Attachment 5

Midwest ISO
Energizing the Heartland

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FILED WITH
Executive Secretary
March 28, 2011
IOWA UTILITIES BOARD
E-21948

March 28, 2011

Ms. Judi Cooper
Executive Secretary
Iowa Utilities Board
350 Maple Street
Des Moines, Iowa 50319-0069

Re: Docket No. E-21948

Dear Secretary Cooper:

In response to the Iowa Utilities Board ("IUB") Order issued March 9, 2011, please find enclosed, the Midwest ISO's Response to that request regarding the Salem-Hazleton project previously reviewed and approved by the Midwest ISO's Board of Directors in Midwest ISO Transmission Expansion Plan 2008 Study. Please note that the Midwest ISO's Response makes reference, in Section 9.0, to certain Workpapers which support the Response but contain Critical Energy Infrastructure Information ("CEII"). Because the Workpapers contain CEII they have not been attached. However, these Workpapers can be provided to the IUB through appropriate nondisclosure processes that are available under the Midwest ISO Tariff Section 38.9.4 Process.

Thank you for the opportunity to assist the IUB with its review in this matter. Should anything further be required, please do not hesitate contacting me.

Kindest regards

/s/ Keith L. Beall

Keith L. Beall

KLB: rrs
Encl: Midwest ISO Response

Response to the Iowa Utilities Board:

P1340 Salem – Hazleton 345 kV line

(Eastern Iowa)

March 28, 2011

CONTENTS

1.0 EXECUTIVE SUMMARY

The Salem to Hazelton 345 kV transmission project (Project ID 1340) was approved for inclusion in the Midwest ISO regional plan in 2008 (MTEP 08). See area map below for reference. The project was recommended on the basis of a variety of benefits that included improved reliability, and reductions in congestion that would contribute to 1) eliminating the need for the Narrow Constrained Area designation in the area[1], and 2) reducing system production costs. This filing provides a review of the continuing relevance of those benefits based on updated system conditions and planning models.

The review confirms that the congestion and Narrow Constrained Area transmission issues, identified in support of MTEP08 approval of the project, still exist using latest data. In addition, under the present planning cases there continue to be reliability issues in Eastern Iowa if P1340 Salem – Hazleton 345 kV line is not constructed. P1340 is a key element of the present expansion plan for the area. The Midwest ISO continues to support construction of the P1340 on the same basis upon which it was originally recommended.

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1 The Independent Market Monitor designates an area as a Narrow Constrained Area (NCA) when one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours during a given year and within which one or more suppliers are pivotal. NCAs are chronically-constrained areas where one or more suppliers are frequently pivotal. Hence, they can be defined in advance and are subject to tighter market power mitigation. Lower-cost generation constrained by a NCA results in inefficient market operations.

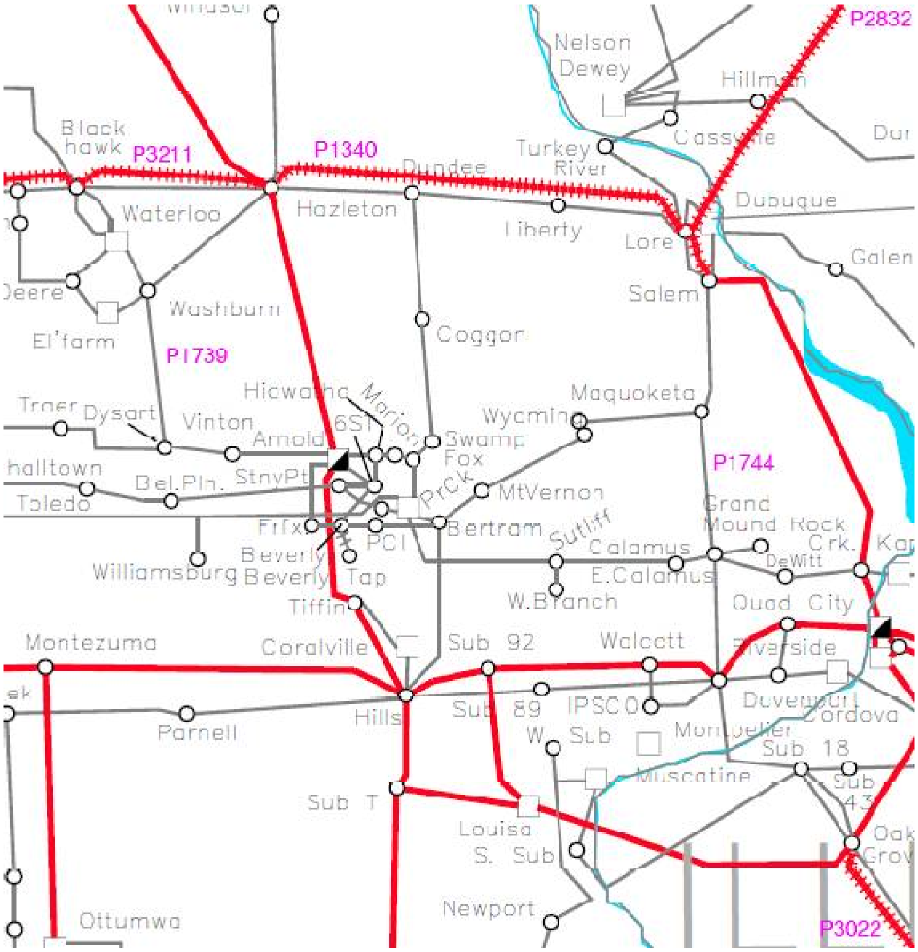

Figure 1 – Eastern Iowa Transmission System

2.0 PURPOSE

Iowa Utilities Board requested[2] that Midwest ISO provide a review of the Salem-Hazelton project proposal's performance based upon current system conditions relative to the project values established at the time of MISO approval of the project.

[2] In an IUB Order dated March 9, 2011, Docekt Nos. E-21948, E-21949, E-21950, & E-21951.

3.0 SCOPE

Review recent congestion and Narrow Constrained Area information. Perform a reliability screening using latest planning models with current assumptions. Identify transmission issues which are addressed by P1340 Salem – Hazleton 345 kV line.

NERC Transmission Planning standards TPL-001, TPL-002, and TPL-003 are the applicable criterion applied for this effort. The reliability screening evaluates NERC defined category A, B, and selected C contingencies.

Midwest ISO stakeholder members' thermal and voltage thresholds are used to flag thermal and voltage violations and voltage deviation exceptions on their respective systems. Results in Eastern Iowa area are presented.

4.0 MODELS

Six current planning cases were analyzed to review reliability issues addressed by P1340 Salem – Hazleton 345 kV line. Three system conditions were analyzed with and without Salem – Hazleton 345 kV line for the six cases listed in Table 4.1 below.

Table 4.1: Planning Cases Analyzed

Base Case \ Topology Scenarios	P1340 Salem-Hazleton 345 kV line
MTEP10_2015 Summer Peak SCED (wind 5%)	In case
MTEP10_2015 Summer Peak SCED (wind 5%)	Not in case
MTEP10_2015 Shoulder SCED (90% wind)	In case
MTEP10_2015 Shoulder SCED (90% wind)	Not in case
MTEP11_2021 Shoulder (90% wind) RMD	In case
MTEP11_2021 Shoulder (90% wind) RMD	Not in case

The 2015 base case dispatch in the Midwest ISO area is based on a Security Constrained Economic Dispatch (SCED) with the external areas having the traditional ERAG MMWG generation dispatch and firm long-term transactions. The 2021 base case dispatch is Midwest ISO Regional Merit Order Dispatch (RMD) with the external areas having the traditional ERAG MMWG generation dispatch and firm long-term transactions.

System Changes in Eastern Iowa

The following planned generation in Iowa entered interconnection queue after 1/1/2007, therefore, were not in 2006 study. Table 4.2 lists new Iowa generation by County with interconnection agreements completed or in process.

Table 4.2: New Iowa Generation Since 2006 Study

County	Estimated In Service Date	Coal	Nuclear	Wind
Madison	6/1/2008			250
Hancock	9/1/2008			200
Lee	9/15/2008	28		
O'Brien	12/1/2008			500
Linn	12/31/2008		30	
Story	12/31/2008			150
Adair	10/1/2009			100
Adair & Guthrie	10/1/2009			200
Hancock	11/1/2009			66
Delaware	12/31/2010			41
Marshall	12/31/2012			121
Grand Total		**28**	**30**	**1628**

Table 4.3 below lists the planned or proposed transmission projects in Eastern Iowa which have been made since the 2006 study along with two that are in the study planning cases. A majority are approved MTEP projects which are in service. The last two are proposed projects are in the planning process.

Table 4.3: New Transmission Upgrades Since 2006 Study

MTEP PrjID	Project Name	Expected In Service Date
2339	G612-Marshalltown-Boone 115kV rebuild to 161kV	10/1/2008
1341	Replace two Hazleton 161/69 kV transformers	6/1/2009
1337	Rose Hollow 161/69 kV substation	12/31/2009
1739	Arnold-Vinton-Dysart-Washburn 161kV Reconductor	12/31/2009
1345	Quad Cities-Rock Creek-Salem 345 kV line: Replace the limiting equipment in substations	6/1/2010
1346	Rock Creek 345/161 kV transformer: replace limiting equipment in substation	6/1/2010
2349	Savanna 161kV Terminal Upgrades on Galena-Savanna-York 161 kV line	6/1/2010
1287	Replace Salem 345/161 kV transformer with 448 MVA unit	7/30/2010
1522	6th Street - Beverly 161 kV line	11/30/2010
2365	Lansing-Genoa 161kV terminal upgrades	12/31/2010
2366	Adams-Harmony 161kV terminal upgrades	12/31/2010
2937	Sub 39: Add 2nd 345-161 kV transformer (proposed)	6/1/2014
2938	Uprate Sub 39 - Cordova 345 kV Line (proposed)	6/1/2014

5.0 CONGESTION REVIEW

A review of historical congestion data from MTEP10 shows that there continues to be congestion in Eastern Iowa. Congestion varies year-to-year as there are many factors which result in congestion, such as maintenance outages and other daily variations in system configuration. However there is persistent congestion in this area. MTEP11 preliminary findings indicate that there are more congestion hours but they are spread over more flowgates. Therefore, a specific flowgate's bound hours may reduce, but related flowgates have additional hours. For example there are twenty variations of the HAZLTON_HAZLTDUNDE16_1_1 flowgate. The flowgate prefixes were ignored to produce the generalized flowgates in Table 5.1 from 103 flowgates to distill the results and facilitate trending. Table 5.1 shows historical congestion on Eastern Iowa flowgates for the first five years of Midwest ISO market operation (not calendar years).

Table 5.1: Historical Congestion in Eastern Iowa – Flowgate Bound Hours

Generalized Flowgate	Sum of April 2005-March 2006	Sum of April 2006-March 2007	Sum of April 2007-March 2008	Sum of April 2008-March 2009	Sum of April 2009-March 2010
ARNOLD_ARNOLTIFFI34_1_1	33	28	0	0	0
ARNOLD_ARNOLVINTO16_1_1	25	73	88	83	0
Arnold_Hazleton_345	112	496	157	46	18
ARNOLD_TR21_TR21	1	6	0	0	7
Arnold_Vinton_161	105	216	135	72	2
Dundee_Hazleton161	0	77	189	81	27
DUNDEE_TR93_TR93	0	0	0	0	72
DUNDEE_TR94_TR94	4	0	0	0	13
Dundee-Hazleton 161	196	0	0	0	0
DYSART_DYSARWASHB16_1_1	0	0	14	0	0
E_CALMS_TR91_TR91	13	0	0	0	8
Emery_Lime_Creek_161	29	5	9	0	0
Hazleton-Blackhawk 161	20	0	17	91	112
HAZLTON_HAZLTARNOL34_1_1	22	176	0	0	0
HAZLTON_HAZLTBLKHA16_1_1	14	14	1	0	14
HAZLTON_HAZLTDUNDE16_1_1	33	47	4	31	5
Hzlton_345by161_xf_21	25	14	5	56	234
LANSING_TR91_TR91	0	0	0	0	267
LIME_CK_LIME_BARTO16_1_1	0	0	0	14	1
LIME_CK_LIME_EMERY16_1_1	36	97	78	0	96
LIME_CK_TR91_TR91	0	0	0	0	38
Lime_Creek_Emery_161	30	291	70	0	0
Rock Creek 345/161 TR	2	0	8	0	0
Salem_345_161_XFMR	9	98	68	9	23
SALEM3_TR21_TR21	4	22	4	2	60
SFOX_SFOXMARIO11_1_1	0	0	14	10	170
Sub_56_Davnprt_ECalamus161	45	81	121	18	52
Tiffin_Arnold_345kV	15	22	0	0	0
Grand Total	**773**	**1763**	**982**	**513**	**1219**

The projects identified in MTEP reports to address congestion in Eastern Iowa are:

P1288 Hazleton 345/161 kV transformer upgrade in MTEP08 report with 2011 expected in service date.

P1340 Salem - (Lore -) Hazleton 345 kV line in MTEP08, MTEP09, and MTEP10 reports (subject line of this review)

P1739 Arnold-Vinton-Dysart-Washburn 161kV reconductor in MTEP 09 and MTEP10 reports (project is in service)

Exhibit 1 contains Eastern Iowa historical congestion data for 103 specific flowgates with bound hours during the first five years of market operation.

Prior MTEP analyses of the Salem-Hazelton 345 kV line indicated that it provided an annual benefit in terms of production cost and LMP metrics in excess of its annual costs. Because congestion persists in the area, the line continues to be expected to provide congestion relief benefits to the area.

6.0 NARROW CONSTRAINED AREAS

Midwest ISO Independent Market Monitor's *2009 State of the Market Report for the Midwest ISO* indicates that Minnesota Narrow Constrained Area (NCA), described as SE MN, N IA, SE WI narrow constrained area in MTEP08 report, is still an NCA with pivotal suppliers and is a concern for market power that must be managed. P1340 is identified in the MTEP 08 report as a project which would help address this NCA. A quote from the Executive Summary of the Independent Market Monitor's report is included below.

Executive Summary Section F. Competitive Assessment and Market Power Mitigation (Page xvii)

> However, a more reliable indicator of potential market power is whether a supplier is "pivotal", which occurs when its resources are necessary to satisfy load or manage a constraint. In the examination of pivotal suppliers, we focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Narrow Constrained Areas ("NCA") and Broad Constrained Areas ("BCA"). NCAs are chronically constrained areas – three are currently defined: one in Minnesota, one in WUMS, and one in North WUMS (a subset of WUMS) – that raise more severe potential local market power concerns (so tighter market power mitigation measures are employed), while BCAs include all other areas within the Midwest ISO that are isolated by a binding transmission constraint.
>
> Sixty-four percent of active BCA constraints had a pivotal supplier in 2009, up from 59 percent in 2008. Seventy-five percent of the active NCA constraints into WUMS have a pivotal supplier (down from 79 percent in 2009), as do 75 percent of the active NCA constraints into Minnesota (up from 69 percent). In addition, nearly 80 percent of all intervals in 2009 exhibited an active BCA constraint with at least one pivotal supplier, while 30 percent and 6.5 percent of the intervals exhibited an active NCA constraint with at least one pivotal supplier in WUMS and Minnesota, respectively. These results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

Additional discussion on the 'Minnesota NCA' which has a majority of its flowgates in Eastern Iowa can be found on pages 109 to 115 of the 2009 State of the Market report which is included as Exhibit 2.

7.0 STEADY-STATE RELIABILITY REVIEW

Steady-state AC contingency analysis was performed on Eastern Iowa system for MTEP10 2015 summer peak and shoulder load system conditions with and without Salem – Hazleton 345 kV line project to determine the ramifications of not constructing the project. Plan year 2021 shoulder load cases were also examined to determine impact of the P1340 Salem – Hazleton 345 kV line on projected reliability issues in the area.

There are expected reliability issues in Eastern Iowa under the latest study assumptions for the near term planning horizon. The tables below highlight reliability issues caused by not proceeding with P1340 Salem – Hazleton 345 kV line project. There are a few issues which were aggravated by P1340, but overall it is beneficial for reliability under present study conditions.

Table 7.1 Thermal Issues in MTEP10 2015 Shoulder and Summer Peak Models Without and With P1340 Salem-Hazleton 345 kV line

Maximum Loading in Percent of Rating	2015 SH		2015 SP	
Limiting Element	**W/O**	**With**	**W/O**	**With**
630003 LANSING8 69.0 631053 LANSING5 161 1			131	130
630046 JASPER 8 69.0 631107 JASPER 5 161 1			102	
630053 NEWTON 8 69.0 630488 MAYTAG 8 69.0 1	101			
630053 NEWTON 8 69.0 631119 NEWTON 5 161 1	100			
630139 ADAMS 8 69.0 631122 ADAMS_N5 161 1	114	111		
630272 KNSASRT8 69.0 630647 TIFFIN R 69.0 1			104	101
630272 KNSASRT8 69.0 630649 TIFFIN 69.0 1			106	103
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1			119	106
630619 N CRNE T 69.0 630919 WASHTONBUS2869.0 1	102	101	119	120
630645 HRTLNDTP 69.0 630647 TIFFIN R 69.0 1			101	
630679 ALTWTIF8 69.0 636421 TIFFIN 5 161 1			135	128
630895 VINTON MUNI869.0 630902 VINTON 8 69.0 1	102			
631051 HAZL S 5 161 631101 DUNDEE 5 161 1	136			
631054 ASBURY 5 161 631055 CNTRGRV5 161 1			117	103
631054 ASBURY 5 161 631056 LORE 5 161 1			106	
631055 CNTRGRV5 161 631120 JULIAN 5 161 1			122	108
631056 LORE 5 161 631060 TRK RIV5 161 1	105	112	108	
631056 LORE 5 161 631125 KERPER 5 161 1			107	
631057 SALEM N5 161 631120 JULIAN 5 161 1			110	
631058 SO.GVW.5 161 631059 8TH ST.5 161 1			105	
631058 SO.GVW.5 161 631061 SALEM S5 161 1			133	118
631059 8TH ST.5 161 631125 KERPER 5 161 1			113	
631060 TRK RIV5 161 681519 CASVILL5 161 1	109	115	102	

Limiting Element	Maximum Loading in Percent of Rating 2015 SH W/O	2015 SH With	2015 SP W/O	2015 SP With
631061 SALEM S5 161 631098 MQOKETA5 161 1				100
631088 ARNOLD 5 161 631089 HIAWATA5 161 1				100
631095 E CALMS5 161 636616 SB 56 5 161 1			101	
631100 LIBERTY5 161 631101 DUNDEE 5 161 1	115			
631115 OTTUMWA5 161 631143 OTTUMWA3 345 1	101			
636640 LOUISA 3 345 636641 LOUIS31G 24.0 1			100	
698840 ACEC BADGERW 138 699240 SAR 138 138 1	117	113		
698840 ACEC BADGERW 138 699808 PETENWEL 138 1	119	115		
699033 DAR 138 138 699036 NOM 138 138 1	104	106		

Legend: Yellow are limiters mitigated by P1340, Green are limiters reduced by P1340, Pink are limiters aggravated by P1340.

Table 7.2 Thermal Issues in MTEP11 2021 Shoulder Model
With and Without P1340 Salem-Hazleton 345 kV line

Limiting Element	Maximum Loading in Percent of Rating 2021 SH W/O	2021 SH With
602016 REDCDR 5 161 602035 CRYSTAL5 161 1	101	
616002 GRE-JOHNJCT7 115 620216 ORTONVL7 115 1	100	
630016 MUSSWTH8 69.0 630507 SALS TAP 69.0 1	123	105
630019 LIBERTY8 69.0 630321 LIBERTP8 69.0 1	121	129
630019 LIBERTY8 69.0 631100 LIBERTY5 161 1	120	
630020 LUANA 8 69.0 630240 MONONA_8 69.0 1	106	
630020 LUANA 8 69.0 680048 POST 69.0 1	112	
630128 HAYWD#18 69.0 630129 HAYWD#28 69.0 1	100	
630128 HAYWD#18 69.0 680275 T GLEN 69.0 1	125	120
630129 HAYWD#28 69.0 630130 CO LINE8 69.0 1	100	
630139 ADAMS 8 69.0 630144 STWRTVL8 69.0 1	102	
630139 ADAMS 8 69.0 631122 ADAMS_N5 161 1	107	103
630145 STEWVLJ8 69.0 680538 AMOCO_8 69.0 1	103	
630290 DBQ 8TH8 69.0 631059 8TH ST.5 161 1	101	101
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1	124	104
630619 N CRNE T 69.0 630919 WASHTONBUS2869.0 1	102	
630895 VINTON MUNI869.0 630902 VINTON 8 69.0 1	104	
631047 LIME CK5 161 631048 EMERY 5 161 1	111	115
631051 HAZL S 5 161 631101 DUNDEE 5 161 1	156	
631056 LORE 5 161 631060 TRK RIV5 161 1	133	
631060 TRK RIV5 161 681519 STONEMAN 161 1	138	
631100 LIBERTY5 161 631101 DUNDEE 5 161 1	145	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	126	118
631127 HAYWD#15 161 631180 FREEBORN5 161 1	131	131

Limiting Element						Maximum Loading in Percent of Rating 2021 SH W/O	With
635032 HASTING5	161	635033 HASTING8	69.0	1		101	
681532 WABACO 5	161	681537 ROCHSTR5	161	1		142	128
698127 SPG 69	69.0	699114 SPG 138	138	1			119
698840 ACEC BADGERW	138	699240 SAR 138	138	1		101	
698840 ACEC BADGERW	138	699808 PETENWEL	138	1		104	

Legend: Yellow are limiters mitigated by P1340, Green are limiters reduced by P1340, Pink are limiters aggravated by P1340.

Table 7. 3 Low Voltage Issues in All Cases (per unit)

Minimum Voltage	2015 SH		2015 SP		2021 SH	
kV - Bus Name	**Without**	**With**	**Without**	**With**	**Without**	**With**
161.0						
8TH ST.5	0.861	0.862	0.778	0.778	0.779	0.794
ASBURY 5					0.888	
CNTRGRV5					0.888	
JULIAN 5					0.888	
KERPER 5			0.868	0.883	0.855	0.882
LIBERTY5	0.890	0.900	0.861	0.862	0.875	0.882
LORE 5			0.874	0.891	0.857	0.886
PRARSTR_WF5					0.900	
SO.GVW.5			0.866	0.881	0.855	0.881
345.0			**0.865**			
HAZLTON3			0.891			
SALEM 3	0.896		0.865		0.845	0.870

There were seven high voltages in MTEP11 2012 Shoulder case without the P1340 project.

Updated analysis shows that P1340 continues to be effective in relieving projected reliability violations in the area. P1340 was approved in MTEP08 and is an integral part of a reliable and efficient regional plan for the area. Without its construction, as originally approved, reliability in the area will not meet below accepted standards.

Exhibit 3 contains detailed steady-state AC analysis results which indicate contingencies for which the thermal overload and voltage issues occur.

8.0 CONCLUSION

The congestion and Narrow Constrained Area transmission issues, identified in the MTEP08, still exist using latest data. The Independent Market Monitor continues to note that there is an NCA in Eastern Iowa and Southern Minnesota which has potential for market power issues. Under present planning cases there are projected reliability issues in Eastern Iowa if P1340 Salem – Hazleton 345 kV line is not constructed. Therefore, P1340 continues to be a key element of the present expansion plan for the area which includes numerous other lines. The Midwest ISO continues to support and recommend that P1340 Salem – Hazleton 345 kV line be constructed.

9.0 EXHIBITS

Exhibits contain supporting documentation and detailed results:

Exhibit 1_Eastern Iowa Historical Congestion

Exhibit 2_2009 State of the Market Report [for the Midwest ISO]

Workpapers: Eastern Iowa Steady-State Results 032411_CEII.xlsx

These Workpapers contain Critical Energy Infrastructure Information and because of that, they have not been attached. These Workpapers can be provided to the authorized representatives of the IUB through appropriate nondisclosure processes that are available under the Midwest ISO Tariff Section 38.9.4 Process.

Exhibit 1: Eastern Iowa Historical Congestion by Market Year

NERC ID	Flowgate Name / Description	Control Area	Bound Flowgate-Hours April 2005-March 2006	April 2006-March 2007	April 2007-March 2008	April 2008-March 2009	April 2009-March 2010
	ALWGEN03_ARNOLD_ARNOLTIFFI34_1_1	ALTW,MEC	30	28	None	None	None
	MEC34025_ARNOLD_ARNOLTIFFI34_1_1	ALTW,MEC	3	None	None	None	None
	ALW34003_ARNOLD_ARNOLVINTO16_1_1	ALTW	3	None	None	None	None
	ALW3403G_ARNOLD_ARNOLVINTO16_1_1	ALTW	13	73	88	53	None
	ALW34X01_ARNOLD_ARNOLVINTO16_1_1	ALTW	None	None	None	30	None
	MEC34000_ARNOLD_ARNOLVINTO16_1_1	ALTW	5	None	None	None	None
	MEC34020_ARNOLD_ARNOLVINTO16_1_1	ALTW	4	None	None	None	None
3706	Arnold_Hazleton_	ALTW	112	480	157	46	18
3749	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	ALTW	None	None	None	None	None
6182	Arnold-Hazleton 345 kV FLO Sherco 3	ALTW	None	16	None	None	None
	NSPGEN07_ARNOLD_TR21_TR21	ALTW	1	None	None	None	None
	MECALW07_ARNOLD_TR21_TR21	ALTW	None	6	None	None	None
	NSPGEN01_ARNOLD_TR21_TR21	ALTW	None	None	None	None	7
3724	Arnold_Vinton_161_for_DArnold_Hazleton_345_	ALTW	105	216	135	72	2
3766	Dundee_Hazleton161_flo_Arnold_Hazleton345	ALTW	None	77	189	81	27
	ALW16012_DUNDEE_TR93_TR93	ALTW	None	None	None	None	72
	ALW34003_DUNDEE_TR94_TR94	ALTW	4	None	None	None	None
	ALW34X01_DUNDEE_TR94_TR94	ALTW	None	None	None	None	12
	ALW11039_DUNDEE_TR94_TR94	ALTW	None	None	None	None	1
13256	Dundee-Hazleton 161kV FLO Dysart-Washburn 161kV	ALTW	196	None	None	None	None
	ALW3403G_DYSART_DYSARWASHB16_1_1	ALTW,MEC	None	None	14	None	None
	ALWGEN03_E_CALMS_TR91_TR91	ALTW	13	None	None	None	8
3756	Emery_Lime_Creek_161_flo_Emery_Floyd_161	ALTW	29	5	9	None	None
13351	Hazleton-Blackhawk flo Dysart-Washburn	MEC	4	None	None	None	None
13323	Hazleton-Blackhawk 161kV flo Dysart-Washburn 161kV	ALTW,MEC	16	None	None	None	None
6190	Hazleton-Black Hawk 161 FLO Ha	ALTW,MEC	None	None	17	91	112
	NSPGEN07_HAZLTON_HAZLTARNOL34_1_1	ALTW	22	176	None	None	None
	ALWMEC13_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	8	14	1	None	None
	ALWMEC16_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	6	None	None	None	None
	MEC16005_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	None	None	None	None	2
	ALW16019_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	None	None	None	None	None
	ALW16043_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	None	None	None	None	11
	ALWGEN01_HAZLTON_HAZLTBLKHA16_1_1	ALTW,MEC	None	None	None	None	1
	ALENSP02_HAZLTON_HAZLTDUNDE16_1_1	ALTW	7	None	None	None	None
	ALENSP1G_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	4	None	None	None
	ALW16038_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None

Exhibit 1: Eastern Iowa Historical Congestion by Market Year

NERC ID	Flowgate Name / Description	Control Area	Bound Flowgate-Hours April 2005-March 2006	April 2006-March 2007	April 2007-March 2008	April 2008-March 2009	April 2009-March 2010
	ALW34003_HAZLTON_HAZLTDUNDE16_1_1	ALTW	11	7	None	None	None
	ALW34004_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	ALWARTIF_HAZLTON_HAZLTDUNDE16_1_1	ALTW	5	None	None	None	None
	ALWMEC08_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	9	None	None	5
	ALWMEC2_ HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	BASE_ HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	10	4	None	None
	MEC34018_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	15	None	1	None
	MEC34020_HAZLTON_HAZLTDUNDE16_1_1	ALTW	10	None	None	None	None
	ALENSP1 _HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	ALW3403G_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	4	None
	CEALW01_ HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	10	None
	CEALW01G_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	6	None
	MEC3401G_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	10	None
	MEC34045_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	NSPALE01_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	NSPALW04_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	None	None	None	None
	NSPGEN07_HAZLTON_HAZLTDUNDE16_1_1	ALTW	None	2	None	None	None
3758	Hzlton_345by161_xf_21_flo_Hzlton_345by161_xf_22	ALTW	25	14	5	56	234
	DPCALW06_LANSING_TR91_TR91	ALTW	None	None	None	None	267
	ALW16080_LIME_CK_LIME_BARTO16_1_1	ALTW	None	None	None	14	1
	MECALW04_LIME_CK_LIME_BARTO16_1_1	ALTW	None	None	None	None	None
	ALW16001_LIME_CK_LIME_EMERY16_1_1	ALTW	None	6	None	None	None
	ALW3403G_LIME_CK_LIME_EMERY16_1_1	ALTW	2	None	None	None	None
	DPCGEN01_LIME_CK_LIME_EMERY16_1_1	ALTW	3	None	None	None	None
	MP50X01 _LIME_CK_LIME_EMERY16_1_1	ALTW	None	4	None	None	None
	NSP34002_LIME_CK_LIME_EMERY16_1_1	ALTW	None	18	None	None	None
	NSP34005_LIME_CK_LIME_EMERY16_1_1	ALTW	8	None	None	None	None
	NSP3405G_LIME_CK_LIME_EMERY16_1_1	ALTW	6	None	None	None	None
	NSP3406 _LIME_CK_LIME_EMERY16_1_1	ALTW	None	1	None	None	None
	NSPGEN01_LIME_CK_LIME_EMERY16_1_1	ALTW	4	None	None	None	None
	NSPGEN02_LIME_CK_LIME_EMERY16_1_1	ALTW	6	None	None	None	None
	NSPGEN05_LIME_CK_LIME_EMERY16_1_1	ALTW	None	8	None	None	None
	NSPGEN07_LIME_CK_LIME_EMERY16_1_1	ALTW	7	28	9	None	None
	ALW16024_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	3	None	None
	ALW16045_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	None	None	26
	ALW16080_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	None	None	1

Exhibit 1: Eastern Iowa Historical Congestion by Market Year

NERC ID	Flowgate Name / Description	Control Area	Bound Flowgate-Hours April 2005-March 2006	April 2006-March 2007	April 2007-March 2008	April 2008-March 2009	April 2009-March 2010
	ALW16096_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	None	None	66
	ALW16X57_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	None	None	3
	ALW16X69_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	None	None	None
	ALW34002_LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	5	None	None
	ALW3403_ LIME_CK_LIME_EMERY16_1_1	ALTW	None	None	23	None	None
	MECALW09_LIME_CK_LIME_EMERY16_1_1	ALTW	None	32	38	None	None
	ALW16X69_LIME_CK_TR91_TR91	ALTW	None	None	None	None	38
3745	Lime_Creek_Emery_161_flo_Adams_Hazleton_345	ALTW	30	291	70	None	None
3716	Rock Creek 345/161 TR for Quad-Sub 91 345	ALTW	2	None	8	None	None
3752	Salem_345_161_XFMR_flo_Tiffin_Arnold_345	ALTW	3	51	59	3	20
3753	Salem_345_161_XFMR_flo_Hills_Tiffin_345	ALTW	None	1	None	None	3
14172	Salem_Xfmr_345by161_kV_FLO_Sub92_345kV_Bus	ALTW	None	None	1	None	None
3719	Salem 345/161 (flo) Quad Cities	ALTW	6	46	8	6	None
3721	Salem 345/161 for Quad-Sub 91 TR	ALTW	None	None	None	None	None
	MEC34018_SALEM3_TR21_TR21	ALTW	None	4	None	None	None
	MEC34033_SALEM3_TR21_TR21	ALTW	None	3	None	None	None
	MEC34X04_SALEM3_TR21_TR21	ALTW	2	None	None	None	None
	ALW16X08_SALEM3_TR21_TR21	ALTW	None	2	None	None	None
	ALW3403_ SALEM3_TR21_TR21	ALTW	None	None	None	None	1
	ALW3403G_SALEM3_TR21_TR21	ALTW	None	None	4	None	31
	ALWGEN03_SALEM3_TR21_TR21	ALTW	None	None	None	None	28
	CEMEC02 _SALEM3_TR21_TR21	ALTW	None	10	None	None	None
	DPCGEN02_SALEM3_TR21_TR21	ALTW	None	3	None	None	None
	MEC34027_SALEM3_TR21_TR21	ALTW	None	None	None	2	None
	MEC34036_SALEM3_TR21_TR21	ALTW	2	None	None	None	None
	ALW3403_SFOX_SFOXMARIO11_1_1	ALTW	None	None	14	10	170
	ALWMEC1_SFOX_SFOXMARIO11_1_1	ALTW	None	None	None	None	None
3725	Sub_56_Davnprt_ECalamus161_for_Quad_RockCr345_	ALTW,MEC	45	81	121	18	52
13350	Tiffin_Arnold_345kV_flo_Arnold_Unit_1	ALTW,MEC	15	20	None	None	None
11775	Tiffin-Arnold 345 flo Montezuma-Bondurant 345	ALTW	None	None	None	None	None
14063	Tiffin-Arnold 345kV flo Sherco Unit 3	ALTW	None	2	None	None	None

2009 State of the Market Report
for the Midwest ISO

Prepared by:

POTOMAC ECONOMICS

Independent Market Monitor
for the Midwest ISO

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Guide to Acronyms

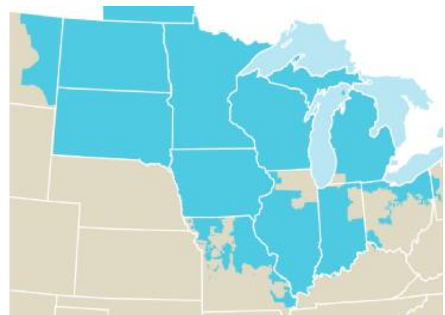
ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ARS	Automatic Reserve Sharing
AS	Ancillary Services
ASM	Ancillary Services Market
BCA	Broad Constrained Area
BRM	Broader Regional Markets Initiative
BTMG	Behind-The-Meter Generation
C&I	Commercial & Industrial
CC	Combined Cycle
CDD	Cooling Degree Day
CT	Combustion Turbine
DAMAP	Day-Ahead Margin Assurance Payment
DCS	Disturbance Control Standard
DLC	Direct Load Control
DR	Demand Response
DRR	Demand Response Resource
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
FFE	Firm Flow Entitlement
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
IESO	Ontario Independent Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
kWh	Kilowatt-Hour
LMP	Locational Marginal Price
LSE	Load-Serving Entity
MCP	Marginal Clearing Price

(Continued)

MHEB	Manitoba Hydro Electricity Board
MidAmerican	MidAmerican Energy Holdings, Inc.
Midwest ISO	Midwest Independent Transmission System Operator
MMBtu	Million British Thermal Units, a measure of energy content
Muscatine	Muscatine Power & Water, Inc.
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corporation
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
O&M	Operations & Maintenance
PAR	Phase Angle Regulator
PJM	PJM Interconnection, Inc.
PVMWP	Price Volatility Make Whole Payment
RDI	Residual Demand Index
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
RTORSGP	Real Time Operating Revenue Sufficiency Guarantee Payment
SMP	System Marginal Price
SPP	Southwest Power Pool, Inc.
STLF	Short-Term Load Forecast
TLR	Transmission Loading Relief
VCA	Voluntary Capacity Auction
WUMS	Wisconsin-Upper Michigan System

I. Executive Summary

As the Independent Market Monitor ("IMM") for the Midwest Independent Transmission System Operator ("Midwest ISO"), Potomac Economics is responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by the Midwest ISO. In this State of the Market Report for 2009, we provide our annual evaluation of the Midwest ISO's markets and our recommendations for future improvements.



The Midwest ISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead and real-time energy markets that produce prices that vary across the region to reflect the marginal cost of supply, transmission congestion, and losses. These markets are designed to facilitate an efficient daily commitment of generation, to dispatch the lowest-cost resources to satisfy the system's demands without overloading the transmission network, and to provide transparent economic signals to guide short-run and long-run decisions by participants and regulators. The Midwest ISO also operates a market for Financial Transmission Rights ("FTRs") that allows participants to hedge the congestion risk associated with serving load or engaging in other transactions.[1]

Two notable additions to the markets were introduced in 2009. First, the Midwest ISO began operating as a balancing authority in January and introduced markets for regulation and contingency reserves known collectively as Ancillary Services Markets ("ASM"). These markets jointly optimize the allocation resources between energy and ASM markets, and allow prices to reflect shortages more efficiently. Despite the scope and complexity of this project, the ASM markets were introduced smoothly and have operated as expected. Second, the Midwest ISO in June began operating a Voluntary Capacity Auction ("VCA") for loads to meet residual requirements under Module E of its Tariff, and clarified the enforcement of these requirements. This establishes a spot market for capacity that will help ensure that long-run economic signals.

1 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

A. Summary of Findings

Overall, we found that the market performed competitively in 2009. Although certain suppliers in the Midwest ISO have local market power, our analysis raised no competitive concerns that suppliers withheld resources to raise prices.

Energy prices decreased by roughly 45 percent from 2008 to 2009 due to sharp reductions in fuel prices and lower load. In a competitive market, suppliers will face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs for most generators. Natural gas prices decreased by 55 percent on average, while oil prices declined by 44 percent. Illinois Basin and Powder River Basin coal prices decreased by approximately 30 percent. In a competitive market, suppliers will face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs for most generators. The continuing close correspondence of energy prices and fuel prices in the Midwest ISO is a demonstration of the competitiveness of Midwest ISO's markets.

After adjusting for lower fuel prices, real-time energy prices still fell by almost 15 percent in 2009. This indicates that several other factors contributed to lower energy prices, including:

- Average load served by the Midwest ISO decreased by 6.6 percent compared to 2008 due to mild weather and poor economic conditions;
- Large quantities of surplus capacity in the Midwest ISO region and low peak demands led to relatively few operating reserve shortages and associated peak energy pricing;
- Substantial increases in generation from wind resources in 2009 lowered prices by displacing higher-cost resources and contributing to surplus generation in real-time; and
- Improved optimization of energy and reserves under ASM.

In addition to the lower energy prices, congestion costs fell by 37 percent in 2009 and RSG costs fell by 47 percent. These reductions were primarily due to:

- Lower fuel prices;
- Lower load;
- Transmission upgrades that relieved a number of key constraints; and
- Improved supply flexibility under the ASM.

Despite the introduction of the ASM and VCA, overall incentives for investment remained weak in 2009 due to the surplus capacity in the region. In long-run equilibrium, markets should provide net revenues that provide efficient incentives for investment and retirement. This report shows that the net revenues provided by the Midwest ISO markets in 2009 would be insufficient to cover the annualized cost of new investment for a generic combined-cycle unit or gas turbine. This is consistent with expectations for a well-functioning market because the prevailing capacity surplus and relatively low load should not produce incentives to build new resources.

Although new resources are not needed currently for reliability, the Midwest ISO continues to develop and promote various changes to its market design and operating procedures to allow additional resources – particularly intermittent resources, Demand Response ("DR") resources, and interruptible load – to integrate more fully into its existing markets. The Midwest ISO is anticipating an additional 1,600 MW of wind generating capacity by the summer of 2010. Although wind provides substantial environmental benefits, its intermittent nature limits its contribution to reliability and resource adequacy in the long-run. It also creates operational challenges that the Midwest ISO is working to address in the short-run.

Given the importance of external transactions and the extensive network interactions in the Midwest, our report evaluates the interchange and coordination with neighboring areas. The Midwest ISO continues to rely heavily on imports from adjacent areas, averaging 3.6 gigawatts ("GW") in the peak hours of 2009 and 2.4 GW in the off-peak hours. The prices at the border between the markets are well arbitraged in most hours, but could be improved by optimizing net interchange, particularly with the PJM Interconnection ("PJM"). In addition, transaction scheduling around Lake Erie remained an issue in 2009 and generated significant un-scheduled power flows (i.e., "loop flows"). The Broader Regional Markets ("BRM") Initiative being jointly developed by the Regional Transmission Organizations ("RTOs") around Lake Erie consists of a package of physical and market solutions that we expect will substantially improve the efficiency of scheduling and pricing throughout the Midwest ISO, New York Independent System Operator ("NYISO"), Independent Electricity System Operator of Ontario ("IESO"), and PJM footprints.

While market-to-market coordination between the Midwest ISO and PJM continues to increase efficiency of the RTOs congestion management, a significant issue was discovered in 2009 that impacted the market to market settlements over the past four years. In April 2009 the Midwest ISO identified an issue with PJM's market flow calculations that frequently understated PJM's market flows for the past several years. The settlement issues associated with these issues is currently the subject of a number of complaints before the Commission. Additionally, a number of disagreements regarding the interpretation of the Joint Operating Agreement ("JOA") between the Midwest ISO and PJM and several other issues have resulted in two referrals by the IMM to the Federal Energy Regulatory Commission (the "Commission"). We recommend that the RTOs work together to institute a process to more closely monitor the exchange of information and other modeling parameters, provisions or procedures to optimize the interchange process, and to clarify the JOA in a number of areas to minimize future disagreements and ensure efficient outcomes.

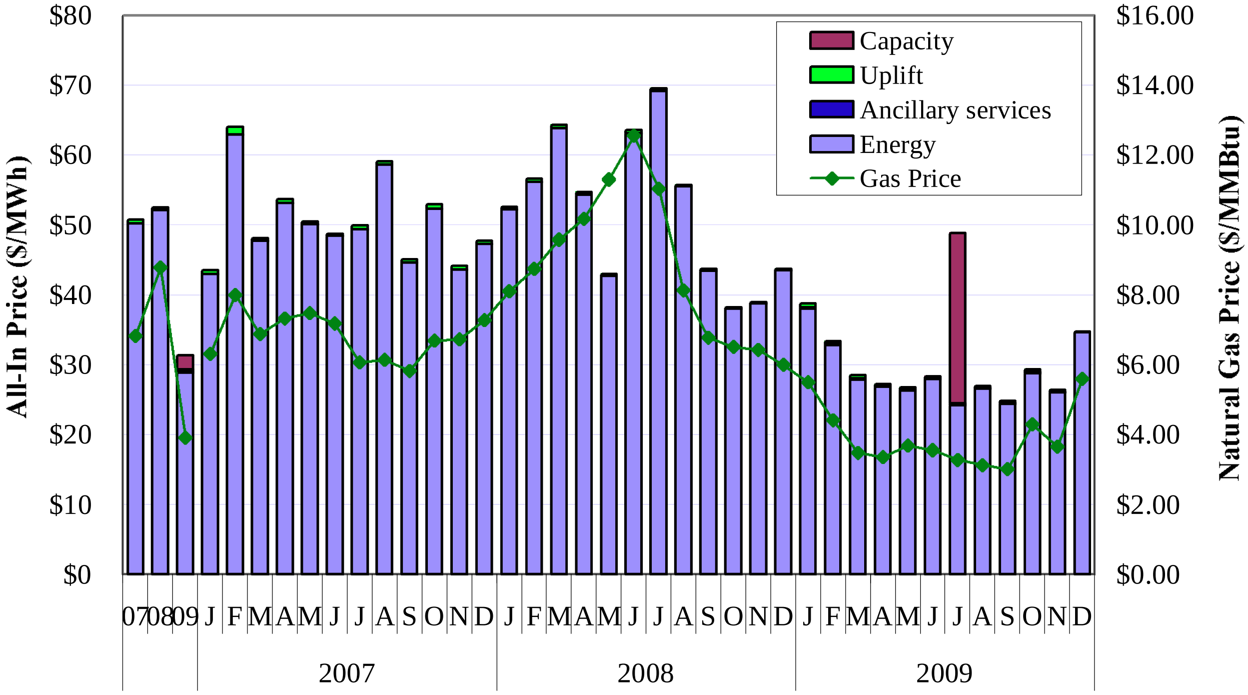
Finally, although the report concludes that the market performed well in 2009, we provide a number of recommendations to improve its efficiency and competitiveness. These recommendations address energy pricing, congestion management, real-time operations, external transaction scheduling, the market-to-market process, capacity market rules, demand response development, and wind integration. Work is underway by the Midwest ISO to evaluate and address these recommendations.

