these various cases, the OMS ICF Study Group does not rule out this possibility. However, the dramatic differences in results between the Day 2 optimal case and the Day 2 no ASM case would still need to be explained. If the previous analysis is in some way incorrect, we would ask ICF to submit an explanation of what caused the production costs savings in the Day 1 case to exceed the production cost savings in the Day 2 optimal case, but the production costs savings in the Day 1 case to be less than the production cost savings in the Day 2 no ASM case.

<u>Explanation 2</u>: The increase in benefits in the Day 2 no ASM case may have been the result of a modeling specification error that resulted in greater substitution of coal-fired generation for natural gas-fired generation than what resulted from decreasing the level of spinning reserves. At the risk of performing a "back of the envelope" calculation, if the difference in Achievable benefits were midway between the differences for Maximum ($13 M) and Actual ($20 M) for the three month period, that difference would have been a decrease in benefits of $16.5 million. With a decrease of $20 million in Achievable benefits, the net change would have been to narrow the three month excess of Actual benefits over Achievable benefits of $25 million by only $3.5 million. Therefore, if explanation 2 is correct, modeling too high of levels for spinning reserves could not be the major reason for the perverse results of Actual benefits exceeding Achievable benefits in January, February and June of 2006.

<u>Explanation 3</u>: A modeling specification error could have been in the model runs involving the higher level of spinning reserves that inappropriately restricted the substitution of coal-fired generation for natural gas-fired generation in the Day 2 no ASM runs, and when the revised model runs were performed, this specification error was somehow corrected. In this explanation, it may be that ICF has underestimated the benefits for the Day 2 no ASM case in its original model runs (with the higher level of operating reserves), and this may be the primary cause for Actual benefits exceeding Achievable benefits in January, February and June of 2006. If explanation 3 is correct, then the estimate of Actual benefit being equal to 35% of Achievable benefits is too high, and the estimate of benefits from an ASM are also too high.

In any event, ICF should explain the cause of the unexpected increase in Achievable benefits (a larger decrease in Day 2 no ASM production costs than in Day 1 production costs, as well as why this occurred for Day 2 no ASM but not for Day 2 optimal).

Item3. Low and Negative Benefits for September through December 2005

The first level of explanation for the negative benefits in December 2005 provided by ICF is that the Actual dispatch involved significantly more dispatch of natural gas-fired generation than what resulted in ICF's model runs for Day 1. ICF estimates that the three combined cycle units with the largest deviations would account for approximately 80% of the negative benefits estimated for Actual results for December. In addition, the next four highest deviations for natural gas-fired units would likely account for the remaining 20% of the negative benefits.

The OMS ICF Study Group appreciates the identification of gas-fired units that were dispatched at much higher levels in Actual operation than what ICF estimated for Day 1 operations. While these are more detailed observations of the differences, they do not provide an explanation as to why these differences occurred. In this regard, in describing the three combined cycle units that accounted for 80% of the negative Actual benefits, ICF states: "In many hours the units were committed for reliability reasons, that is, they were committed either as reliability must run (RMR) or under reliability accessment commitment (RAC)." These alternative explanations, RMR versus RAC, can be significantly different, particularly if a portion of the MISO power grid was out of service and these units were needed for voltage support (RMR).

If coal units would normally have been available to provide either the voltage support (RMR) or needed capacity (RAC), but were not committed, it would appear that by committing and dispatching these units in its Day 1 run, the ICF is using different dispatch prices than what were bid into the MISO market. In this respect, ICF states that it is analyzing actual MISO data to determine if the difference between modeled and actual offers at coal units provides an explanation of why these significant differences between modeled and actual dispatch occurred. The OMS ICF Study Group is currently analyzing the additional information provided by MISO on June 4.

BRIEFING FROM THE OMS PRICING GROUP
TO THE OMS BOARD OF DIRECTORS
ON POST TRANSITION TRANSMISSION PRICING

JUNE 14, 2007

I. Background

At the inception of the Midwest ISO, the charter transmission-owning (TO) members agreed to retain license plate rates for a six year transition period from start-up of MISO operations and then re-examine the issue. Under license plate rates, the load in each zone gets access to all of the generators in the Midwest ISO in exchange for paying a network transmission rate based on the cost of transmission facilities in its particular zone.

In its 1998 Order approving the Midwest ISO as an ISO, FERC accepted the TOs' rate design compromise and directed the Midwest ISO to "establish procedures to ensure that a superseding proposal can be negotiated and filed with the Commission [FERC] at least six months before the end of the minimum six-year transition period."[1]

In a 2004 Order addressing PJM and Midwest ISO, the FERC discussed rate design "for transmission service under the tariffs of the two regional transmission organizations (RTOs) to serve load in their combined regions."[2] (FERC stated that "the RTOs and their transmission owners are directed to make a filing at least six months prior to the end of this period containing a reevaluation of fixed cost recovery policies for pricing transmission service between the two RTOs and proposing a rate design to take effect February 1, 2008. This is a minimum term before the end of which the fixed cost recovery policies for service between the RTOs must be formally reevaluated."[3]

FERC synchronized the Midwest ISO and PJM transition period to end February 1, 2008, and directed that the rate design re-evaluation filing be submitted by August 1, 2007.