In the remainder of this Executive Summary, we provide a more detailed discussion of the market outcomes and issues in 2009, along with a description of each of our recommendations to improve the performance of the Midwest ISO markets.

B. Short-Term Prices and Long-Term Economic Signals

We summarize changes in prices and costs in Figure E-1, which shows an "all-in" price of electricity. This represents the total cost of serving load. The all-in price of electricity is equal to the load-weighted average real-time energy price plus capacity costs, ancillary service costs, and average real-time uplift costs per megawatt ("MW") of real-time load.[2]

Figure E-1: All-In Price of Electricity
2007 – 2009



The all-in price was $31.28 per megawatt-hour ("MWh") in 2009, a 40-percent decrease from 2008. The figure shows that price fluctuations are generally driven by changes in fuel prices as one would expect in a well-functioning market. This relationship exists because fuel costs represent the majority of most suppliers' marginal costs of production. Since suppliers in a competitive market have the incentive to offer their supply at marginal cost, changes in fuel prices directly translate into changes in offer prices when the market performs competitively.

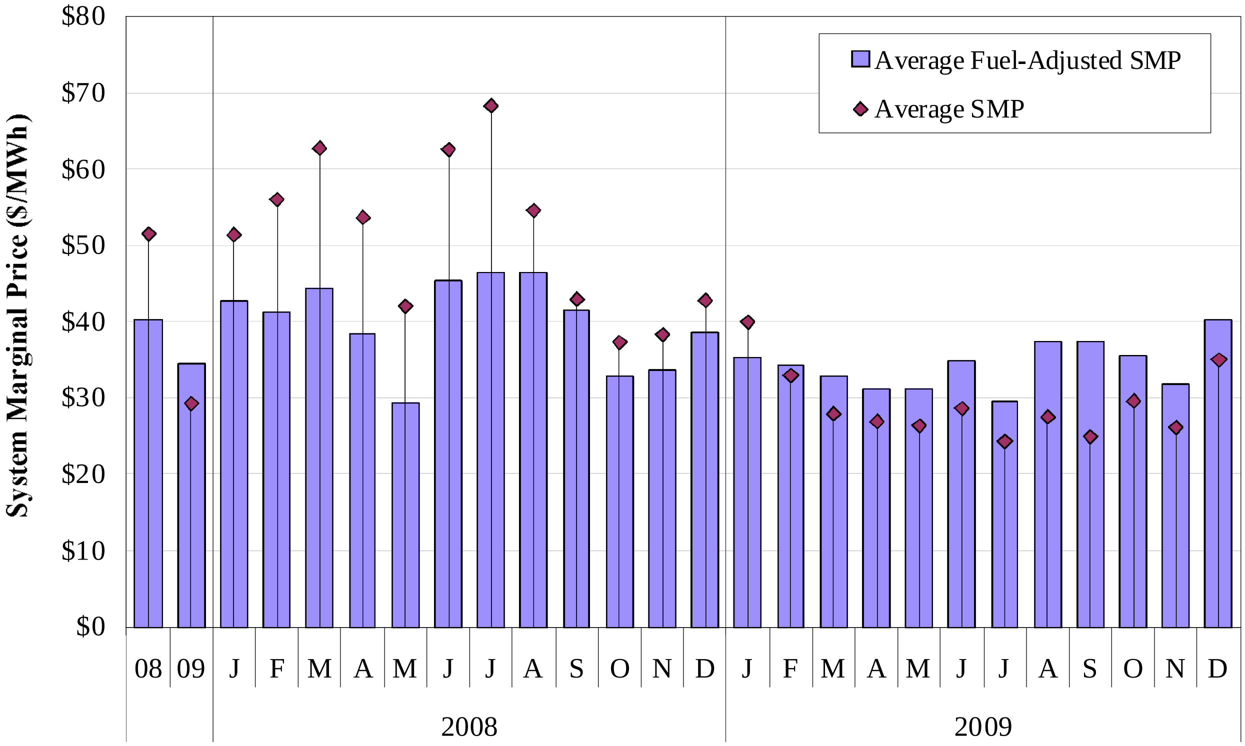
Figure E-1 also shows that the price of energy was lower in nearly every month in 2009 than in any month during the preceding two years. Uplift and ancillary services costs continue to be a small share of the all-in price (less than one percent). The VCA was introduced in June 2009.

2 Uplift costs are primarily comprised of real-time Revenue Sufficiency Guarantee Make Whole Payments ("RSG").

The VCA cleared at very low prices in all months except July, when the auction cleared at a high price due to large amounts of capacity that were not offered competitively.[3]

As discussed above, the energy price reductions in 2009 were largely driven by lower fuel prices. To estimate the price effects of other factors, we calculate a fuel price-adjusted system marginal price ("SMP"), shown in Figure E-2 below. To calculate this metric, each interval's SMP was indexed to the average two-year fuel price of the marginal fuel during the interval. The price-setting fuel for each interval was assumed to be the fuel that was most frequently on the margin during the particular interval (more than one fuel can be on the margin in a single interval). This metric does not account for changes in commitment or dispatch that may occur under different levels of fuel prices.

Figure E-2: Fuel Price-Adjusted System Marginal Price
2008 – 2009



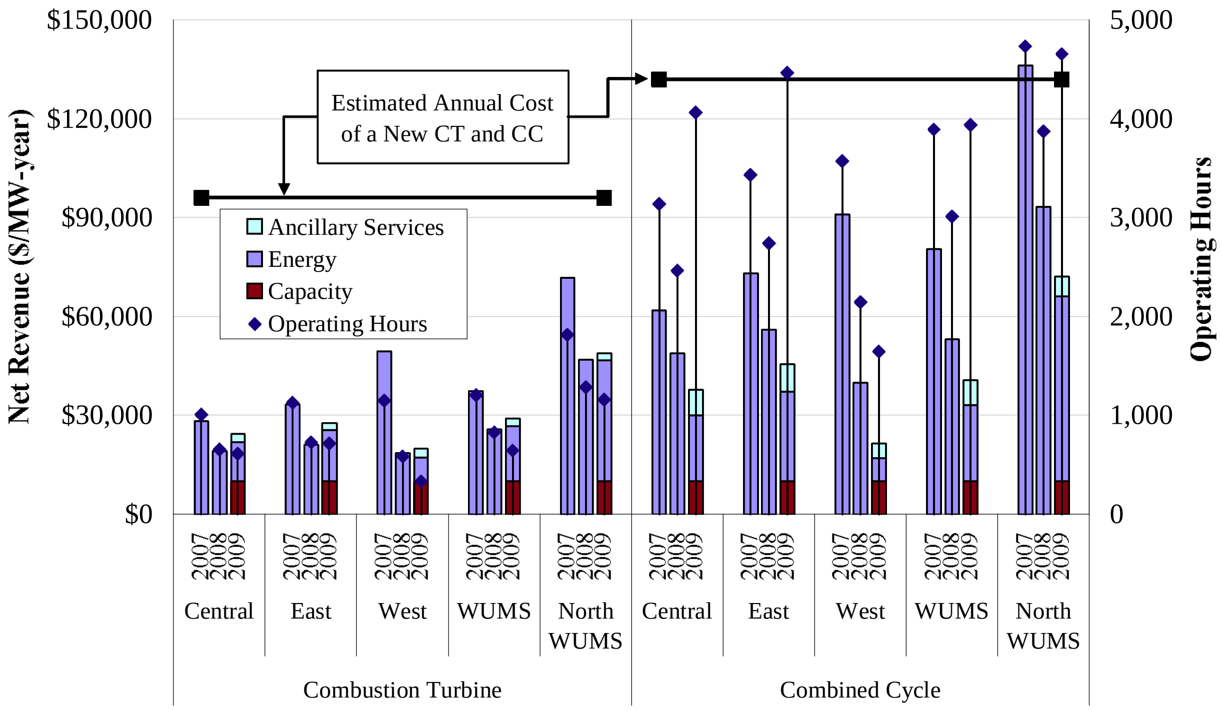
Average fuel-adjusted energy prices fell almost 15 percent in 2009. This reduction was

3 Although little capacity cleared, the spot price is used to estimate the market's capacity costs for the month, so it is sizable in July.

primarily due to milder than normal temperatures, reduced economic demand, and the effects of ASM. Although the methodology does not capture several likely impacts of changing fuel prices on generation dispatch, the figure clearly demonstrates that fuel price changes account for a significant share of the year-over-year change in electricity prices.

Finally, one of the most important assessments of the Midwest ISO markets is our evaluation of wholesale prices as signals for investment in new resources and transmission capability. We evaluate wholesale price signals by estimating the "net revenue" that a new generating unit would have earned from the market under prevailing prices. Net revenue is the revenue that a new generator would earn above its variable production costs if it runs when it is economic and does not run when it is not economic. A well-designed market should produce net revenues sufficient to finance new investment when the available resources are not sufficient to meet the needs of the system. Figure E-3 shows estimated net revenues for a hypothetical new combustion turbine ("CT") and combined-cycle ("CC") generator for 2007 through 2009.

Figure E-3: Net Revenue Analysis
2007 – 2009



The figure also shows the estimated annual cost of each unit type, which is the minimum annual net revenue that would be needed for these investments to be profitable. The net revenue analysis indicates that net revenues for both a new combined-cycle unit and combustion turbine were substantially less than the annual cost of new entry for both technology types in 2009, even in the highest-priced regions. This is consistent with expectations because the Midwest ISO footprint continues to exhibit a sizable capacity surplus and did not experience significant periods of shortage in 2009.

Even though shortages were not frequent, shortage pricing improved considerably in 2009 with the introduction of AS markets, which are jointly optimized with energy markets. When resources are not sufficient to satisfy reserve requirements, the operating reserve demand curve will set reserve prices and consequently improve energy price signals. The Midwest ISO is working on pricing changes to allow peaking units and interruptible load to set prices, which would further improve efficient shortage prices and increase net revenues. Long-term market signals also improved in 2009 with the introduction of the VCA, which is a monthly spot market for capacity that provides an additional means for loads to satisfy their Module E capacity requirements. As excess capacity in the region declines, it will be important that the Midwest ISO's markets send efficient long-term signals. To that end, we recommend several improvements to pricing mechanisms in this report.

C. Day-Ahead and Real-Time Market Performance

The spot markets for electricity run by the Midwest ISO operate in two timeframes: the actual operating timeframe referred to as the real-time market and one day in advance of the operating timeframe referred to as the day-ahead market. The real-time market reflects the actual physical supply and demand conditions at any point in time. The day-ahead market is largely financial and establishes financially-binding, one-day forward contracts for energy and ancillary services. This section of the executive summary describes our evaluation of the day-ahead and real-time markets.

1. Day-Ahead Market

The performance of the day-ahead market is important for three reasons:

- The day-ahead market determines most of the generator commitments in the Midwest ISO; hence, efficient commitment requires efficient day-ahead market outcomes;
- Most wholesale energy bought or sold through the Midwest ISO markets is settled in the day-ahead market; and
- The entitlements of firm transmission rights are determined by the outcomes of the day-ahead market (the payment to an FTR holder is based on day-ahead congestion).

We evaluate the performance of the day-ahead market primarily by measuring the degree to which it converges with the real-time market because the real-time market reflects the actual physical supply and demand for electricity. Based on our analysis in this report, we find price convergence in the Midwest ISO was fair in 2009. The Midwest ISO generally exhibits day-ahead premiums which can be attributed to the higher volatility, risk, and RSG cost associated with buying in the real-time market. The day-ahead premiums are generally larger in the Midwest ISO than in other RTOs due to higher RSG allocations to real-time purchases. The convergence in congested areas in the West was worse than in other locations, in part because virtual trading activity fell substantially in 2009. This caused day-ahead congestion out of the West to be understated.

By arbitraging price differences, active virtual supply and demand participation in the day-ahead market also contributed to good price convergence in the Midwest ISO. However, virtual trading levels decreased substantially since late 2008 and into 2009. These reductions can be attributed to RSG allocation decisions made by the Commission in November 2008 and to tight credit conditions. Liquidity in the day-ahead market should improve when the Midwest ISO implements its new Indicative Rate RSG allocation, which will reduce the costs imposed on virtual supply offers.

2. Real-Time Market

Prices in the real-time market are generally more volatile than prices in the day-ahead market. However, real-time price volatility decreased 17 percent in 2009, due in part to the introduction of ASM. ASM has resulted in improved supply flexibility that allows the real-time market to satisfy the system's demands with less price volatility. Volatility in the Midwest ISO remained substantially higher than in neighboring RTOs because the Midwest ISO runs a true five-minute real-time market that produces a new dispatch and prices every five minutes.[4] Since the real-time market software is limited in its ability to look ahead, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can up or down). This results in transitory spikes in prices up or down. Ramp constraints can also bind and cause price volatility when large changes in the Net Scheduled Interchange ("NSI") occur or when several generators are either started or shutdown. This report includes recommendations to improve the management of ramp capability.

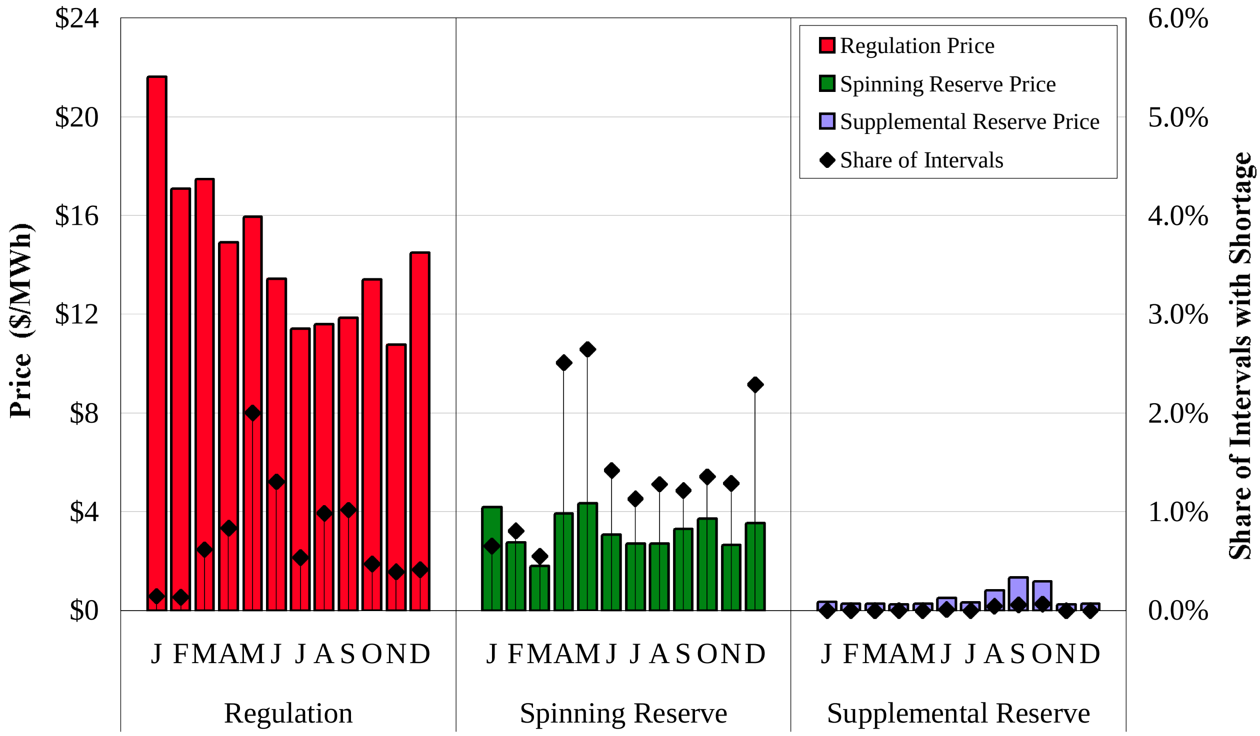
3. Ancillary Services Markets

The Midwest ISO introduced ASM markets in January 2009, which have performed as expected with no significant issues. ASM markets have led to improved system flexibility, lower price volatility, and have set more efficient prices that reflect the economic trade-offs between energy and operating reserves. ASM prices have been consistent with expectations and with ASM results in similar RTO markets.

Figure E-4 shows the monthly average prices for regulation, spinning reserves, and supplemental reserves. It also shows the portion of the intervals that exhibited a shortage in each respective product. Regulation prices decreased over the course of 2009, dropping from $22 per MWh in January to less than $11 per MWh in November. Much of this decline is attributable to reductions in reserve requirements during the first half of the year and increased commitment of regulating resources available for scheduling. Spinning reserve prices averaged approximately $3 per MWh in 2009, and were very stable at levels consistent with our expectations based on the costs of providing spinning reserves and prices in other RTO markets. Spinning reserve prices were slightly higher in the spring of 2009 due to higher levels of shortages.

4 A number of other RTOs produce a new dispatch approximately every 15 minutes with a 15-minute time horizon.

Figure E-4: ASM Prices and Shortage Frequency
2009



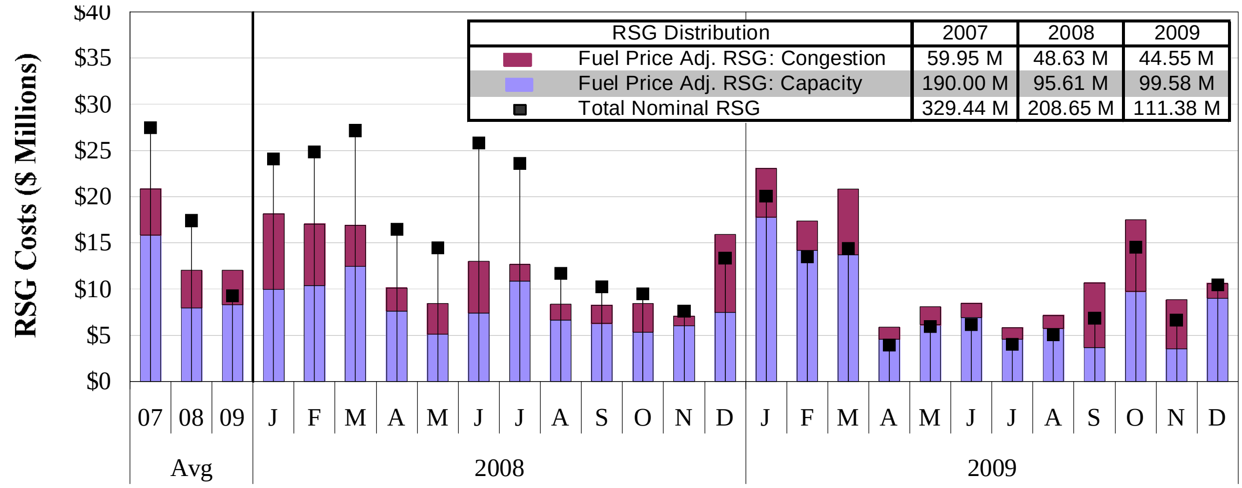
Spinning reserve shortages occurred at a moderate frequency in 2009. The report concludes that many of these shortages reflect market requirements that exceed the true reliability requirements. This inconsistency decreased over the year, but it could be improved further. This report also shows that prices do not always accurately reflect the spinning reserve shortages due to the method of relaxing the requirement during the shortage. This report includes a recommendation to improve pricing during shortage periods by discontinuing the relaxation process.

4. RSG Payments

RSG payments ensure that the total market revenue a generator receives when its offer is accepted is at least equal to its as-offered costs. Resources committed by the Midwest ISO after the day-ahead market receive "real-time" RSG payments when their costs are not recovered through the Locational Marginal Price ("LMP") in the real-time market, which accounts for more than 90 percent of all RSG. Because the day-ahead market is a financial market, it generates minimal RSG costs.

Figure E-5 shows RSG payments generated in the real-time market. Due to the considerable influence of fuel prices, the figure shows RSG in both nominal and fuel-adjusted terms. It also separately shows the fuel price-adjusted RSG payments associated with commitments made for capacity purposes or to relieve a constraint. The table below shows the share of RSG costs paid to peaking resources and non-peaking resources broken down by the reason for the unit commitment.

Figure E-5: Real-Time RSG Payments
2008 – 2009



Share of Real-Time RSG Costs by Unit Type (%)

Peaker	68	59	64	68	59	45	65	60	60	53	50	73	46	57	75	58	65	50	46	66	68	49	61	74	80	70	71
Congestion	19	22	19	35	24	12	15	30	31	8	11	21	10	6	42	9	12	9	5	20	18	10	15	53	34	47	12
Capacity	48	37	45	33	35	34	50	30	29	45	38	52	36	51	34	48	53	41	41	47	51	38	46	21	46	23	59
Non-Peaker	32	41	36	32	41	55	35	40	40	47	50	27	54	43	25	42	35	50	54	34	32	51	39	26	20	30	29
Congestion	4	12	10	10	15	16	11	13	14	6	10	5	26	7	8	11	5	25	18	4	3	11	6	12	8	10	2
Capacity	28	29	26	22	26	39	24	27	26	41	41	22	28	36	17	32	29	25	36	30	29	40	33	14	12	20	27

Nominal RSG costs fell by almost half in 2009 due primarily to lower fuel prices. This is evident because the fuel price-adjusted RSG was nearly unchanged in 2009. Even though they produced less than one percent of the energy generated in the Midwest ISO, the figure shows that peaking resources received two-thirds of real-time RSG payments in 2009. This is because peaking resources are generally the highest-cost resources and must be relied upon in real time to meet the reliability needs of the system.

5. Dispatch of Peaking Resources

The dispatch of peaking resources is an important component of the real-time market because peaking units are a primary source of RSG costs and a critical determinant of efficient price signals. The dispatch of peaking resources decreased from 270 per hour in 2008 to an average of 227 MW in 2009. During the peaking summer months, this amount rose only slightly to 287 MW due to mild weather conditions.

Our analysis also shows that a large share of the peaking resources were dispatched out-of-merit. A resource is out-of-merit when its offer price is greater than the LMP. A peaking resource that is dispatched out-of-merit does not indicate it was dispatched inappropriately, it simply indicates that the LMP was set by a lower-cost resource. When a large share of peaking resources is dispatched out-of-merit, it indicates that they frequently do not set the energy price and results in higher RSG costs to ensure the peaking resources recover their as-offered costs. Out-of-merit dispatch of peaking resources also contributes to the under-scheduling of load in the day-ahead market. Peaking resources are generally the only resources that can be committed in real time to serve the load not scheduled day-ahead. Hence, if real-time prices are not set by the peaking resources, real-time prices will be lower and create a disincentive to purchase day-ahead. The Midwest ISO continues to work on a pricing method to address this issue that will allow inflexible units and demand response resources to set prices.

6. Generating Capacity and Reserve Margins

The additions of MidAmerican Energy (“MidAmerican”) and Muscatine Power & Water (“Muscatine”) to the Midwest ISO in September 2009 increased the total amount of generating resources in the market to almost 140 GW. This is measured in nameplate capacity and does not include typical deratings (i.e., reductions in generators’ capabilities). These deratings tend to be particularly large during periods of hot weather. When we fully account for deratings and outages, we project a system reserve margin of 17 to 26 percent for 2010 depending on the level of interruptible load assumed.[5] These margins have increased over the last four years as peak loads have fallen and new resources have entered the market. For summer 2010, the 5-percent

5 The integration of Dairyland Power Cooperative on June 1, 2010 is reflected in these estimates.

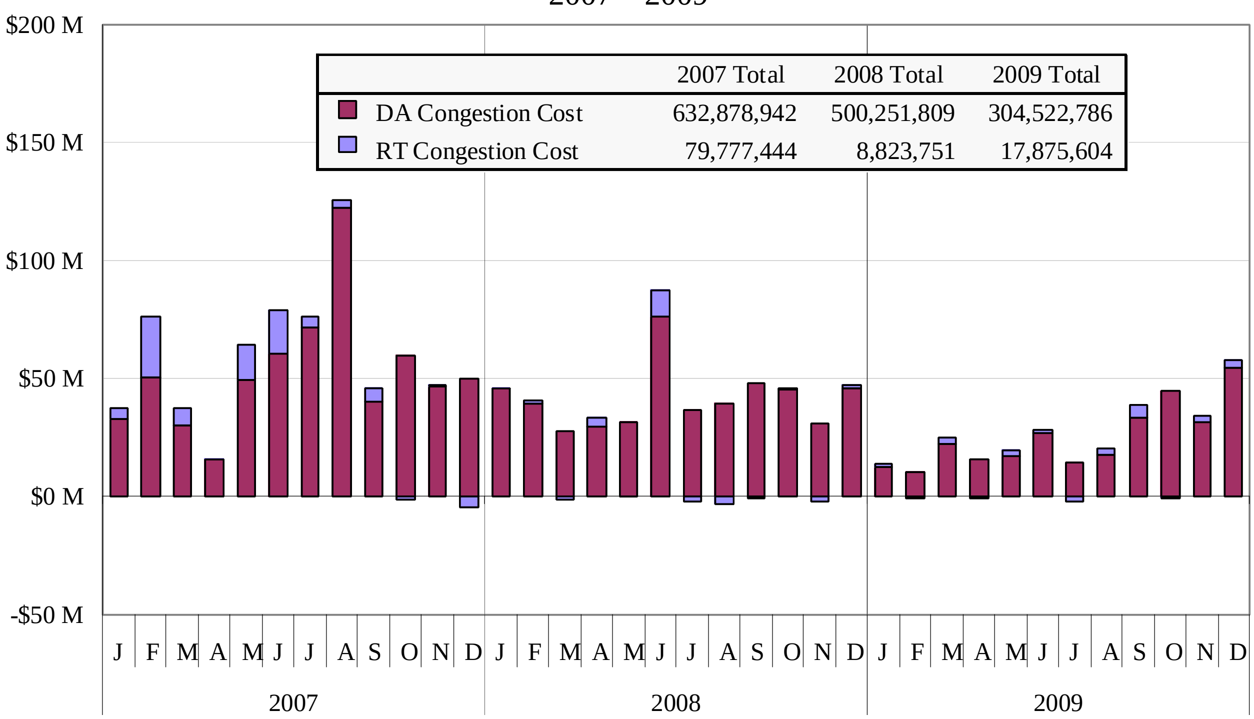
increase in the forecasted peak load (to 107.6 GW) is entirely due to the additions of new members.

Despite the surplus of capacity that currently exists, more than 3,000 MW of new capacity is scheduled to be added prior to the summer of 2010, 1,600 MW of which is wind. Only 756 MW of generation is scheduled to retire. The rapid development of wind resources in the western portion of the footprint provides substantial environmental benefits, although it also creates forecasting and operational challenges that the Midwest ISO is working to address.

D. Transmission Congestion

One significant benefit of the Midwest ISO energy markets is accurate and transparent locational price signals that reflect congestion on the network. Figure E-6 below shows the total congestion costs in the day-ahead and real-time markets. Total congestion costs shown in this figure were \$305 million in 2009, a decrease of more than 39 percent from 2008 and almost 52 percent from 2007. The decrease was caused by a number of factors, including lower load, lower fuel prices, and transmission upgrades that reduced congestion into WUMS.

Figure E-6: Day-Ahead and Real-Time Congestion Costs
2007 – 2009



	2007 Total	2008 Total	2009 Total
DA Congestion Cost	632,878,942	500,251,809	304,522,786
RT Congestion Cost	79,777,444	8,823,751	17,875,604

Additionally, over 94 percent of total congestion was captured in the day-ahead market in 2009, a slight decline from the 98 percent in 2008 but a significant improvement from 2006 and 2007. Residual real-time congestion costs generally arise when the day-ahead modeling of the network is not consistent with the real-time system. Hence, the reduction in residual real-time congestion indicates that the Midwest ISO's day-ahead modeling has improved.

One of the significant issues in the area of congestion management is the frequency with which the real-time market model was unable to reduce the flow below the transmission limit – that is, the congestion was not manageable. This generally occurred for brief periods when the market had insufficient redispatch capability due to the amount of generation that affected the constraint, or the lack of flexibility of that generation. The presence of an unmanageable constraint does not mean that the system is unreliable (reliability standards require the flow to be less than the limit within 30 minutes). Twenty-one percent of internal congestion in 2009 was not manageable on a five-minute basis, which is an improvement from nearly 28 percent in 2008. The Midwest ISO implemented two recommendations in 2009 that contributed to this improvement in manageability. Importantly, however, the congestion reflected in LMPs was inefficiently dampened in many cases when constraints were unmanageable due to a software algorithm that "relaxed" the transmission constraint. We continue to recommend that the ISO discontinue the use of this algorithm.

1. Market-to-Market and Coordination with PJM

This report evaluates the market-to-market process under the JOA with PJM that is instrumental in efficiently managing constraints affected by both RTOs. Overall, the market-to-market coordination has resulted in more efficient management of congestion and more efficient LMPs in each RTO's energy market. The frequency of jointly-managed constraints increased in 2009 for Midwest ISO-managed flowgates and decreased for PJM-managed flowgates. Payments from PJM to the Midwest ISO decreased by 17 percent in 2009, while payments from the Midwest ISO to PJM decreased almost 30 percent. Net payments were made by PJM to the Midwest ISO in each month of 2009. This suggests that the Midwest ISO generally provides more relief on PJM constraints than PJM does on Midwest ISO constraints.

In April 2009 the Midwest ISO identified an issue with PJM's market flow calculations that understated PJM's market flows and settlements from 2005 until the problem was corrected in June 2009. This matter is now the subject of complaints at the Commission and the RTOs are improving their auditing and validation of the market-to-market settlements to minimize future errors. Other JOA issues have arisen that have prompted us to make two referrals on PJM to the Commission's Office of Enforcement, as well as a number of disagreements between the RTOs regarding the interpretation of the JOA. We recommend that the RTOs work together to clarify the JOA in a number of areas to minimize future disagreements and ensure efficient outcomes.

2. Financial Transmission Rights

FTRs are important in an LMP-based energy market because they provide an opportunity for the FTR holder to hedge against day-ahead congestion since day-ahead congestion over the path that defines an FTR is rebated to the holder. We analyzed the performance of the FTR market by evaluating how FTR prices reflect the value of their entitlements (i.e., the value of day-ahead congestion associated with the FTRs). Our evaluation shows that FTR pricing has improved substantially since 2005, which indicates that market liquidity has improved and participants have gained experience with the LMP market.

The report also evaluates FTR prices by comparing them to the actual value of congestion payable to FTRs (higher payments are FTR "profits"). FTR profits have decreased from the start of the markets through 2009. This suggests that the overall performance of the FTR market is improving as it becomes more liquid and participants improve their ability to properly value FTRs.

Day-ahead congestion in 2009 was 17 percent less than the obligations due to FTR holders. This compares to a 14 percent shortfall in 2008 and a 19-percent shortfall in 2007. The primary factors contributing to the continued shortfall include difficulties in accurately forecasting loop flows on the Midwest ISO network and topology differences between the FTR and the day-ahead models, including significant line outages that reduced transfer capability assumed in the FTR auctions. To address the under-funding, the Midwest ISO modified assumptions on loop flows and the transmission limits used in the FTR market in prior years. However these results indicate that further improvements are possible. This report identifies one type of constraint in the day-ahead market that has contributed to substantial underfunding, recommending that this type of constraint be removed from the day-ahead market.

E. External Transactions

The Midwest ISO continues to rely heavily on imports from adjacent areas, averaging 3.8 GW in on-peak hours in 2009 and 2.4 GW in off-peak hours. Although the direction of the power flows depend on prevailing prices, the Midwest ISO generally imports power from PJM and Manitoba and exports power to IESO. Net import levels can fluctuate substantially. Large NSI changes contribute to increased price volatility and can raise reliability issues. Large changes in real-time net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources.

Our analysis indicates that prices between Midwest ISO and PJM are relatively well arbitraged in most hours. However, some hours exhibit large price differences because transactions must be scheduled physically at least 30 minutes in advance. This suggests that significant savings could be achieved from optimizing the dispatch of the external interfaces. Hence, we have recommended that the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to optimize the flow on these interfaces and to modify scheduling and settlement provisions to better align physical flows (i.e., loop flows) with the settlements by the RTOs for transactions around Lake Erie. The RTOs have begun these discussions and developed the Broader Regional Market initiatives to address these issues.

In addition to addressing energy transactions between areas, we recommend that the Midwest ISO remove barriers to trading capacity between regions. This will include working actively with PJM to ensure that undue barriers do not prevent Midwest ISO suppliers from selling in PJM's capacity market.

F. Competitive Assessment and Market Power Mitigation

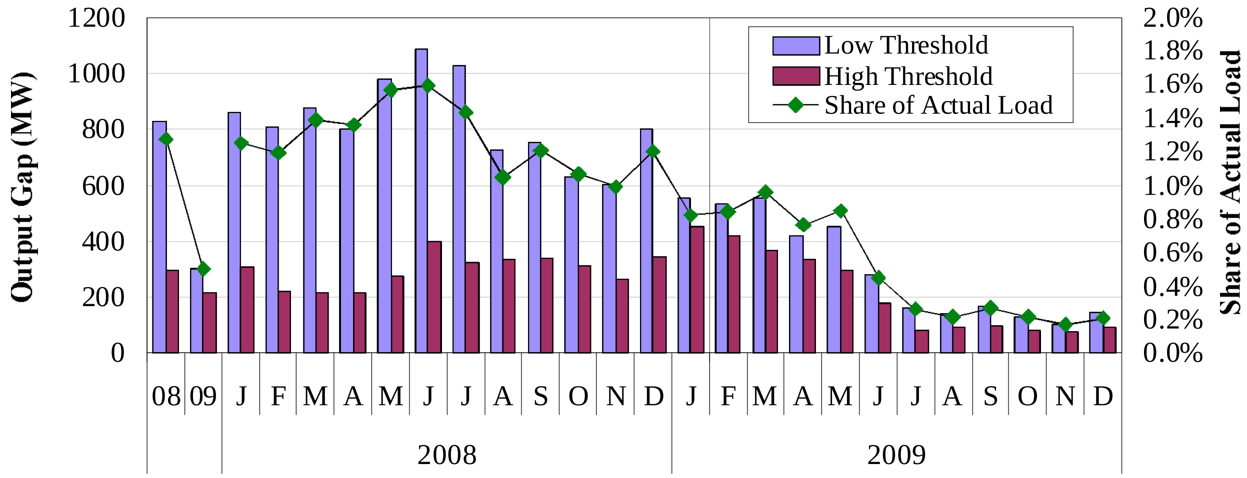
Section VI of our report is a competitive assessment of the Midwest ISO markets that includes a review of potential market power indicators, an evaluation of participants' conduct, and a summary of the imposition of mitigation measures in 2009. Our analysis shows that market concentration measured using the Herfindahl-Hirschman Index ("HHI") is low for the overall Midwest ISO region, although it is considerably higher in the individual regions.

However, a more reliable indicator of potential market power is whether a supplier is "pivotal", which occurs when its resources are necessary to satisfy load or manage a constraint. In the examination of pivotal suppliers, we focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Narrow Constrained Areas ("NCA") and Broad Constrained Areas ("BCA"). NCAs are chronically constrained areas – three are currently defined: one in Minnesota, one in WUMS, and one in North WUMS (a subset of WUMS) – that raise more severe potential local market power concerns (so tighter market power mitigation measures are employed), while BCAs include all other areas within the Midwest ISO that are isolated by a binding transmission constraint.

Sixty-four percent of active BCA constraints had a pivotal supplier in 2009, up from 59 percent in 2008. Seventy-five percent of the active NCA constraints into WUMS have a pivotal supplier (down from 79 percent in 2009), as do 75 percent of the active NCA constraints into Minnesota (up from 69 percent). In addition, nearly 80 percent of all intervals in 2009 exhibited an active BCA constraint with at least one pivotal supplier, while 30 percent and 6.5 percent of the intervals exhibited an active NCA constraint with at least one pivotal supplier in WUMS and Minnesota, respectively. These results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

Although the report shows that structural market power remains a significant issue in the Midwest ISO, our analyses of participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. Figure E-7 shows our "output gap" metric, which we use to detect instances of potential economic withholding and some forms of physical withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using a higher threshold (the mitigation threshold) and a lower threshold (one-half of the mitigation threshold).

Figure E-7: Economic Withholding – Output Gap Analysis
2008 – 2009



Low Threshold Results by Commitment Status (MW)

	08	09	J 2008	F	M	A	M	J	J	A	S	O	N	D	J 2009	F	M	A	M	J	J	A	S	O	N	D
Off-Line	102	31	35	35	47	91	89	112	130	102	84	146	126	222	66	57	35	7	44	41	18	4	56	16	1	26
On-Line	727	105	825	771	828	708	888	971	897	625	671	484	479	579	491	472	441	412	407	238	144	136	113	113	105	120

High Threshold Results by Commitment Status (MW)

	08	09	J 2008	F	M	A	M	J	J	A	S	O	N	D	J 2009	F	M	A	M	J	J	A	S	O	N	D
Off-Line	55	11	17	10	25	16	31	26	73	79	65	124	83	110	57	38	4	3	0	1	2	1	19	0	1	7
On-Line	242	199	289	213	194	203	244	373	250	257	273	189	181	235	394	381	305	331	296	176	84	96	81	84	77	85

Overall, the output gap levels have decreased each year since 2007. The output gap in 2009 averaged 0.5 percent of actual load and declined to 0.2 percent during the second half of the year. These results and others in our report show little indication of significant economic or physical withholding in 2009. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

In addition to these screens for potential withholding, we calculate a “price-cost mark-up” that compares the system marginal price based on actual offers to a simulated system marginal price based on the assumption that all suppliers submitted offers at their estimated marginal costs. Based on this metric we found an average “mark-up” of the system marginal price of roughly 1.2 percent (down from 2 percent in 2008), indicating that the market outcomes in 2009 were highly competitive. Finally, market power mitigation in the Midwest ISO’s energy market continues to occur pursuant to automated conduct and impact tests that utilize clearly specified criteria. Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

G. Demand Response

Demand participation in the market improves reliability in the short-term, contributes to resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power. Accordingly, the development of demand response in the Midwest ISO remains a high priority. When all forms of demand response (both passive and active) are included, the Midwest ISO has more than 12,000 MW. Most of this is interruptible load developed under regulated utility programs and is only curtailable for reliability purposes. This interruptible load is not price-responsive.

Only modest amounts of this demand response capability participates in the Midwest ISO's markets:

- Twenty-two units account for 2,353 MW of non-dispatchable "Type I" demand response which can provide energy and supplemental reserves to the Midwest ISO.[6] These resources must typically be notified well in advance and are therefore not responsive to real-time prices. Peak participation in 2009 totaled just 340 MW due to low load conditions.
- Four units provide 111 MW of dispatchable "Type II" demand response resources that participate in all Midwest ISO energy and ancillary services markets and are dispatchable on a five-minute basis comparable to generation.
- Emergency Demand Response ("EDR") capability (totaling 242 MW) is used to satisfy a Load-Serving Entity's ("LSE") capacity requirements under Module E.

In order to comply with Order 719 and 719-A to create a platform for expanded demand response participation, the Midwest ISO established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements. It filed tariff revisions with the Commission on October 2, 2009, to allow Aggregators of Retail Customers ("ARC") to participate in the Midwest ISO market. ARCs were scheduled to be eligible to participate in the Midwest ISO as of June 1, 2010, but the Commission has not yet approved the Tariff language. Since there is a retail component to this demand response capability, ARC-owed resources are paid the LMP minus the predetermined marginal foregone

6 Type I capacity for Planning Year 2010 is only 210 MW due to certain pumped storage resources no longer offering their capacity when pumping as Type I (effective September 1, 2009). As of February 2010, Type I resources can also offer spinning reserves, subject to a 10 percent participation cap.

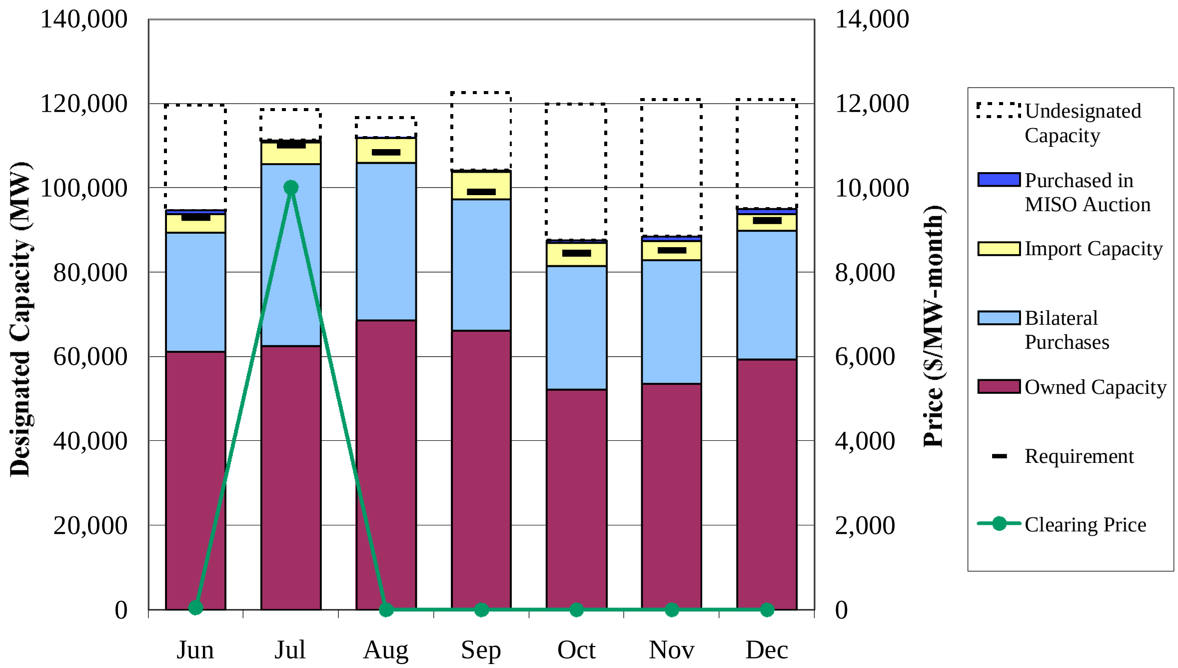
retail rate when load is curtailed. This is an efficient approach because it provides the same incentives to the retail customer that they would have under a dynamic retail pricing regime. However, this approach is not consistent with the current settlements for other DR resources, which the Midwest ISO should consider revisiting. The Commission has been considering these issues more broadly in its recent Notice of Proposed Rulemaking on compensation for DR resources.

In addition, the Midwest ISO is also considering pricing changes that would be necessary to allow load interruptions and other emergency actions to set prices in energy and reserve markets. We strongly support this work because it should improve pricing during peak conditions when demand response resources are called.

H. Capacity Market

Beginning in June 2009, the Midwest ISO began running a monthly VCA to allow load-serving entities to procure capacity to meet their Module E capacity requirements. Figure E-8 shows the VCA market results for the each month in 2009.

Figure E-8: Voluntary Capacity Auction Results
June 2009 – December 2009



Note: Total column height represents the total designated capacity, including imports.

The capacity cleared in the VCA is a small portion of the total designated capacity, ranging from 0.1 percent in August to 1.2 percent in November. The VCA is serving as a balancing market with most LSEs' needs satisfied through owned capacity or bilateral purchases. The total capacity available significantly exceeded the requirements (from a minimum of 12 percent for August to a maximum of 51 percent for October). This fluctuation occurs because the monthly requirement is based on the forecasted peak energy demand for the month. The VCA clearing prices have been close to zero in most months, which is consistent with the substantial capacity surplus prevailing in the Midwest ISO.

The high capacity clearing price in July was the result of the peak demand for capacity and large quantities of capacity that were not offered into the VCA. We attributed these results to inexperience with this new market and uncertainty regarding a retail load auction occurring in the same timeframe.

Finally, we have concerns regarding the ability of participants to import and export capacity, particularly with PJM. Capacity markets serve an important role in providing long-term economic signals to govern investment in the RTO markets. However, capacity prices will only be efficiently determined if participants are able to freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Therefore, it is critical to identify and eliminate barriers that inefficiently hinder such transactions.

I. Summary of Recommendations

Although the markets performed well in 2009, we recommend the Midwest ISO consider the following improvements:

1. Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set energy prices.

This change would improve the efficiency of real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs. To set prices correctly, the market must distinguish between gas turbines that are needed versus those that would be shut-down if they were flexible and dispatched optimally. The Midwest ISO has made substantial progress in this area.

2. Develop provisions that allow non-dispatchable demand response (or interruptible load) to set energy prices in the real-time market when they are called upon in a shortage.

Like the first recommendation, this recommendation also would improve price signals in the highest-demand hours, which are important for ensuring that the markets send efficient economic signals to maintain adequate supply resources and to develop additional demand response capability. It may be possible to address this recommendation in conjunction with the prior recommendation associated with the role of gas turbines in setting energy prices.

3. Improve the integration of wind resources into the Midwest ISO system by allowing them to be curtailable at a specified offer price and be eligible to set prices in the energy market.

The Midwest ISO is presently working to address this recommendation and expects to file Tariff changes in 2010.

4. Develop improved "look-ahead" capabilities in the real-time that would improve the commitment of quick-starting gas turbines and the management of ramp capability on slow-ramping units.

The Midwest ISO's commitment of peaking resources can be improved by using an economic model to commit and de-commit peaking units. This look-ahead capability could also include a multi-period dispatch optimization to move slower-ramping units in anticipation of system demands over the ensuing hour. Better management of ramp needs and the commitment of gas turbines would reduce out-of-merit quantities, reduce RSG payments, and improve energy pricing. We have recommended this previously and the Midwest ISO has initiated a project to develop such capabilities.

5. To address the loop flows around Lake Erie, we recommend the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements.

Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate equitable cost transfers. The scheduling coordination around Lake Erie being discussed by the ISOs through the Broader Regional Markets Initiative should address both efficiency and manipulation concerns with the current system.

6. Improve the real-time operation of the system by:

a) Optimizing the use of the load offset to improve the Midwest ISO's management of ramp capability in the near term; and

b) Reducing the system ramp consumed by interval-to-interval changes in load by improving the short-term load forecast ("STLF") used by the real-time market.

These changes will allow the system to satisfy the fluctuating demands on the system while ramping generation up and down more smoothly. This will reduce price volatility and improve the efficiency of the dispatch of generation in the real-time market.

7. Improve congestion pricing and FTR funding by:

a) Discontinuing its constraint relaxation procedure and use the marginal value limits to set the LMPs when a transmission constraint is unmanageable;

b) Discontinue the modeling of radial constraints in the day-ahead market; and

c) Establish criteria for determining when the Midwest ISO should accept the responsibility to secure low voltage transmission facilities.

These changes will allow prices to efficiently reflect the true congestion on the transmission network, while eliminating inefficient congestion costs.

8. Improve the performance of the spinning reserve market by:

a) Improving the consistency between the reliability requirement for spinning reserves and the market requirement; and

b) Allowing the spinning reserve penalty price to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.

Although the spinning reserve market has generally performed well in 2009, these changes will improve the dispatch and pricing of the market during shortage conditions.

9. Evaluate the formula for the regulation penalty price to ensure that it accurately reflects the costs of committing peaking resources in the Midwest ISO.

Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.

10. Improve the Market-to-Market process by:

a) Instituting a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating optimally;

b) Clarifying the JOA in several areas, including:

1. Use of marginal value limits;
2. Pre-positioning on coordinated constraints;
3. Use of proxy flowgates;
4. Obligation to activate a coordinated constraint;
5. Obligation to test new constraints; and
6. Flowgate definitions and the thresholds used to identify new coordinated constraints.

The market-to-market process plays a vital role in coordinating congestion management between the two areas. These changes should increase the effectiveness and efficiency of this process.

11. To achieve better price convergence with PJM, we recommend that the RTOs consider expanding the JOA to optimize the interchange between the two areas.

This could be accomplished by allowing participants to submit offers to transact within the hour if the spread in the RTOs' real-time prices is greater the offer price. This type of change or others that will allow the interface between the markets to be more fully utilized would generate substantial benefits by allowing lower-cost resources in one area to displace higher-cost resources in the other area.

12. Remove inefficient barriers to capacity trading with adjacent areas by:

a) Modifying deliverability requirements for external resources to establish a maximum amount of capacity imports by interface that can be utilized to satisfy LSEs' capacity requirements; and

b) Working with PJM to identify transmission access, deliverability, and issues related to capacity obligations that may create inefficient barriers to exporting capacity to PJM.

These changes should allow participants to be able to more effectively arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Ultimately, this will cause both markets to send more efficient long-term price signals and improve the stability of the RTOs by reducing incentives for participants to alter RTO membership.

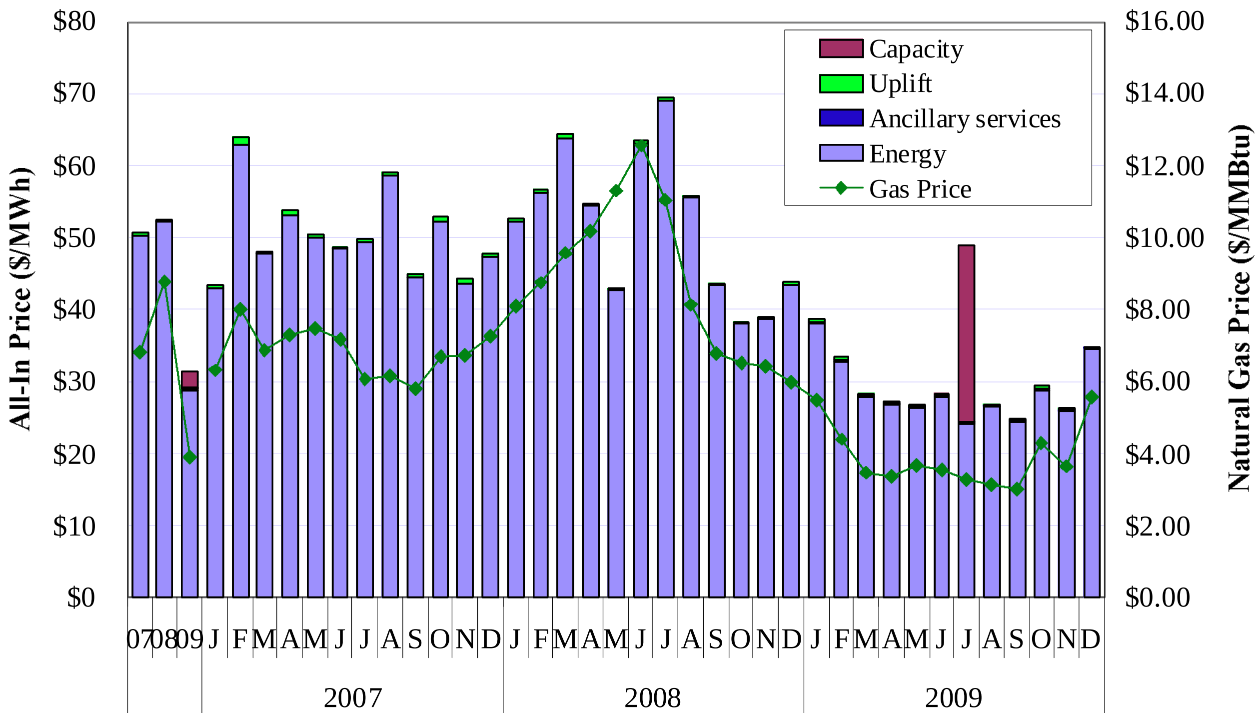
II. Prices and Revenues

The Midwest ISO has operated competitive wholesale electricity markets since April 2005. The Midwest ISO operates markets for day-ahead and real-time energy and for financial transmission rights. New ancillary services markets were introduced in January 2009 and a monthly capacity auction was launched in July 2009. These markets have improved the efficiency of the Midwest ISO's use of its generation and transmission assets in the short-term. They have also improved the long-term price signals governing investment decisions. In this section, we evaluate prices and revenues associated with each of the Midwest ISO's day-ahead and real-time markets.

A. Prices

Our first analysis is an overview of electricity and fuel prices for the Midwest ISO markets. Figure 1 shows the "all-in" price of wholesale electricity, which represents the costs of serving load from the Midwest ISO's real-time markets, and the price of natural gas. The all-in price includes the load-weighted average real-time energy price, uplift (the average real-time RSG costs), average real-time ASM costs, and monthly capacity costs per MWh of real-time load.

Figure 1: All-In Price of Wholesale Electricity
2007 – 2009



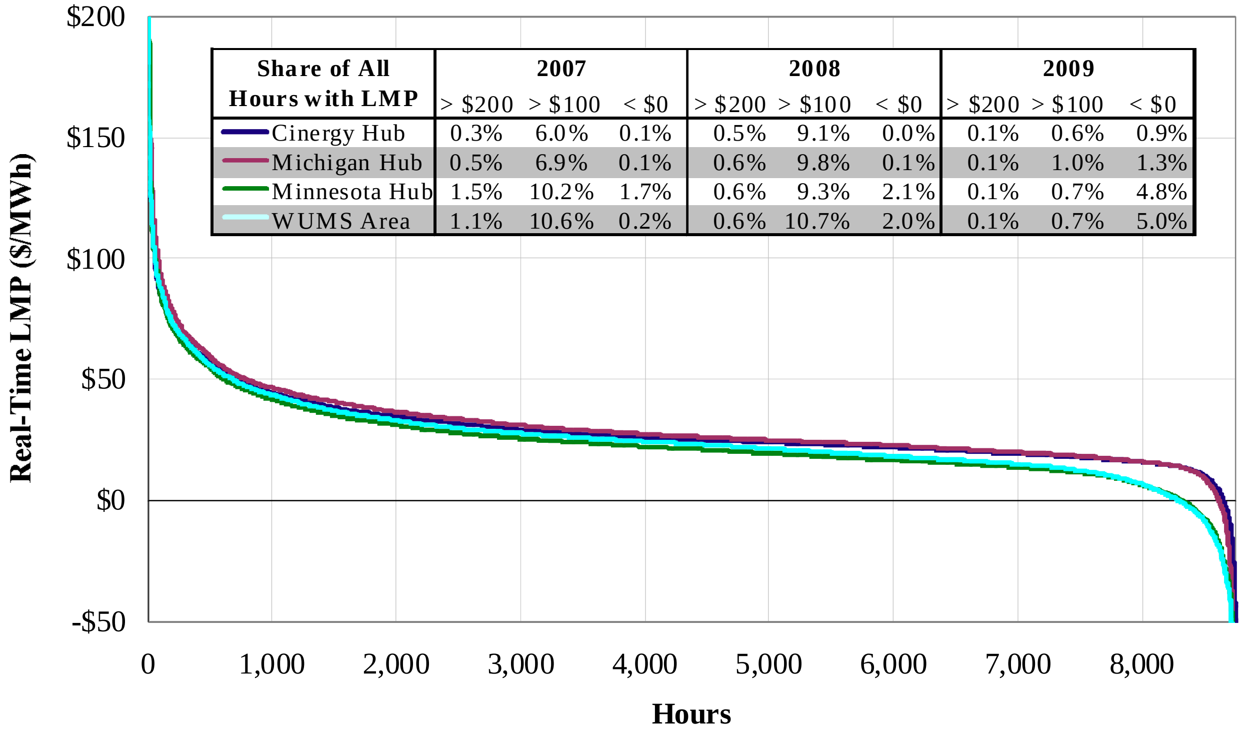
The average all-in price for 2009 was $31.28 per MWh, a 40 percent decrease from 2008. Real-time energy prices are the dominant component of the all-in price. Real-time prices decreased by 45 percent from 2008 to 2009 due to sharply lower natural gas and coal prices and lower load, particularly during the summer months.

Average real-time uplift costs also decreased considerably, declining 16 percent from 2008. Uplift costs remained a very small percentage (less than 1 percent) of the all-in price. Capacity and ASM costs each comprised a very small portion of the all-in price, except in July when the VCA auction cleared at a high price due to large amounts of capacity that was not offered. Although only a small amount of capacity cleared in the auction, the VCA spot price is used in the all-in price because the spot market drives the forward bilateral prices.

The figure shows that prices were correlated positively with natural gas prices, even though low load levels resulted in fewer hours with natural gas units on the margin. The fact that electricity prices were highly correlated with fuel prices indicates that the Midwest ISO energy market performed competitively in 2009. Suppliers in a well-functioning, competitive market have the incentive to offer energy at their marginal cost. Since fuel costs represent the majority of their variable production costs (i.e., marginal costs), generators' energy offers tend to rise in step with fuel costs in a competitive market. Therefore, the correlation of fuel prices and electricity prices indicates that the markets are performing competitively.

Our next analysis shows the range of hourly prices in the real-time energy market in the form of a price-duration curve. A price-duration curve shows the number of hours (horizontal axis) when the LMP is greater than or equal to a particular price level (vertical axis). For example, the curve for the Cinergy Hub indicates that in approximately 800 hours during 2009 the Cinergy Hub price exceeded $50 per MWh. Figure 2 shows the real-time energy price-duration curves for four representative Midwest ISO hubs. The table in the figure summarizes the highest and lowest prices each year from 2007 to 2009.

Figure 2: Real-Time Energy Price-Duration Curve
2009: All Hours



Share of All Hours with LMP	2007			2008			2009		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Cinergy Hub	0.3%	6.0%	0.1%	0.5%	9.1%	0.0%	0.1%	0.6%	0.9%
Michigan Hub	0.5%	6.9%	0.1%	0.6%	9.8%	0.1%	0.1%	1.0%	1.3%
Minnesota Hub	1.5%	10.2%	1.7%	0.6%	9.3%	2.1%	0.1%	0.7%	4.8%
WUMS Area	1.1%	10.6%	0.2%	0.6%	10.7%	2.0%	0.1%	0.7%	5.0%

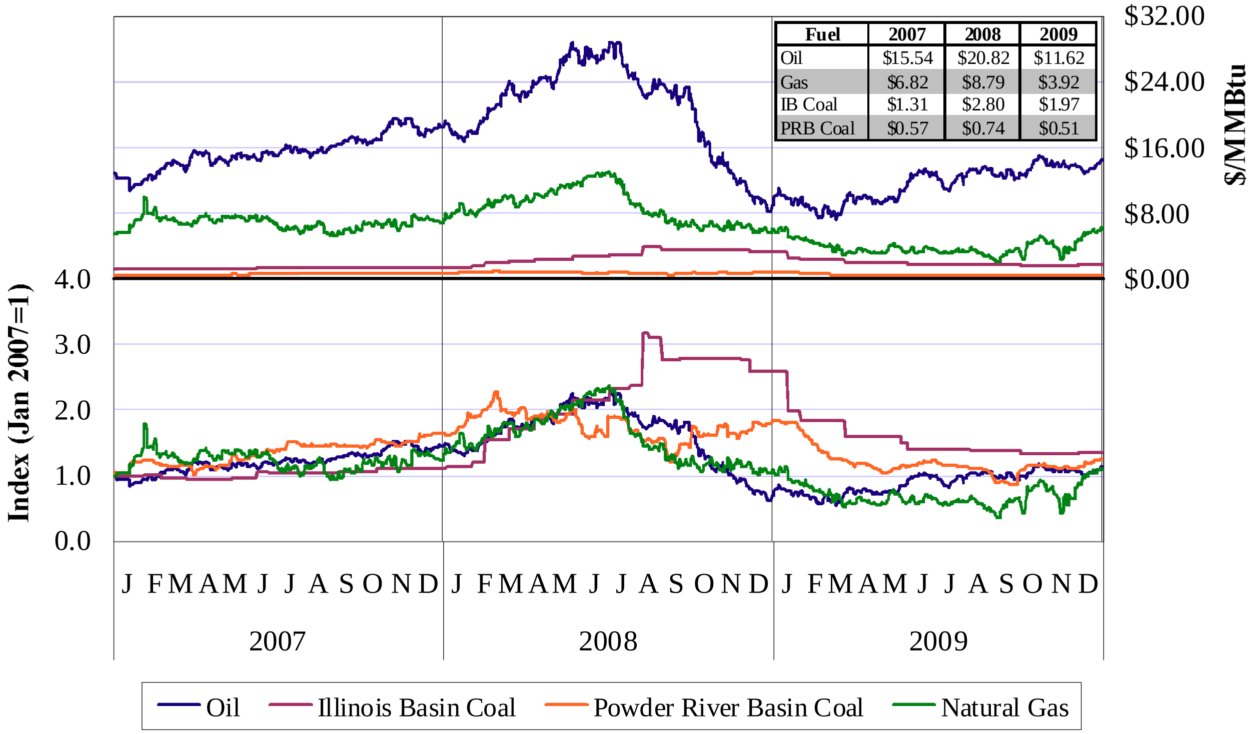
The differences between these curves are due to congestion and losses that cause energy prices to vary by location. In 2009, prices were more closely aligned across the Midwest ISO hubs than in prior years. The exception was in low-priced hours when there was substantial divergence between western hubs and eastern hubs, indicating a pattern of west-to-east congestion. Prices were below zero in approximately five percent of hours at the Minnesota Hub and Wisconsin-Upper Michigan System ("WUMS"), up from two percent of hours in 2008. This congestion pattern is in contrast to prior years when there was frequent congestion into WUMS and Minnesota that resulted in higher LMPs in those areas. The number of hours with price exceeding $200 per MWh and $100 per MWh were comparable for all hubs and were substantially lower than prior years as a result of lower peak loads, lower fuel prices and considerable transmission improvements since 2008. Congestion into Michigan resulted in slightly more high-priced hours than the other hubs.

We focus particular attention on energy prices during these peak hours because they play a critical role in sending the economic signals that govern investment and retirement decisions. In particular, high prices during shortage conditions are needed to support investment in the region.

However, mild weather and lower overall load in 2009 led to very few periods of shortage. Long-run price signals are further explored in the net revenue analysis later in this section.

As noted previously, fuel prices are the largest component of most generators' marginal cost and are, therefore, a primary determinant of the overall price of energy. Poor economic conditions beginning in late 2008 drove the relevant fuel prices for electricity generation down by 30 to 55 percent in 2009. Figure 3 below shows the prices for natural gas, oil, and coal in the Midwest ISO region from 2007 to 2009. The top panel shows the nominal prices in dollars per million British Thermal Units ("MMBtu") while the bottom panel shows the fuel price movements in relative terms with each fuel indexed to January 2007.

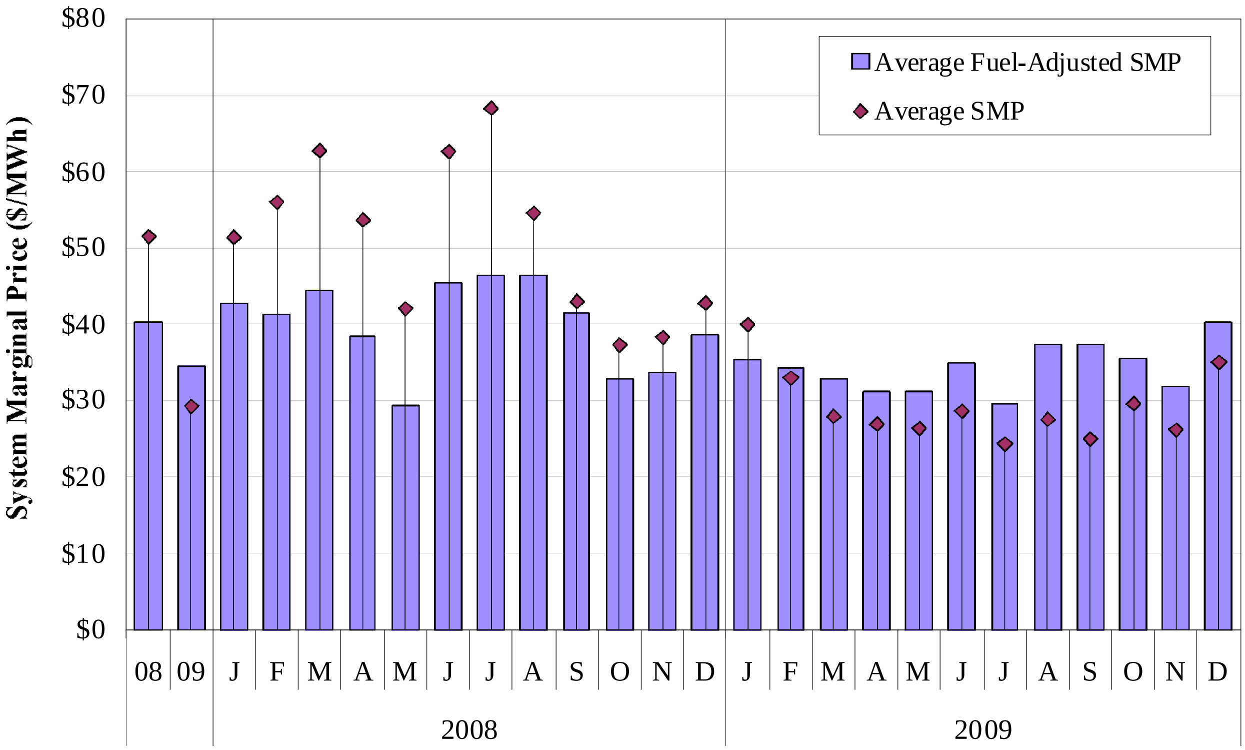
Figure 3: Midwest ISO Fuel Prices
2007 – 2009



Overall, natural gas prices fell 55 percent from 2008 and 2009 on average, while the oil prices fell 44 percent. Natural gas prices averaged only $4 per MMBtu in 2009, the lowest annual average in years. Natural gas prices began and ended the year at approximately $6 per MMBtu but fell to as low as $2 in the late summer. Oil prices rose steadily from an average of almost $10 per MMBtu in January to more than $13.50 in December. Coal prices declined substantially throughout the first quarter of 2009 and then remained relatively stable for the rest of the year. Both Illinois Basin coal prices and Powder River Basin coal prices fell roughly 30 percent on average in 2009 from 2008.

The impact of fluctuations in marginal fuel prices can obscure the underlying electricity market performance. Hence, we calculate a fuel price-adjusted SMP, shown in Figure 4 below. This measure highlights variations in electricity prices that are due to factors other than fluctuations in fuel prices, such as changes in load or congestion costs. To calculate this metric, each interval's SMP was indexed to the average two-year fuel price of the marginal fuel during the interval. The price-setting fuel for each interval was assumed to be the fuel that was most frequently on the margin during the particular interval (more than one fuel can be on the margin in a single interval). This metric does not account for changes in commitment or dispatch that may occur under different levels of fuel prices.

Figure 4: Fuel-Price Adjusted System Marginal Price
2008 – 2009



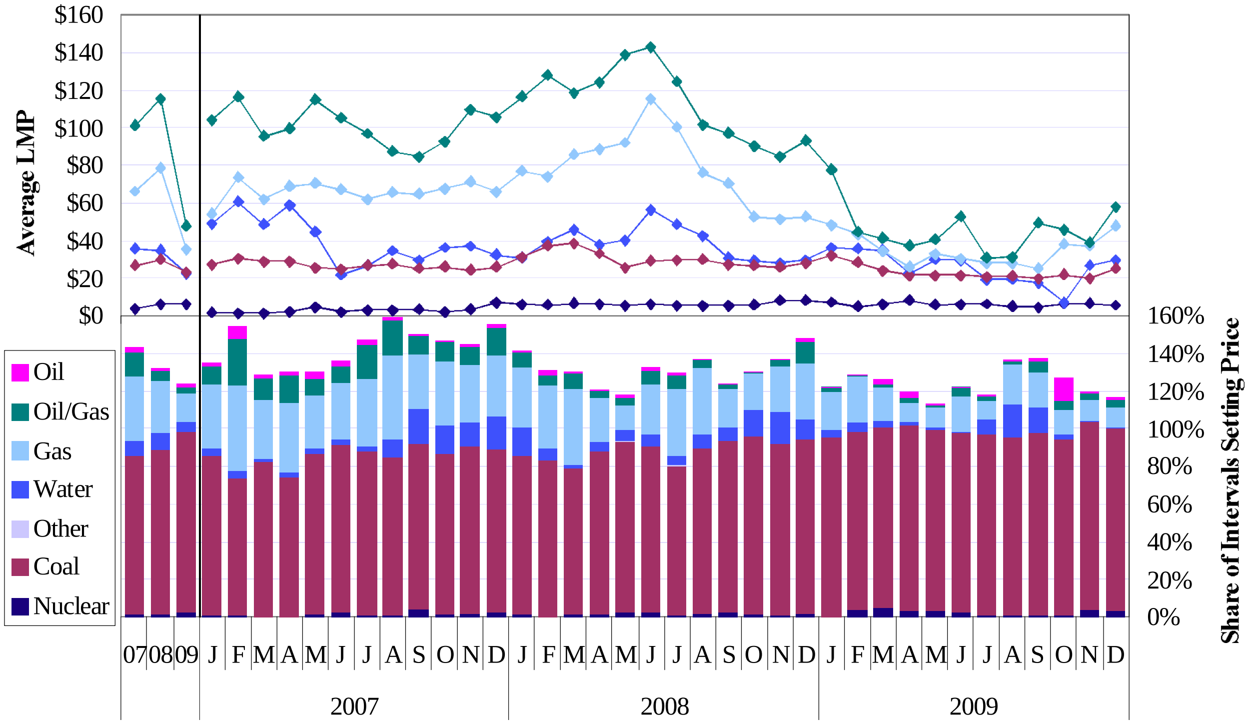
Average fuel-adjusted energy prices fell almost 15 percent in 2009. This reduction was primarily due to milder than normal temperatures, reduced economic demand, and the effects of

ASM. Although the methodology does not capture several likely impacts on generation dispatch due to changing fuel prices, the figure clearly demonstrates that fuel price changes account for a significant share of the year-over-year change in electricity prices.

Next, we analyze the frequency with which different types of units are on the margin in the Midwest ISO. When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained area). Therefore, the total for all the fuel types exceeds 100 percent.

Figure 5 shows the average prices that prevail when each type of unit is on the margin (in the top panel) and how often each type of unit sets the real-time clearing price (in the bottom panel).

Figure 5: Price Setting by Unit Type
2007 – 2009



Coal units set prices in 96 percent of all intervals, including virtually all off-peak intervals, up from 87 percent in 2008. This increase in coal-fired units setting prices is due to the substantial decrease in average load and the 600 MW increase in average wind generation that generally displaces generation from higher-cost units.

Natural gas and oil resources typically set prices during the highest-load hours. Hence, these fuel prices have a larger effect on the load-weighted average prices than the percentages suggest. Natural gas-fired, oil-fired, and dual-fired resources set prices in 20.5 percent of intervals during 2009, but almost 28 percent of all real-time energy costs were incurred when these resources were on the margin. This is a significant decrease from 2008, when these resources set prices in 34 percent of hours, which accounted for nearly one-half of all real-time energy costs. Some of this decrease is likely due to the lower congestion in 2009 causing natural gas-fired units to be used less frequently to manage congestion.

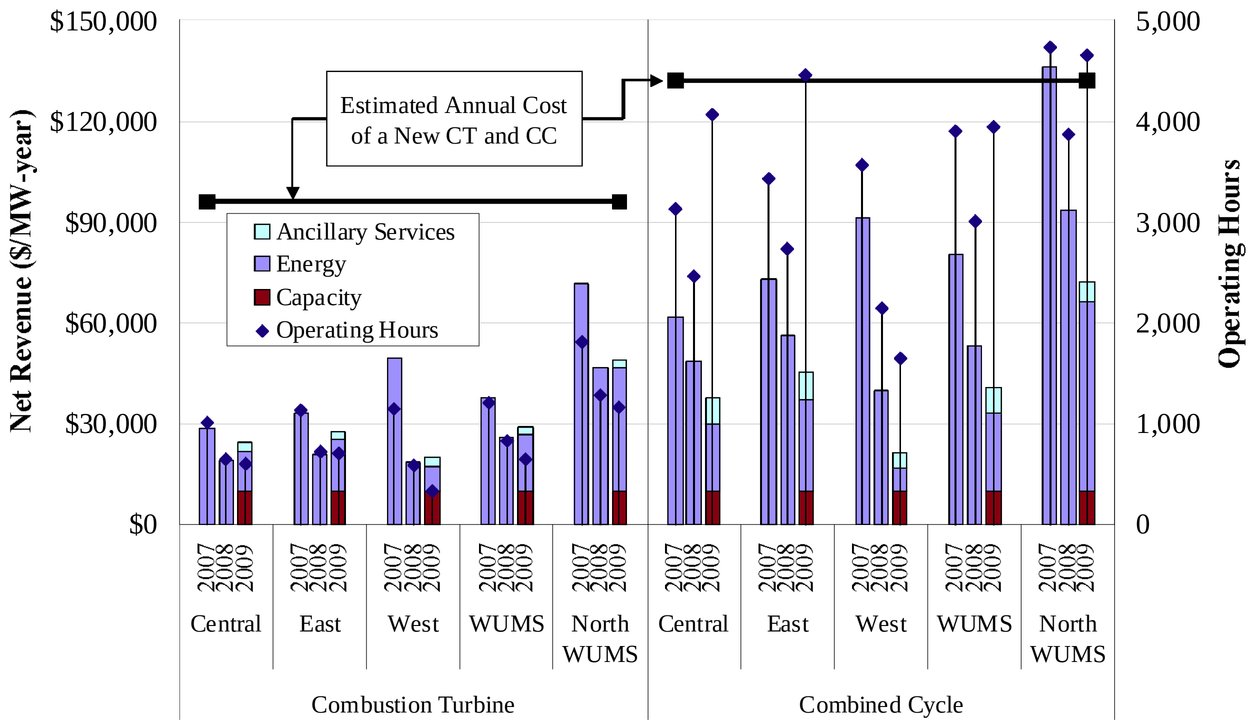
B. Net Revenue Analysis

The previous subsection provided a summary of the Midwest ISO energy market prices in 2009. In this subsection, we evaluate the resulting economic signals associated with these prices. Our evaluation uses the "net revenue" metric, which measures the revenue that a new generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. A well-designed market should allow a new entrant to earn a level of net revenue that is sufficient to finance new investment when new resources are needed. However, even if the system is in long-run equilibrium, random factors in each year will cause the net revenue to be higher or lower than the equilibrium value (e.g. weather conditions, generator availability, competing fuel prices, etc.).

Our analysis examines the economics of two types of new units: a natural gas CC unit with an assumed heat rate of 7,000 Btu per kilowatt-hour ("kWh") and a natural gas CT (or "gas turbine") unit with an assumed heat rate of 10,500 Btu per kWh. We also incorporate standardized assumptions for calculating net revenues put forth by the Commission that account for variable Operations and Maintenance ("O&M") costs, fuel costs, and forced outages. In addition to energy revenues, our analysis for 2009 considers revenues from capacity and ancillary services markets, which have improved the long-run economic signals provided by the Midwest ISO markets.

Figure 6 shows net revenue provided by the Midwest ISO markets from 2007 to 2009. To determine whether these net revenue levels would support investment in new resources, the figure also shows the estimated annualized cost of a new unit (which equals the annual net revenue a new unit would need to earn in the Midwest ISO wholesale markets to make the investment economic). Because combined cycle generators have substantially lower production costs per MWh than simple-cycle combustion turbine generators, they run more frequently (more than 40 percent of all hours in 2009, compared to roughly 10 percent for combustion turbines). Hence, the estimated net revenues for CC generators from the energy and AS markets are substantially higher. Capacity revenues, however, are constant across unit types and regions. Since combustion turbines provide far less energy, the capacity revenues have a larger relative impact on a combustion turbine's net revenues than on a combined cycle unit's net revenues.

Figure 6: Net Revenue and Operating Hours
2007 – 2009



Net revenues for a new combined cycle generator in 2009 ranged from $22,000 to $49,000 per MW-year in the regions shown, while net revenues for a new combustion turbine range from $20,000 to $29,000 per MW-year. This variation in net revenues across the footprint is expected. For example, net revenues are substantially higher in the East than in the West due to prevailing congestion patterns.

Compared to 2008, net revenues were 4 to 32 percent higher for combustion turbine generators in 2009 across the footprint, even though operating hours are modestly lower (especially so in the West). This increase is entirely due to the net revenues attributable to the capacity market, most of which is associated with the spike in capacity prices that occurred in the July 2009 Voluntary Capacity Auction. Absent the VCA results from July, the net revenues would have been lower in each of the areas studied. In contrast to the result for combustion turbines, the estimated net revenues for a new combined cycle generator were 18 to 45 percent lower in 2009. This net revenue reduction was despite the fact that a new combined cycle generator would generally have run more in 2009 because natural gas prices fell more sharply than coal prices. Nonetheless, the loss of inframarginal revenues associated with less frequent periods with very high energy prices led to lower net revenues in 2009.

For both types of units, the net revenues are substantially below the estimated annual cost of entry, notwithstanding the addition of the AS markets and the capacity market. These entry costs are shown in the figure as horizontal black segments. The estimated cost of new entry for a new combustion turbine increased from $90 per kW-year in 2008 to $96 per kW-year in 2009 due primarily to an increase in capital costs. Likewise, the cost of entry for a new combined cycle unit increased to more than $130 per kW-year. These annualized costs far exceed the estimated net revenues in even the highest-cost areas.

The net revenue results are consistent with expectations because the Midwest ISO footprint continues to exhibit a sizable capacity surplus and did not experience significant periods of shortage in 2009. Even though shortages were not frequent, shortage pricing improved considerably in 2009 with the introduction of AS markets, which are jointly optimized with energy markets. When resources are not sufficient to satisfy reserve requirements, the operating reserve demand curve will set reserve prices and consequently improve energy price signals. The Midwest ISO is working on pricing changes to allow peaking units and interruptible load to set prices, which would further improve efficient shortage prices and increase net revenues. Long-term market signals also improved in 2009 with the introduction of the VCA, which is a monthly spot market for capacity that provides an additional means for loads to satisfy their Module E capacity requirements. As excess capacity in the region declines, it will be important that the Midwest ISO's markets send efficient long-term signals. To that end, we recommend several improvements to pricing mechanisms in this report.

III. Load and Resources

In this section, we provide an overview of the supply and demand conditions in the Midwest ISO markets. We summarize load and generation within the Midwest ISO region and evaluate the resource balance in light of available transmission capability on the Midwest ISO network.

In delineating the Midwest ISO geographic boundaries, we confine our analysis to the participants in the Midwest ISO markets. There are more than 80 owners of generation resources in the Midwest ISO market footprint. This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

For our analysis, we generally divide the Midwest ISO into four geographic areas. Three of the four are coordination regions that the Midwest ISO uses to operate the system. The final area is the WUMS area that has experienced a relatively high level of congestion historically. These regions are:

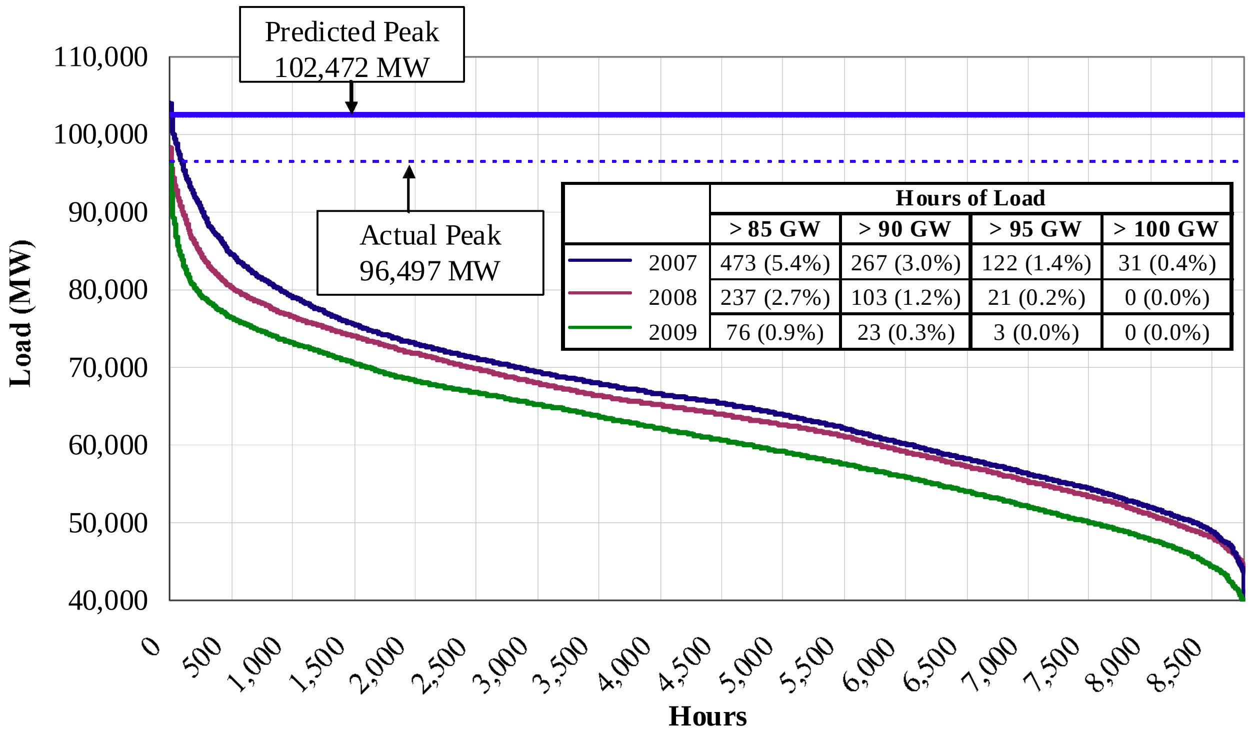
- East — generally includes the Midwest ISO areas that had been located in the North American Electric Reliability Corporation's ("NERC") ECAR region;
- West — generally includes the Midwest ISO areas that had been located in the NERC MAPP region;
- Central — generally includes the Midwest ISO areas that had been located in the NERC MAIN region, but excluding MAIN utilities located in the WUMS area; and
- WUMS — the Midwest ISO control areas located in the WUMS area. It is part of the East reliability region, but we examine it separately due to differences in transmission topology and historical congestion patterns.

These four regions should not be viewed as distinct geographic markets, particularly with respect to generation ownership concentration. Conventional concentration analysis in these regions does not allow one to draw reliable competitive conclusions. Accurate market power conclusions require analyses beyond calculating market share and concentration statistics. This is discussed at length in Section VI.

A. Load Patterns

Our first analysis in this section summarizes 2009 load patterns throughout the Midwest ISO. The Midwest ISO is a summer-peaking region overall, although the northern areas in the West can be winter-peaking. The peak load in 2009 occurred in late June at 96.5 GW, almost 6 percent below the forecast peak load of 102.5 GW. Figure 7 shows overall load levels for the past three years in the form of hourly load duration curves, which show the number of hours (horizontal axis) in which load is greater than an indicated level (vertical axis).

Figure 7: Load Duration Curves
2007 – 2009



Hourly loads at all levels were down in 2009. Average load dropped 6.5 percent compared to 2008 and 8.9 percent compared to 2007. These reductions in load are attributable to both mild temperatures and reduced economic activity.[7] The figure also shows that nearly 20 percent of the peak energy demand occurs in only the top three percent of hours, which is a typical pattern of energy demand. Because electricity cannot be economically stored in large quantities, this load pattern indicates that a large share of the Midwest ISO's resources is needed primarily to meet the system's peak energy or operating reserve demands. This underscores the importance

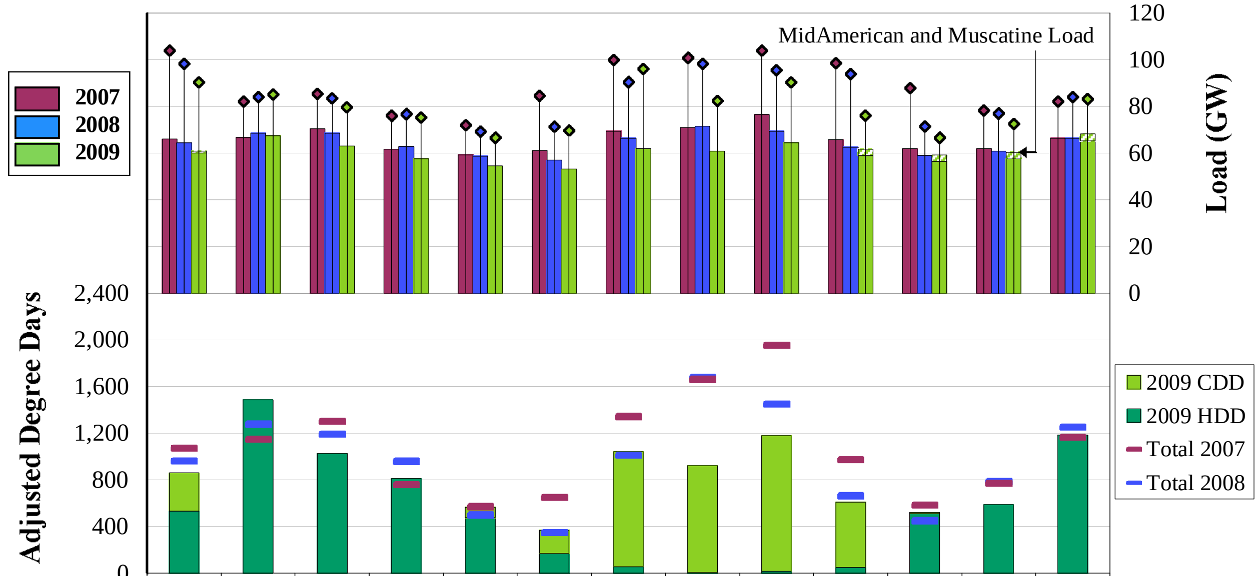
7 The Midwest ISO performed an analysis concluding that the decline in economic activity alone contributed to a 6.5 percent reduction in average load in 2009.

of efficient pricing during peak load hours as well as in the capacity market to ensure that the system continues to maintain adequate resources.

A large share of the load in the Midwest ISO is temperature sensitive. Figure 8 illustrates the influence of weather on load by showing the heating and cooling requirements together with the monthly average load levels for 2007 to 2009.

Figure 8: Heating and Cooling Duration Curves

Weekly Average of Four Cities in Midwest ISO, 2007 – 2009



08-09 %Chg	2009	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg. Load	-6.5%	-1.7%	-8.1%	-8.4%	-7.3%	-6.7%	-6.8%	-14.9%	-7.0%	-5.8%	-4.3%	-5.0%	-1.9%
Degree Days	-10.8%	16.6%	-13.7%	-15.4%	14.1%	5.8%	3.1%	-44.9%	-18.5%	-7.9%	15.6%	-25.2%	-5.5%

The top panel shows the monthly average loads in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") summed across four representative locations in the Midwest ISO.[8]

8 HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). For example, a mean temperature of 25 degrees Fahrenheit in a particular week in Minneapolis results in (65-25) * 7 days = 280 HDDs. To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (i.e., so one adjusted HDD will have the same impact on load as one CDD). This factor was estimated using a regression analysis.

Mild summer and winter weather (except in January) also contributed to lower load in 2009. The figure shows that the total degree days decreased by almost 11 percent year-over-year. The largest monthly decline occurred in July when the coolest temperatures on record for much of the Midwest ISO footprint resulted in a 45 percent drop in total degree days. This decrease contributed to a 15 percent drop from the prior year in average load. Conversely, unusually cold January weather led to a relatively modest 1.7 percent load decline, the smallest monthly year-over-year load decrease in 2009.