II. The Midwest ISO TOs' Rate Design Re-Evaluation Process

John Procario, who was a key player in the formation of the Midwest ISO in the 1990s (and has since semi-retired), was hired as the TOs' consultant and facilitator for the rate design re-evaluation process.

The Midwest ISO TOs have been meeting over the last six months or so. They have also held several open meetings with stakeholders during that same time period.

The Midwest ISO TOs met several times with the PJM TOs but no combined stakeholder meeting has been held.

---

[1] *Midwest Independent Transmission System Operator, Inc.,*84 FERC ¶ 61,231, at P. 63
[2] *Midwest Independent Transmission System Operator, Inc.,*109 FERC ¶ 61,168, at P. 1
[3] *Midwest Independent Transmission System Operator, Inc.,*109 FERC ¶ 61,168, at P. 62

John Procario has given several briefings to the OMS Pricing Group regarding the Midwest ISO TOs' progress.

The Midwest ISO TOs have also briefed the Midwest ISO Advisory Committee on their progress.

During the Midwest ISO TOs' rate design re-evaluation process, they considered a range of different options from pure license plate to pure postage stamp to various highway/byway approaches and various hybrids.

III. FERC's Order on Intra-PJM Rate Design

When the Midwest ISO TOs began the rate design re-evaluation process, a proceeding was pending at FERC in which rate design for intra-PJM transmission facilities was under consideration. After a litigated proceeding in that PJM case, an administrative law judge (ALJ) had recommended moving away from license plate rates within PJM to a postage stamp rate design approach for all existing PJM transmission facilities.

In an April 19 Order, the FERC overruled its ALJ on this point and approved retention of license plate rates for intra-PJM rate design.[4]
FERC's decision in the PJM case ruled there was insufficient evidence to find the existing license plate rate design is unjust and unreasonable. Although the grid today is operated on an integrated basis, this fact alone does not support a reallocation of sunk transmission costs within PJM. The Commission found that the current license plate rate design reflects prior investment decisions and continues to serve that load. Moreover, proposed alternatives "would cause large cost shifts that are not clearly associated with the actual use of these facilities" and could create adverse incentives with respect to decisions concerning joining or remaining in PJM.[5] In short,, a major justification for retaining the license plate rate design for existing facilities was FERC's application of a "cost-causation" principle. Therefore, since FERC determined that the load within the zones was the historical cost causer, FERC found that that load should continue to pay for the transmission facilities, regardless of the current distribution of beneficiaries from those facilities.

FERC's Order in the PJM case, and FERC's apparent change in direction on rate design, influenced many of the Midwest ISO TOs and other parties who were working on the intra-Midwest ISO rate design issue as well as the inter-RTO rate design issue.

IV. Current Positions of Midwest ISO TOs

At the May 31 stakeholder meeting, Mr. Procario stated that 21 out of 25 Midwest ISO TOs support retention of license plate rate design for existing Midwest ISO transmission facilities. Two Midwest ISO TOs support a highway/byway rate design.

---

[4] *PJM Interconnection, L.L.C.,*119 FERC ¶ 61,063
[5] *PJM Interconnection, L.L.C.,*119 FERC ¶ 61,063 , at P. 3

Similarly, a large percentage of the Midwest ISO TOs appear to support retention of the RECB approach to allocating costs of new facilities (at least for the time being). However, there are TOs that support alternative approaches.

The American Transmission Company (ATC) supports retaining license plate rates for existing facilities and socializing (using a postage stamp rate) the costs of all new facilities of 345 kV and greater. New "cross-border" facilities with PJM would be allocated using load flow analyses.

The LSE Coalition proposed socializing (using a postage stamp rate) the costs of all existing facilities of 345 kV and up and all new facilities of 100 kV and up.

V. Summary of the OMS Board's December 2006 White Paper on Post Transition Transmission Pricing

In December 2006, the OMS Board of Directors issued a White Paper on Post Transition Transmission Pricing. The highlights of that White Paper are: (1) for existing facilities, neither pure license plate rates nor pure postage stamp rates would be appropriate; (2) for new facilities, retain the RECB cost allocation approach for intra-Midwest ISO facilities and the stakeholders' cross-border approach to new cross-border facilities with PJM; (3) the OMS strongly supports the "beneficiary-pays" principle; (4) unwarranted rate shock should be avoided, but cost shifting would be acceptable if it improved equity and efficiency; and (5) a majority of the OMS supports a role for OMS of "asserting the right to approve or reject any transmission rate designs that are developed in the stakeholder process before any filing is made at FERC."