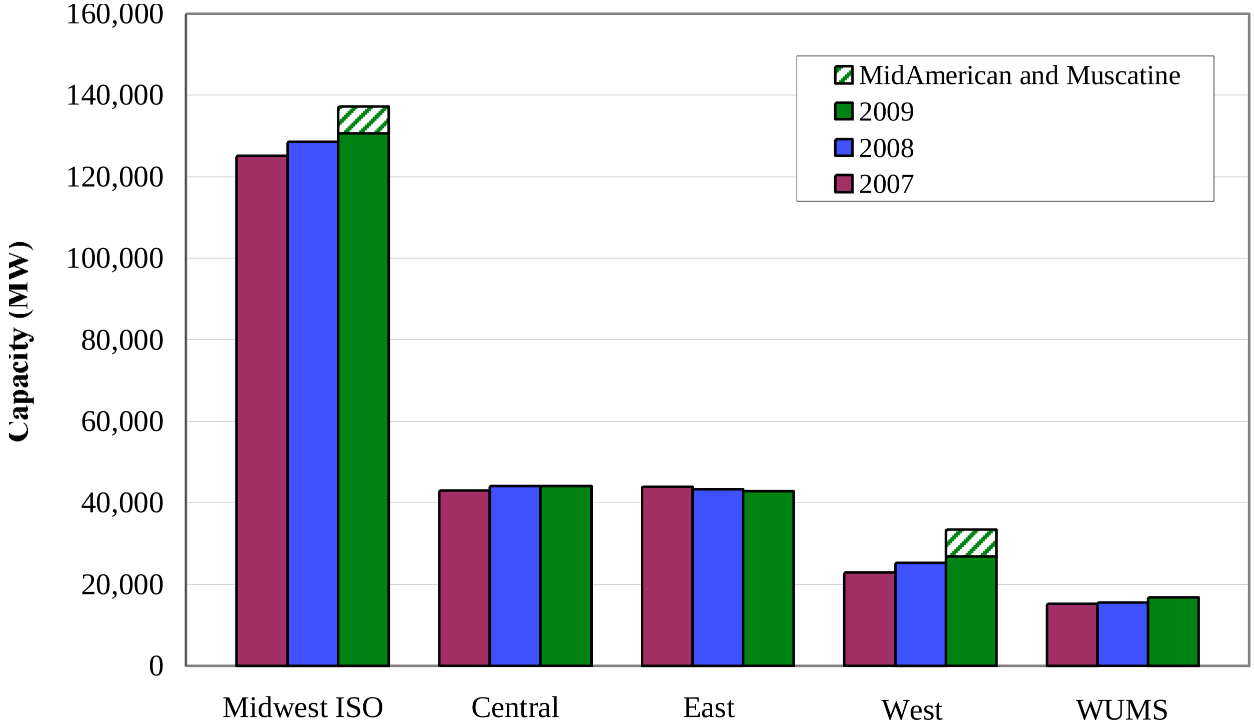
While 2009 was a mild year in terms of heating and cooling requirements compared to 2007 and 2008, poor economic conditions were the primary driver of the reduction in demand. This is consistent with the fact that average load in 2009 was lower in every month compared to 2008, including months during which the HDD or CDDs were higher. The Chicago Purchasing Managers Index, a leading business barometer and a broad measure of regional economic activity, measured almost 8 percent lower in 2009 than in 2008.

B. Generation Capacity

The capacity in the figures below includes only capacity owned by entities that are participants in the Midwest ISO markets and excludes capacity owned by Midwest ISO reliability-only members (e.g. Manitoba Hydro, Western Area Power Administration). The Midwest ISO serves as the Reliability Coordinator for these entities, but reliability-only members do not submit bids or offers in the Midwest ISO wholesale markets. Including the resources of the reliability-only members, the total generating capacity for the Midwest ISO was nearly 160 GW in 2009. It had exceeded 170 GW by the end of 2008, but this amount declined when OPPD, NPPD, and Lincoln Electric System left the Midwest ISO for the Southwest Power Pool ("SPP") in April 2009.

Generating resources in the Midwest ISO market footprint totaled nearly 137 GW by the end of 2009. Figure 9 shows the distribution of this capacity by coordination region.

Figure 9: Generation Capacity in MW by Coordination Region
2007 – 2009

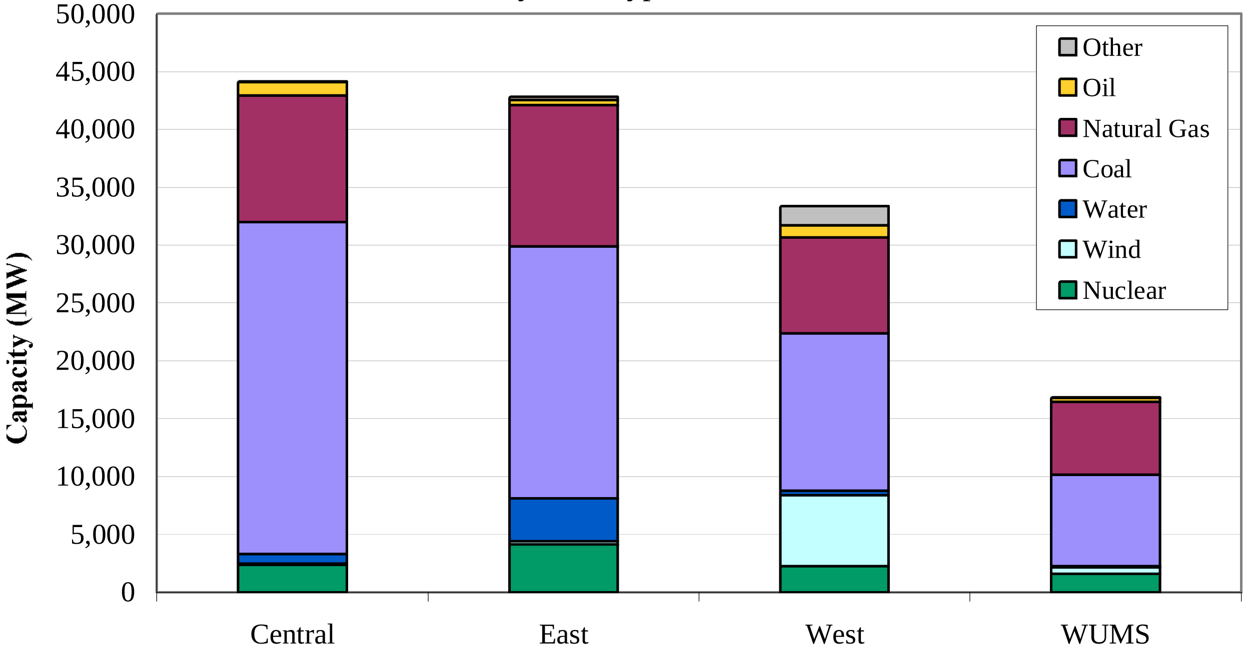


Consistent with the distribution of the load in the Midwest, more than 70 percent of the generating resources are located in the East and Central regions. Because it is a frequently congested area, we show the WUMS area separately from the rest of the East region of the Midwest ISO.

The year-over-year increase shown in the figure is primarily due to the new member additions of MidAmerican, Muscatine, and the Municipal Electric Utility of the City of Cedar Falls, Iowa in September 2009, which added 6.5 GW of capacity in the West (of which 1.5 GW is wind capacity). In addition, the Midwest ISO added another 1.6 GW of new wind resources and 1.4 GW of other new resources, primarily fired by coal and natural gas.

In addition to the location of generation, the geographic distribution of fuel used by those generators is important because it determines marginal costs and ultimately the patterns of prices in the Midwest ISO region. Our next analysis shows the generating capacity by fuel type in the four primary regions of the Midwest ISO.

Figure 10: Distribution of Generation Capacity by Region
By Fuel Type, 2009



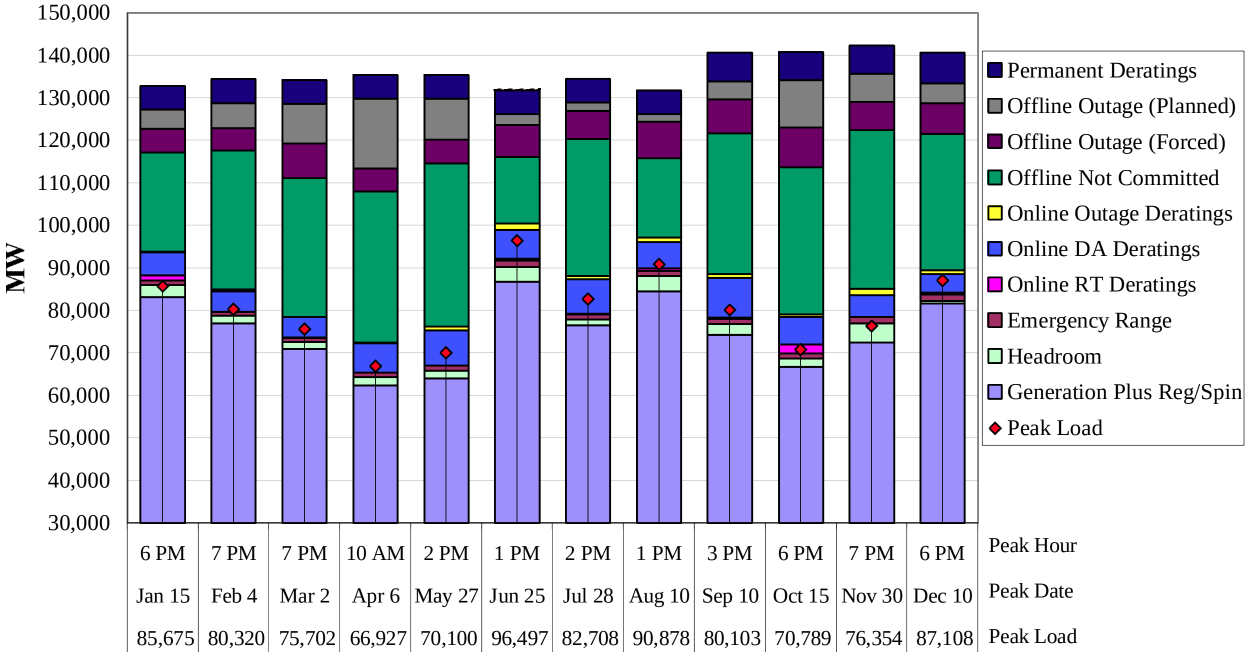
The Midwest ISO continues to rely on coal-fired generating resources for the majority of its installed capacity (52 percent). Because coal units are generally baseloaded, they generate an even larger share (74 percent) of the total energy produced. The second largest fuel type is natural gas, which accounts for almost 28 percent of the generating resources in the Midwest ISO. These resources are more expensive than most of the other resources in the region and are therefore dispatched at a lower capacity factor, producing less than 18 percent of the energy in the region; although, they frequently set the price in peak hours. Nuclear units account for fewer than 8 percent of total capacity but produce 15 percent of the generation because they are among the lowest-cost resources and run at very high capacity factors. Continued growth in wind capacity (up 66 percent from 2008) has increased wind's share of capacity and generation to 5.1 and 2.9 percent, respectively.

While the mix of generation is fairly homogeneous across the Midwest ISO footprint, certain regions have conditions that favor investment in particular generator types. The West region, for example, contains the vast majority of total wind generation (87 percent) due to the relatively attractive wind conditions in the area. Such concentrations can present operating and reliability challenges that are addressed later in the report.

C. Generator Availability and Outages

In this section, we examine the availability of generation capacity, particularly in peak-load hours when resource availability is most important. Figure 11 shows the status of generation capacity during the peak-load hour of each month in 2009.

Figure 11: Availability of Capacity during Peak Hours
2009



For reference, the peak load in each hour is shown as a red diamond. Most of the load is served by Midwest ISO generation, as indicated by the bottom (blue) segment of each bar. The next two stacked segments in the figure are (1) "headroom", which is the amount of economic capacity remaining on the committed units above their dispatch point, and (2) the emergency output range. These three segments together represent the total online capacity. The other segments comprise the remaining total capacity that cannot be dispatched for various reasons.

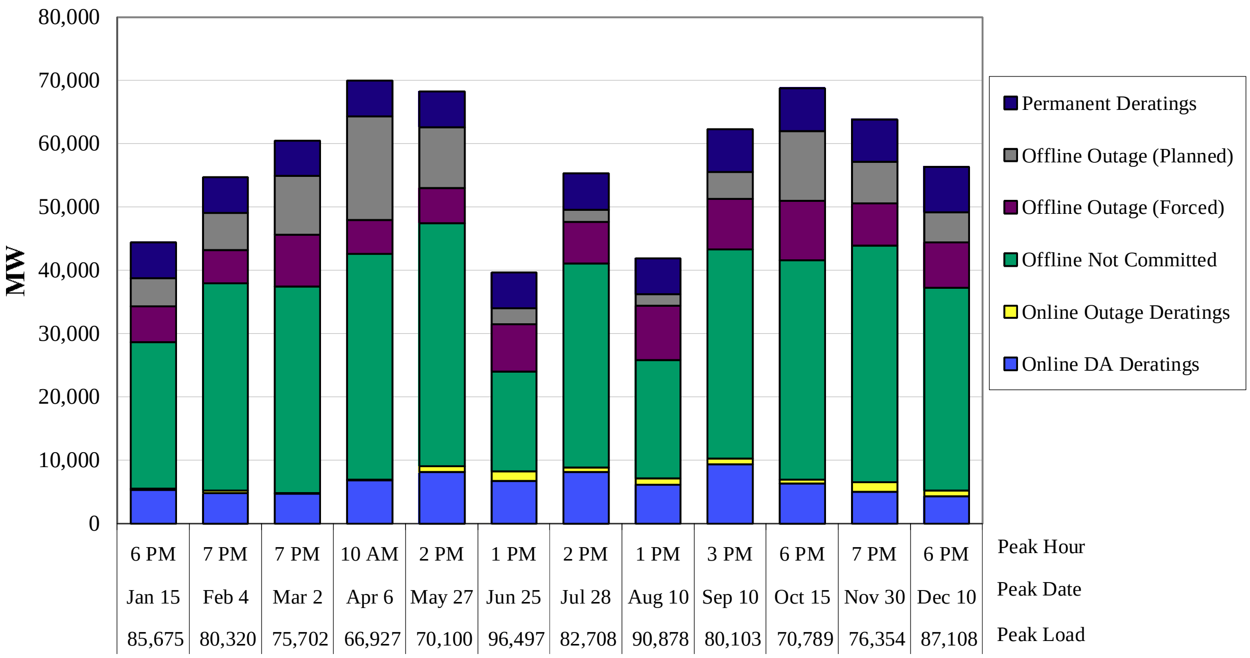
The figure shows that peak load was higher than the total online capacity during most months, which is consistent with the fact that the Midwest ISO relies upon imports to satisfy its demands for energy and operating reserves. The figure also shows that headroom on the highest load days was generally low and near the expected dispatch margins. However, during each of the two highest monthly peaks (June and August), headroom at the peak hour was more than 2,500 MW.

This raises a potential concern regarding over-commitment in the peak hours which can suppress peak pricing. We evaluate this topic later in Section IV of the report. Due to the mild conditions during the summer, there were no situations that required the Midwest ISO to call for load interruptions or demand response curtailments during the summer peak periods.

Finally, this figure also shows changes in total generation capacity. The most notable change is the 6 GW increase in September associated with the additions of MidAmerican and Muscatine. Other monthly differences in total capacity are due to the variability of intermittent generation in each peak hour (unavailable intermittent capacity is not shown). To better depict the unavailable capacity in the peak hours, Figure 12 shows only deratings, outages, and other offline capacity.

Figure 12: Capacity Unavailable during Peak Hours

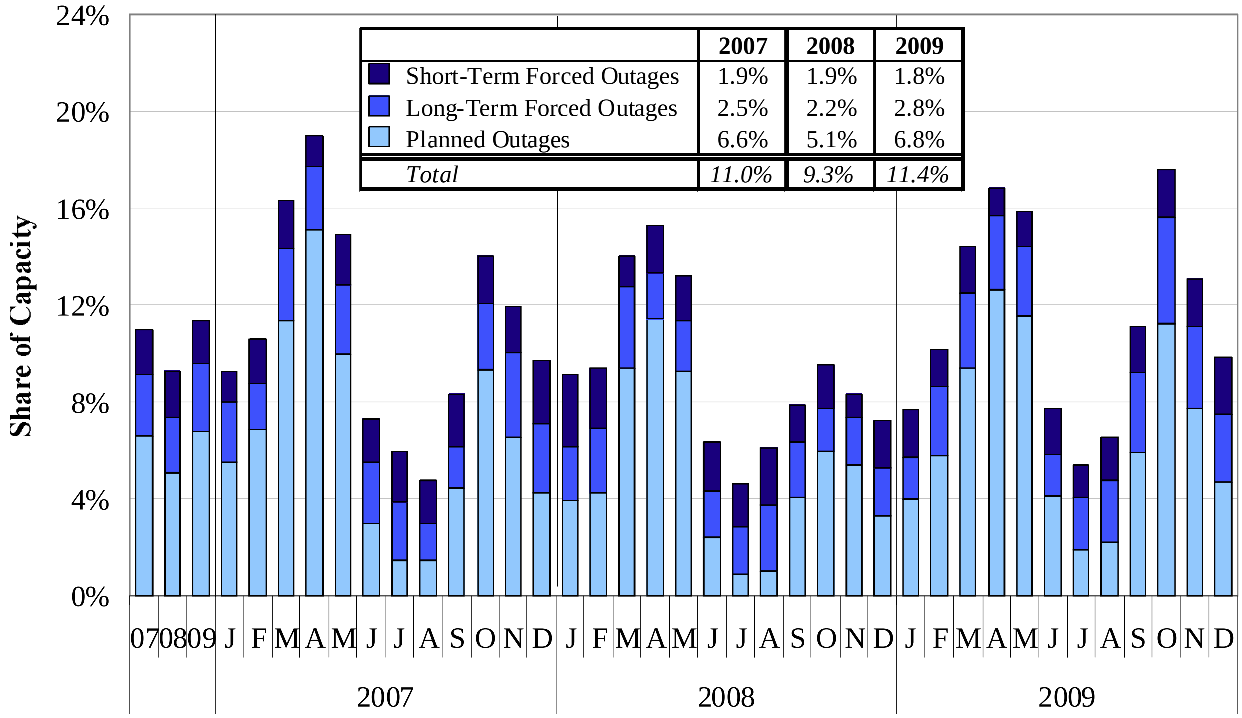
2009



Deratings in the day-ahead market (shown in bright blue) were higher during summer months, which may be attributable to high ambient temperatures that reduce the capability of some types of generators. The figure shows large quantities of uncommitted generation in every month (exceeding 30 GW on average), due in part to the decline in peak monthly demand in 2009. Also, planned outages are lowest in the summer and, as a result, the larger universe of units in service adds to the total non-outage deratings. In addition, over 7.6 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch in any hour. This represents an increase of 1.6 GW over 2008 and is attributable to three factors: (1) the new Midwest ISO member additions of MEC and MPW; (2) aging baseload capacity that cannot operate at its nameplate rating; and (3) new wind resources that do not operate close to their nameplate ratings.[9]

Figure 13 illustrates the planned and forced generator outage rates in 2009 by month. The values in the figure include only full outages—they do not include the partial outages or deratings shown in the prior figure. The analysis in the figure divides the forced outages between short-term (less than seven days) and long-term (seven days or longer).

Figure 13: Generator Outage Rates
2007 – 2009



The annual combined outage rate increased in 2009 to 11.4 percent for the three categories of outage, an increase over the 2008 rate of 9.3 percent and the 2007 rate of 11.0 percent. Planned outages rose 32 percent as low load levels and prices made it more attractive to schedule

9 The average capacity factor of wind generation in the Midwest ISO was 27 percent in 2009.

maintenance in 2009. These results show no indication that suppliers were deferring maintenance due to poor economic or credit conditions. Similarly, long-term forced outage rates rose to almost 3 percent in 2009. Although these occur somewhat randomly, lower prevailing energy prices decreased the economic incentive to return a unit from a forced outage quickly. Short-term outages, which are more likely than other outages to constitute physical withholding, fell slightly in 2009.[10]

Outages and deratings were highest in the fourth quarter of 2009, which may be partly attributable to the new business practices associated with must-offer requirements of Module E capacity. In September of 2009, the Midwest ISO began monitoring the compliance of the must-offer obligations. This increased the incentive to accurately report unit outages and deratings.

D. Resource Margins and Generation Adequacy

This section assesses capacity levels in the Midwest and their adequacy to cover the forecasted peak loads in the summer of 2010. We evaluate generator availability by analyzing outages in 2009. For purposes of evaluating resource adequacy, estimated reserve margins will be optimistic if all potential deratings are not fully reflected. In particular, many resources during peak-load events must be derated in response to environmental restrictions or due to the effect of high ambient temperatures. Available capacity levels during high temperature conditions can therefore be significantly lower than typically assumed in planning studies, resulting in lower actual reserve margins.

Table 1 shows our analysis of the Midwest ISO’s capacity levels for the summer of 2010, given the forecasted peak load and the announced capacity additions and retirements. The table includes separate reserve margins calculated based upon internal demand and internal load. We define internal demand as internal load less the sum of behind-the-meter generation, interruptible load, and other demand response (“DR”) capability. Hence, the statistics based upon internal demand will include the effects of various demand response capability and those based upon internal load will not.

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10 Outages and deratings are evaluated from a competitive perspective in Section VI.

We calculate the reserve margin as follows:

Reserve margin = [(Capacity + Firm Imports) ÷ Internal Demand or Load] – 1.

Table 1: Capacity, Load, and Reserve Margins for each Midwest ISO Region
2009-2010 Planning Year

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temp. Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin[4]
East								
Internal Load	36,987	-	43,200	16.8%	42,100	13.8%	39,688	7.3%
Internal Demand[3]	34,090	-	43,200	26.7%	42,100	23.5%	39,688	16.4%
Central								
Internal Load	37,615	2,032	46,866	30.0%	44,230	23.0%	41,030	14.5%
Internal Demand	35,576	2,032	46,866	37.4%	44,230	30.0%	41,030	21.0%
West								
Internal Load	25,568	2,234	34,812	44.9%	26,941	14.1%	24,716	5.4%
Internal Demand	24,101	2,234	34,812	53.7%	26,941	21.1%	24,716	11.8%
WUMS								
Internal Load	12,532	712	17,114	42.3%	15,988	33.3%	15,118	26.3%
Internal Demand	11,552	712	17,114	54.3%	15,988	44.6%	15,118	37.0%
MISO								
Internal Load	112,701	5,549	141,993	30.9%	129,259	19.6%	120,552	11.9%
Internal Demand	105,318	5,549	141,993	40.1%	129,259	28.0%	120,552	19.7%

[1] Midwest ISO Summer-Rated Capacity from its 2010 Summer Assessment, including full rating for Run of River.
[2] High Temperature capacity is based upon tempearture derates that occurred in the Day-Ahead market of August 1, 2006.
[3] Net Internal Demand estimate excludes interruptible load and behind the meter generation.
[4] Our planning reserve margins differ from the Midwest ISO's because: a) we include temperature-related deratings (reduces our margins), b) we include all physical capacity, not only those designated as capacity (increases our margins), c) we calculate our margins based on internal load and internal demand while the Midwest ISO's is generally based on internal demand, d) we exclude estimated forced outage rates (increases our margins).

Reserve margins are highly sensitive to the assumed maximum-capacity levels and whether interruptible demand is included. Using nameplate capacity levels and the projected capacity changes for 2010, we find the reserve margin for the Midwest ISO region is 31 percent based upon internal load and 41 percent based upon internal demand. These reserve margins vary within the Midwest ISO subregions from 17 percent to 45 percent based upon internal load and from almost 27 percent to more than 54 percent based upon internal demand. Nameplate capacity-based reserve margins are considerably higher in the western half of the Midwest ISO footprint.

These reserve margins are similar to 2009 levels and notably higher than in prior years due to lower peak load levels over the past two years, and indicate that the Midwest ISO currently has a substantial capacity surplus. However, when the typical deratings and the temperature-sensitive capacity that is unavailable under peak-demand conditions are removed, the reserve margin projected for 2010 for the Midwest ISO region is 12 percent based upon internal load and 20 percent based upon internal demand. At the regional level, the reserve margin varies from 5.4 percent to more than 26 percent based upon internal load and from 12 percent to 37 percent based upon internal demand. Since 10 percent or more of the capacity can be unavailable due to forced outages or set aside for operating reserves, real-time conditions may be tight on some peak days. Hence, interruptible load may need to be curtailed under extreme conditions or if forced outages are higher than average at under peak demand conditions.[11]

Although these results indicate that the system's resources are adequate for the summer of 2010, new resources will be needed over the longer term. The results of the net revenue analysis presented earlier in this report indicate that the long-term economic signals do not currently support new entry. Consistent with these signals, little conventional capacity has been added in the last few years. The introduction of ancillary services and capacity markets promote more efficient pricing. The adoption of several recommended pricing changes should help to further align the economic signals and reliability needs of new investment.

Table 2 shows the new capacity additions in the Midwest ISO's 2010 Summer Assessment that have been added since the 2009 Summer Assessment.[12]

Table 2: Planned Capacity Additions
Quantities in MW, 2009-2010 Planning Year

Region	**Coal**	**Gas**	**Oil**	**Other**	**Waste**	**Water**	**Wind**	**Total**
Central	0	0	0	0	0	0	50	50
East	18	656	0	0	0	0	120	794
WUMS	640	60	0	0	0	10.4	99	809
West	0	6	37	2	7.5	0	1,340	1,392
Total	**658**	**722**	**37**	**2**	**7.5**	**10.4**	**1,609**	**3,045**

11 The Midwest ISO's planning margins are slightly lower than the ones we estimate in Table 1. While it does not remove high-temperature deratings as we do, it removes capacity that is not needed to satisfy Load Serving Entities' ("LSEs") capacity obligations. Our estimate includes all physical capacity.

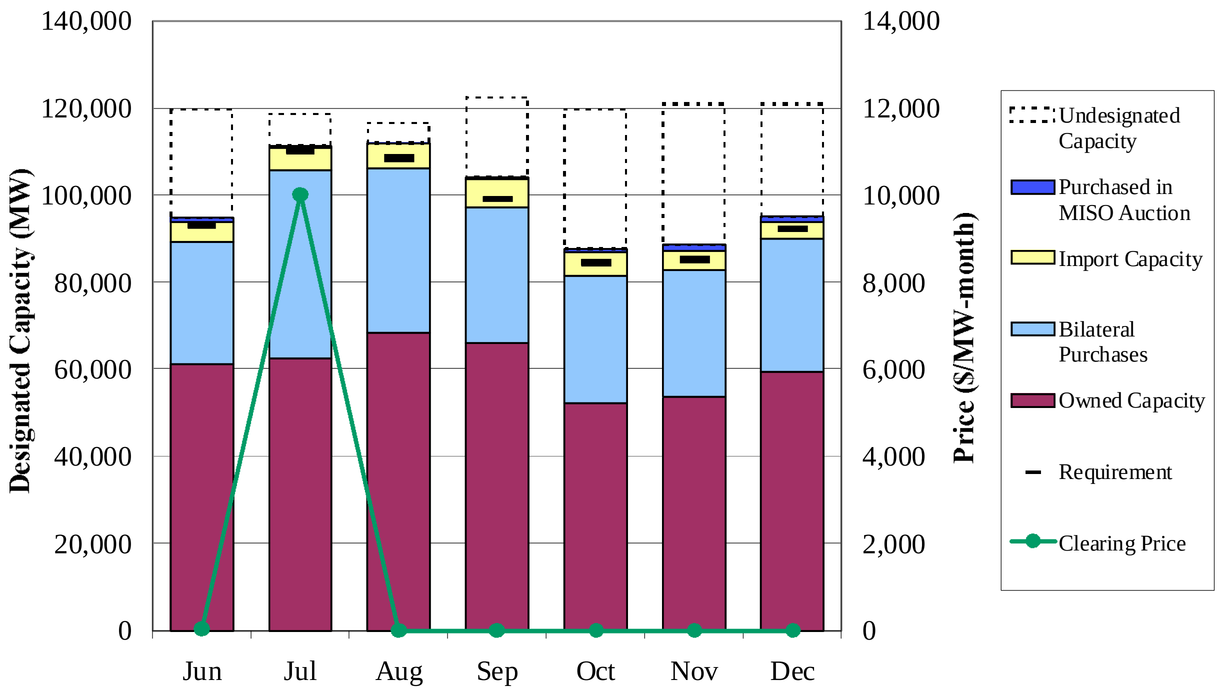
12 Some of these additions occurred in the fall of 2009, after the completion of the 2009 Summer Assessment.

In total, 3,045 MW of additions and 756 MW of retirements have been incorporated into the 2010 Summer Assessment. Although the additional capacity is substantial, almost than half of it is in the form of wind generation, which contributes less to reliability than conventional supply or DR resources due to its intermittent nature. Wind investments are often driven by factors other than the price signals from the Midwest ISO market, such as state renewable portfolio standards or governmental subsidies. These investments can cause significant congestion and other operational issues that may require new investments in transmission capability and improvements in operating procedures. Much of the remaining new capacity additions are natural gas and oil-fired resources located in congested regions, which should improve the Midwest ISO's ability to manage congestion in those areas.

E. Voluntary Capacity Auction

The Midwest ISO began operating a voluntary monthly capacity auction in June 2009 to allow Load Serving Entities ("LSE") to procure capacity to meet their Module E capacity requirement. Figure 14 shows the monthly results of the VCA during 2009.

Figure 14: Voluntary Capacity Market Results
June 2009 – December 2009



Note: Total column height represents the total designated capacity, including imports.

Capacity cleared in the VCA is a small portion of the total designated capacity, ranging from 0.1 percent in August to 1.2 percent in November.[13] This indicates that the VCA is serving as a balancing market with most LSEs' capacity needs satisfied through owned capacity or bilateral purchases. The figure further indicates that capacity designations have always met or exceeded requirements (at times by 5 percent).

The VCA has cleared at exceptionally low prices in every month except July, when peak demand and large quantities of capacity that were not offered (or offered at very high prices) resulted in a clearing price of approximately $10,000 per MW-month. We investigated this conduct and concluded that these results were attributable to inexperience with this new market and uncertainty regarding a retail load auction occurring in the same timeframe.

The low prices in all other months during 2009 are consistent with the substantial capacity surplus prevailing in the Midwest ISO. The total capacity available significantly exceeded the requirements, from a minimum of 12 percent in August to a maximum of 51 percent in October. These surpluses should decline as load grows and supply contracts through retirements, declining imports, or increasing exports.

Finally, we have concerns regarding the ability of participants to import and export capacity, particularly with PJM. Capacity markets serve an important role in providing long-term economic signals to govern investment in the RTO markets. However, capacity prices will only be efficiently determined if participants are able to freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Therefore, it is critical to identify and eliminate barriers that inefficiently hinder such transactions.

13 Designated capacity includes capacity owned, purchased from internal resources, and imported from outside the Midwest ISO.

IV. Day-Ahead and Real-Time Market Performance

In this section, we evaluate the performance of the day-ahead and real-time markets. Our evaluation is focused on four main areas: (1) energy prices relative to load and other operating conditions; (2) the convergence of prices between the day-ahead and real-time energy markets; (3) the performance of ancillary service markets; and (4) load scheduling and virtual trading. We also address RSG payments, the dispatch of peaking resources in real time, and the integration of wind generation. We conclude this section with a number of suggested improvements intended to enhance efficiency and competitive performance of the markets.

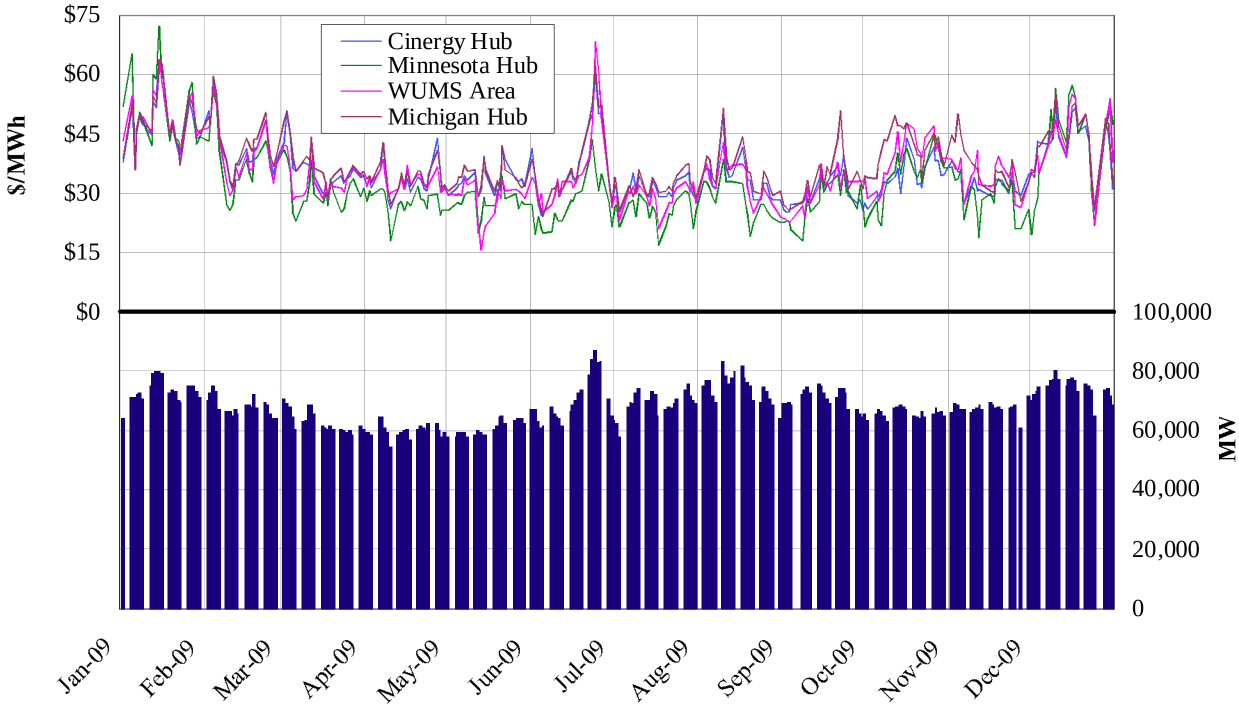
A. Day-Ahead Market Performance

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real time to hedge their portfolios and manage risk. For example, loads can insure against volatility in the real-time market by purchasing in the day-ahead market and using FTRs to hedge against congestion. The performance of the day-ahead market is important because most of the power that is procured through the Midwest ISO markets is financially settled in the day-ahead market. In addition, FTRs are settled based upon day-ahead market results. The day-ahead market also plays a crucial role in coordinating generator commitments because most generator commitments are determined through the day-ahead market.

1. Day-Ahead Energy Prices and Load

In this subsection, we review day-ahead, peak-hour energy prices in each region relative to scheduled load. This overview of day-ahead market results is shown in Figure 15. This figure shows daily average day-ahead prices during peak hours (6:00 a.m. to 10:00 p.m. on weekdays) at four representative hub locations in the Midwest ISO and the corresponding scheduled load (which includes net cleared virtual demand). Differences in prices among the hubs show the prevailing congestion patterns throughout the year (high prices in one location relative to another location indicate congestion from the low-price area to the high-price area).

Figure 15: Day-Ahead Hub Prices and Load
2009: Peak Hours



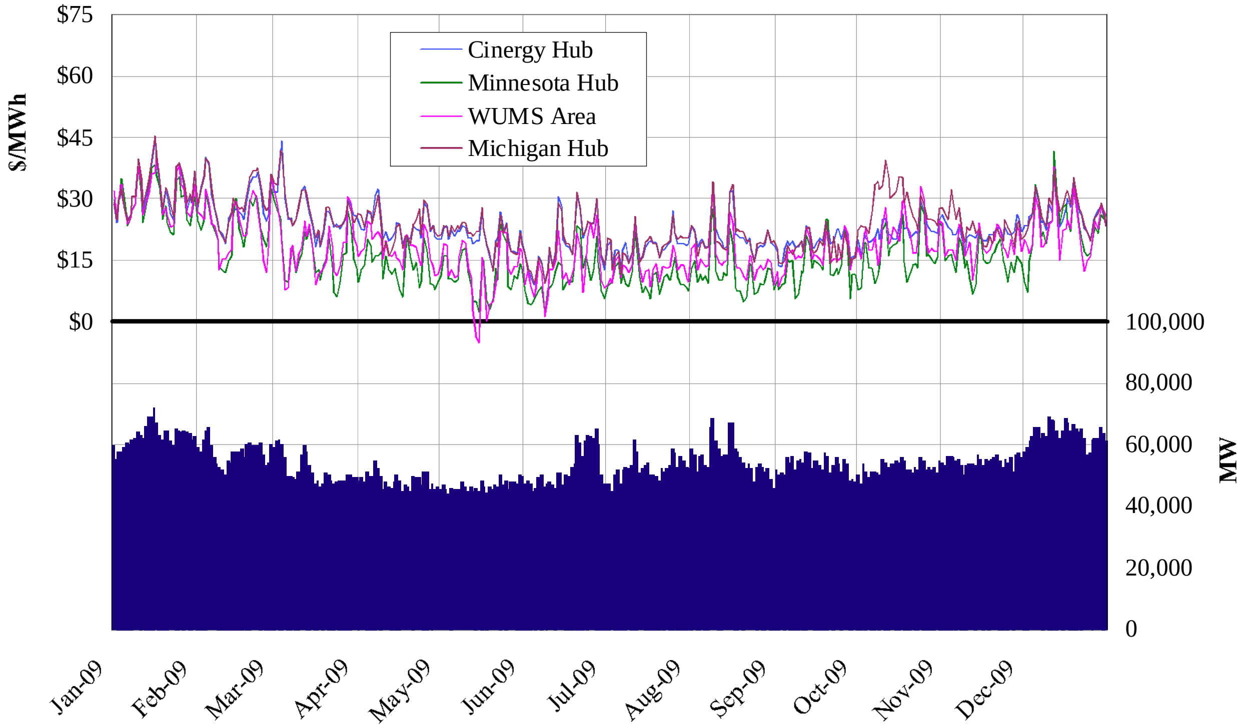
Day-ahead prices were stable throughout the year with the highest pricing occurring during the highest load periods, as expected. Due to mild weather and relatively poor economic conditions, load was not as high or as variable as one would normally expect, particularly during the summer. As a result, price volatility declined in 2009. The introduction of ASM led to significant improvements in generating unit flexibility, which also contributed to the reduction in price volatility.

The load-weighted average day-ahead energy price in all peak hours in 2009 was $35.85 per MWh, a 48 percent decrease from 2008. This decrease was due to very low fuel prices and mild peak load conditions. Fuel costs were highest at the beginning and end of the year, leading to higher day-ahead energy prices in these periods.

Persistent west-to-east congestion across the Midwest ISO caused the lowest average prices in Minnesota ($33 per MWh) and the highest prices in Michigan ($38.40). Transmission outages and high load in late June contributed to substantial congestion out of the West and the highest day-ahead prices of the year in eastern areas. Traditionally congested regions in the Midwest

ISO, notably WUMS, were less congested in 2009 as a result of continued transmission investments. Figure 16 shows the same results for off-peak hours.

Figure 16: Day-Ahead Hub Prices and Load
2009: Off-Peak Hours



Off-peak prices were 38 percent lower on average in 2009 than in 2008. Congestion between eastern and western hubs and volatility were more prominent in the off-peak hours, and were higher on a percentage basis than in prior years. For example, prices in WUMS and at the Minnesota Hub averaged $21 and $19 per MWh, respectively. Prices at the Cinergy Hub and Michigan Hub averaged close to $25 per MWh.

Day-ahead, off-peak prices were highest from January through March due to winter load patterns and higher fuel prices. Prices at the Cinergy and Michigan Hubs were only marginally higher than prices at the Minnesota Hub and WUMS during these months. The high loads in the winter-peaking western areas resulted in less congestion out of and more congestion into the West. The decline in prices was driven partly by the decrease in coal prices since coal-fired generation was almost always the marginal fuel in off-peak hours. Lastly, transmission outages were not as significant in 2009 as in prior years, although outages in Michigan resulted in higher prices in that area in October.

2. Day-Ahead and Real-Time Price Convergence

Our next analysis examines convergence of day-ahead and real-time energy prices. Good convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market. Since the day-ahead market determines most of the energy settlements and generator commitments in the Midwest ISO region, good price convergence with the real-time market helps ensure efficient day-ahead commitments that reflect actual real-time operating needs.

Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day, but a variety of factors can cause real-time prices to be significantly higher or lower than expected. While a well-performing market may not result in prices converging on a daily basis, it should lead prices to converge well on a monthly or annual basis. A modest day-ahead price premium is rational because purchases in the day-ahead market are subject to less price volatility (which is valuable to risk-averse buyers). Additionally, purchases in the real-time market are subject to allocation of real-time RSG costs (which are much larger than day-ahead RSG costs). The current RSG allocation methodology imposes disproportionately large costs on virtual supply transactions. This has contributed to sharp declines in virtual activity and contributed to larger price differences by reducing the effectiveness of the arbitrage by participants. This is discussed in more detail later in Section IV of the report.

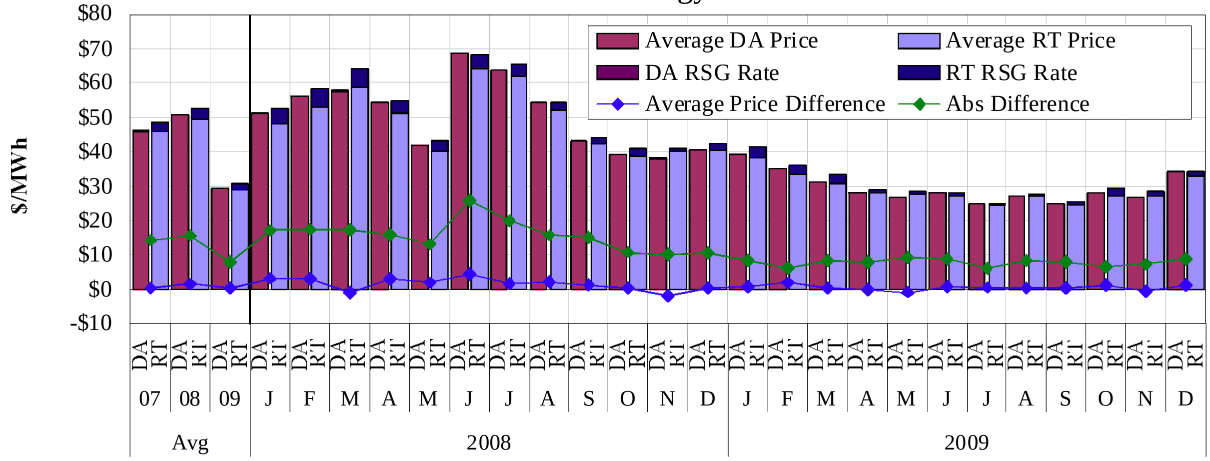
To evaluate how well day-ahead and real-time prices converged in 2009, Figure 17 shows monthly average prices in the day-ahead and real-time markets at the Cinergy Hub, along with the average RSG cost per MWh. The table below the figure shows two measures of price convergence for four representative locations:

- The difference between the average day-ahead and real-time price, which measures overall convergence; and
- The average of the hourly absolute value of the day-ahead and real-time price difference. This shows the typical difference regardless of whether the difference was positive or

negative. This measure shows how consistent day-ahead and real-time prices were on an hourly basis.

Figure 17: Day-Ahead and Real-Time Prices

2007 – 2009: Cinergy Hub



Average Price Difference (% of Real-Time Price)

Cinergy Hub	1	3	2	7	6	-2	6	5	7	3	4	3	1	-5	0	2	6	1	0	-3	3	2	1	1	4	-2	3
Michigan Hub	2	3	2	7	7	-1	7	3	7	3	8	0	-1	-4	1	4	5	4	0	-4	-1	0	4	3	7	-1	2
Minnesota Hub	3	3	3	11	11	-2	7	6	-2	0	3	1	4	4	-1	7	8	12	3	1	11	-3	6	-5	1	4	-1
WUMS Area	2	3	7	1	8	-3	8	5	-3	2	7	4	7	1	-2	8	12	12	6	4	13	2	8	5	8	16	5

Average Absolute Price Difference (% of Real-Time Price)

Cinergy Hub	31	32	27	36	33	29	31	33	40	32	30	35	28	25	26	22	19	28	28	34	33	25	32	32	24	27	27
Michigan Hub	32	33	31	36	32	29	33	34	42	34	33	38	29	26	27	22	19	29	33	34	34	27	37	44	39	34	27
Minnesota Hub	41	38	37	39	35	34	34	39	56	35	34	45	39	34	37	29	28	43	46	51	51	34	42	41	34	35	36
WUMS Area	35	37	36	36	35	31	32	34	61	33	33	47	37	32	30	25	31	38	39	55	55	33	37	39	37	41	37

There was only a slight day-ahead energy price premium at the Cinergy hub in 2009, which was roughly equal to the real-time RSG allocation borne by real-time load purchases. Overall, convergence was comparable to prior years at this location. However, the Minnesota Hub and WUMS experienced larger and more volatile price differences. This is especially evident in the average absolute price differences at these locations. Price convergence in historically congested locations is more difficult to achieve because of congestion-driven price volatility in these areas. Some of this volatility is associated with negative price spikes in off-peak hours.