VI. Where Does the OMS Board Want to Go From Here?

The next post-transition rate design stakeholder meeting is scheduled for June 27, 2007. It is likely that Mr. Procario will use that meeting to try to firm up the position on which the Midwest ISO TOs will make their filing on August 1, 2007.

With respect to rate design for <u>new transmission facilities</u>, one option is to allow the RECB approach to play out for a while. Forums for re-examining the RECB cost allocation methods were factored into that process, so the OMS can use them to address any concerns that it may have. In addition, the Midwest ISO is shopping around a proposal that would change the current approach regarding the financing and rate recovery for new transmission facilities associated with generation development distant from load. Those forums are most likely more effective arenas for the OMS to deal with new transmission facility rate design than the post transition proceeding. If the OMS Board believes otherwise, both the ATC proposal and the LSE Coalition proposal provide possible alternatives for modifying the current RECB approach for cost allocation of new facilities.

If the OMS Board wishes to try to influence the direction that the Midwest ISO TOs will take in their filing concerning rate design for <u>existing facilities</u>, the June 27 meeting provides the best forum for trying to do that. Unless circumstances change, it appears that a large majority of the Midwest ISO TOs are gravitating toward a filing that would retain license plate rate design for existing Midwest ISO transmission.

The OMS Pricing Group suggests that the OMS Board consider the extent to which it subscribes to FERC's rationale concerning historical cost causers continuing to be cost payers regardless of the possible changes in the distribution of beneficiaries over time.

The OMS Pricing Group suggests that the OMS Board also consider the weight it wishes to give to two principles enunciated in its December 2006 White Paper on Post Transition Transmission Pricing. The two relevant principles are "beneficiaries should pay" and the "minimization or mitigation of cost shifts."

If the OMS Board agrees that the Midwest ISO TOs should focus on the "minimization or mitigation of cost shifts" then retention of license plate rates would reflect the historical cost causer principle and would minimize cost shifts relative to the status quo. However, retention of license plate rates would violate the "beneficiaries pay" principle <u>to the extent that</u> existing transmission facilities are being used by, or benefiting, load outside the zone in which those transmission facilities are physically located.

If the OMS Board wishes the Midwest ISO TOs to give more weight to the "beneficiary pays" principle, it may want to consider the following options:

> 1) urge the Midwest ISO TOs to attempt to develop a rate design for existing facilities that incorporates the allocation of costs to those currently benefiting from the use of the existing transmission system;
> 2) urge the Midwest ISO TOs to give consideration to the following benefits: (a) that the reliability of service for all market participants is dependent upon the integrated operation of all of the transmission facilities in the region; and (b) that the reductions in energy costs that accrue to all market participants from the centralized Midwest ISO energy market are dependent upon the integrated operation of all of the transmission facilities in the region; and
> 3) support a gradual blending in to the rates of the impacts of the above-mentioned benefits, or accept an extension of the current transition period under which license plate rates remain effective with a re-examination of the issue on a future date certain while benefits analysis and measurement methods are honed.

If the OMS Board wishes to try to influence the direction that the Midwest ISO TOs will take concerning rate design for existing facilities, the OMS Pricing Group offers to provide the Board with additional background and relevant source documents as well as an "Outline of Options" for possible consideration at the Board's June 20 meeting in Minneapolis.

In addition, the OMS Board may wish to weigh in on the failure (so far) of Midwest ISO and PJM to facilitate a joint stakeholder process to re-examine "transmission service under the tariffs of the two regional transmission organizations (RTOs) <u>to serve load in their combined regions</u>" as directed by FERC.

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY
OFFICE OF ELECTRICITY DELIVERY AND ENERGY RELIABILITY

Attn: Docket No. 2007-OE-01 (Draft Mid-Atlantic Area National Corridor)
Docket No. 2007-OE-02 (Draft Southwest Area National Corridor)

COMMENTS OF THE ORGANIZATION OF MISO STATES

The Organization of MISO States, Inc. (OMS) submits the following comments in response to the U.S. Department of Energy's (Department) May 7, 2007 Federal Register Notice (Notice) requesting comments on the proposed designation of two National Interest Electric Transmission Corridors (NIETCs) in the above-referenced dockets.[1] The OMS appreciates the Department's decision to solicit comments before taking final action on any specific corridor designations. When considering these issues, the OMS requests that the Department take notice of the OMS's prior comments submitted on September 17, 2004, March 6, 2006, and October 12, 2006.