One of the contributors to the large day-ahead premiums in the West was the fact that wind output was substantially under-scheduled in the day-ahead market. The large supply increase in the real-time market results in lower real-time prices (sometimes negative prices). Normally, this price separation would be arbitraged by virtual supply; however, the decline in virtual trading discussed above limited the response of the market to arbitrage these large price differences.

For comparison purposes, Table 3 compares day-ahead and real-time energy price differences in the Midwest ISO to other RTO markets in the Eastern Interconnect. For each market, we show the average price difference and the average of the absolute value of the hourly price difference for multiple locations (representing prices in select constrained and unconstrained areas in each market). Overall, these analyses indicate that price convergence in the Midwest ISO has been consistent with the other RTO markets.

Table 3: Price Convergence in Midwest ISO and Other RTO Markets
2009

	Average Clearing Price			Average of Hourly
	Day-Ahead	**Real-Time**	**Difference**	**Absolute Price Difference**
Midwest ISO:				
Cinergy Hub	$30.77	$30.30	$0.47	$8.21
Michigan Hub	$32.17	$31.51	$0.66	$9.70
Minnesota Hub	$26.17	$25.43	$0.74	$9.30
WUMS Area	$28.89	$26.95	$1.93	$9.77
New England ISO:				
New England Hub	$43.18	$43.90	-$0.72	$6.52
Maine	$41.13	$41.72	-$0.59	$6.23
Connecticut	$44.52	$44.90	-$0.37	$6.94
New York ISO:				
Zone A (West)	$32.92	$32.95	-$0.03	$10.72
Zone G (Hudson Valley)	$44.94	$45.24	-$0.30	$13.27
Zone J (New York City)	$49.12	$49.16	-$0.04	$15.46
PJM:				
AEP Gen Hub	$32.79	$33.07	-$0.28	$4.98
Chicago Hub	$30.68	$30.84	-$0.16	$6.68
New Jersey Hub	$43.73	$43.27	$0.46	$8.10
Western Hub	$40.69	$40.29	$0.39	$7.44

Neighboring markets, which had exhibited consistent day-ahead premiums in 2008, exhibited slight real-time premiums at many locations in 2009. Meanwhile, the Midwest ISO has maintained its day-ahead premium across the footprint. This is consistent with higher real-time price volatility and higher RSG cost allocations in the real-time market compared to the day-ahead market. Real-time RSG cost allocations averaged $1.60 per MWh while day-ahead RSG cost allocations averaged $0.03 per MWh. Higher RSG cost allocations in the real-time market provided an incentive to schedule load in the day-ahead market even if it was slightly more expensive.

The average absolute differences are consistent with the overall price volatility in each market and are slightly lower in every market in 2009 than the absolute differences in 2008 as a percentage the real-time price. Prices were most volatile in the Midwest ISO and New York ISO, which both run true five-minute markets. The congested locations exhibit the largest average absolute differences in each market due to the higher volatility in these areas. Overall, these analyses indicate that price convergence in the Midwest ISO was consistent with other RTO markets. However, convergence in some of the Midwest ISO's congested areas has eroded as virtual activity has diminished.

3. Day-Ahead Ancillary Services Markets

The ancillary services markets are day-ahead and real-time markets for regulating reserves, operating reserves, and supplemental reserves that are jointly optimized with the energy markets. They were introduced in January 2009 and have operated with no significant issues. ASM prices have been consistent with expectations and are comparable to results in similar RTO markets.

Figure 18 shows monthly average day-ahead clearing prices for the Midwest ISO's ancillary service products for 2009, along with day-ahead to real-time price differences. Day-ahead prices for regulation averaged nearly $21 per MWh in January 2009. This was higher than in subsequent months due in large part due to higher initial procurement levels to ensure sufficient resources to maintain reliability. The regulation requirements were reduced gradually over the first several months of operation based on experience and the determination that reliability could be maintained at lower product scheduling requirements. Prices averaged approximately $11 per MWh after the first quarter.

Figure 18: Day-Ahead Ancillary Services Prices and Price Convergence
2009

Regulation prices were higher in real time in every month of the year due to increased real-time energy price volatility (which increases the opportunity costs of generators providing regulation) and reduced regulation availability due to the Midwest ISO's regulation commitment process (which selects only subset of regulation-eligible units). In addition, real-time requirements include more stringent ramping constraints that can lead to result in more frequent shortages and higher prices. Overall, spinning reserve and supplemental reserve prices converged well between the day-ahead and the real-time during 2009. However, occasional shortages of supplemental reserves (occurring mostly during Automatic Reserve Sharing ("ARS") events) resulted in some divergence.

4. Day-Ahead Load Scheduling and Virtual Trading

Our next analysis addresses day-ahead load scheduling and virtual trading. These aspects of the market play an important role in overall market efficiency by promoting optimal commitments and improved price convergence between day-ahead and real-time markets. Day-ahead load includes price-sensitive load, fixed load, and virtual load. Price-sensitive load is scheduled if the day-ahead price is equal to or less than the load bid. A fixed load schedule does not include a bid price, indicating that the load should be scheduled regardless of the day-ahead price. We are generally interested in comparing the net load cleared (defined as the physical load, plus virtual load minus virtual supply) in the day-ahead market as a percentage of the actual real-time load. This relationship affects commitment patterns and RSG costs because units are committed and scheduled in the day-ahead to satisfy the net load.

When day-ahead net load is significantly less than real-time load, particularly in the peak load hour of the day, the Midwest ISO will frequently commit peaking resources to satisfy the incremental increase in load. As shown later in this section, peaking resources often do not set real-time prices, even when these resources are effectively marginal. This can contribute to suboptimal real-time pricing and can result in inefficiencies because lower-cost units that could have been committed through the day-ahead market will be displaced by peaking resources committed in real-time.

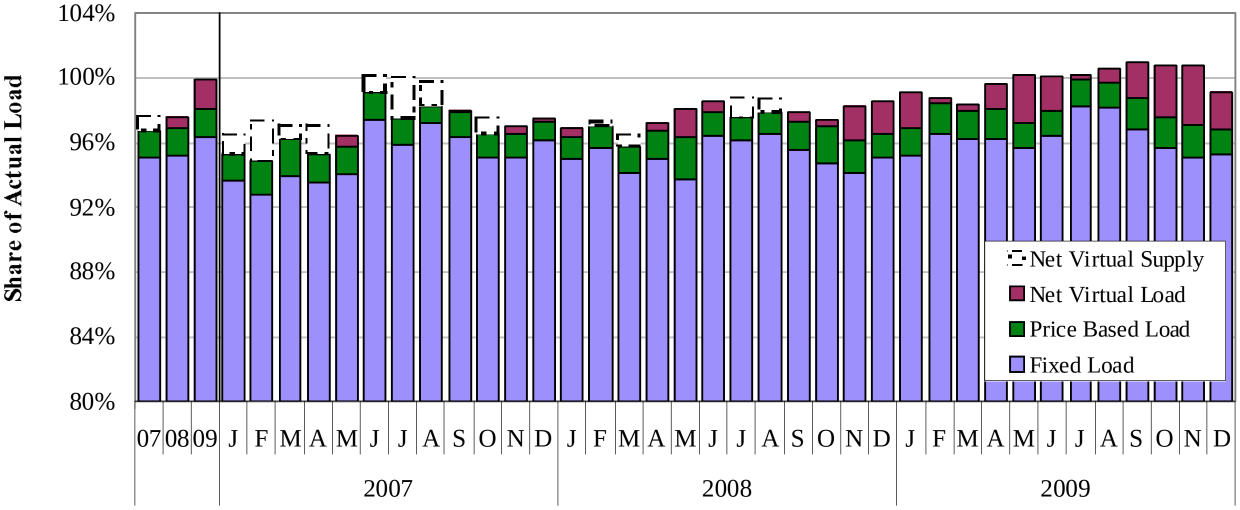
Additionally, when significant quantities of generation are committed by participants or by the ISO after the day-ahead market, this additional supply will lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of additional supply increases real time are:

- Supplemental commitments by the Midwest ISO made for reliability after the day-ahead market;
- Self-commitments by market participants after the day-ahead market; and
- Wind output that was under-scheduled in the day-ahead market.

To show the net load-scheduling patterns in the day-ahead market, Figure 19 compares the monthly peak-hour day-ahead scheduled load to actual load. We show the peak hour of each month because this is when the Midwest ISO is most likely to require additional generation.

Figure 19: Peak Hour Day-Ahead Scheduled Load versus Actual Load

2007 – 2009



Share of Actual Load

All Hour	98.9%	99.2%	99.9%
Peak Hour	96.8%	97.6%	99.9%

All Hour	97.5%	97.1%	98.8%	97.2%	98.4%	100.1%	98.7%	99.7%	99.8%	99.4%	99.8%	100.3%
Peak Hour	95.3%	94.9%	96.2%	95.3%	96.5%	99.1%	97.5%	98.3%	97.9%	96.5%	97.0%	97.5%

All Hour	99.2%	99.8%	98.2%	99.5%	98.8%	99.7%	98.7%	99.0%	98.9%	98.9%	99.5%	99.6%
Peak Hour	96.9%	97.0%	95.8%	97.2%	98.0%	98.5%	97.6%	97.9%	97.8%	97.4%	98.3%	98.5%

All Hour	100.1%	99.4%	98.7%	99.2%	99.4%	99.9%	100.3%	100.7%	100.4%	100.1%	100.2%	100.6%
Peak Hour	99.1%	98.7%	98.4%	99.6%	100.2%	100.1%	100.2%	100.5%	101.0%	100.8%	100.7%	99.1%

Net load scheduling in 2009 was higher than during the prior two years. Net load scheduled in all hours of the day-ahead market as a percent of the actual load increased slightly to 99.9 percent. The vast majority of this load is "fixed", meaning it will be scheduled at any price. In 2009, price-sensitive and net virtual load accounted for 3.6 percent of the scheduled load, up from 2.2 percent in 2008. The day-ahead market consistently cleared net virtual load in 2009.

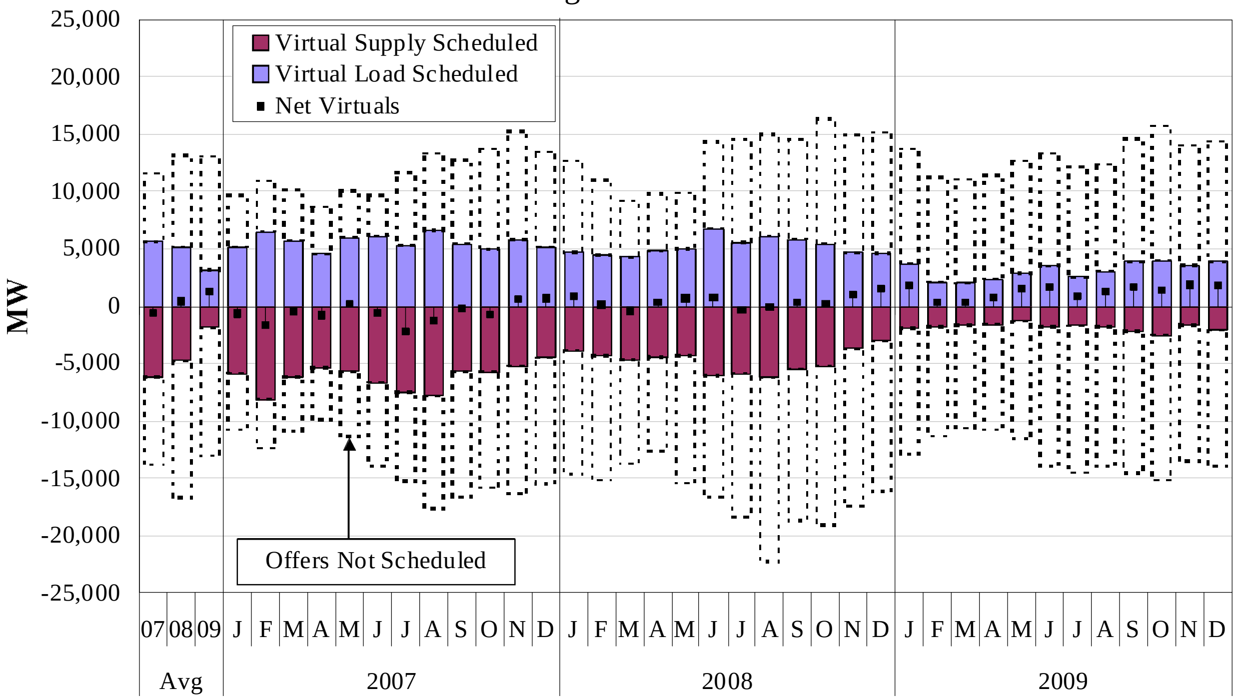
Net load scheduling in the peak hour of each day (the hour that is most likely to require the Midwest ISO to commit additional generation) increased substantially. In 2009, 99.9 percent of the peak hour actual load was scheduled on net in the day-ahead market, versus 97.6 percent in 2008 and 96.8 percent in 2007. Higher load scheduling and lower overall load have together reduced the Midwest ISO's reliance on peaking resources in the real-time and have lowered real-time RSG costs.

Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual trading provides essential liquidity to the day-ahead market because it constitutes a large share of the price-sensitivity at the margin that is needed to establish efficient day-ahead prices.

Virtual transactions scheduled in the day-ahead market are settled in the real-time. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price; conversely, virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. For example, if the market clears one MW of power for $50 in the day-ahead market, the seller must then purchase or produce one MW in real time to cover the trade. Accordingly, if a virtual trader expects real-time prices to be lower than day-ahead prices, the trader would sell virtual supply in the day-ahead market and buy the power back in the real-time market. Likewise, if a virtual trader expects real-time prices to exceed day-ahead prices, the trader will buy virtual load in the day-ahead and sell the power back in the real-time. This trading is one of the primary means of arbitraging the prices in the two markets, causing day-ahead prices to converge with real-time prices. The price convergence resulting from this arbitrage increases the efficiency of the day-ahead market.

Figure 20 shows virtual supply and demand volumes in the day-ahead market.

Figure 20: Virtual Load and Supply in the Day-Ahead Market
2007 – 2009: Average Cleared and Offered MW



The figure shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It shows the components of daily virtual bids and offers and the net virtual load (cleared virtual load less virtual supply) in the day-ahead market from 2007 to 2009. The virtual bids and offers that did not clear (because they were not economic given the prevailing market prices) are shown as dashed areas at the end points of the solid bars.

Cleared virtual transactions decreased 50 percent in 2009, while total offered virtual transactions decreased only 12 percent. These decreases were due primarily to:

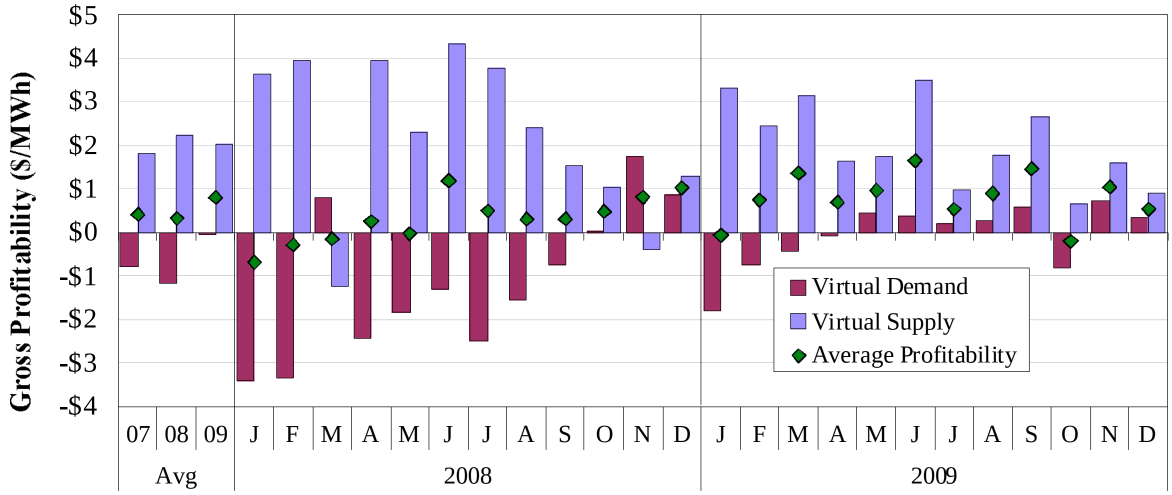
- Tightened credit conditions early in the year – volumes increased in the second half as these attenuated; and
- Changes in the allocation of real-time RSG costs described below.

The Commission issued a series of Orders from April 2006 to November 2008 that established a real-time RSG cost allocation rate (the "Interim Rate") to be used until the new RSG cost allocation is implemented. The Interim Rate allocates nearly all real-time RSG costs to deviations between the day-ahead and real-time markets, such as real-time physical load changes, virtual supply, and import schedule changes. However, RSG charges are also caused by peaking resources not setting prices, congestion, reliability needs, and outages. Hence, the Interim Rate over-allocates costs to deviations relative to the portion of the RSG they actually cause, including virtual supply, which bore roughly 24 percent of all real-time RSG costs under this rate in 2009.

Reduced virtual trading activity raises potential concerns regarding the performance of the day-ahead market because active virtual trading in the day-ahead market promotes price convergence with the real-time market. Good price convergence, in turn, facilitates an efficient commitment of generating resources. Active virtual supply also protects the day-ahead market against market manipulation and market power abuses.

Figure 21 shows monthly average gross profitability of virtual purchases and sales, as well as the volume of virtual supply and demand that cleared the market. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market compared to the price at which these positions were covered in the real-time market. Gross profitability does not account for RSG cost allocations.

Figure 21: Profitability of Day-Ahead Virtual Trading
2007 – 2009



Share of Cleared Virtuals with Extreme Profitability (%)

Profit>$50/MWh	4.7	2.8	1.2	2.5	1.9	1.3	1.4	1.1	9.5	6.4	3.0	2.3	0.8	0.5	1.2	0.7	1.2	1.7	0.9	2.0	1.6	0.7	1.4	1.5	0.8	0.7	1.4
Profit<-$50/MWh	3.7	3.7	1.6	3.8	3.3	4.3	3.6	2.9	7.4	4.9	3.2	4.2	2.1	1.3	2.8	0.9	1.0	1.6	1.7	1.6	1.7	0.8	1.6	1.6	1.7	2.5	2.2

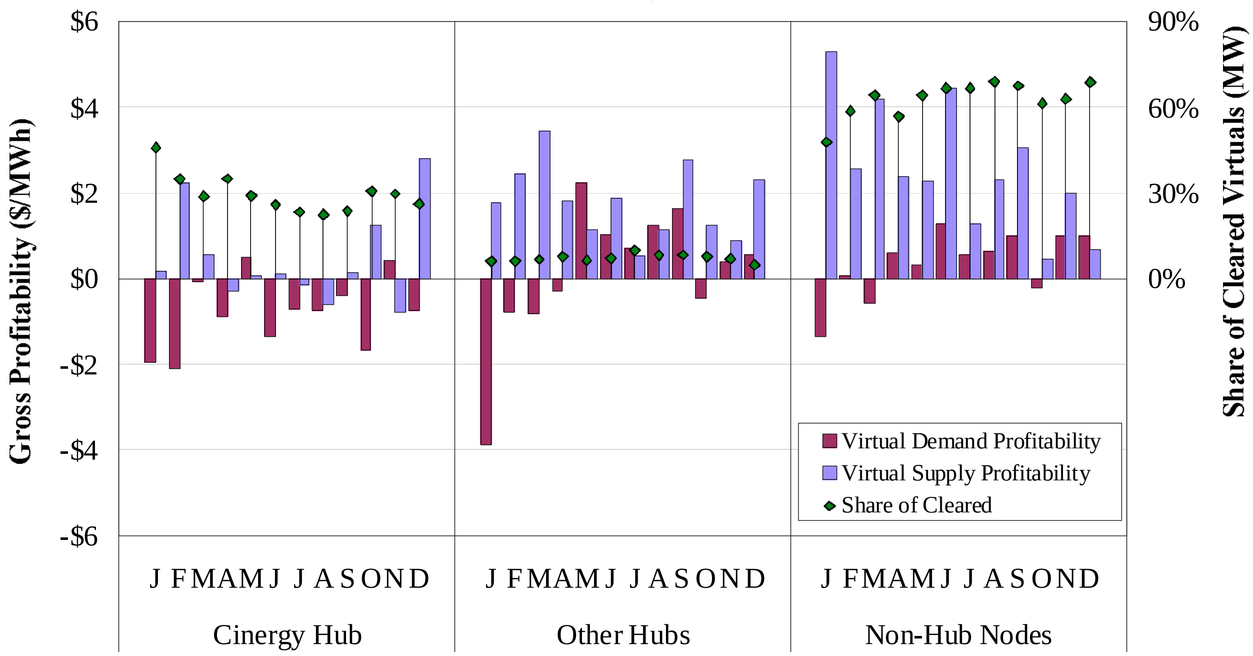
Profits available to virtual traders were low in 2009, as expected in a market that is well arbitraged. Profitability of all cleared virtual transactions increased modestly to $0.80 per MWh in 2009 from $0.42 and $0.33 per MWh in 2007 and 2008, respectively. Virtual supply has been considerably more profitable than virtual demand ($2.03 per MWh versus -$0.06 per MWh) due to the prevailing day-ahead price premium. However, after paying RSG charges of $1.60 per MWh, virtual supply transactions netted an average profit of only $0.43 per MWh.

The table below the figure shows the percentage of virtual transactions clearing with abnormally large profits or losses. Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies. The share of cleared transactions generating profits greater than $50 per MWh has fallen by more than one-half since 2008, to 1.2 percent.

We continually monitor for large losses on virtual transactions because they can indicate an attempt by a participant to manipulate the day-ahead market prices. Attempts to create artificial congestion or other price movements in the day-ahead market will cause prices to diverge from real-time prices and will be unprofitable. For example, a participant may submit a high-priced virtual bid at a constrained location that causes artificial congestion in the day-ahead market. The participant will buy in the day-ahead at the high (congested) price and sell the energy back at a lower (uncongested) price in the real-time market. Although it is foreseeable that the virtual transaction would be unprofitable, the participant could earn net profits if it increases its FTR payments (or payments through some other leveraged bilateral position) resulting from the increased day-ahead congestion. Virtual losses that warrant further investigation have been rare, although one pattern of losses did indicate conduct that warranted mitigation under the Tariff and the participant was mitigated accordingly.

To examine how the profitability of virtual transactions varies by type of location, Figure 22 shows the monthly average profitability of virtual purchases and sales at the Cinergy Hub, other hubs, and other nodes. The trading volume is shown by the diamonds in the figure that are plotted against the axis on the right side of the figure. The figure shows that Cinergy Hub is the single most liquid trading point in the Midwest ISO with almost 30 percent of all trading volume. Most other virtual trading activity occurs at individual nodes – over 60 percent in 2009.

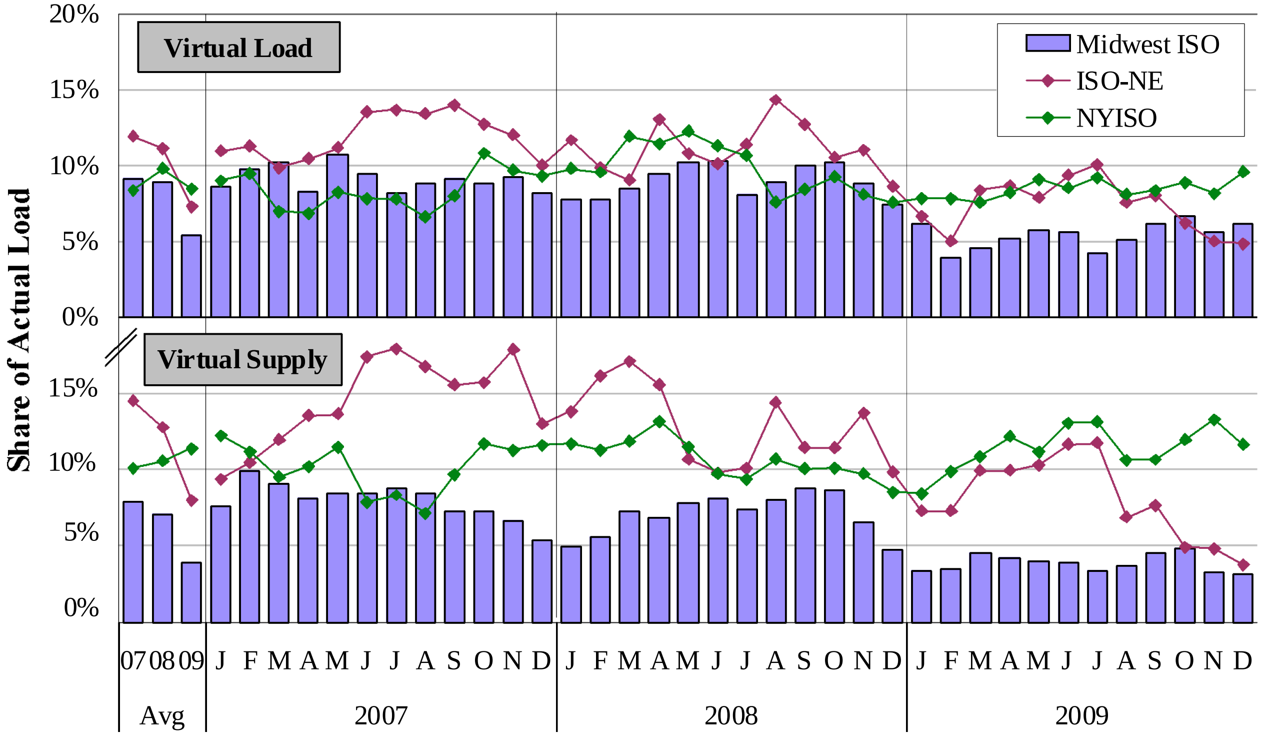
Figure 22: Virtual Profitability by Location
2009



Virtual supply was generally more profitable at the nodal level ($2.46 per MWh) because larger price differences occur at individual nodes that are less liquid than Cinergy Hub. Almost $36 million of the $41 million in gross virtual supply profits in 2009 occurred at individual nodes, although the allocation of RSG costs offsets more than one-half of these profits. Virtual demand was consistently unprofitable at the Cinergy Hub and generally profitable at other locations. However, many of the demand bids at Cinergy are likely physical hedges (which tend to be modestly unprofitable), rather than speculative bids by virtual-only participants. The average loss of cleared virtual-demand bids at the Cinergy Hub was $0.87 per MWh in 2009, compared to a profit of $0.44 per MWh at nodal locations.

To compare the trends in the Midwest ISO to other RTO markets, Figure 23 shows monthly average virtual supply and demand transactions for the Midwest ISO, ISO New England, and New York ISO as a percent of actual load.

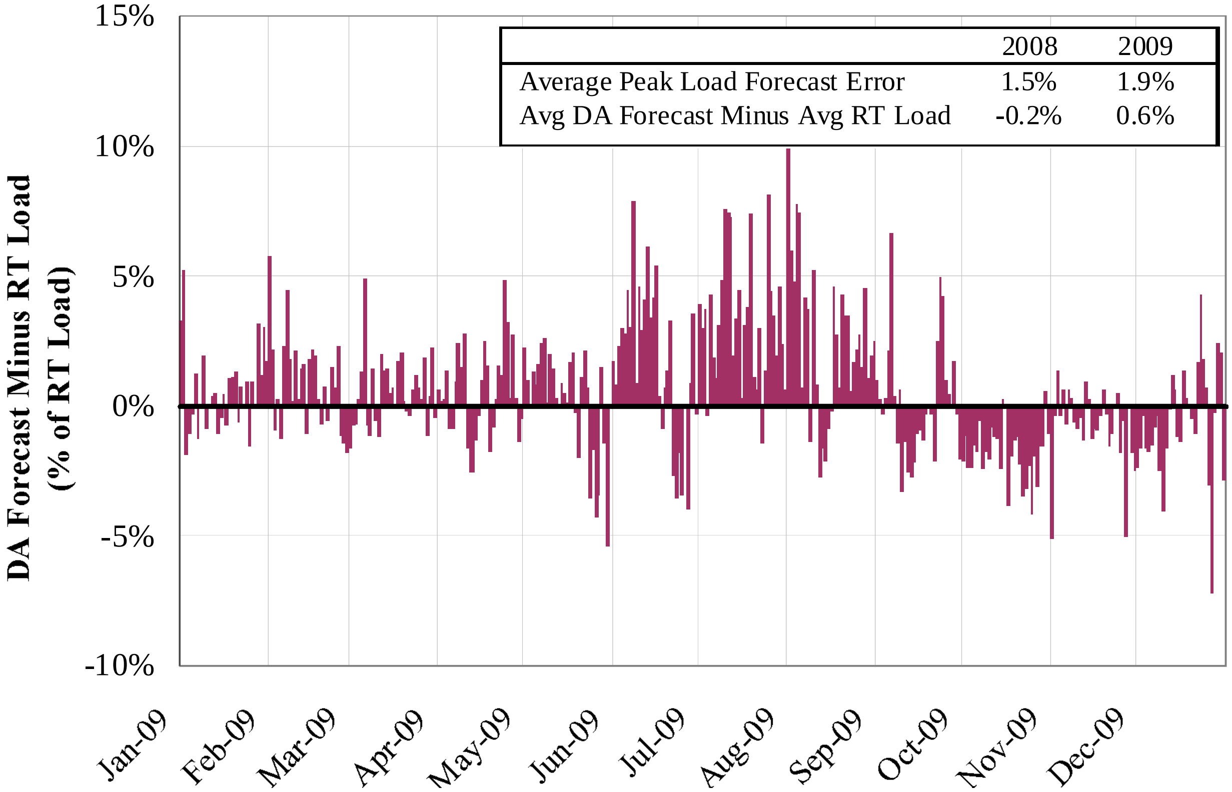
Figure 23: Virtual Transaction Volumes
2007 – 2009



Virtual load and supply volumes declined in all of the markets beginning in the fourth quarter of 2008 due to tight credit conditions. Virtual trading in neighboring markets returned to normal levels by mid-year, although volumes in ISO-NE declined once more in the second half of 2009 due to a general reduction in congestion and arbitrage opportunities. Virtual load as a percentage of actual load in the Midwest ISO declined by more than one-third from the 2007-2008 levels and remained near 5 to 6 percent of actual load throughout 2009. Virtual supply volumes declined by almost half from previous years, averaging only 3.8 percent of actual load. This is substantially less than in the other markets. As noted above, the high RSG cost allocation rate applied to virtual supply beginning in November 2008 contributed to the decline in virtual supply quantities.

Our next analysis examines the Midwest ISO's day-ahead forecasted load. Figure 24 shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day in 2009.

Figure 24: Daily Day-Ahead Forecast Error in Peak Hour
2009



Day-ahead load forecasting is a key element of an efficient day-ahead commitment process. The accuracy of the day-ahead load forecast is particularly important for the Reliability Assessment

Commitment process performed after the close of the day-ahead market. Inaccurate forecasts can cause the Midwest ISO to commit unnecessary resources or to not commit sufficient resources to meet demand, both of which can be costly. Some participants in the day-ahead scheduling and bidding processes may also rely on day-ahead forecasts.

The day-ahead forecast of peak load was on average 0.6 percent greater than real-time peak load. This indicates that the forecasting was relatively accurate. The average peak load forecast error – the magnitude of the error, regardless of direction – was 1.9 percent in 2009. This is slightly higher than the 1.5 percent observed in 2008, but lower than the 2.2 percent error in 2007. The result is comparable to the performance of other RTOs. Consistent with the prior two years, the figure shows the load tended to be over-forecasted in the summer and under-forecasted in the fall. The magnitude of this seasonal bias increased in the summer of 2009 due to an unexpectedly cool summer, but decreased in the winter. The Midwest ISO is working to identify the source of this bias.

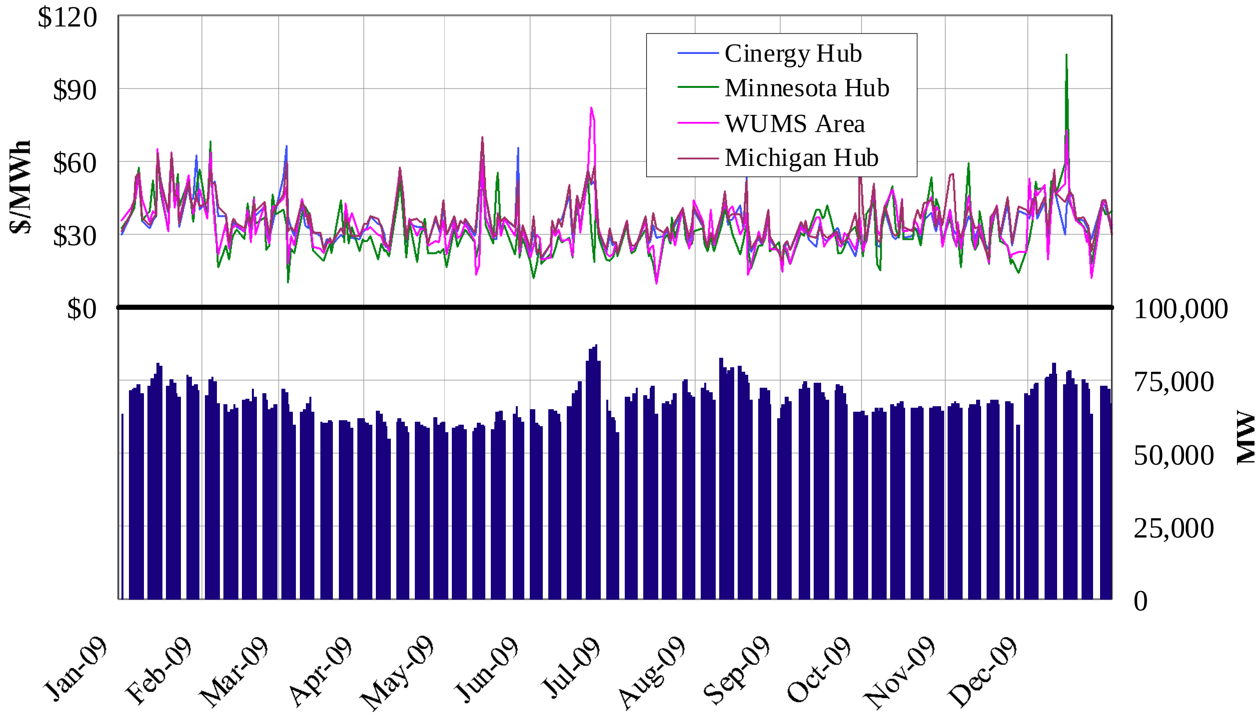
B. Real-Time Market Performance

In this subsection, we evaluate real-time market outcomes. The real-time market is important because its outcomes directly affect day-ahead outcomes. Energy purchased in the day-ahead market (and other forward markets) is priced based on expectations of future prices in the real-time markets. Therefore, higher real-time prices will lead to higher day-ahead and other forward market prices. Because forward purchasing is a primary risk-management tool for participants, increased volatility in the real-time market also leads to higher forward prices by potentially raising risk premiums in the day-ahead market.

1. Real-Time Prices and Load

We begin this subsection by providing an overview of daily average real-time energy prices during peak hours, along with the corresponding actual load, in Figure 25 below.

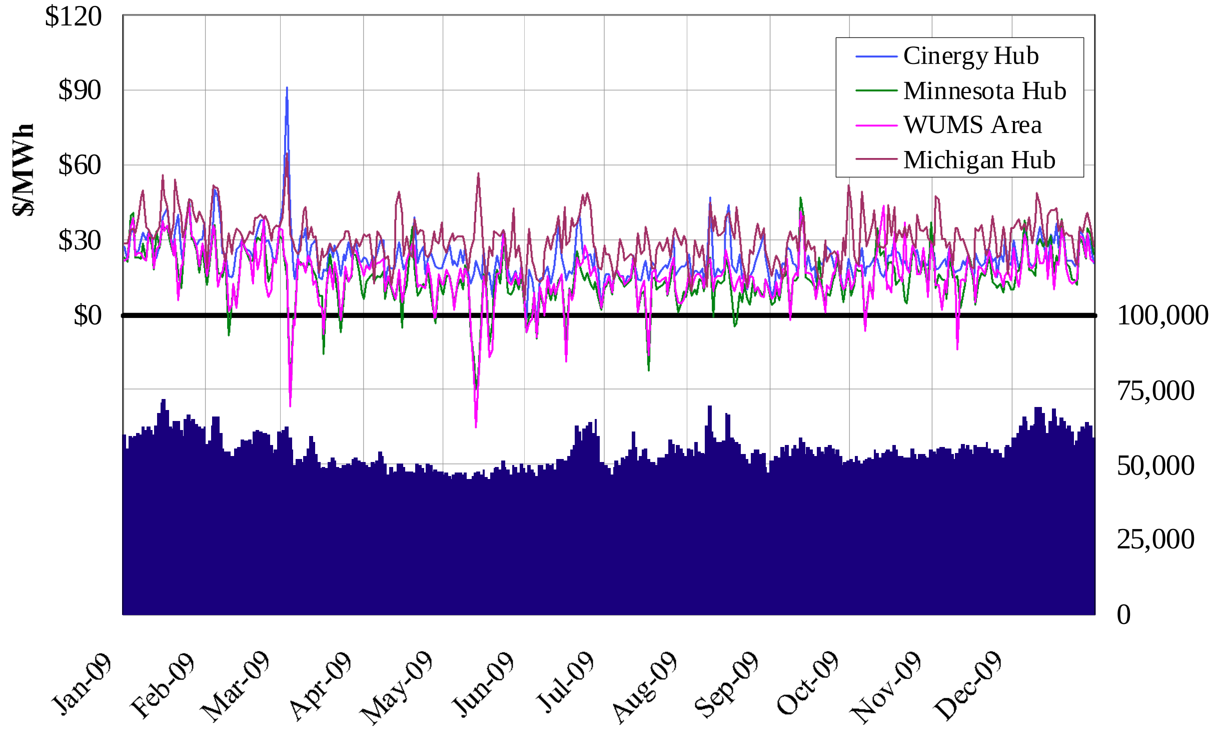
Figure 25: Real-Time Hub Prices and Load
2009: Peak Hours



The figure shows a general correlation between peak load and peak energy price with some notable price separations due to congestion events. Overall, fuel prices and load were substantially lower in 2009 than in 2008, particularly during the summer months. These factors led to lower energy prices throughout the footprint. The load-weighted, real-time energy price during peak hours in 2009 was $35.49 per MWh, down 47 percent from 2008. This reduction was primarily due to a reduction in fuel prices of 30 to 55 percent, depending on the fuel.

Average load and peak load also decreased in 2009, which reduced the frequency of high price events. For example, average daily peak prices rarely exceeded $70 per MWh and never did so at the Cinergy Hub. Congestion resulted in transitory price spikes, primarily in WUMS (e.g. June 23) and Minnesota (e.g. December 15). As in the day-ahead market, west-to-east congestion prevailed throughout the year and occurred periodically into Michigan. This trend was less apparent during peak hours than off-peak hours, when high levels of wind generation and exports from Commonwealth Edison led to large west-to-east flows. Much of the congestion into Michigan in 2009 was associated with a series of planned transmission outages related to transmission upgrades. Figure 26 shows the off-peak hours.

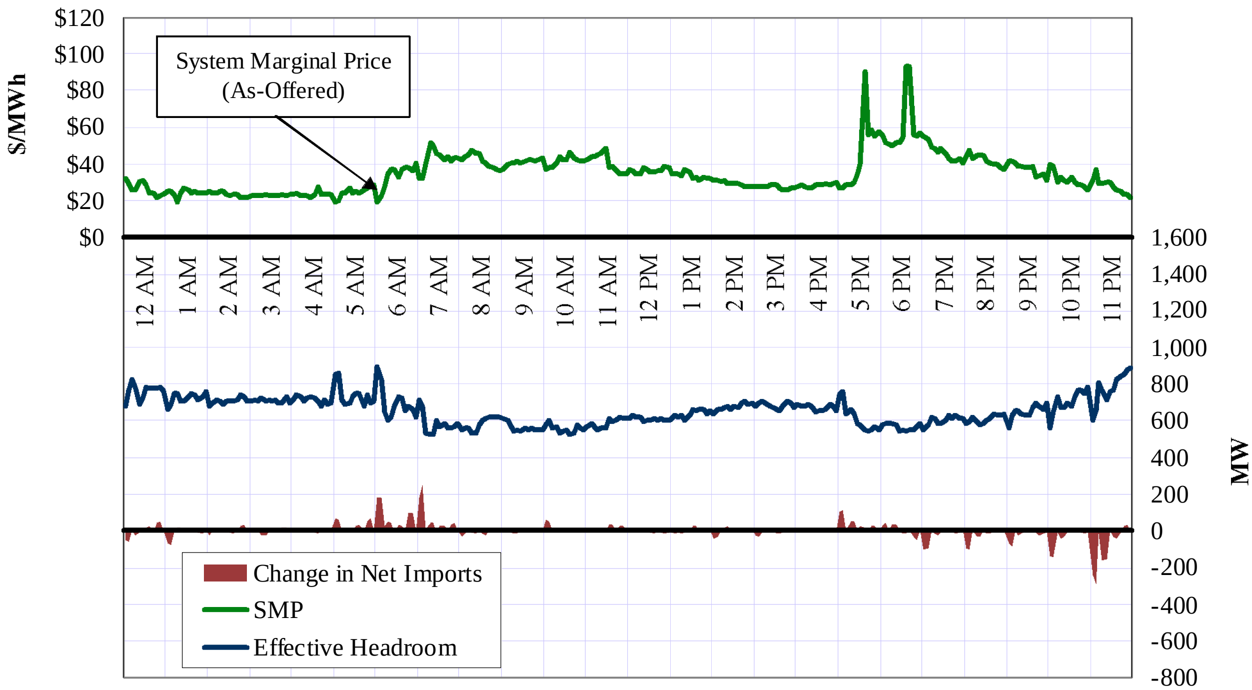
Figure 26: Real-Time Hub Prices and Load
2009: Off-Peak Hours



Energy prices were generally very low during off-peak hours. Higher levels of wind generation occurred in off-peak hours and a high percentage of off-peak hour prices were set by coal-fired resources. Off-peak prices were volatile in 2009. There was a consistent daily price spread of $6 and $8 per MWh between the western and eastern hubs. The persistent west-to-east congestion throughout the year resulted in 25 days with negative average off-peak prices at both the Minnesota Hub and WUMS. Congestion into eastern areas in early March was caused by several forced and planned generator outages, as well as substantial volumes of wheeled transactions from IESO to PJM.

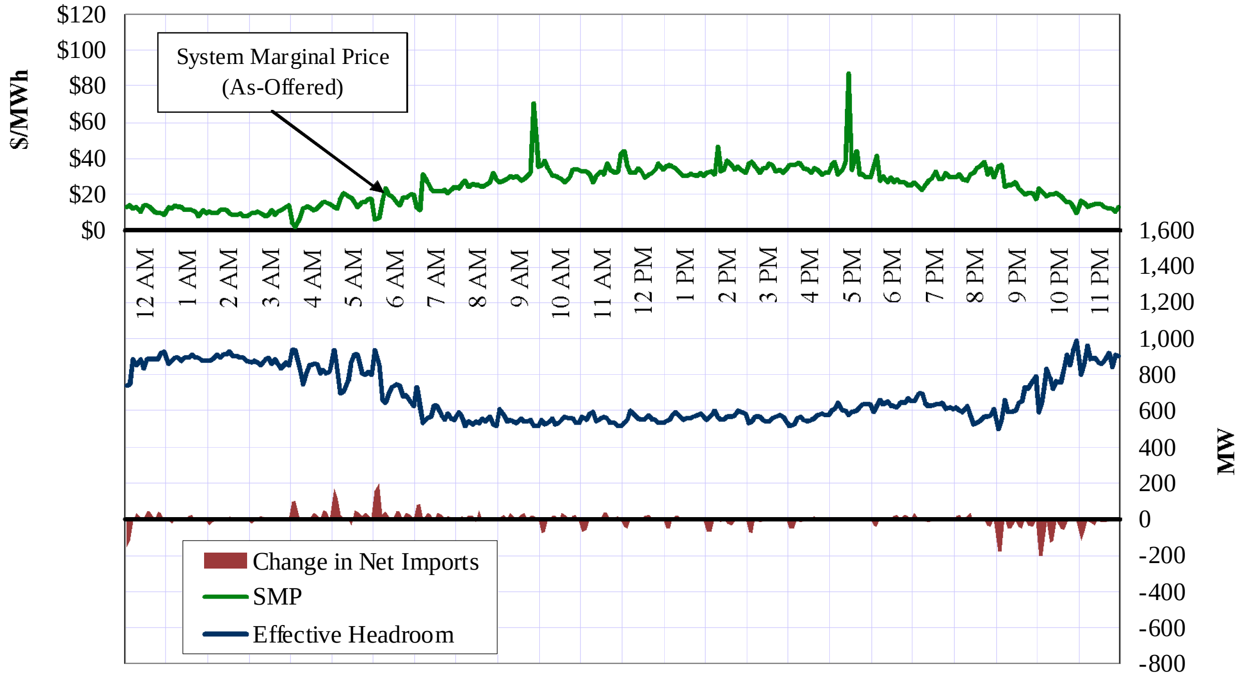
Figure 27 and Figure 28 show average real-time prices by time of day in the winter and summer months of 2009, when loads are the highest. Volatility decreased significantly in 2009 under the ASM market because the real-time market now has the flexibility to jointly optimize the use of resources for energy and ancillary service needs. To examine the drivers of the price fluctuations, the figures show the effective "headroom" on the system. Headroom is the amount of generation that can be utilized in the five-minute horizon, given ramp limitations. The figures also show the SMP and the average change in net imports.

Figure 27: Real-Time Prices and Headroom by Time of Day
Winter 2009



In winter and summer 2009, as in prior years, prices fluctuate most when load is ramping up or down near the peak load hours of the day (afternoon in the summer, and dual morning and evening peaks in the winter). Changes in real-time prices are directly related to changes in effective headroom, which often changes significantly at the top of the hour when hourly import schedules change and the commitment and de-commitment of units most often occurs. The sharp upward price movements that result from these patterns indicate a short-term system scarcity and are generally caused by generator operating constraints such as binding ramp constraints. Ramp constraints are limits to how quickly the system's generation can change in response to system conditions. These ramp constraints are exacerbated by generator inflexibility arising from decreases in offered ramp capability or dispatch range.

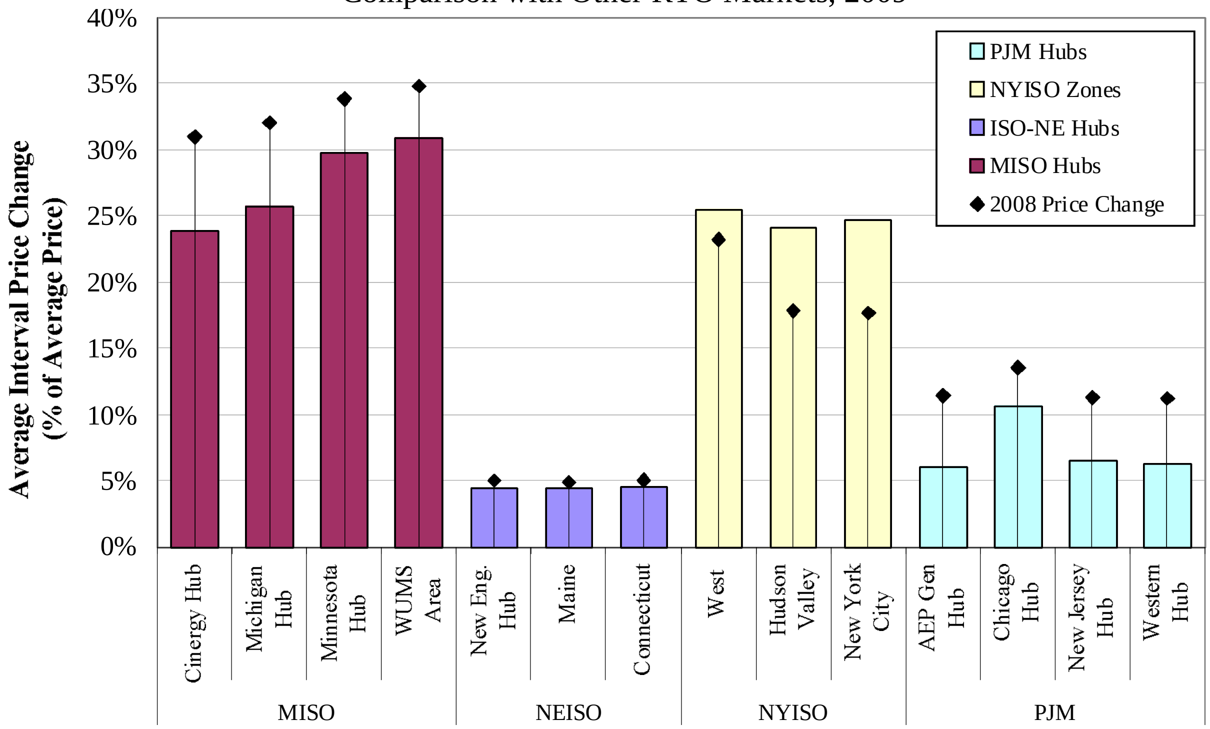
Figure 28: Real-Time Prices and Headroom by Time of Day
Summer 2009



To determine whether price volatility in the Midwest ISO is excessive, Figure 29 shows the average percentage change in real-time prices between five-minute intervals for several hubs in other RTO markets. Within the Midwest ISO, the Cinergy Hub exhibited the least volatility interval-to-interval because it was the least affected by congestion. WUMS is historically the most congested location and, in turn, it exhibited the largest average interval price change. The figure shows that average volatility dropped significantly in 2009 when compared to 2008 at all four representative locations in the Midwest ISO, which is likely due in part to the AS markets. These markets have led to substantial improvements in supply flexibility in the Midwest ISO.

The figure also shows that the Midwest ISO and the NYISO have the most price volatility, and ISO-NE has the least. These differences can be explained by software and operational characteristics of the various markets. The Midwest ISO and NYISO are true five-minute markets with a five-minute dispatch horizon. Ramp constraints are more prevalent in these markets due to the shorter time to move generation. However, NYISO's real-time dispatch is a multi-period optimization that looks ahead one hour, so it can anticipate ramp needs and begin moving generation to accommodate those needs. We recommend a similar approach for the Midwest ISO.

Figure 29: Five-Minute Real-Time Price Volatility
Comparison with Other RTO Markets, 2009



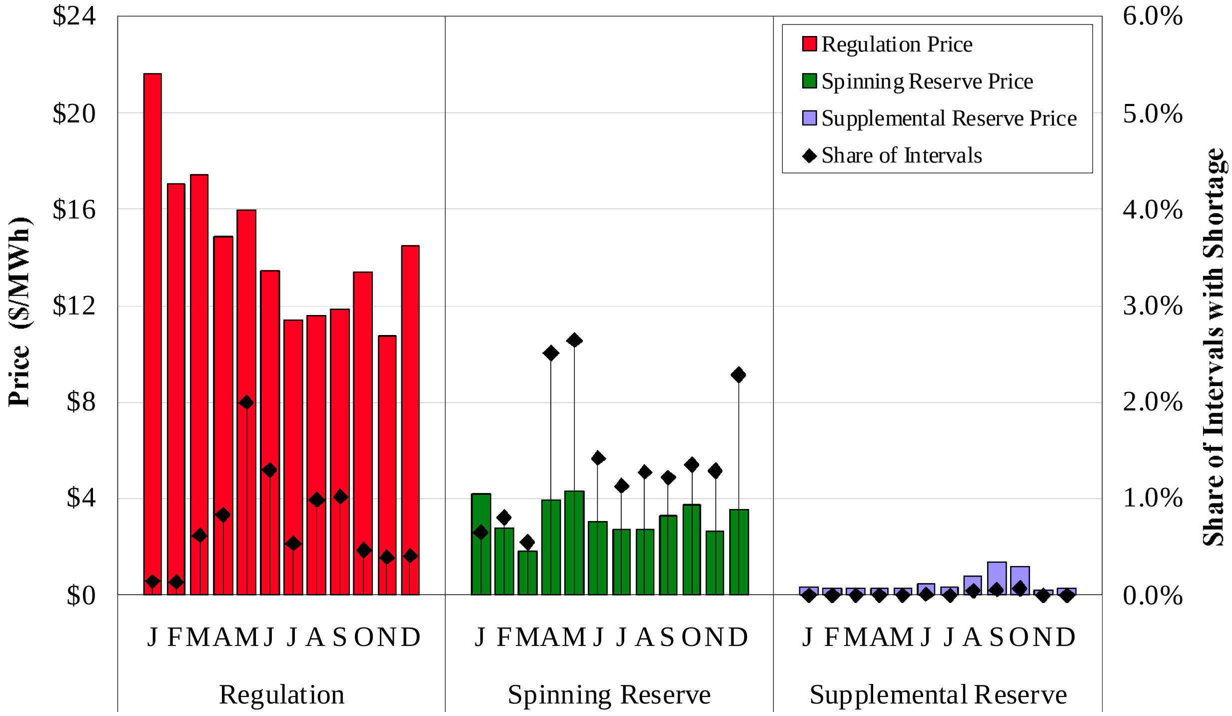
PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes, although they produce five-minute prices using ex-post pricing models. As a result, these systems are less likely to be ramp-constrained because they have 15 minutes of ramp capability to serve system demands. Because the systems are redispatched less frequently, these markets likely rely more heavily on regulation to satisfy shorter-term changes in load and supply, which is likely less efficient than the Midwest ISO's real-time dispatch.

Finally, the real-time load served by the real-time market can fluctuate substantially from interval-to-interval, which can demand a significant portion of the system's ramp capability. In some cases, these fluctuations are real and often caused by changes in "non-conforming" load. In other cases, the fluctuations are due to errors in the STLF. To reduce this source of price volatility, we recommend that the Midwest ISO consider means to improve its STLF to reduce the ramp demand on the system.

2. Ancillary Services Markets

The introduction of ASM in 2009 was a major accomplishment that substantially improves the completeness and efficiency of the Midwest ISO markets. In their first year of operation, ASM markets performed as expected with no significant issues. Figure 30 shows monthly average real-time clearing prices for the Midwest ISO's ancillary service products in 2009.

Figure 30: Real-Time Ancillary Services Prices and Shortages
2009



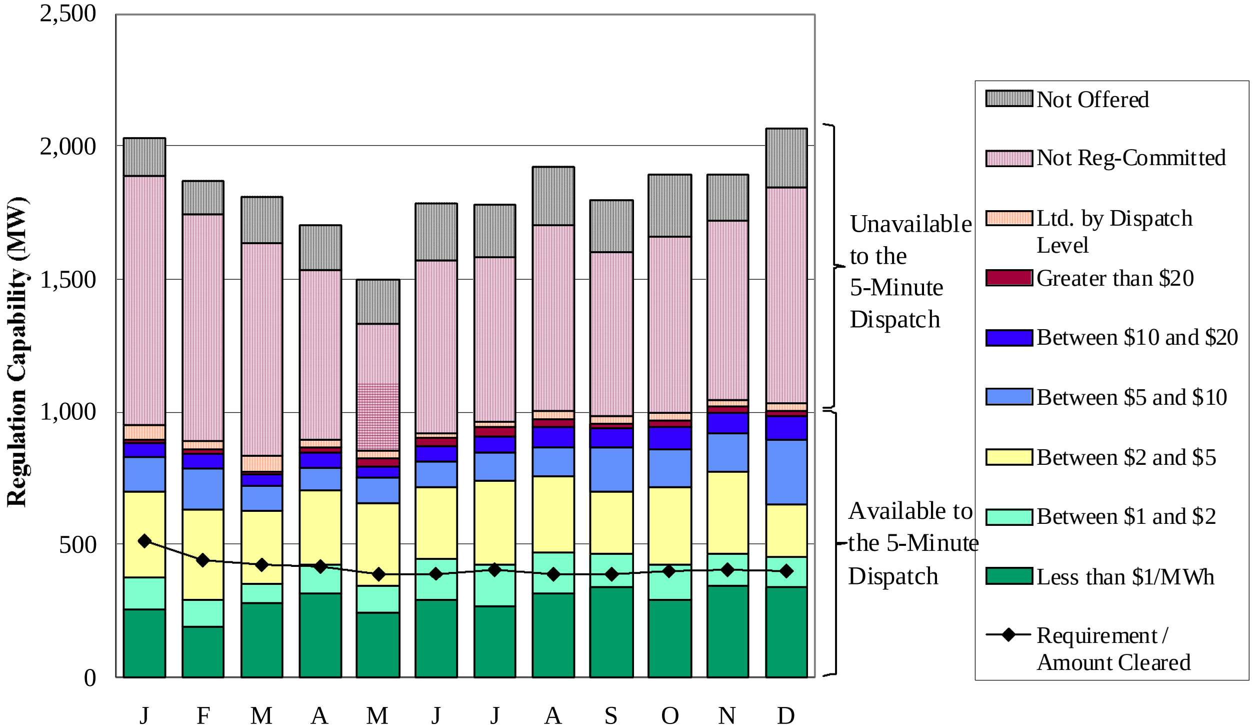
Regulation prices decreased over the course of 2009, dropping from $22 per MWh in January to less than $11 per MWh in November. Much of this decline is attributable to reductions in reserve requirements during the first half of the year. These reductions occurred because the Midwest ISO determined that it could satisfy the reliability needs of the system with less regulation. In addition, the Midwest ISO increased its commitment of regulating resources, which is its process for designating the units that will be available to be scheduled in the real-time market on a 5-minute basis. Since suppliers must incur some costs to be prepared to be selected to provide regulation, it would not be optimal for the Midwest ISO to commit all of the online resources that were offered into the real-time regulation market.

Spinning reserve prices averaged approximately $3.25 per MWh in 2009. These prices were very stable at levels consistent with both our expectations based on the costs of providing spinning reserves and prices in other RTO markets. Spinning reserve prices were slightly higher in the spring of 2009 due to higher levels of shortages. Spinning reserve and regulation shortages occurred at a moderate frequency in 2009. These shortages are evaluated later in this section.

Finally, supplemental reserves cleared at an average price of $0.51 per MWh for the year. The low price for this product is expected because the balance of the operating reserve requirements that are not spinning reserves can be satisfied either by spinning reserve resources or offline peaking resources. Offline resources can generally supply these reserves at minimal cost. However, prices rose in August through October to an average of $1.10 per MWh because there were 15 intervals of operating reserve shortages. Total operating reserves are the most valuable class of reserves because a shortage of total operating reserves has the biggest potential impact on reliability. Therefore, total operating reserves have the highest reserve demand curve and supplemental reserve prices during the shortage intervals averaged $1,100 per MWh. As the surplus of generating capability dissipates in the Midwest ISO region, an increasing frequency of operating reserve shortages will play a key role in providing the long-term economic signals to invest in new resources.

Our next analysis examines the real-time offer prices and quantities of the ASM products. The average regulation capability was over 1,800 MW in 2009. This is less than other operating reserves because it is limited to five minutes of bi-directional ramp capability, whereas spinning reserve is 10 minutes. In addition, only a limited number of resources are qualified to provide regulation. Our analysis is shown in Figure 31 and Figure 32. In the figures, the solid segments of the bars show the capability that is available to be scheduled on a five-minute basis, while the hatched segments represent capability that cannot be scheduled.

Figure 31: Regulation Offers and Commitments
2009

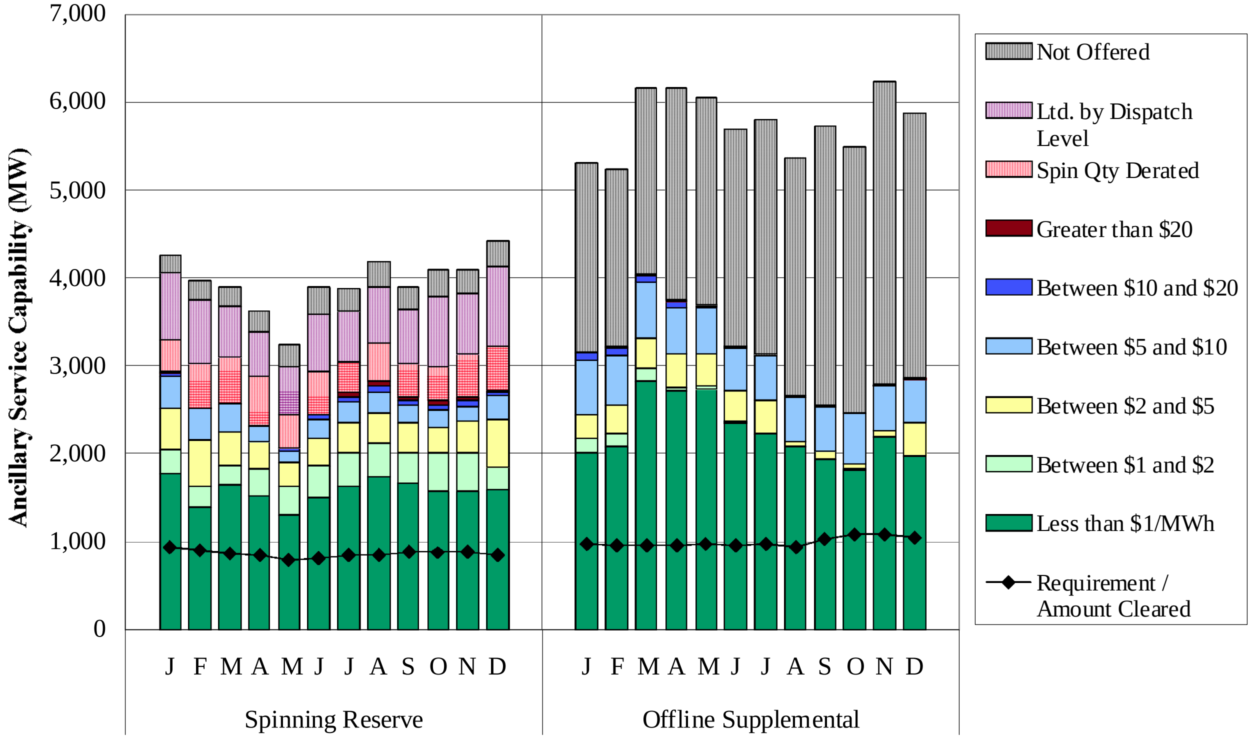


Three quarters of the unavailable regulation is due to the resources not "committed" for regulation. Figure 31 shows that lower-cost offers (the green bars) became marginal later in the year because the requirement (black line) decreased gradually over the year and the regulation resources committed increased after the first quarter of 2009. These changes have contributed to price reductions throughout the year. Regulation prices averaged nearly $15 per MWh, which is substantially higher than the typical marginal offer price because the clearing price includes the opportunity costs of not producing energy when resources must be dispatched up or down from their economic level to provide bi-directional regulation capability.

Figure 32 shows offer prices and quantities of qualified spinning and offline supplemental reserves available in the real-time market. The figure shows that the share of each ancillary service product that cleared the market averaged between 15 and 25 percent of the qualified capability in each month. This finding suggests competitive performance of the markets because individual suppliers are unlikely to be pivotal when there is substantial excess capability in the market.

Figure 32: Spinning and Supplemental Reserves Offers and Commitments

2009



There were generally sufficient supplemental reserve offers at less than $1 per MWh to satisfy the supplemental reserve requirements, which explains why the clearing price for supplemental reserves averaged $0.51 per MWh. The figure also shows that a substantial amount of the supplemental reserves are not offered into the market. This amount grew from a low of about one third of the total capability in March 2009 to more than half of the capability later in the year.

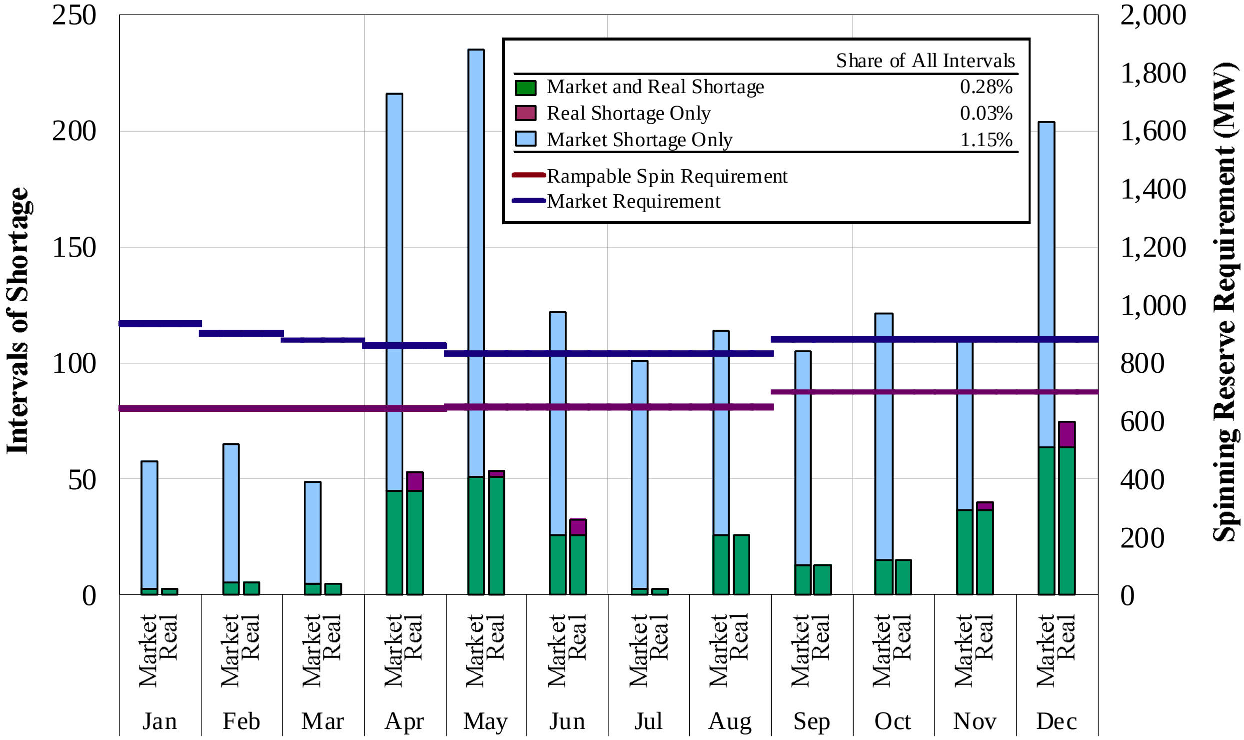
We have been investigating this reduction in supplemental reserve offers. In general, the decrease in supplemental reserve offers occurred as concerns arose that some of the units holding supplemental reserves were unable to provide their energy within the required 10-minute timeframe when deployed. This reduction in offers contributed to the shortages in the August to October timeframe discussed above. Since no offline supplemental reserves can deploy with 100 percent reliability, it will be important to establish a guideline for suppliers to determine a minimum level of deployment reliability to justify offering their resources. Suppliers with resources that exceed the minimum level of expected deployment reliability may be deemed to be withholding if their failure to offer their resources results in a price spike for supplemental reserves and energy.

Clearing prices for spinning reserves averaged approximately $3.25 per MWh in 2009, although sufficient capability was typically available to meet the requirement with offer prices less than $1 per MWh. As with regulation, spinning reserve prices were higher than the marginal offer prices because they sometimes include opportunity costs or shortage costs. Figure 32 also shows that almost one-half of the spinning reserves that cannot be scheduled are due to units that are being dispatched near their dispatch maximum, which limits available spinning reserves. This is not unusual – our monitoring of the unavailable spinning reserves did not raise any significant concerns.

The Midwest ISO operates with a minimum required amount of spinning reserves that can be deployed immediately in response to a contingency. However, units scheduled for spinning reserves may temporarily not be able to provide the full quantity in 10 minutes if the real-time energy market is instructing them to ramp up. To account for this, the Midwest ISO maintains a market requirement that exceeds its real requirement for "rampable" spinning reserves by 200 MW to 300 MW. As a result, market shortages can occur when the Midwest ISO is not physically short, and vice versa. Therefore, the Midwest ISO should set the market requirement to make the market results as consistent with the real conditions as possible.

To evaluate how well the Midwest ISO has satisfied this general objective, Figure 33 shows all intervals with either a real or market shortage in 2009.

Figure 33: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2009

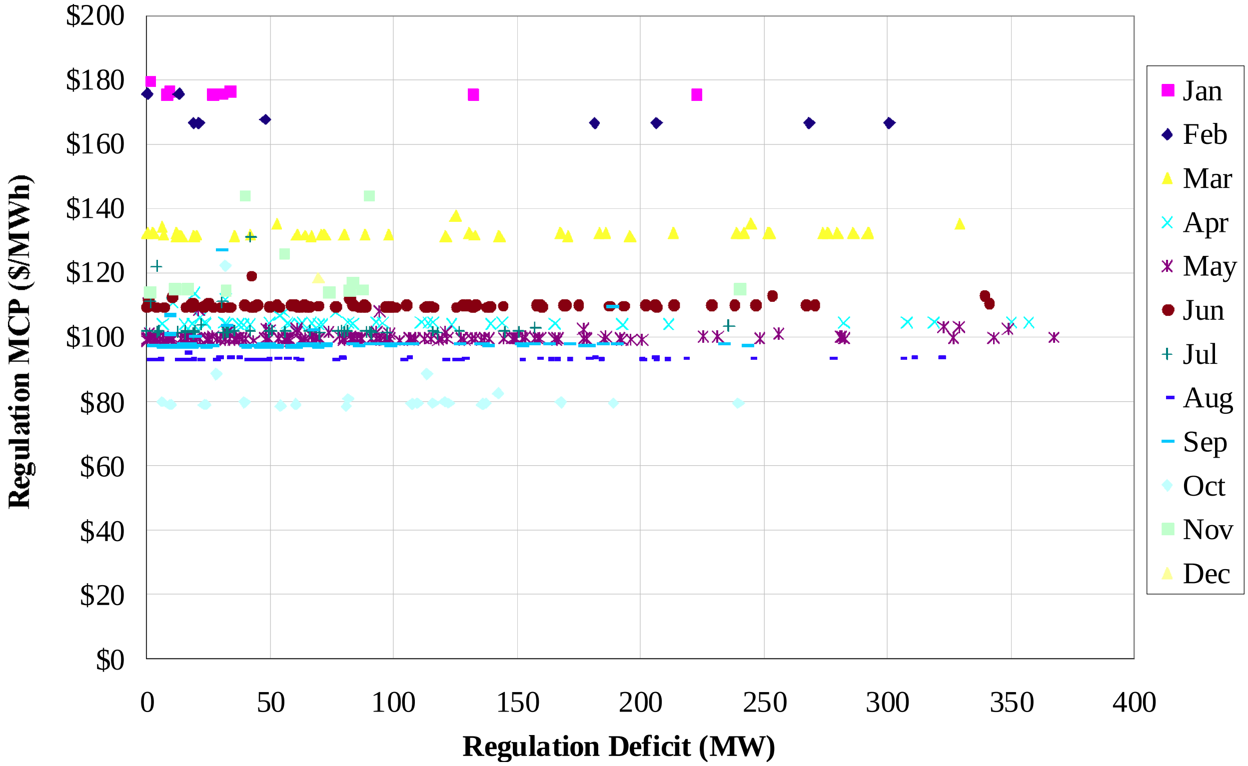


In nearly 20 percent of the shortage intervals, there were both real and market shortages. In almost 80 percent of the shortages, the market indicated a shortage that was not real. The results indicate that the consistency between the market and real requirements could be improved, which would improve the economic signals provided by the market. Hence, we recommend that the Midwest ISO improve the consistency of the requirements by setting the market requirement dynamically – that is, equal to the real requirement as it changes – or, alternatively, reducing the difference between the two requirements.

Regulation shortages occurred in 778 intervals in 2009, less than one percent of all intervals. Three quarters of these shortages occurred during off-peak hours. The shortages are most frequent in these hours because fewer regulation-capable units are online. The shortages are typically small: 33 percent of deficits were less than 50 MW and 59 percent were less than 100 MW. Figure 34 shows a plot of regulation prices during shortage intervals. There is a separate marker for each month.[14] The figure shows that the regulation price during shortage intervals is reliably equal to the monthly regulation penalty price plus the spinning reserve price. These penalty prices are determined formulaically each month and are intended to reflect the commitment cost of a typical peaking resource.

Figure 34: Regulation Deficits and Prices

2009



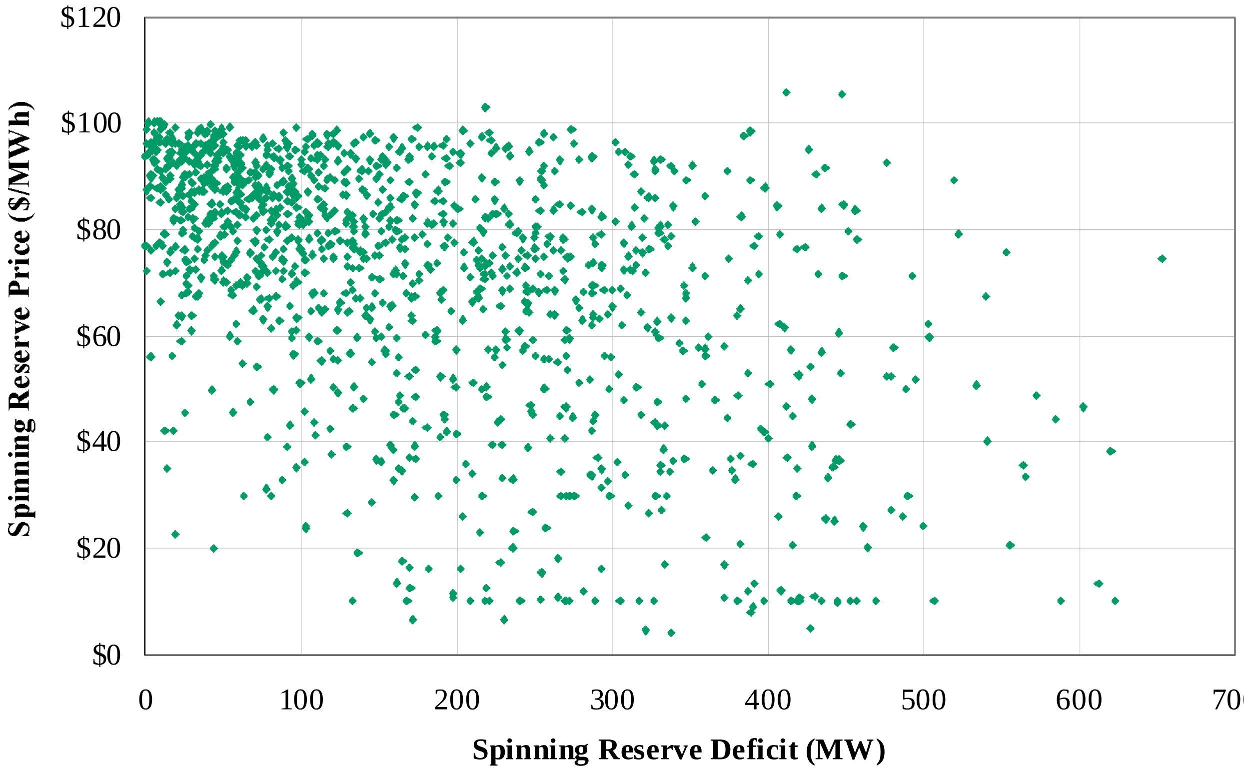
The regulation price during intervals with a shortage is determined consistent with the penalty price, regardless of the size of the deficit. This is evident by the horizontal nature of the relationship for each month's plot. This is a favorable result because it indicates that the price reliably reflects the shortage. Beginning in 2010, however, the formula-based penalty price has increased sharply. We have reviewed the formula and data used by the Midwest ISO in calculating the penalty price and have recommended changes intended to allow the penalty price to more accurately reflect the cost of a peaking resource.

14 Period of spinning reserve shortages are excluded because the spinning reserve shortages will substantially affect the regulation price.

Figure 35 plots similar price-quantity results for each spinning reserve shortage in 2009. There were 1,501 spinning reserve shortages deficits in 2009, or 1.4 percent of all intervals. In general, shortages occur when the demands on the system cause the real-time market to have insufficient ability to ramp up online resources to satisfy both the energy requirements and the spinning reserve requirements. In these cases, the price for spinning reserves should theoretically reflect the reliability cost of being short of the required reserves. In 2009, this value was set at approximately $100 per MWh, preventing the real-time market from taking actions more costly than $100 to maintain its spinning reserves. Although it would be most efficient for prices to be set at the penalty price when the system is short of spinning reserves, this is not always the case because the Midwest ISO "relaxes" its spinning reserve requirement when it is short.

Figure 35: Spinning Reserve Deficits vs. Spinning Reserve Prices

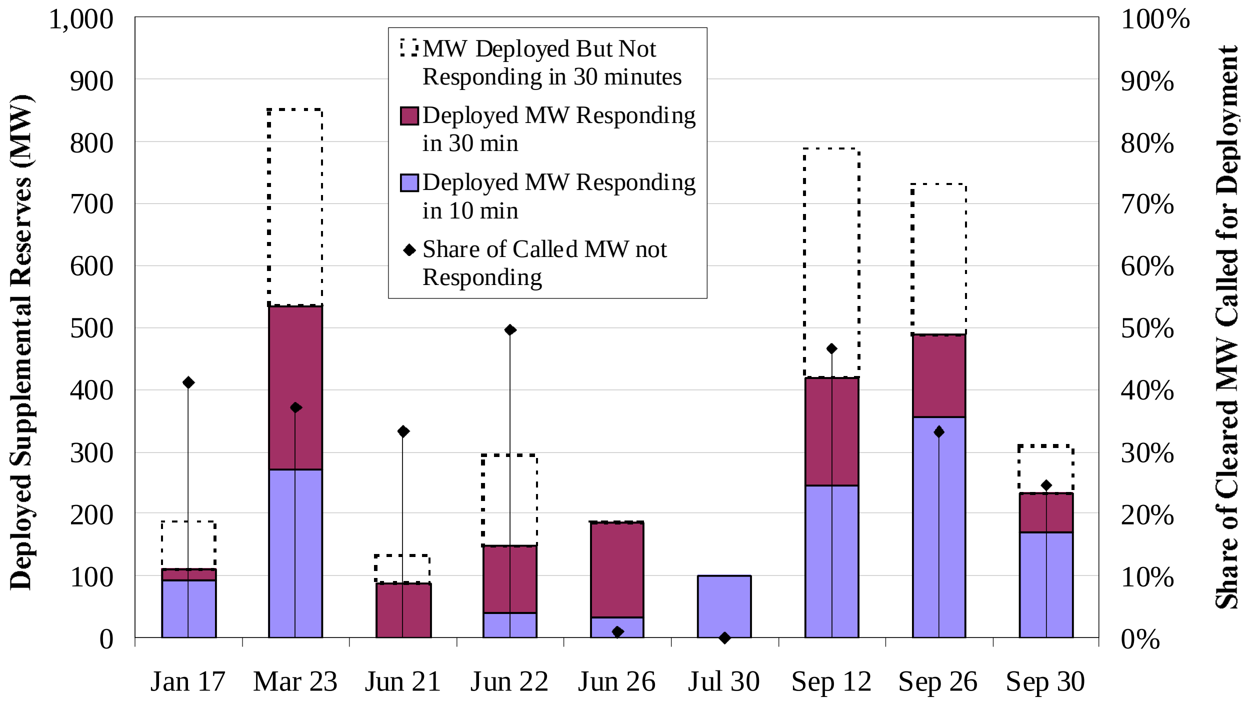
2009



The average spinning reserve price during shortage intervals was $77 per MWh. The figure shows that spinning reserve prices are widely dispersed and many of the largest deficits are often priced the lowest. For example, the second largest shortage (of over 600 MW) was priced at less than $10 per MWh. This suggests that the relaxation methodology is distorting spinning reserve prices. We recommend that the Midwest ISO discontinue its relaxation practice and set prices based on the penalty price during shortages.

The Midwest ISO began directly deploying supplemental reserves during Disturbance Control Standard ("DCS") and ARS events in 2009. There were nine such deployments in 2009. Figure 36 shows the response of the supplemental reserves deployed, separately indicating those that were successfully deployed within 10 minutes (as required) and within 30 minutes.

Figure 36: Non-Responsive Supplemental Reserve Deployments
2009



The response of units deployed for supplemental reserves was poor in 2009. Only 39 percent of reserves were successfully deployed within 10 minutes during the nine events, and an additional 32 percent were deployed within 30 minutes. Hence, almost 30 percent of the reserves did not respond within 30 minutes – this share was even higher during the events that required the largest deployments. Poor performance can significantly degrade reliability and raises concerns that suppliers may be selling reserves that they are knowingly incapable of deploying.

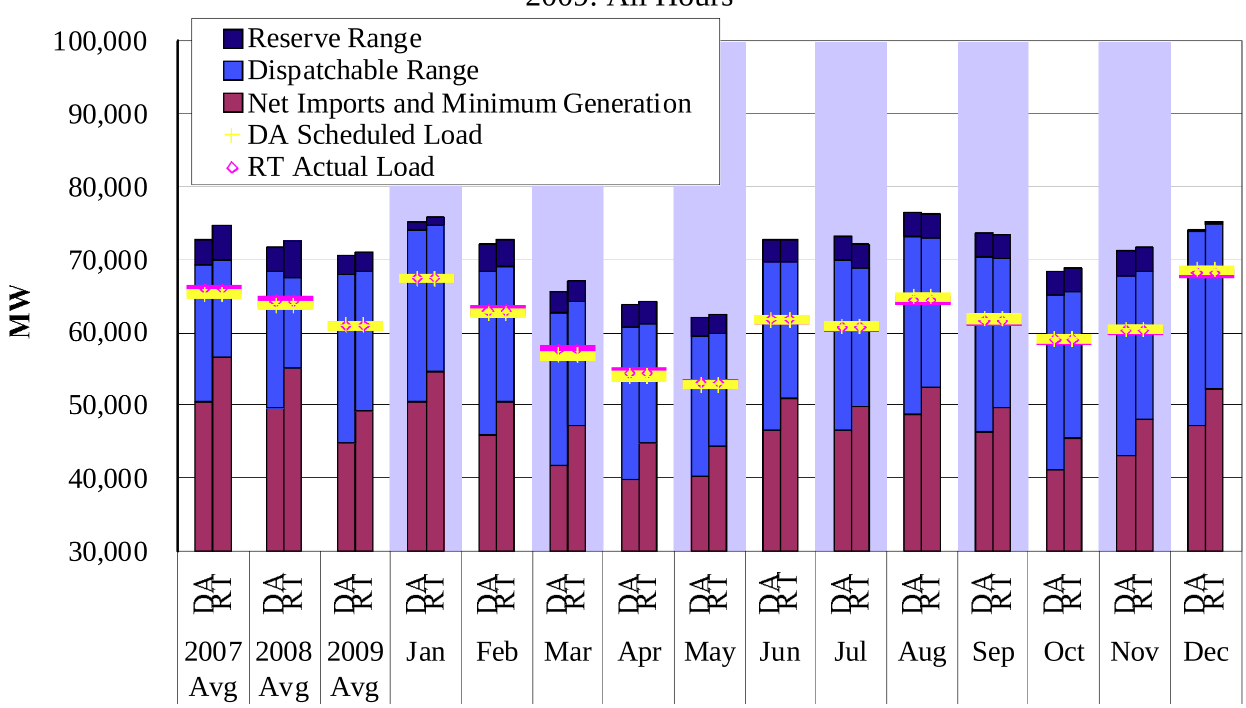
In response to this poor deployment performance, the Midwest ISO has proposed Tariff changes to add additional testing and verification requirements for offline supplemental reserves.

Resources failing to deploy during events or during tests would lose their bid qualification status until subsequent testing is successful. While new testing requirements should help, they may not entirely address the issue: an efficient penalty might ultimately be needed. Scrutiny on the poor deployment performance by the Midwest ISO and the Commission has led some participants to reduce their offer quantities, particularly on less reliable units. This change has resulted in a more capable (but smaller) set of supplemental reserve supplies. This has contributed to improved deployment response in 2010, but also higher supplemental reserve prices.

3. Availability of Generation in Real Time

The availability of generation in the real-time market is important because it enables the Midwest ISO to redispatch the system to manage transmission constraints, while satisfying all energy and operating reserves requirements. In general, the day-ahead market coordinates the commitment of most generation that will be dispatched in real time. Figure 37 details the average monthly generation scheduled in the day-ahead and real-time markets.

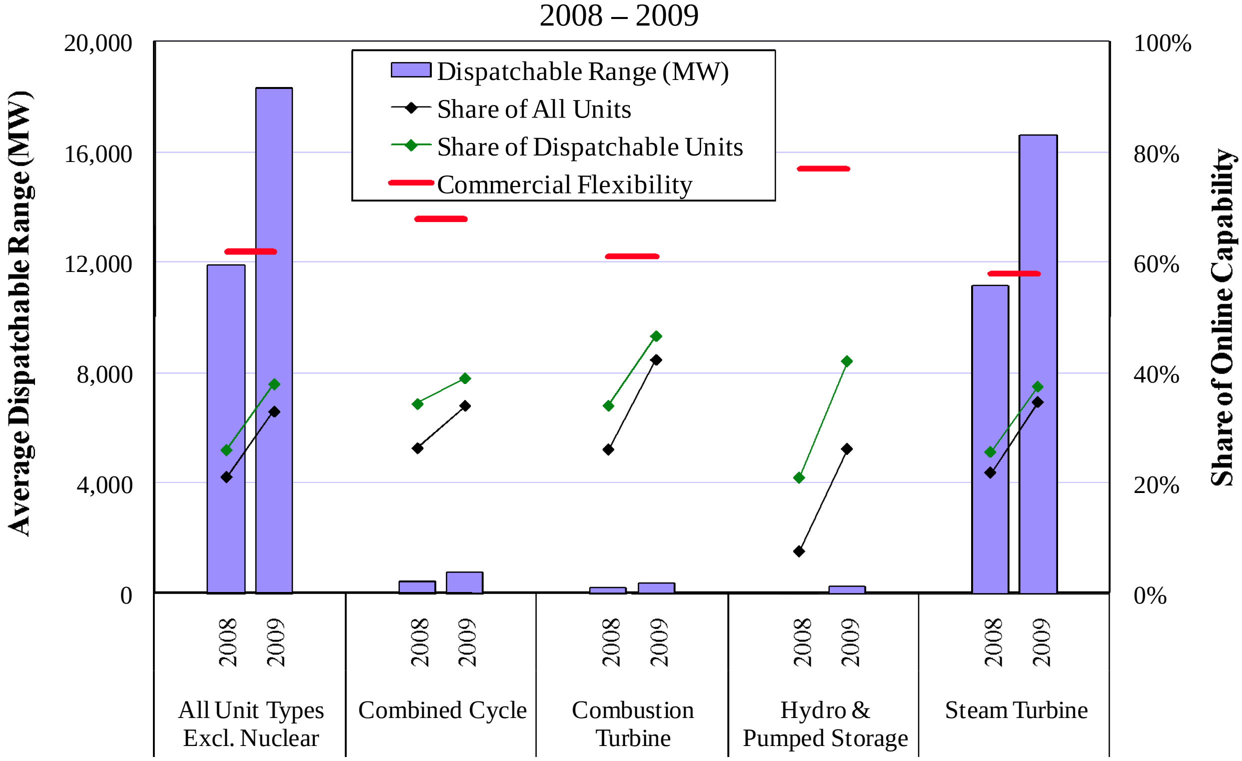
Figure 37: Day-Ahead and Real-Time Generation
2009: All Hours



Generation capability is consistently greater in the real-time market than in the day-ahead. This occurs because some resources are self-scheduled by participants after the day-ahead market and because generation is committed by the ISO after the day-ahead market. On a market-wide basis, the Midwest ISO commits generation after the day-ahead market when load is higher than expected; when load is under-scheduled in the day-ahead markets; or when net virtual supply scheduled in the day-ahead market must be replaced in real time. In addition, the Midwest ISO often commits additional generation to manage congestion or satisfy the local reliability needs of the system.