The OMS and its members have a direct interest in the Department's proposed Mid-Atlantic corridor designation because several OMS member states are within the corridor or are identified as having underused generation capacity and/or potential wind generation capability that could serve the Mid-Atlantic critical congestion area.[2] However, these comments focus on the Department's interpretation of its authority to designate corridors under Section 216 of the Federal Power Act (FPA), including the discretion to designate "conditional congestion areas."[3] The Department's interpretation is of particular interest to the

[1] The OMS is filing these comments in both dockets to address the Department's conclusions regarding its authority to designate national corridors. The comments do not take a position on any specific issues related to the proposed Southwest area national corridor, but do address certain issues related to the proposed Mid-Atlantic corridor.

[2] The proposed Mid-Atlantic corridor includes areas in Ohio and Pennsylvania within the Midwest ISO; although these areas are not part of the "critical congestion area" they are included in the proposed corridor as "source areas." *See* 72 Fed. Reg. 25904-05, Figures VIII 18 and 19 (2007). Also, several additional OMS member states (Indiana, Michigan, and Kentucky) are shown as having underused generation capacity and/or undeveloped wind generation capability that could serve the Mid-Atlantic critical congestion area absent key transmission constraints. See notice at p. 25897 and Figure VIII.15. As discussed in section III.C of these comments, the Department identifies two such key transmission constraints in Michigan and Indiana. See Figure VIII.16 at p. 25900.

[3] U.S. Department of Energy, National Electric Transmission Congestion Study at ix (August 2006).

OMS because four out of the five conditional areas identified in the Department's congestion study are within or partially within the Midwest ISO.[4]

I. Summary

The OMS believes that the Department's interpretation of its authority to designate corridors, particularly as it relates to conditional congestion areas, is inconsistent with the plain reading and legislative intent of the Energy Policy Act of 2005 (EPAct). In particular, the OMS is concerned with the Department's overly broad interpretation that it has discretion under section 216 of the FPA to designate a corridor if a constraint is hindering the development or delivery of a generation source that is in the public interest, without explicitly showing adverse effects on consumers or demonstrating present or future congestion.[5] [6] The OMS believes that even if the Department proceeds cautiously, the Department's application of this new standard to conditional congestion areas would indirectly and inappropriately encroach on the on going work of regional planners, states, and market participants in the planning and development of the nation's electrical infrastructure. As discussed below, the OMS respectfully requests that the Department reconsider its position or, at a minimum, refrain from making these and similar findings in its final order on the two corridor designations at issue.

The OMS offers additional comments addressing the duration and boundary of corridor designations, rationale for identifying source areas, identification of key transmission constraints, and preferred solutions to congestion problems.

II. Background

On May 7, 2007, the Department published in the Federal Register (Vol. 72, No. 87) a Notice of its intent to designate the Mid-Atlantic and Southern California regions as national corridors; these areas were characterized as containing "critical congestion areas" in the Department's August 2006 congestion study. In the Notice, the Department also summarized and responded to comments on the congestion study that are relevant to national corridor designations, including, but not limited to, the Secretary of Energy's

[4] These areas are: Montana-Wyoming (coal and wind); Dakotas-Minnesota (wind); Kansas-Oklahoma (wind); Illinois-Indiana and upper Appalachia (coal).

[5] Notice at 25844.

[6] The North Dakota Public Service Commission (NDPSC) and the South Dakota Public Utilities Commission (SDPUC) believe that NIETC designation in conditional congestion areas where electric transmission is needed to make use of plentiful and low-cost domestic resources is in the national interest. The NDPSC and the SDPUC support designation of a NIETC within the Dakotas–Minnesota conditional congestion area identified as one of the principle areas of interest in the Department's congestion study.

(Secretary) scope of authority to designate corridors. Having reviewed the Department's conclusions in the Notice, the OMS feels it is necessary to reinforce and expand upon its concerns with the Department's interpretation of section 216 of the FPA.

III. Specific Comments on the Department's May 7, 2007 Notice

A. Section II.A - Scope of Authority

Under section 216(a) of the FPA, the Secretary is required to issue a report, based on the congestion study, which:

> . . . may designate any geographic area **experiencing** electric energy transmission capacity **constraints or congestion that adversely affects consumers** as a national interest electric transmission corridor.[7] (emphasis added)

In the Notice, the Department suggests that it is not attempting to define the complete scope of the term "constraints or congestion that adversely affects consumers" as used in this section. After concluding that the term is ambiguous, the Department distinguishes between its authority to designate corridors based on "congestion that adversely affects consumers" and its authority to designate corridors based on "constraints that adversely affect consumers."