The figure further shows that load was considerably lower in 2009 than in prior years, but it was more fully scheduled. This chart also shows that the average dispatchable range (the range between each online unit's economic maximum and economic minimum) was seven percentage points lower in the real-time (29 percent) compared to the day-ahead (36 percent). This difference can result from an increase in a unit's dispatch minimum or a decrease in its dispatch maximum. Figure 38 shows there was substantially more dispatch flexibility in 2009 than in prior years, although it remains well below the actual physical flexibility of the resources.

Figure 38: Real-Time Dispatchable Range
2008 – 2009



The figure shows the change in the dispatchable range for online generators in 2008 and 2009 as well as the "commercial flexibility", which reflects the maximum dispatchable range they could offer physically according to the data they provide to the Midwest ISO. The vast majority of the Midwest ISO's flexibility is provided by steam turbines. Although flexibility increased significantly in 2009, it remains considerably lower than the full physical flexibility that many generators could provide. This is important because losses in flexibility limit the Midwest ISO's redispatch options for managing congestion.

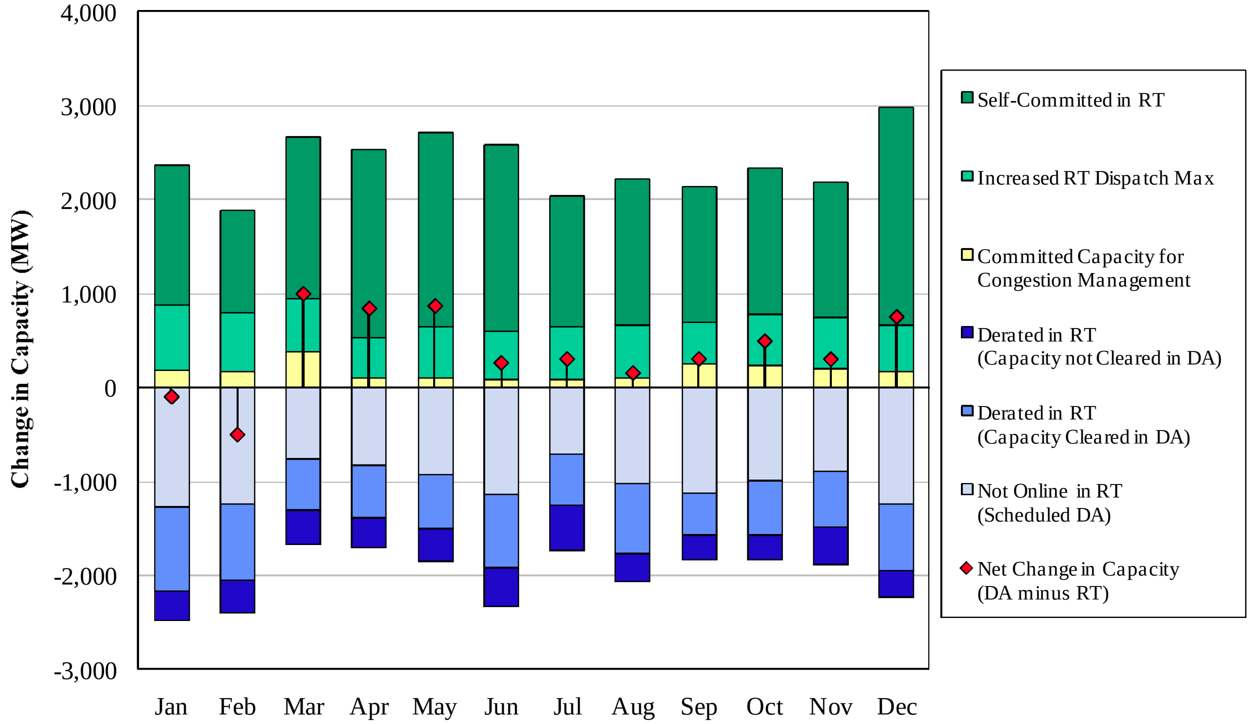
The figure shows that flexibility increased substantially across all unit types in 2009. The introduction of the ASM markets contributed to the improved flexibility in several ways. First, the quantity of ASM products that a participant can offer is limited by the dispatchable range, as well as ramp rates. Second, the introduction of the Day-Ahead Margin Assurance Payment ("DAMAP") makes generators whole if they are harmed by responding flexibly in periods when prices are volatile. Third, output ranges previously held out of the real-time market to provide ancillary services are now available and co-optimized with energy. In other words, suppliers no longer offer exclusively energy or ancillary services, but can offer both.

The next analysis evaluates changes in the availability of generation after the day-ahead market because they can compel the Midwest ISO to commit additional capacity in real time. These changes in supply between the day-ahead market and real-time market are shown in Figure 39.

On average, 3.2 GW (6 percent) of capacity scheduled in the day-ahead was unavailable for the real-time market dispatch in 2009. This is an increase of almost 10 percent from 2008, which was primarily attributable to:

- Forced outages;
- De-commitments or deratings after the day ahead; and
- Decisions by suppliers scheduled day-ahead to not start and buy back energy at the real-time price instead.

Figure 39: Changes in Supply, Day-Ahead to Real-Time
2009



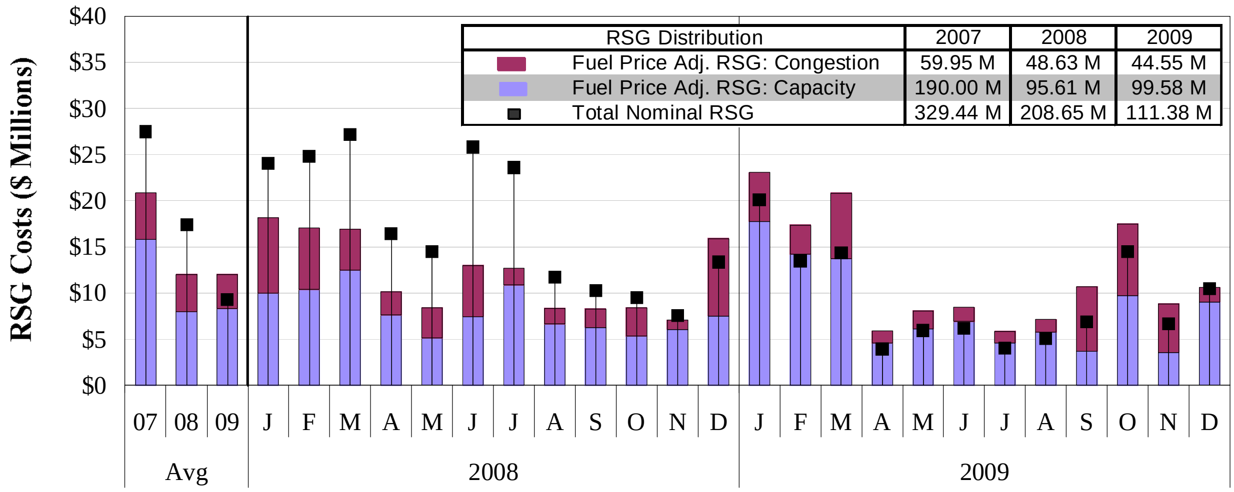
The capability lost in real-time was partially offset by almost 1 GW of average increases in capacity from units scheduled in the day-ahead increasing their dispatch maximum in real-time and from self-scheduling of resources. For most months in 2009, the average capability lost from day-ahead to real-time was more than fully replaced. Most of this was in the form of self-scheduled resources that were not price sensitive.

C. Revenue Sufficiency Guarantee Payments

This subsection reviews RSG payments that are made to generators committed by the Midwest ISO when the market revenues in the applicable Midwest ISO market are not sufficient to cover generators' as-offered production costs. Resources that are not committed in the day-ahead market but must be started to maintain reliability are the most likely recipients of RSG payments. These are called "real-time" RSG payments because such units receive their LMP (and ASM) revenues from the real-time market. Because the day-ahead market is financial, it generates minimal RSG costs—a unit that is uneconomic will generally not be selected. Peaking resources are typically the most likely to warrant an RSG payment because they are generally the highest-cost resource and receive minimal LMP margin to cover their startup costs. Additionally, peaking resources frequently do not set the energy price (i.e., the price is set by a lower-cost unit), which increases the likelihood that an RSG payment will be required. Figure 40 and Figure 41 show monthly RSG payments in the real-time and day-ahead markets, respectively.

The results are divided between RSG payments to peaking and non-peaking units. We also distinguish between payments made to commit resources for overall capacity needs versus to manage congestion or satisfy a local reliability requirement. To exclude the effects of fuel price changes, these figures adjust the RSG costs for changes in fuel prices (based on 2009 year-end fuel prices).

Figure 40: Total Real-Time RSG Payment Distribution
2007 – 2009



Share of Real-Time RSG Costs by Unit Type (%)

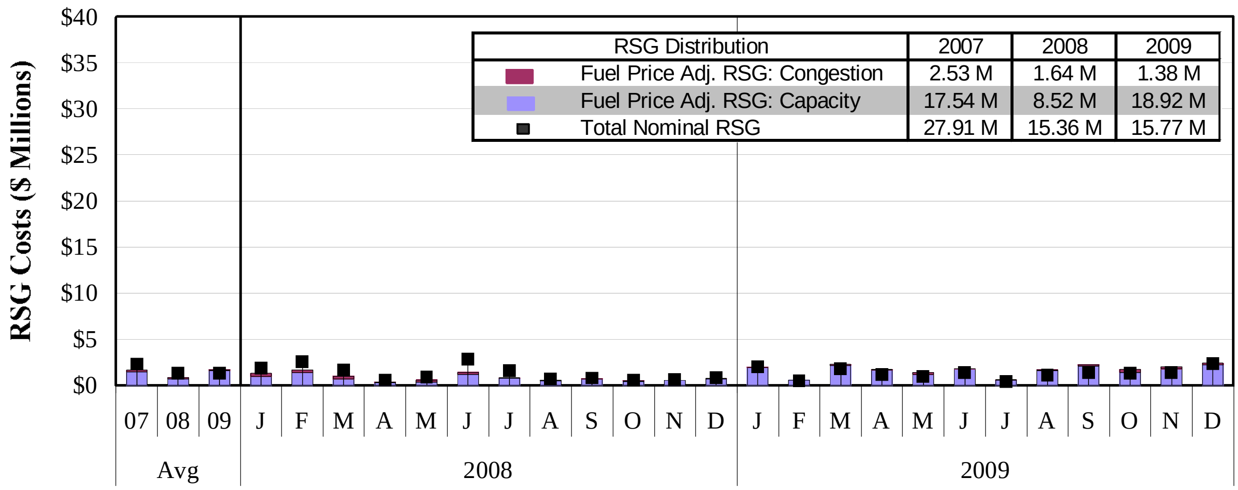
Peaker	68	59	64	68	59	45	65	60	60	53	50	73	46	57	75	58	65	50	46	66	68	49	61	74	80	70	71
Congestion	19	22	19	35	24	12	15	30	31	8	11	21	10	6	42	9	12	9	5	20	18	10	15	53	34	47	12
Capacity	48	37	45	33	35	34	50	30	29	45	38	52	36	51	34	48	53	41	41	47	51	38	46	21	46	23	59
Non-Peaker	32	41	36	32	41	55	35	40	40	47	50	27	54	43	25	42	35	50	54	34	32	51	39	26	20	30	29
Congestion	4	12	10	10	15	16	11	13	14	6	10	5	26	7	8	11	5	25	18	4	3	11	6	12	8	10	2
Capacity	28	29	26	22	26	39	24	27	26	41	41	22	28	36	17	32	29	25	36	30	29	40	33	14	12	20	27

Over 90 percent of RSG costs are generated in the real-time market, most of which was paid to peaking resources even though they produced less than one percent of total energy generated in 2009. This is expected because the commitments needed for reliability occur after the day-ahead market when peaking resources are the primary available resources. Over 70 percent of RSG payments in the real-time market were paid to units committed for capacity reasons in 2009.

Load was much more fully scheduled (nearly 100 percent) in the day-ahead in 2009 than in prior years. However, lower average and peak loads limited the need for peaking units in 2009.

Nominal real-time RSG costs fell 47 percent in 2009 to $111 million. The sharp decline is attributable to lower fuel prices in 2009 and fully-scheduled load in the day-ahead for most months of the year. On a fuel-adjusted basis, RSG costs were largely unchanged. In addition, reduced reserve requirements and improvements in commitment processes contributed to a decline in RSG costs after the first three months under ASM. Figure 41 below shows that nominal day-ahead RSG costs increased 2.7 percent to almost $16 million in 2009. On a fuel-price-adjusted basis, these costs doubled. However, they continue to be a small percentage of total uplift costs in the market.

Figure 41: Total Day-Ahead RSG Payment Distribution
2007 – 2009



Share of Day-Ahead RSG Costs by Unit Type (%)

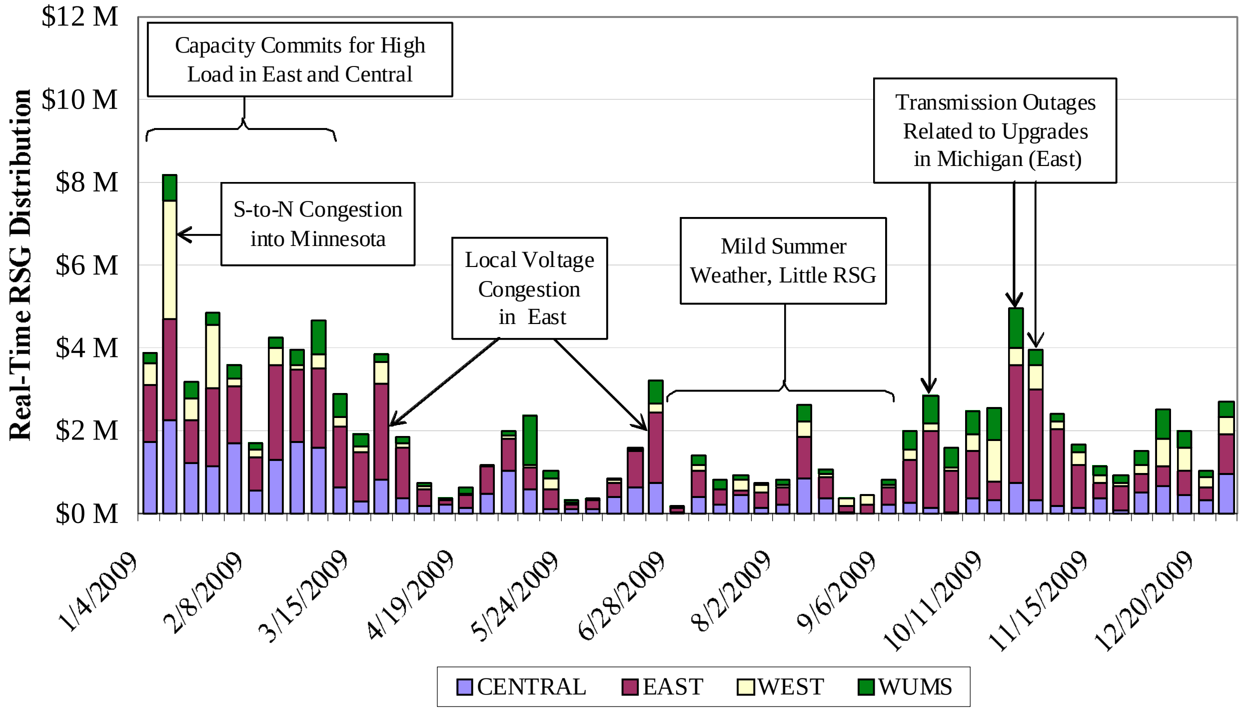
	07	08	09	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Peaker	19	15	7	4	12	8	2	0	23	49	13	32	1	4	5	4	3	1	1	21	17	4	13	10	6	4	4
Congestion	4	1	2	1	1	7	0	0	1	2	4	0	0	0	0	0	0	0	1	14	1	0	1	2	2	1	1
Capacity	16	14	5	3	11	2	2	0	23	47	9	32	1	4	5	4	3	1	1	8	17	4	12	8	4	3	2
Non-Peaker	81	85	93	96	88	92	98	100	77	51	87	68	99	96	95	96	97	99	99	79	83	96	87	90	94	96	96
Congestion	9	16	4	26	18	22	13	46	15	3	8	3	18	1	5	1	1	4	2	2	1	5	4	5	17	6	5
Capacity	72	68	89	70	71	70	86	54	62	47	79	65	81	96	90	95	97	95	97	77	82	90	84	85	77	89	91

To better illustrate the trends in RSG costs, Figure 42 analyzes the real-time RSG distribution data by week and region. The figure highlights several trends. As detailed elsewhere in this report, the summer peak was mild relative to prior years and relative to the 2009 Summer Assessment. Accordingly, the real-time RSG costs incurred during these weeks was minimal.

High day-ahead load scheduling and low fuel prices contributed to lower RSG costs. RSG payments exceeded $5 million per week only once during 2009, compared to 11 weeks in 2008.

Figure 42: Weekly RSG Payment Distribution by Region

2009



In the figure, the text boxes point out some of the notable instances of RSG payments. Many of the highest weekly RSG costs were caused by transmission congestion. Early in 2009, the West region incurred more RSG costs than during the rest of 2009 due to extreme winter weather and forced generator outages. However, RSG payments in the West were 63 percent lower in 2009 than in 2008. The East region had the largest share of RSG costs (45 percent) due to transmission outages on market-to-market flowgates and transmission outages related to transmission upgrades in Michigan. The latter were particularly prevalent in the fall. In addition, many of the lowest-cost units to commit for capacity are in the East region. Finally, reduced congestion into WUMS, as a result of significant transmission upgrades, contributed to a 66 percent year-over-year reduction in RSG payments to units within WUMS.

D. RSG Cost Study

We conducted a study of RSG cost to quantify the contributions of various factors to real-time RSG costs. The study sought to determine the various causes of RSG commitments and then to compare these cost causation results to actual RSG allocations under the Interim Rate. The study is based on a detailed analysis of individual real-time unit commitments that resulted in RSG Make-Whole Payments.[15] The methodology and results of this study are summarized in this section of the report.

We first determined whether each individual commitment was made to satisfy system capacity needs or to manage a transmission constraint. Hence, we analyzed two types of commitments: those for "Capacity" and those for "Constraint." Within these two types of commitments, we then estimated the amount of RSG that may be attributed to 17 types of deviations and the amount that was not attributable to deviations. The cost-causation links are grouped into the following three classes:

- RSG cost attributed to commitments whose need was not apparent (23 percent). These are labeled as "Need Unknown". This does not mean the commitment should not have been made. Uncertainties regarding load, unit availability, loop flows, and other issues may have justified these commitments, but we did not have this information.
- RSG cost attributed to needed commitments that were not deviation-related (19 percent). These commitments may be related to issues such as loop flow or line deratings that require capacity commitment in real time.
- RSG cost attributed to day-ahead-to-real-time deviations (58 percent), including:

    1. Eight types of generation and load deviations that currently incur all RSG cost under the Interim Rate allocation (51 percent);

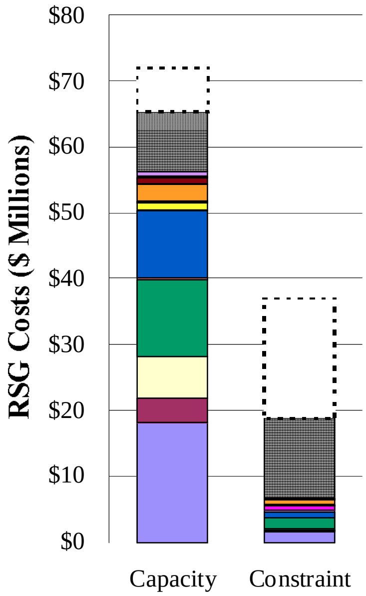
    2. Seven types of deviations that are explicitly exempt from paying RSG costs under the Interim Rate allocation (6 percent); and

    3. The two types of deviations that are not explicitly exempt, but that do not incur RSG costs under the Interim Rate allocation – virtual load and wheeled transactions (1 percent).

15 We estimated only the direct effects of various generation and load deviations on real-time RSG costs. Indirect effects were not included in the study.

Figure 43 provides a detailed breakdown of the RSG attribution results. This figure provides the total real-time capacity and constraint-related RSG costs that we attributable to each type of deviations.

Figure 43: Attribution of RSG Costs by Factor
January 6, 2009 to December 31, 2009



	Capacity	Constraint	Total	Share
Need Unknown	$6.68	$18.29	$24.97	23%
Not Deviation Related	9.17	12.04	21.21	19%
Other Exemption	0.52	0.06	0.58	0.5%
Testing	0.00	0.02	0.02	0.0%
Start Stop	0.44	0.08	0.52	0.5%
Intermittent	0.85	0.20	1.05	1.0%
Wind	2.68	0.68	3.36	3.1%
Cont Res Deployment	0.03	0.00	0.03	0.0%
Dispatch Bands	1.35	0.11	1.46	1.3%
Virtual Load	0.00	0.74	0.74	1%
Wheels	0.00	0.10	0.10	0%
Must-Run	0.00	0.15	0.15	0%
Deratings	10.22	0.89	11.12	10%
Deficient Energy	0.21	0.02	0.23	0%
Excessive Energy	0.00	0.01	0.01	0%
Virtual Supply	11.77	1.66	13.44	12%
Exports	6.23	0.19	6.42	6%
Imports	3.71	0.31	4.02	4%
Load	18.13	1.48	19.61	18%
Total	***$72.01***	***$37.03***	***$109.04***	***100%***

Note: Due to data limitations, the eight types of deviations at the bottom of the table includes deviations from participants that have "carve-out" rights associated with GFAs that are not allocated RSG.

Deviations that currently bear all of the real-time RSG costs only cause approximately one-half of those costs. This results in inefficient incentives for the participants responsible for those deviations. The implementation of the improved RSG cost allocation should address this issue, but it has been pending FERC action since February 2009.

The figure also shows that of the seven exempt factors, the largest quantities of real-time RSG costs were caused by intermittent resources, totaling more than four percent of the real-time RSG costs. Most of this quantity was caused by wind resources (approximately three percent). Since the publication of our study, the Midwest ISO has resolved to eliminate dispatch bands and proposed to remove the exemption from deviations for wind resources.

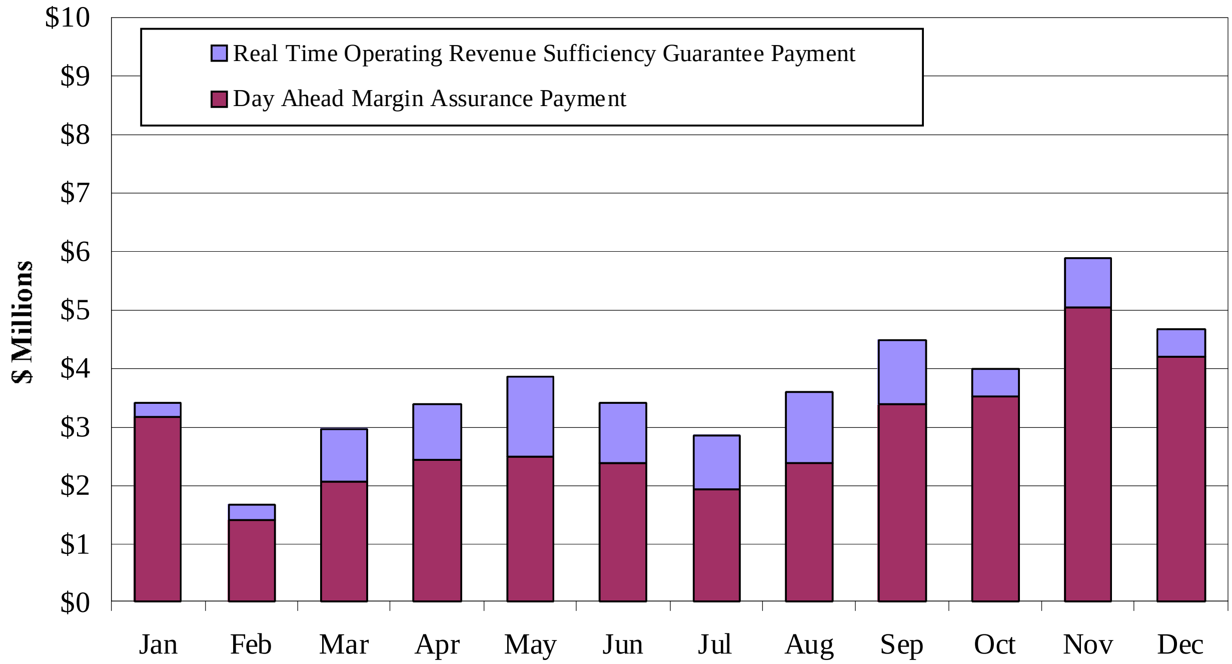
E. Price Volatility Make-Whole Payments

The Midwest ISO introduced the PVMWP along with ASM to ensure adequate cost recovery in the real-time for resources offering dispatch flexibility. The payment ensures that suppliers responding to the Midwest ISO's prices and following its dispatch signals in real time are not harmed by doing so. The payment should, therefore, eliminate a generator's incentive to be inflexible. The PVMWP consists of two separate payments: a DAMAP and a Real Time Operating Revenue Sufficiency Guarantee Payment ("RTORSGP").

The DAMAP is paid to a qualified resource committed in the day-ahead and following a real-time dispatch signal below their day-ahead schedule. If they settle at a real-time LMP or Marginal Clearing Price ("MCP") that reduces their margin, they are eligible for a make-whole payment. This ensures that the resource will be better off by being flexible and responding to the real-time price signals. The RTORSGP is paid to a qualified resource that is dispatched above its day-ahead schedule and where the real-time hourly LMP ends up below its as-offered costs. Figure 44 shows total PVMWP payments in 2009.

Figure 44: Price Volatility Make-Whole Payment

2009

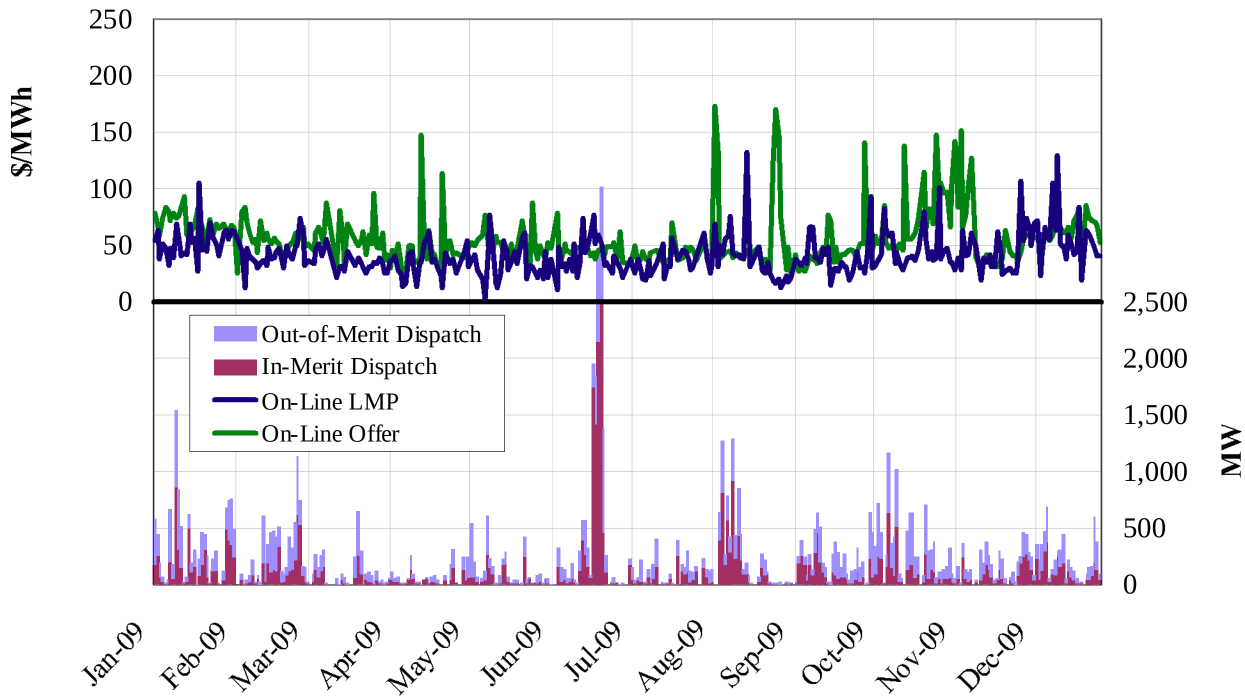


Total payments were $44.2 million in 2009, of which $34.4 million consisted of DAMAP payments. A large majority of DAMAP payments were made to a relatively small set of flexible coal units during peak hours, particularly during the second half of the year. Payments increased late in 2009 as fuel and energy prices increased. RTORSGP payments remained a relatively small part of total PVMWP payments throughout 2009. Based on our monitoring of these payments, we conclude that the payments are consistent with the intention of the Tariff and not the result of manipulation.

F. Dispatch of Peaking Resources

As discussed above, real-time demand is often satisfied by supplemental generator commitments, typically in the form of quick-start peaking resources because of their low commitment costs and commitment flexibility. The dispatch of peaking resources is important because peaking resources are an important determinant of RSG costs and efficient energy pricing. Figure 45 shows the average daily dispatch levels of peaking resources in 2009 and evaluates the consistency between peaking unit dispatch and market outcomes.

Figure 45: Average Daily Peaking Unit Dispatch and Prices
2009: All Hours



An average of 227 MW was dispatched per hour in 2009, down from 267 MW in 2008. A heat wave in late June led the Midwest ISO to commit 3,500 MW of peaking units in a single day, the highest hourly dispatch of peaking units for the year. The reduction in dispatch of peaking resources can be attributed to a number of factors, some of which have been discussed previously in this report. Load was more fully scheduled in the day-ahead market in 2009, thereby reducing the need for real-time commitments. In addition, lower average and peak load levels and modest reductions in congestion levels have further reduced the need for peaking units to satisfy overall demand or to manage local transmission constraints.

The figure also provides an evaluation of the consistency between the peaking resource dispatch and market outcomes. In the top panel, we compare the average LMP at the peaking resources' locations (On-Line LMP) to the average offer price of the dispatched peaking resources (On-Line Offer). In the bottom panel, we show the shares of the peaking resource output that are in-merit (LMP greater than offer price) and out-of-merit (LMP less than offer price). Approximately 33 percent of the dispatched peaking resources in 2009 were in-merit, down from 45 percent in 2008. Because out-of-merit units have costs that exceed the prevailing LMP, the large amount of out-of-merit peaking units indicates that they continue to set the energy price infrequently. This is not uncommon because gas turbines often have a very narrow operating range and, therefore, tend to operate at their dispatch minimum or maximum.

When peaking (or demand response) resources are the most economic option for meeting the markets' demands but do not set prices, real-time prices will generally be inefficiently low. This affects the incentives to schedule in the day-ahead market and, ultimately, the commitment of resources that is coordinated by the day-ahead market. A suboptimal commitment coming out of the day-ahead will tend to raise real-time production costs. Inefficiently low real-time prices when peaking resources are dispatched also distorts the incentives of participants to import and export power efficiently. We have recommended changes to improve real-time pricing by allowing peaking resources and demand resources to set prices. The Midwest ISO has done substantial work to develop a feasible approach in this area

G. Wind Generation

Wind generation and capacity have grown rapidly in the Midwest ISO market since its inception. Wind resources now make up 5.1 percent of installed capacity (approximately 7.5 GW) and 2.9 percent of generation, producing up to 6,000 MWh. This growth trend is expected to continue due to the prevalence of abundant wind capability in the western areas of the footprint, favorable existing federal and state mandates, and various subsidies and tax incentives. In addition, future federal carbon and energy policies will likely further encourage wind generation.

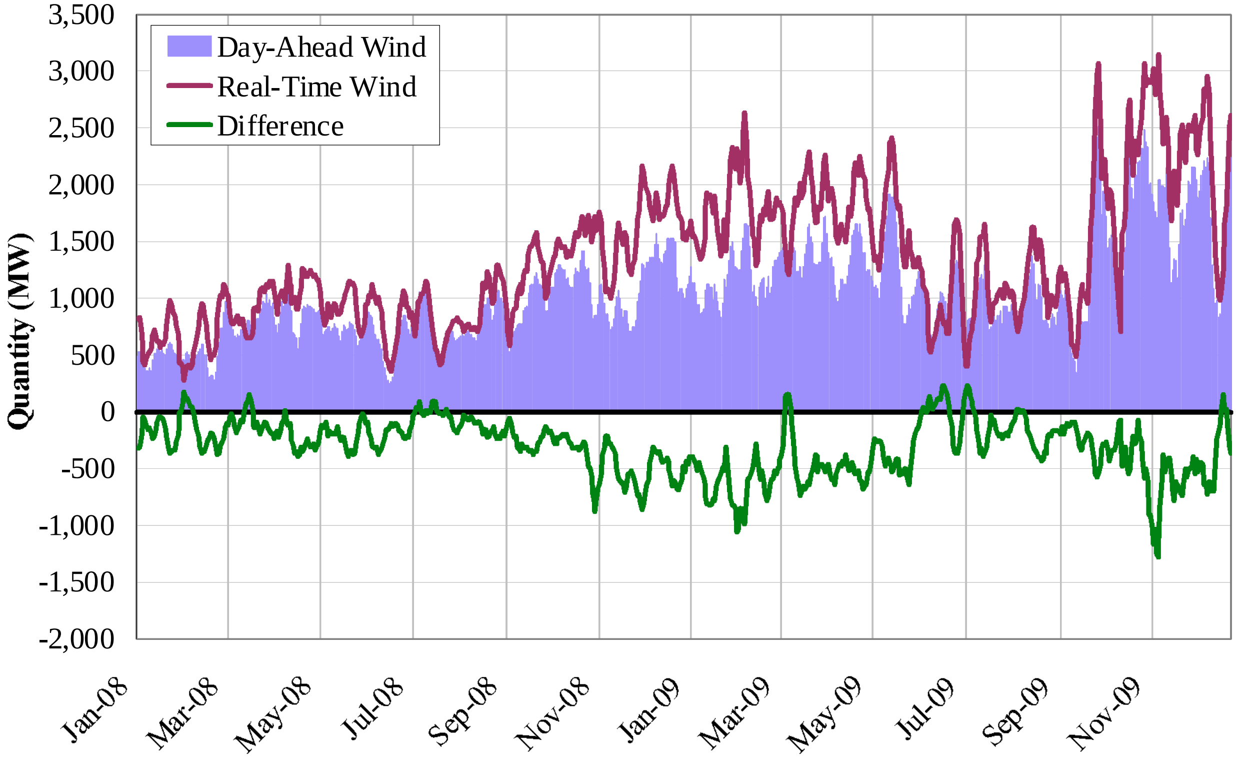
Wind generation promises substantial environmental benefits. As intermittent resources, however, wind generators present particular operational, forecasting, and scheduling challenges that most conventional resources do not. These challenges are amplified as wind's portion of total generation increases. Intermittent resources are by definition prone to changes in output that can result in system reliability and congestion management problems.

In the day-ahead market, intermittent resources can submit offers (accompanied by generation forecasts) and can be committed as capacity resources under Module E of the Tariff at a 20 percent capacity factor.[16] In real time, however, they cannot schedule offers, be committed, follow setpoint instructions, or be dispatched by the real-time market. As a result, the market generally does not coordinate the production of intermittent resources. Instead, the Midwest ISO relies on rule-based methods in the commitment and scheduling algorithms to relax lower priority requirements and utilizes manual dispatch when necessary to ensure reliability.

Figure 46 shows the day-ahead commitment and real-time output of wind resources in 2008 and 2009.

16 This capacity factor was reduced to 8 percent for Planning Year 2010-2011.

Figure 46: Day-Ahead Scheduling vs. Real-Time Wind Generation
2008 – 2009

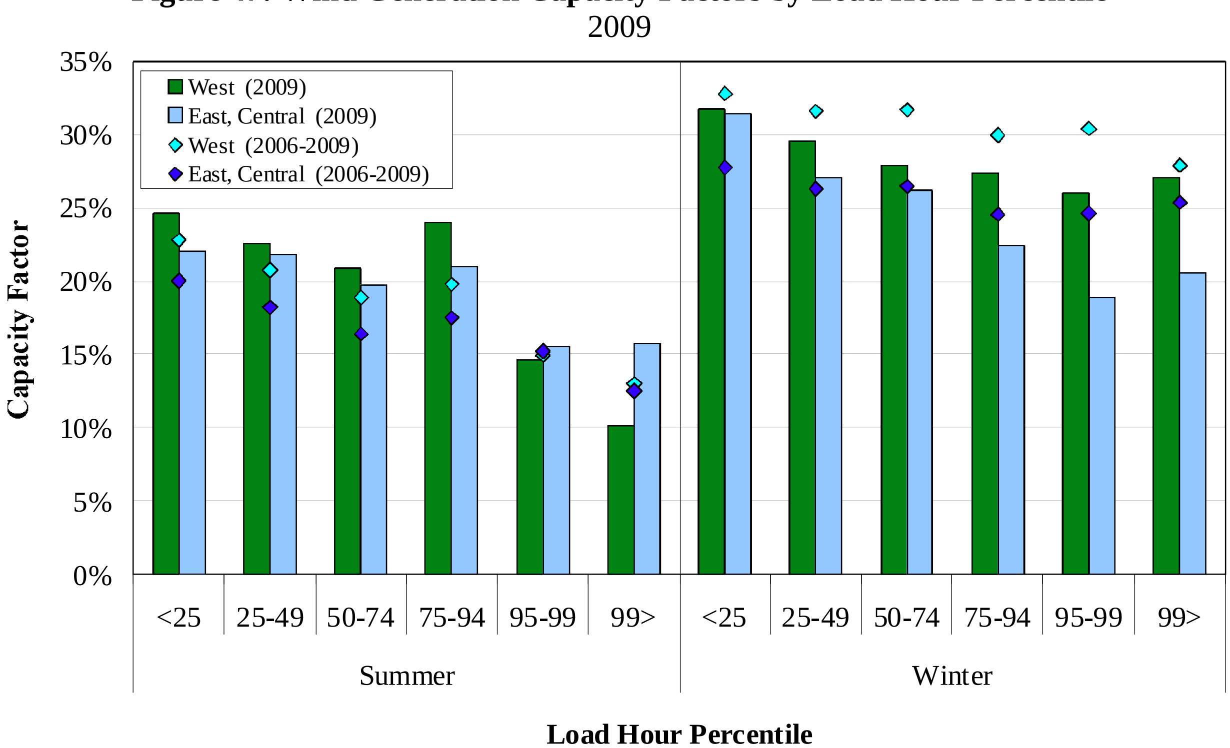


The figure shows the continued rapid growth of wind generation and seasonality of wind – output is generally higher during shoulder months. Wind generation was under-scheduled in the day-ahead market for most of the year. This creates price convergence issues in western areas and can lead to uncertainty regarding the need to commit resources for reliability. It can also cause real-time RSG costs that are not currently allocated to wind suppliers because wind capacity is an intermittent resource. Efficient RSG cost allocation is essential to the effective integration of wind generation, but allocations must remain incentive-compatible with energy markets and should be assessed on a cost-causation basis. The Midwest ISO filed with the Commission to remove this exemption on December 7, 2009, and will take effect along with the implementation of the Dispatchable Intermittent resource type on June 1, 2011.

Wind capacity factors, measured as actual output as a percentage of maximum output, vary substantially across the footprint by region, hour, season, and temperature. They have been higher in the western portion of the footprint where the resource potential is greater. Wind capacity factors have also generally been higher during off-peak hours, during the winter and spring, and when temperatures are mild.

Figure 47 shows average hourly wind capacity factors by load-hour percentile. Load-hour percentile helps to show how capacity factors changed in accordance with the various levels of load. The x-axis in the figure shows the tranches of data by load level. For example, '<25' bars show the capacity factor during the 25 percent of 2009 hours when load was the lowest. The figure is also organized by season and region.

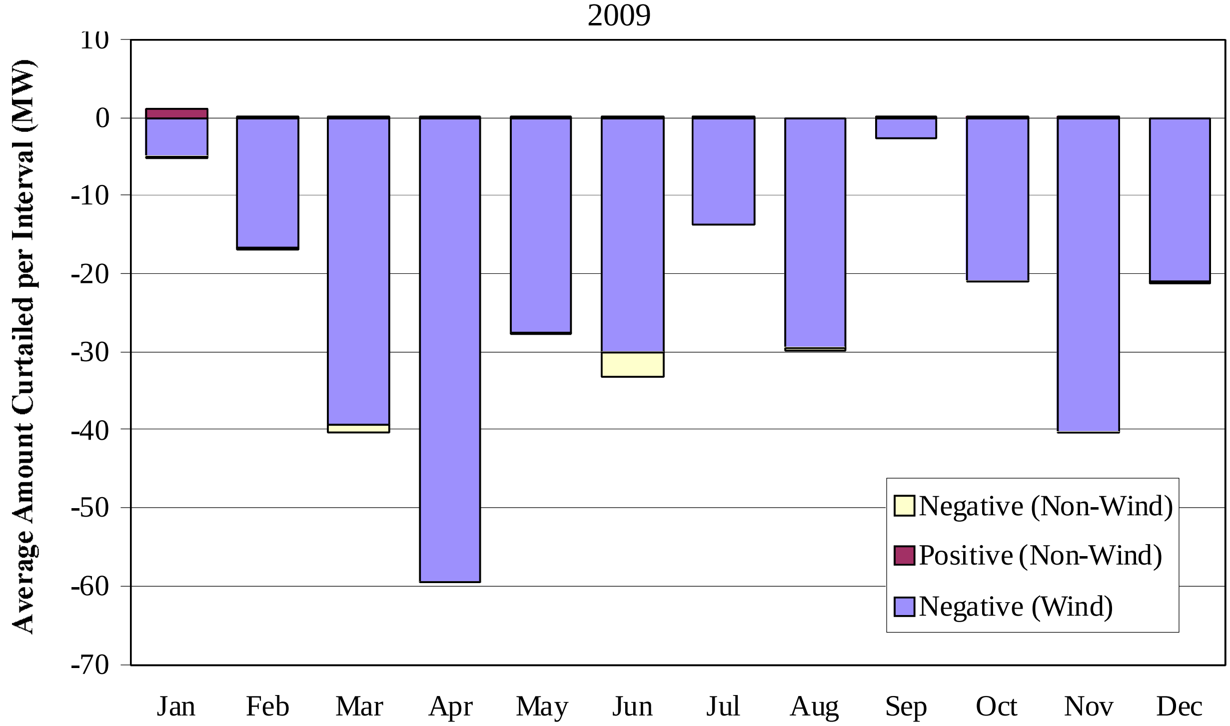
Figure 47: Wind Generation Capacity Factors by Load Hour Percentile



Wind output (reflected in the capacity factors) is generally negatively correlated with load, particularly in the summer. Capacity factors are lowest when the output is most valuable. The spread between western and eastern capacity factors is larger in the winter than in the summer, but the difference narrows at the highest load levels. These results are consistent with the Midwest ISO's analysis supporting the reduced capacity credits for wind resources from 20 percent to 8 percent.

As described above, intermittent resources cannot currently be dispatched by the real-time market when output reductions are needed to prevent a transmission constraint from being overloaded. Instead, the Midwest ISO operators manual dispatch the wind resources to reduce their output as needed to manage overloaded transmission constraints. Figure 48 shows all of the Midwest ISO's manual dispatch actions.