With regard to congestion, the Department finds that it has the discretion to designate a corridor upon a showing of "persistent congestion" without any additional demonstration of adverse effects on consumers.[8] Although it may be relatively easy to demonstrate that persistent congestion is adversely affecting consumers, the OMS believes that the Department still needs to explicitly demonstrate such adverse effects to designate any national corridor based on congestion. The OMS also finds unacceptable the Department's explanation that the congestion study did not attempt to define when congestion adversely affects consumers.[9]

With respect to "constraints that adversely affect consumers," the Department concludes it has the discretion to designate a corridor:

> . . upon a showing of the existence of a constraint, including the total absence of a transmission line, that is hindering the development or delivery of one or more generation sources that is in the public interest,

---

[7] 16 U.S.C. 824p(a).

[8] Notice at 25844.

[9] *Id*. at 25843.

> regardless of whether there is congestion and without the need for any additional demonstration of adverse effects on consumers.[10]

The Department takes no action in the Notice with respect to conditional congestion areas, but concludes that:

> . . . were the Secretary to designate a National Corridor for one of those areas, the Secretary would need only to demonstrate the existence of a constraint that was hindering the development or delivery of a generation source that is in the public interest, and would not need to rely on demonstrations of future, or even present, congestion.[11]

The remaining portion of this section addresses these findings regarding constraints hindering the development or delivery of generation in the public interest and their potential implications if used to designate future corridors in conditional congestion areas or similarly situated areas.

National Corridor Designation Was Not Intended to Solve the So-Called "Chicken and Egg" Problem of Generation and Transmission Development

The Department defined conditional congestion areas in the 2006 congestion study as having "some transmission congestion at present, but significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity."[12] Before addressing the merits of the Department's legal interpretation, it is important to point out to the Department that the FERC-approved generation interconnection procedures and RTO planning processes are designed to ensure that the necessary system upgrades are constructed simultaneously with the development of new generation.

With that said, the OMS recognizes that new mechanisms may be needed to address what some call the "chicken and egg" problem of new resource development, in which generation is not constructed until transmission capacity is built and transmission capacity is not expanded until there are generators committed to interconnect. The Department notes that constraints can hinder the development of new power sources, "since project sponsors may not be able to obtain the financing they need if there is uncertainty over the degree to which their electricity could be delivered to consumers."[13] The OMS disagrees with the Department that section 216 of the FPA was intended to remedy this multi-

---

[10] *Id*.

[11] *Id*.

[12] Congestion Study at ix.

[13] Notice at 25844.

faceted problem. The OMS believes it is a targeted federal pre-emption provision aimed at addressing perceived delays in state siting of needed transmission facilities.

The OMS comments of October 12, 2006, observed that "a NIETC designation can only be in the public interest if it would expedite or facilitate a transmission solution to a national interest congestion problem." In other words, section 216(a) had a limited purpose of assuring timely state consideration of a transmission proposal. However, the Department seems to read this section as giving it wide-ranging authority to assure that transmission gets built. For instance, the Notice cites "concern about the need to strengthen transmission infrastructure,"[14] although this concern is tempered by statements that a corridor designation does not imply a need for new transmission.[15] The OMS believes the Department should resolve this internal inconsistency in favor of the more limited view of the section 216(a) process.

As further discussed in OMS's October 2006 comments, designation of a national corridor based on anything other than siting barriers could result in an inefficient application of resources, may fail to resolve the constraint, and would be an inappropriate federal infringement on state siting laws.[16]

The Department Disregards Key Terms in the Statute While Creating a New Standard for Corridor Designations

Rather than clarifying and implementing the terms in EPAct, the Department appears to be downplaying key terms in the statute such as "adversely affects consumers." The Department even acknowledges that the congestion study did not attempt to define when constraints or congestion adversely affects consumers.[17] At the same time, the Department has created an entirely new standard with new terms not in the statute. Though methodically presented in the Notice, new terms such as "generation source in the public interest" are not defined or supported by the statute.

Section 216(a)(4) identifies several factors that the Secretary may consider when determining whether to designate a corridor. Although some of these considerations relate to the development or diversification of energy supplies, the statute notably does not mention "hindrances" to the "development or delivery of a generation source that is in the public interest." Moreover, EPAct uses the phrase "public interest" in numerous instances, including a reference in

---

[14] *Id*.

[15] *See*, *e.g.*,Notice at 25839 and 25845.

[16] Comments of the Organization of MISO States at 4 (October 12, 2006).

[17] Notice at 25843.

section 216 pertaining to FERC's finding that transmission facilities are in the public interest; the term is not, however, used in the context of national corridor designations.

The Department explains "that it is unnecessary in this notice to reach the question of the type of information that would be required to demonstrate that a constraint is hindering the development or delivery of a generation source that is in the public interest."[18] The Department suggests, however, that the considerations in section 216(a)(4) provide "some examples of generation sources the development of which would be in the public interest."[19] The Department appears to be using the considerations in section 216(a)(4) to help define an entirely new standard, rather than applying the plain language of the statute.

Constraints Cannot be "Experienced" Absent Generation to Constrain the System

Section 216 of FPA provides that the Secretary may designate as a national corridor any geographic area "experiencing" constraints that adversely affect consumers. But how can a constraint that adversely affects consumers be "experienced" if there is not yet generation that constrains the system? Is coal in the ground in Appalachia a "generation source"? It appears to be based on the Department's identification of conditional congestion areas, and yet there are numerous factors—far beyond the siting of transmission—that will determine *whether* and *where* generation facilities will actually be constructed to burn that coal. The Department appears to gloss over this reality when it states:

> With regard to the source area, where the decision to designate a National Corridor is based on the existence of a constraint that is hindering the development or delivery of a particular generation source that is in the public interest, the identification of the appropriate source area would be relatively straightforward: the source area would be the geographic area within which that particular source of supply is, or is likely to be, located.

Under the Department's interpretation of section 216, it appears that the Department could designate a corridor if a potential generation source that is in the public interest—however that is defined—needs transmission to deliver the resulting electrical power to some end market. This could be done even in the absence of actual, concrete proposals to construct generation or transmission facilities. Based on the generation sources identified in the conditional congestion areas, this interpretation could essentially result in the entire contiguous United States being covered by a national corridor designation. This cannot be what Congress intended as part of this pre-emption provision.

[18] *Id.*, Footnote 15.

[19] *Id.*

If the Department implements this new standard to support designation of conditional congestion areas, it will necessarily expand its role into system planning in a manner that could supplant or otherwise duplicate the traditional roles of states and other entities. Again, the OMS recognizes that transmission construction can be a significant barrier to the development of wind generation and other location-constrained generation sources. But there are more efficient and effective ways to ensure that transmission is properly planned, financed, and constructed to promote renewable energy goals than the Department designating conditional areas as national corridors.

The Implications of the Corridor Designation Should Not be Downplayed

The OMS acknowledges and appreciates the Department's intention to proceed carefully in the exercise of its discretion to designate corridors. This intention does not, however, alleviate the OMS's concern that the Department has interpreted section 216 in a manner that is not consistent with the plain reading and spirit of EPAct. The OMS also disagrees that section 216's limitations on FERC's ability to exercise siting authority provides rationale for the Department to broadly interpret its authority to designate national corridors. If anything, these limitations on FERC's authority serve as an indication that Congress did not intend section 216 to represent a sweeping change in the federal government's role in siting transmission.

The Department appears to attempt to downplay states' interest and concern with respect to the corridor designation process. For example, the Department states that, "a National Corridor designation itself does not preempt state authority or any state actions."[20] However, the Department must acknowledge that its designation of a corridor will trigger events that can result in the pre-emption of states. The Department appears to be saying that the first step in a journey of a thousand steps is not part of the journey. However, if the first step in the journey is not taken, none of the subsequent steps will follow. If the Department does not designate a corridor, the Federal Energy Regulatory Commission does not acquire a pre-emptive role in transmission siting. So, despite the Department's narrative that attempts to downplay and minimize state commission concerns with the Department's corridor designation policy and process, the state commissions have legitimate concerns.

For these reasons, the OMS asks the Department to reconsider its interpretation of its authority to designate corridors in conditional congestion areas or other areas where constraints may "hinder the development or delivery of generation sources in the public interest." In the alternative, the OMS requests that the Department reserve these legal findings for a future date after it

[20] Notice at 25839.

has gained experience with national corridor designations in areas with existing persistent congestion that is already adversely affecting consumers.

B. Section VI - Duration of Corridor Designation

With regard to the duration of the corridor designation, the Notice states that ". . . DOE intends to adopt a default approach, under which an initial designation would be for a period of 12 years unless it finds reason in a particular case to set some other initial term."[21]

The OMS does not believe that the Department has adequately supported its position to establish a default approach. Establishing a fixed time frame may lead to circumstances in which the congestion or constraint that led to the designation of the corridor is eliminated, but the corridor designation nevertheless remains in effect for years.

The Department notes that it will stipulate in any corridor designation order that the designation may be modified, rescinded, or renewed for cause at any time, after a period of public notice and comment.[22] However, the OMS recommends a more defined process for modifying the term after the initial designation to address changes in system conditions within the corridor. As stated previously, the OMS is particularly concerned that the corridor designation be removed as soon as the stated goal of the designation has been accomplished.

C. Section III and VIII.D.1 - Definition of Source Area and Identification of Key Transmission Constraints

With regard to the proposed Mid-Atlantic corridor, the Notice states that "DOE selected as source areas locations of substantial amounts of existing, under-used economic generation capacity, as well as locations with the potential for substantial development of wind generation capacity."[23] The OMS does not believe the Department has adequately explained why it selected this definition of source area and the specific criteria for identifying these areas. In the general discussion of source areas in Section III of the Notice, the Department recognizes that when the national corridor is based on the existence of persistent congestion, the selection of source areas "will necessarily involve discretion and is not suited to a formulaic approach."[24] The Department goes on to state that the considerations identified in FPA section 216(a)(4) provide guidance on some

[21] *Id*. at 25851.

[22] *Id*.

[23] *Id*. at 25897.

[24] *Id*. at 25848.

of the possible bases for selecting source areas. However, the Department did not fully explain whether and how it applied such considerations or other factors when selecting the sources areas for the proposed Mid-Atlantic corridor.

Another area of the Notice that warrants additional clarification is Figure VIII.16, which identifies “key transmission constraints preventing electricity transfers from available lower cost generation sources to Mid-Atlantic critical congestion area.”[25] Two of these “key transmission constraints” are located in Michigan and Indiana but the Notice provides no explanation or details. Moreover, Figure VIII.16 is not sufficiently clear to determine the exact location of the constraints and how they may correspond with the results of the combined system study conducted by the PJM and Midwest ISO that, among other things, examined the deliverability of resources across the combined RTO footprints.[26] The constraints shown in Indiana and the southwestern corner of Michigan in the Department’s Figure VIII.16 do not seem to correspond with the binding constraints identified in the joint PJM-Midwest ISO study, although there is binding constraint in the joint PJM-Midwest ISO study (Dunes Acres – Michigan City) that is near the one shown in Figure VIII.16.[27] The OMS recommends that the Department provide additional details related to Figure VIII.16 and similar figures to avoid ambiguity and provide adequate justification for its findings.

D. Section VIII.D.1 - Boundaries of the Draft Mid-Atlantic Area National Corridor

The proposed Mid-Atlantic national corridor includes part of PJM and part of New York. The Notice explains:

> . . . the draft National Corridor for the Mid-Atlantic Critical Congestion Area is a single Corridor—the draft Mid-Atlantic Area National Corridor—covering part of the PJM footprint and part of New York, partly because some of the transmission planning that is needed should involve both PJM and NYISO, and also because transmission projects may be proposed that would cross their common boundary.[28]

The Department did not adequately explain why it decided to specify a single corridor, especially considering that the identified source areas for the

[25] *Id*. at 25900.

[26] 2006 Midwest ISO-PJM Coordinated System Plan. Available at http://www.pjm.com/committees/stakeholders/inter-regional-planning-adv/downloads/20061207-2011-csp-report-final.pdf.

[27] *Id*. at 18-20. The joint study identifies proposed solutions for this constraint.

[28] Notice at 25902-25903.

critical congestion in PJM and the critical congestion in New York are mostly different.

The NIETCs proposed by the Department are geographically expansive. For example, Figure VIII-19 shows that just the so-called PJM portion of the proposed Mid-Atlantic corridor (which includes portions of the Midwest ISO territory) encompasses eastern Ohio all the way to the Atlantic Ocean and ranges form the northern border of Pennsylvania well into the heart of Virginia and West Virginia.

In its October 12, 2006 Comments, the OMS recommended as follows:

> Just because a proposed transmission project is located within the geographic area encompassed by the NIETC, it should not automatically be assumed that the project will address the circumstances for which the NIETC was designated. Accordingly, it is critical that the Department clearly define the goal of the NIETC so that only projects intended to address that stated goal would be eligible for the FERC backstop siting treatment specified in Section 216(b) of the amended FPA. OMS Comments at 6.

In its Notice, the Department acknowledged the concerns of the OMS in this regard, but declined to act on these concerns, arguing that Section 216(b) of the Act specifies the scope of FERC jurisdiction over projects to be built in NIETCs.[29] The Department specifically referred to Section 216(b)(4) which requires FERC to find that "the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers" prior to issuing permits for the construction or modification of electric transmission facilities.

However, the Section 216(b)(4) does not resolve the OMS's concern about possible misuse of the NIETCs. It is the OMS's position that only transmission projects intended to address the particular reason(s) for which the corridor was designated by the Department should be eligible for the FERC backstop siting treatment.

If the Department shares that view, it could make that position clear in its final notice designating corridors. It serves no purpose for the Department to leave this matter ambiguous. Doing so would just open the door for future contentiousness and wasteful litigation. It is the Department's decision to propose geographically expansive corridors, rather than simply specifying sources and sinks as recommended by the OMS in previous comments, that has made the OMS's concern manifest. *See, e.g.*, OMS October 12, 2006 Comments at 5-6. Furthermore, it is the Department's Notice that specifies the

[29] Notice at 25849.

reasons for the proposed corridor designations. Therefore, the Department should take the responsibility to make its position clear on this issue raised by the OMS, rather than deferring the issue to potential future litigation in FERC proceedings.

E. The Department is Inconsistent on Whether or Not its Proposed Corridor Designation is Identifying Transmission as the Optimal Remedy

The Notice states:

> The Department acknowledges that transmission expansion is but one possible solution to a congestion or constraint problem; increased demand response, improved energy efficiency, and conservation, as well as siting of additional generation close to load centers are also potential solutions. However, given the effect of a National Corridor designation and the existing obligations of State and Federal siting authorities as discussed in Section I.A above, there is no need for the Department to undertake an analysis of transmission solutions and nontransmission solutions or to speculate about any theoretical indirect effects a National Corridor designation would have on the market. Indeed, the Department believes that expanding its role to include making findings on the optimal remedy for congestion could supplant or otherwise duplicate the traditional roles of States and other entities.[30]

However, later in the Notice when discussing the Mid-Atlantic corridor, the Department states:

> The data detailed above indicate that consumers in the Mid-Atlantic Critical Congestion Area now pay high electricity prices because their electricity suppliers are unable to access low-cost supplies due to insufficient transmission capacity.[31]

Similarly, the Department states:

> Further, while efforts are being made to increase the participation of demand-side resources in the PJM wholesale electricity markets, it does not appear that such efforts are capable of producing near-term results on the scale needed to forestall the need for additional transmission.[32]

---

[30] Notice at 25845.

[31] *Id*. at 25894-25895.

[32] *Id*. at 25895.

These last two statements, which identify transmission as the solution, seem to contradict the first quoted statement above assuring that, in making corridor designations, the Department is not "making findings on the optimal remedy for congestion." The OMS recommends that the Department refrain from making even indirect judgments on the optimal remedy and available options. As the Department seems to acknowledge in at least some portions of the Notice, this is important to ensure that the Department is not duplicating or encroaching on the traditional planning roles of state authorities, local and regional planners, and other entities.

Also, in the first statement above, the Department indicated that there is no need to speculate about any "theoretical indirect effects" a national corridor designation would have on the market. The OMS believes that the Department should be fully cognizant of the potential effects of any corridor designation because these effects are central to understanding the need for and scope of particular designations. With regard to conditional congestion areas, "theoretical indirect effects," such as the siting of potential generation and transmission facilities and the expected benefits to consumers, would be the primary reasons to support such a designation. The OMS suggests that as part of any designation, the Department should not overlook the potential effects on the market and how the designation may shape the development of the nation's electric infrastructure and potentially favor—albeit indirectly—certain locations, generation sources, consumers, or technologies. The Department should also be clear on whether its overarching purpose is to "strengthen the transmission system" or whether its purpose is more of an administrative one of designating corridors upon finding a constraint or congestion and then letting the solutions develop as they may.

IV. Conclusion and Recommendation

The OMS believes that the Department is overstepping the statutory authority granted to it under section 216 of the FPA. At a minimum, the Department should reserve the issue regarding its authority to designate conditional areas for a future time, after it has gained experience with designations in areas with actual, persistent congestion that already adversely affects consumers. There are more direct and constructive ways to ensure that a lack of transmission is not a barrier to cost-effective development of renewables and other generation sources than the Department designating conditional congestion areas as national corridors.

The OMS also recommends that the Department:

- Explicitly demonstrate adverse effects on consumers even in cases of persistent congestion prior to designating a NIETC.
- Clearly define the goal of the NIETC designation so that only projects intended to address that stated goal would be eligible for the FERC backstop siting treatment.

- Establish an explicit process to modify the default term of a corridor, particularly after the stated goal of the designation has been achieved.
- Further explain the selection of source areas and key transmission constraints related to the proposed Mid-Atlantic corridor.
- Further explain its decision to designate portions of New York and PJM as a single national corridor.
- Refrain from making judgments on the optimal remedy to congestion or constraint problems and identifying transmission as the needed solution.
- Fully consider the potential impacts—even the "theoretical"—that national corridor designation may have on particular markets, customers, and the configuration of the electric system.

The OMS submits these comments because a majority of the members have agreed to support them. Individual OMS members reserve the right to file clarifying comments or minority reports on their own regarding the issues discussed in these comments. The following members generally support these comments:

Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Missouri Public Service Commission
Montana Public Service Commission
Nebraska Power Review Board
North Dakota Public Service Commission
Pennsylvania Public Utility Commission
South Dakota Public Utilities Commission
Wisconsin Public Service Commission

The Manitoba Public Utilities Board did not participate in this pleading. The Public Utilities Commission of Ohio abstained from support of these comments.

The Minnesota Department of Commerce, the Iowa Office of Consumer Advocate, and the Indiana Office of Utility Consumer Counselor, as associate members of the OMS, support these comments.

Respectfully Submitted,
William H. Smith, Jr.
William H. Smith, Jr., Executive Director
Organization of MISO States
100 Court Avenue, Suite 218
Des Moines, Iowa 50309
Tel: 515-243-0742

Dated: July 6, 2007