Figure 48: Manual Redispatches
2009



The vast majority of manual redispatches were of wind units. On average, 25 MW of wind was curtailed per interval in 2009. Wind units were curtailed in 36 percent of intervals, with an average of 70 MW per interval. During certain intervals, as much as 600 MW was manually redispatched. The manual redispatch of non-wind units was exceedingly rare, averaging less than 1 MW per interval.

The manual curtailment of wind units is not generally an efficient means to manage congestion. Additionally, it does not allow congestion to accurately reflect the marginal costs incurred to manage the congestion. The Midwest ISO is currently working on an initiative to allow wind units to be dispatchable through the real-time market and to set LMPs. This initiative will create a new resource category called Dispatchable Intermittent that allows wind resources to respond flexibly to setpoint instructions. The dispatch range of these units will change hourly based on the prevailing wind forecast. This is expected to be implemented on June 1, 2011.

H. Market Conclusions and Recommendations

Overall, the Midwest ISO's real-time markets performed efficiently in 2009. The nodal market accurately reflected the value of congestion in the Midwest ISO and the introduction of ASM went smoothly and operated as expected. The ASM markets have led to increased dispatch flexibility and contributed to lower real-time price volatility.

As expected, prices in the real-time market were substantially more volatile than in the day-ahead market, although this volatility has declined since the introduction of ASM in January 2009. The performance of the real-time market is compromised by at least four factors:

- Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage – this has improved substantially in 2009 but remains an issue;
- The absence of a real-time model that optimizes the commitment and de-commitment of peaking resources;
- Prices that do not always reflect the costs of peaking or DR resources when they are the marginal source of energy; and
- Difficulties faced in integrating wind resources into the Midwest ISO markets.

To further improve the performance of the real-time market, we recommend the Midwest ISO consider the following changes (we provide recommendations regarding congestion management and external transactions in subsequent sections).

1. Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set prices.
2. Develop provisions that allow non-dispatchable demand response (or interruptible load) to set energy prices in the real-time market when they are called upon in a shortage.
3. Improve the integration of wind resources into the Midwest ISO system by allowing them to be curtailable at a specified offer price and be eligible to set prices in the energy market.

4. Develop improved “look-ahead” capabilities in real time that would improve the commitment of quick-starting gas turbines and the management of ramp capability on slow-ramping units.

5. Improve the real-time operation of the system by:

    a. Optimizing the use of the load offset to improve the Midwest ISO’s management of ramp capability in the near-term; and

    b. Reducing the system ramp consumed by interval-to-interval changes in load by improving the STLF used by the real-time market.

6. Improve the performance of the spinning reserve market by:

    a. Improving the consistency between the reliability requirement for spinning reserves and the market requirement; and

    b. Allowing the spinning reserve penalty price to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.

7. Evaluate the formula for the regulation penalty price to ensure that it accurately reflects the costs of committing peaking resources in the Midwest ISO.

V. Transmission Congestion and Financial Transmission Rights

One of the primary functions of the Midwest ISO energy markets is to meet load requirements with the lowest-cost resources given the limitations of the transmission network. The locational market structure in the Midwest ISO is designed to ensure that transmission capability is used efficiently and that energy prices reflect the marginal value of energy at each location. Congestion costs arise when flow limits on transmission lines prevent lower-cost generation on the unconstrained side of a transmission interface from replacing higher-cost generation on the constrained side of an interface. The results are higher LMPs in the constrained area. An efficient system typically will have some congestion because investment in transmission to alleviate the congestion should only occur when the cost of such investment is less than the benefit of eliminating the congestion.

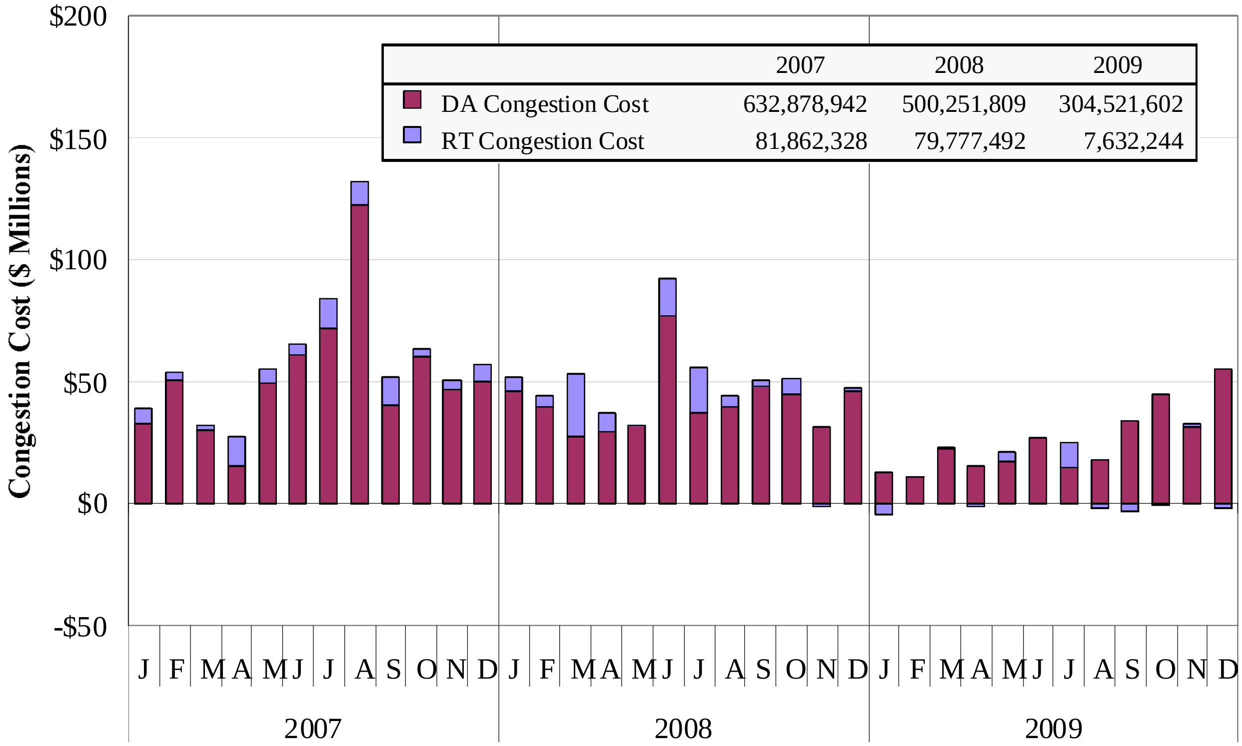
When congestion arises, the difference in prices across the interface represents the marginal value of transmission capability between the two areas. When power is transferred across the interface up to the limit, congestion costs are approximately equal to the difference in LMP prices across the interface multiplied by the amount of the transfer. These congestion costs are collected by the Midwest ISO in the settlement process through the congestion component of the LMP. Net load in the constrained area settles at the constrained area price and the net generation in the unconstrained area settles at the unconstrained price. As a result, more payments are received from the load than are paid to the generators. These excess payments are congestion costs. Locational prices that reflect congestion provide economic signals that are important in managing congestion on the transmission network in both the short run and long run. These signals are important in the short run because they allow generation to be efficiently redispatched to manage the network flows. They are also important in the long run because they govern investment and retirement decisions.

In this section of the report, we evaluate congestion costs, FTR market results, and the Midwest ISO's management of congestion during 2009. We begin this section by presenting an overall summary of congestion costs incurred in the day-ahead and real-time markets.

A. Real-Time Congestion Costs

Figure 49 shows the total congestion costs incurred in the day-ahead and real-time markets from 2007 through 2009.

Figure 49: Total Congestion Costs
2007 – 2009

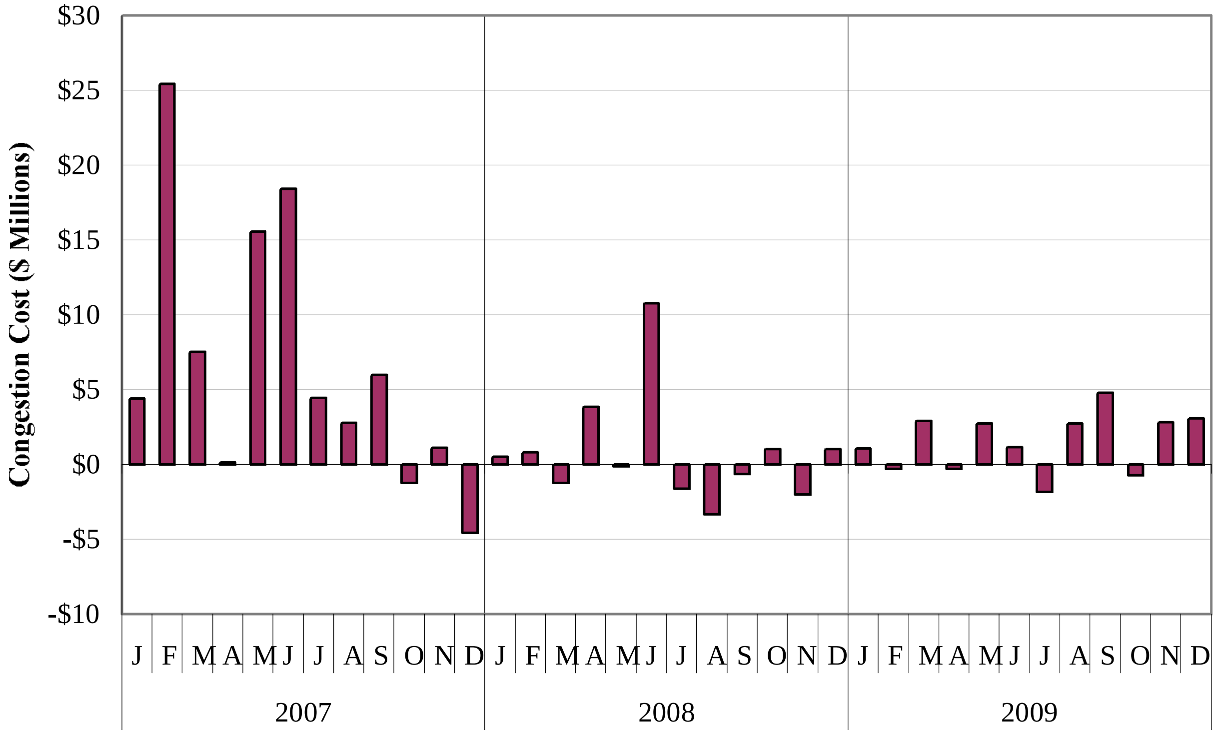


Day-ahead congestion costs declined by nearly $200 million (39 percent) in 2009 compared to 2008. This reduction was due to reduced natural gas prices (which lower redispatch costs), lower average load, and transmission improvements. Day-ahead congestion costs were higher in the last four months of the year as economic conditions improved and natural gas prices increased.

Real-time balancing congestion is congestion that settles based on real-time market results. Normally, one would expect the real-time-congestion costs to be minimal if modeling of the transmission system is consistent between the day-ahead and real-time markets. In other words, congestion costs collected in the real-time market occur only when the transmission limits decrease from those in the day-ahead market model or when loop flow increases from the levels assumed in the day-ahead market (both of which reduce the transmission capability available for real-time market). These reductions in transmission capability can compel the Midwest ISO to incur real-time congestion costs to reduce the flow on constrained facilities from the day ahead to real time, which is recovered through uplift charges.

For example, if a transmission interface is fully scheduled in the day-ahead market and is congested, no additional congestion costs will be collected in the real-time market. The cost of congestion may increase or decrease (i.e., the price differences may be larger or smaller in real-time than they were day ahead) but there will be no additional real-time settlement unless the flow over the interface changes in real time from the amount scheduled day-ahead. However, if the limit falls (the interface is derated) or loop flow increases over a congested interface, the Midwest ISO will incur real-time congestion costs to achieve the required reduction in real-time flows over the interface. Figure 50 shows the real-time congestion costs from 2007 to 2009. [17]

Figure 50: Real-Time Balancing Congestion Costs
2007 – 2009



17 Real-time congestion costs caused by increased use of the Midwest ISO's transmission capability by PJM are reimbursed under the JOA. Hence, the net market-to-market payments are included in the figure.

Balancing congestion costs totaled nearly $18 million in 2009, up from $9 million in 2008 but substantially below the $80 million incurred in 2007. The lower costs in recent years are due to improvements made in the day-ahead modeling of loop flows and an overall decrease in congestion. No month incurred more than $5 million in costs in 2009. Occasional negative balancing congestion costs reflect a surplus of revenue when loop flows were lower or real-time limits were higher than assumed in the day-ahead market.

B. Day-Ahead Congestion and FTR Obligations

The economic value of transmission capacity is reflected in FTRs. Holders of FTRs are entitled to the congestion costs collected between the source and sink locations that define a specific FTR. Hence, FTRs allow participants to manage the price risk associated with congestion. FTRs are distributed through an annual allocation process as well as through seasonal and monthly auctions. The Midwest ISO introduced Auction Revenue Rights (“ARRs”) to the FTR market in June 2008. This approach provides the value of the FTRs to customers by allocating the revenue payments from an FTR to the customer rather than the FTR itself. However, if the customer would rather have the FTR, it can still purchase the FTR and be in the same position as it would have been had it been allocated the FTR directly.

The Midwest ISO is obligated to pay FTR holders the value of the day-ahead congestion over the path that defines each FTR. In particular, the payment obligation associated with an FTR is the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[18] Obligations for FTRs are paid with congestion revenues collected in the Midwest ISO’s day-ahead market. Surpluses and shortfalls are expected to be limited when the portfolio of FTRs held by participants matches the power flows over the transmission system. However, when the FTR rights exceed the physical capability of the transmission system (or loop flows from activity outside of the Midwest ISO region use some of the transmission capability), the Midwest ISO may collect less day-ahead congestion revenue than it owes to the FTR holders. [19] Congestion revenue surpluses in one month can be used to fund FTR shortfalls in other months during the

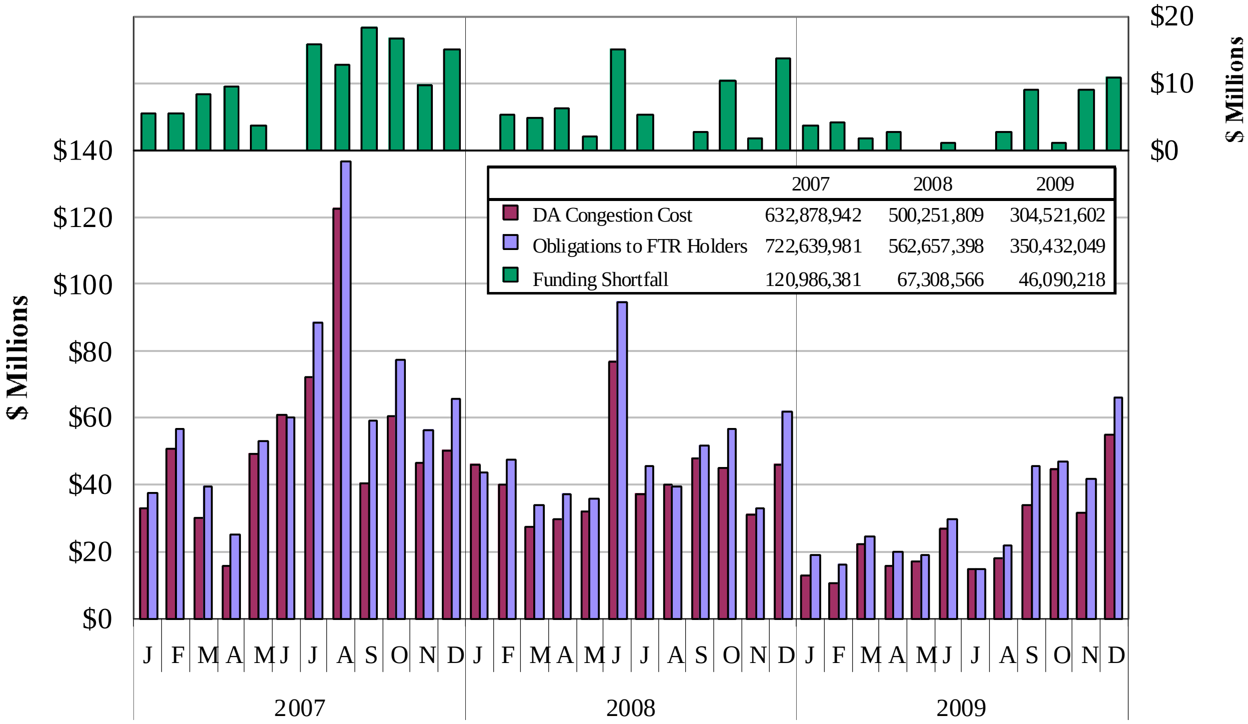
18 An FTR obligation can be in the “wrong” direction (counter flow) and can require a payment from the FTR holder.

19 The day-ahead model includes assumptions on loop-flows that are anticipated to occur in real-time.

same year. If the Midwest ISO has a shortfall over the entire year, FTR payments are reduced pro rata.

Figure 51 compares the monthly total day-ahead congestion revenues to the monthly total FTR obligations. The figure shows that the day-ahead congestion collections continue to be substantially less than FTR obligations (by approximately 13 percent in 2009). The shortfall was 12.0 and 16.7 percent in 2008 and 2007 respectively. Shortfalls are undesirable because they introduce uncertainty and can distort the value of the FTRs.

Figure 51: Day-Ahead Congestion Revenue and Payments to FTR Holders
2007 – 2009: All Hours



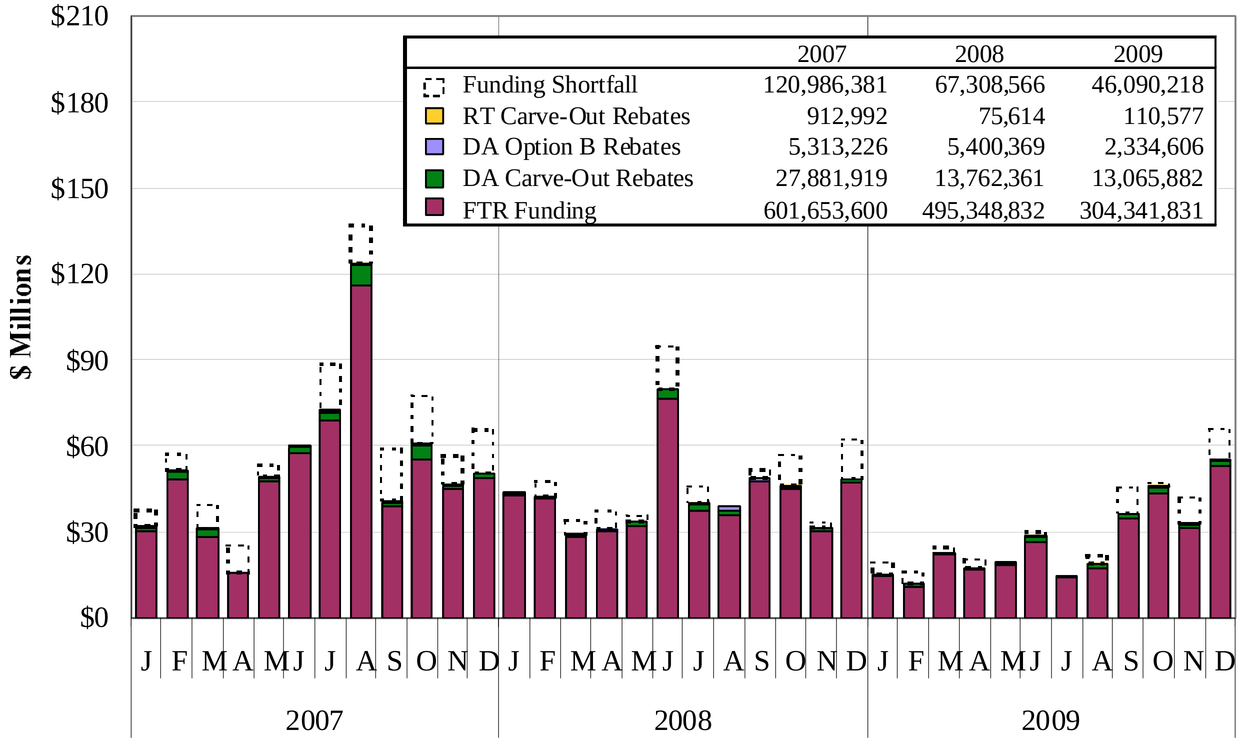
Surpluses or shortfalls occur when the Midwest ISO sells fewer or more FTRs than the actual capability of the network in the day-ahead market. The reasons for the differences between the FTR and day-ahead modeling that contribute to surpluses and shortfalls are generally similar to the differences discussed previously between the day-ahead and real-time. Transmission outages or other factors cause the capability of the system in the day-ahead modeling to differ from the capability assumed when the FTRs were allocated or sold. In addition, loop flows over the system caused by generators and loads outside of the Midwest ISO use more or less of the transmission capability in the day-ahead model than assumed in the FTR market model. Unanticipated loop-flow is a problem because the Midwest ISO collects no congestion revenue from transactions that cause loop flow. If the ISO allocates FTRs for the full capability on these interfaces, the loop flow will create an FTR revenue shortfall.

The Midwest ISO has continued to work on the FTR and ARR allocation processes and associated modeling to reduce the shortfalls. The changes include improving loop flow assumptions; adding additional constraints related to market-to-market and non-market constraints; and broadly reducing transmission line limits in the FTR market model to account for expected differences in FTR-modeled conditions and actual hourly results. While the improvements introduced in 2008 contributed to lower shortfalls in 2009, we have recommended additional improvements. The Midwest ISO has recently proposed a new initiative to enhance screening for topology discrepancies between the planning and actual system topology.

In the Midwest ISO region, other types of transmission rights were created to protect entities with pre-existing agreements to use the transmission system (referred to as “grandfathered” agreements). These rights generally allow the holder not to have to pay congestion in the day-ahead or real-time market, which is accomplished by providing a rebate of the congestion costs associated with the rights. The rights include an alternative type of FTR with use-it-or-lose-it characteristics (known as “Option B” FTRs) and congestion “Carve-Outs”.

Figure 52 shows the monthly payments and obligations to conventional FTR holders, as well as the payments to Option B and Carve-Out FTRs. The figure shows that the vast majority of the payments (approximately 95 percent) were made to holders of conventional FTRs. Only five percent of payments were made to holders of FTR Option B and Carve-Out FTRs. The modest payments for these other types of rights are a good outcome because they do not provide the same efficient incentives as conventional FTRs. As a percentage of obligations, payments to the holders of the alternative rights increased slightly from 3.3 percent in 2008 to 4.2 percent in 2009. The FTR funding rate declined in 2009, even though the nominal shortfall fell by more than $21 million. We recommend improvements later in this section that should increase the FTR funding rate.

Figure 52: Payments to FTR Holders
2007 – 2009: All Hours



One of the sources of FTR shortfalls is the use of “radial constraints” in the day-ahead market. The Midwest ISO imposes radial constraints *from* the transmission network *to* individual generator buses to limit the day-ahead modeled flow to the generator buses when excessive virtual loads are submitted at them. These radial constraints are used because virtual load bids at these locations can result in infeasible day-ahead model solutions. This is because the market software reflects the low voltage facilities at the unit site (i.e., where the step-up transformer that brings the power onto the higher-voltage network is modeled). Of course, such radial constraints are unnecessary in the real-time market because such infeasibilities cannot exist (because power never flows out to a generator location since there is no physical load there). The radial constraints ensure that the day-ahead market will solve, but they can cause congestion that would never exist in the real-time market. Because these constraints were not generally reflected in the FTR market in 2009, more FTRs could sink at the generator locations than the radial constraints would support in the day-ahead model. This led to FTR shortfalls and potential manipulation opportunities.

Figure 53: FTR Underfunding and Day-Ahead Congestion
Radial Constraints, 2009

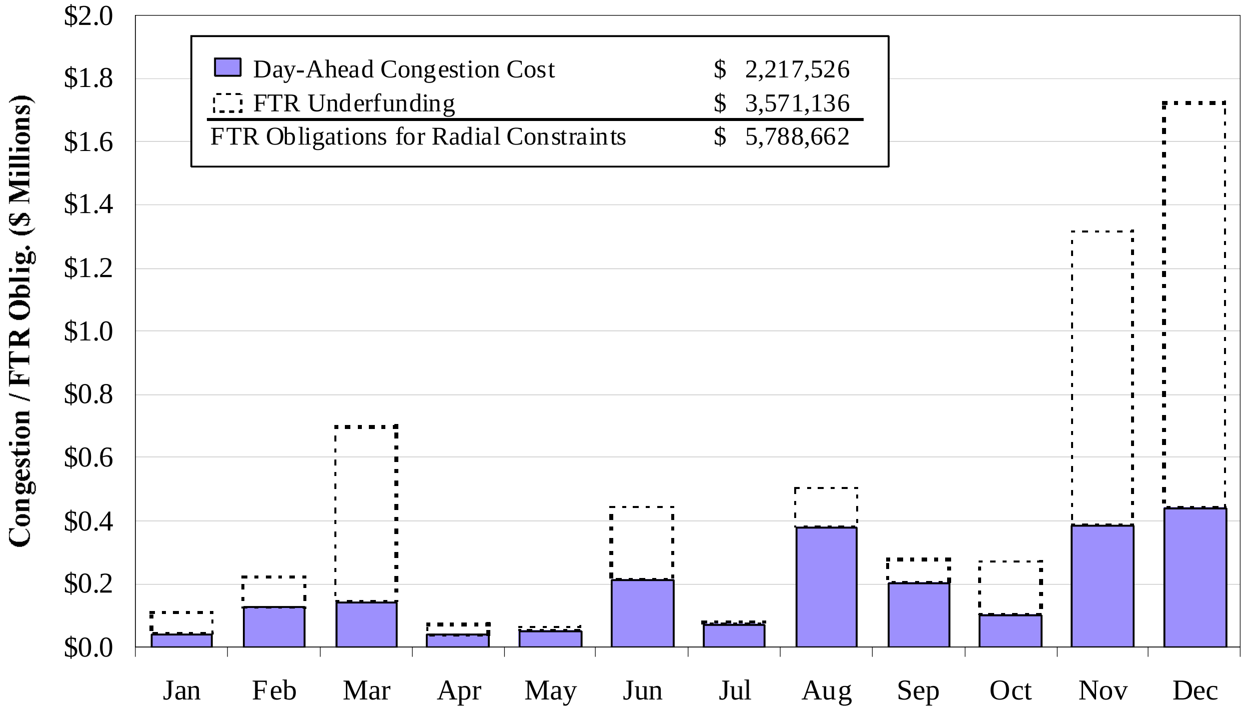
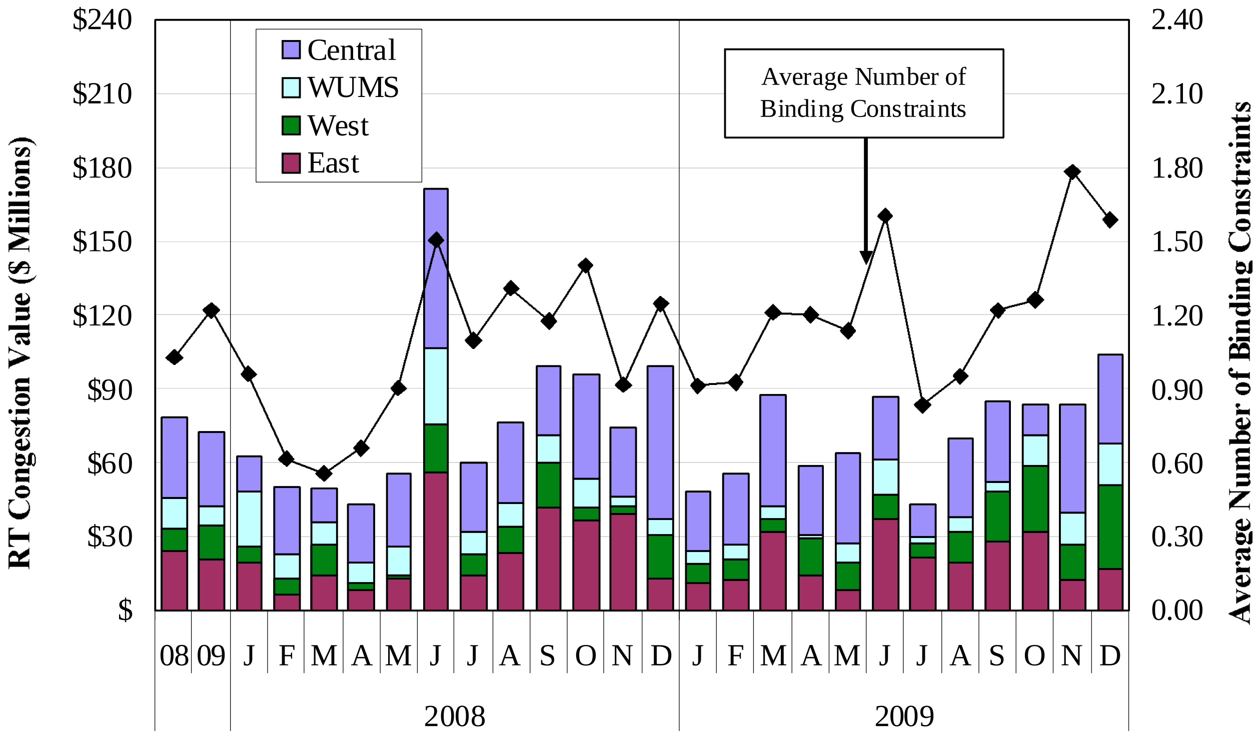


Figure 53 above shows day-ahead congestion and FTR shortfalls for radial constraints. Day-ahead congestion costs on radial constraints totaled $2.2 million, while FTR obligations on these constraints totaled nearly $5.8 million. On a percentage basis, radial constraints generated roughly one percent of the day-ahead congestion costs but accounted for almost 8 percent of the FTR shortfalls. The Midwest ISO is taking steps to limit shortfalls by including radial constraints in the FTR market. However, we recommend the Midwest ISO work to remove these constraints from the day-ahead market since this congestion cannot exist in the real-time market.

C. Value of Congestion in the Real-Time Market

In this subsection, we study congestion patterns in the real-time market. We focus here on the *value* of real-time congestion, rather than the day-ahead and real-time balancing congestion *costs* collected by the Midwest ISO that were discussed in the previous subsection. This difference is important because the Midwest ISO does not collect congestion costs for all the actual flows over its system (loop flow incurs no congestion costs).[20] For the purposes of the analyses in this subsection, we calculate an implied "value" of real-time congestion. This value is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint in a given dispatch interval. Figure 54 shows the value of real-time congestion by region and the average number of binding constraints in 2008 and 2009. The average monthly congestion value and number of binding constraints over each year is shown on the left side of the chart.

Figure 54: Value of Real-Time Congestion by Coordination Region
2008 – 2009



Real-time congestion totaled $863 million in 2009, a reduction of eight percent from $938 million in 2008. These values exceed the day-ahead and real-time congestion costs collected by the Midwest ISO. This is because (1) loop flows use some of the transmission network capability without reimbursing the Midwest ISO, (2) PJM is entitled to use some of the Midwest ISO system (referred to as Firm Flow Entitlements, or "FFE"), and (3) there was poor price convergence in western areas of the footprint affected by congestion.

20 In our discussion, congestion refers generally to the cost of a particular constraint. The term "congestion costs" specifically refers to the component of a generator's LMP that is collected by the Midwest ISO.

As in prior years, over two-thirds of real-time congestion occurred in the eastern half of the footprint. However congestion occurred more uniformly across the footprint in 2009 than in 2008. Congestion was down 10 percent in the East and 14 percent in the Central region, respectively, while it rose 50 percent (to $167 million) in the West due to increasing supply in that region (primarily wind resources). Transmission upgrades contributed to lower congestion into WUMS in 2009.

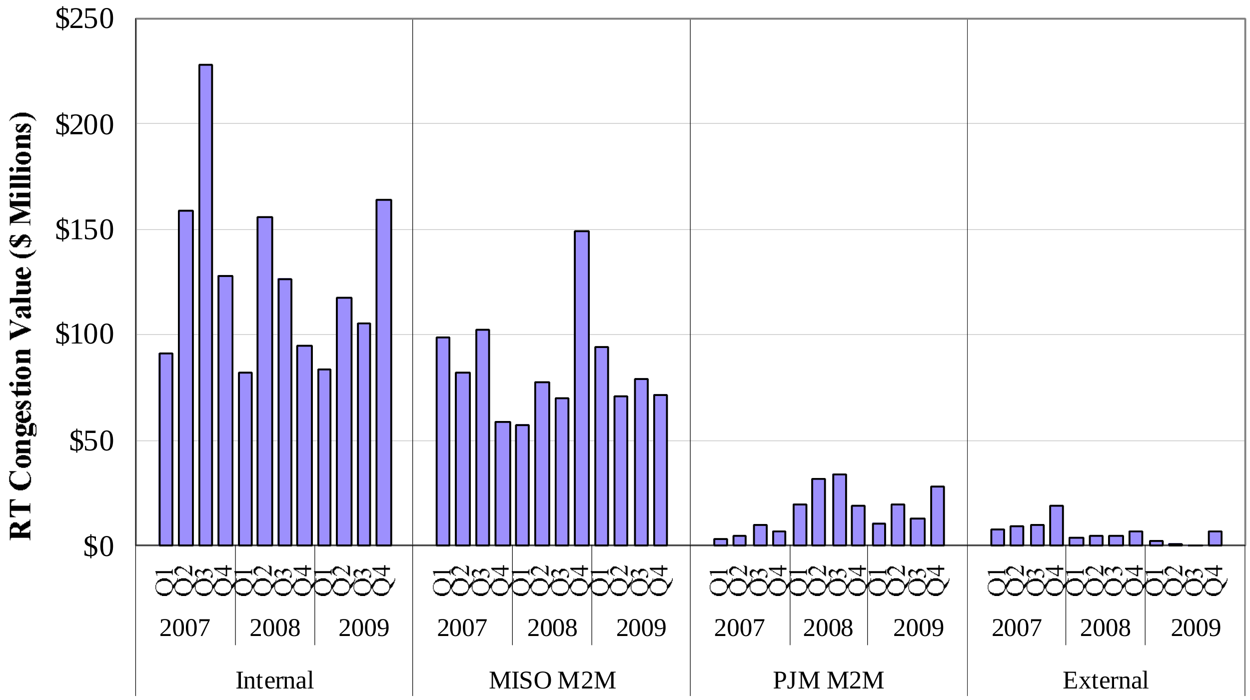
The figure also shows transmission constraints were binding more frequently in 2009, from 1.03 constraints per interval to 1.21. This is largely due to more low voltage constraints binding (partly as a result of uncontrollable wind generation in the West). The frequency of these constraints generally increased throughout the year.

To better identify the sources of congestion, Figure 55 shows the value of real-time congestion by type of constraint. This is computed in the same manner as the value of congestion in the previous analysis. For our analysis, we define four types of constraints:

- Constraints internal to the Midwest ISO that are not coordinated with PJM. These are not market-to-market constraints and are labeled as "internal" constraints in our analysis;
- The Midwest ISO constraints coordinated with PJM. These are labeled as Midwest ISO market-to-market constraints;
- The PJM constraints coordinated with the Midwest ISO. These are labeled as PJM market-to-market constraints; and
- Constraints located on other systems that the Midwest ISO must redispatch to relieve when Transmission Loading Relief ("TLR") is requested. These are referred to as "external" constraints in our analysis. Congestion occurs on external constraints when a TLR is called on a neighboring system that causes Midwest ISO to re-dispatch its generation.

As in prior years, most of the congestion in 2009 occurred on Midwest ISO-managed constraints (internal and Midwest ISO market-to-market constraints), which represent over 90 percent of the total congestion value. Of this congestion on the Midwest ISO system, over 40 percent occurred on market-to-market constraints. Although relatively few constraints are coordinated under the market-to-market process, those constraints are some of the most valuable on the Midwest ISO system. The top five constraints alone comprised 61 percent of all market-to-market congestion in 2009, down from 72 percent in 2008. Moreover, 31 percent of all market-to-market congestion occurred on one constraint.

Figure 55: Value of Real-Time Congestion by Type of Constraint
2007 – 2009



Congestion on non-Midwest ISO-managed constraints (PJM market-to-market and external constraints) was a relatively small portion of overall real-time congestion in 2009. PJM market-to-market congestion fell 32 percent to $72 million, while external congestion fell nearly 50 percent to $10 million.

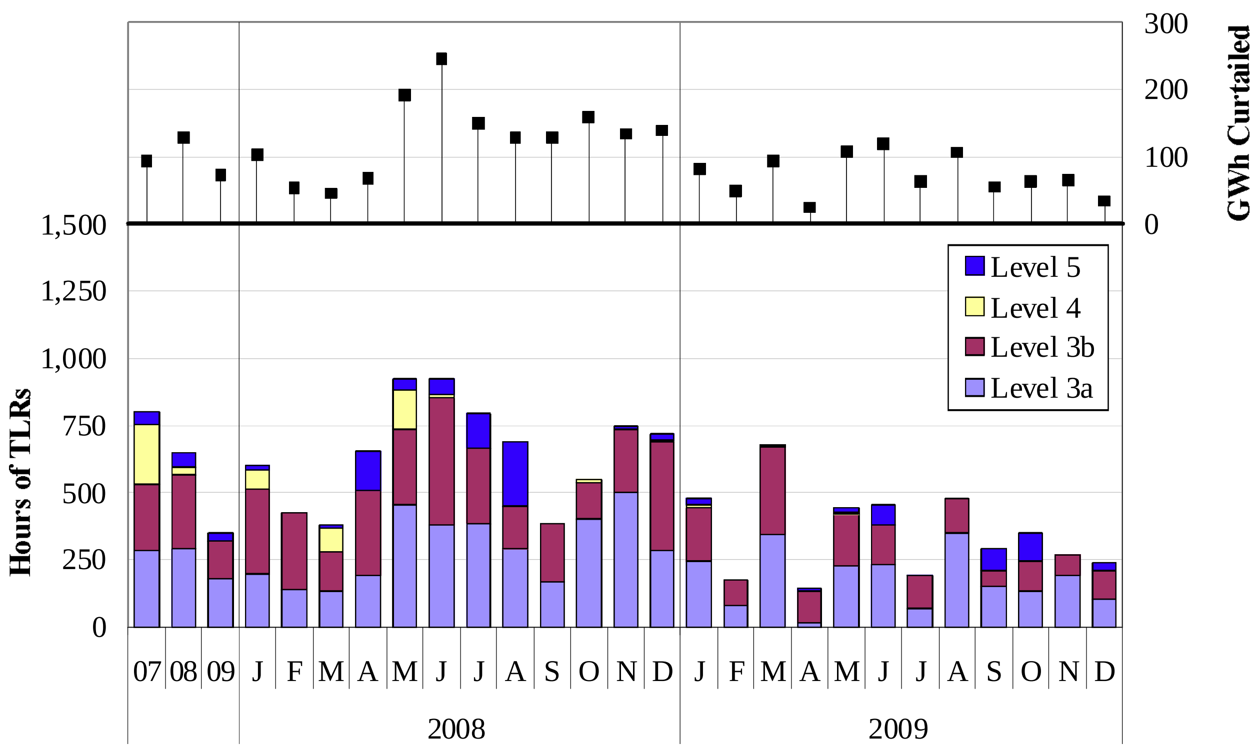
D. TLR Events

The Midwest ISO continues to use TLR procedures and the NERC Interchange Distribution Calculator to support certain aspects of congestion management. Prior to the introduction of the energy markets, virtually all of the congestion management for Midwest ISO transmission facilities was accomplished through the TLR procedure, an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. When a constraint is binding, the real-time dispatch model manages the flow over the constrained transmission facility by economically redispatching generation. However, external entities contribute to the flows over the constrained internal transmission facilities. Hence, the Midwest ISO invokes a TLR procedure to ensure that the external parties contribute to reducing the flow over the constrained facility. As we have shown in previous reports, the TLR process is a much less efficient and a less controllable means to manage congestion than economically redispatching generation through LMP markets. This less efficient process leads to:

- More than three times the curtailments to manage congestion on average than the quantity of economic redispatch needed; and
- Less timely and accurate control of the system, resulting in lower reliability.

LMP markets help to efficiently manage most internal congestion through redispatch rather than the curtailment of scheduled transactions through the TLR process. Figure 56 shows TLR activity on Midwest ISO flowgates on an annual basis from 2007 to 2009 and monthly basis for 2008-2009.

Figure 56: Monthly TLR Activity
2007 – 2009



The top panel of the figure shows the quantities of scheduled energy curtailed by the TLR events. The bottom panel of the figure provides the hourly TLR activity by the various TLR levels. NERC's active response TLR levels include:

- Level 3 — non-firm curtailments;[21]
- Level 4 — commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5 — curtailment of firm transactions.[22]

In 2009 TLR activity as measured in flowgate-hours fell 46 percent compared to 2008. TLR curtailment volume decreased 44 percent. The more severe Level 4 and 5 TLRs have been largely eliminated since 2007. Although significant quantities of TLRs are still invoked to ensure that transactions external to the Midwest ISO are curtailed when contributing to congestion, the Midwest ISO relies primarily on economic redispatch for managing congestion.

E. Congestion Manageability

Congestion management is one of the most important activities of the Midwest ISO. The Midwest ISO monitors thousands of potential network constraints in real time throughout the footprint. As the flow over each of these constraints approaches its limit (or if it is anticipated to do so) in real-time, the constraint is "activated" in the market model. The Midwest ISO's real-time market model will then manage the flow on the activated constraints to keep the flow below its operating limit on the facility while minimizing overall production costs.

The Midwest ISO's real-time LMP-based energy market will redispatch generation subject to transmission constraints on the network. This process utilizes the redispatch capability of generators, especially those with high generation shift factors ("GSFs") that have relatively large impacts on constraints. Constraints are at times difficult to manage if the available redispatch

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21 Level 3a allows for the reallocation of transmission service by curtailing interchange transactions to allow interchange transactions using higher priority transmission service. Level 3b allows for the curtailment of interchange transactions to mitigate an SOL or IROL violation.

22 NERC's TLR levels include four other levels: Level 1 (notification), Level 2 (holding transfers), Level 6 (emergency procedures) and Level 0 (TLR concluded).

capability of the generators that affect the flow on the constraint is limited. The available redispatch capability is reduced when:

- Generators that are most effective at relieving the congestion are not online;
- Generator flexibility is reduced (i.e., generators set operating parameters, such as dispatch range or ramp rate, lower than actual physical capabilities); or
- Generators are already at their limits (e.g. operating at their maximum point of their dispatch range, the "EcoMax").

When available redispatch capability is insufficient to reduce the flow below the transmission limit in the next five-minute interval, we refer to the transmission constraint as "unmanageable". Importantly, the presence of an unmanageable constraint does not mean the system is unreliable. The Midwest ISO performance criteria for most constraints require control within the limit in 20 minutes. If control is not obtained within 30 minutes, a reporting criterion to stakeholders is triggered. The small subsets of constraints that can lead to cascading outages are controlled to limits that are more stringent than the actual security limits. When a constraint is unmanageable in the Midwest ISO market, an algorithm is used to "relax" the limit of the constraint for purposes of calculating a shadow price for the constraint and the associated LMPs. While an unmanageable constraint is not necessarily a reliability concern, it nonetheless warrants evaluation.

Figure 57 and Figure 58 evaluate the manageability of constraints by month and by voltage level, respectively. The first figure shows the frequency with which constraints were unmanageable in each month in 2008 and 2009. Overall, total constrained hours increased in 2009 compared to 2008, but manageability improved. In 2009, 21 percent of internal congestion costs were unmanageable, which is a decrease of more than one quarter from 2008. The introduction in 2009 of ASM and the PVMWP led to substantial increases in generation flexibility, which the real-time market can use to better manage congestion. In addition, the Midwest ISO has also modified a number of real-time modeling parameters in response to prior IMM recommendations that have increased the amount of congestion relief available to the real-time market.

Figure 57: Unmanageable Constraints
2008 – 2009

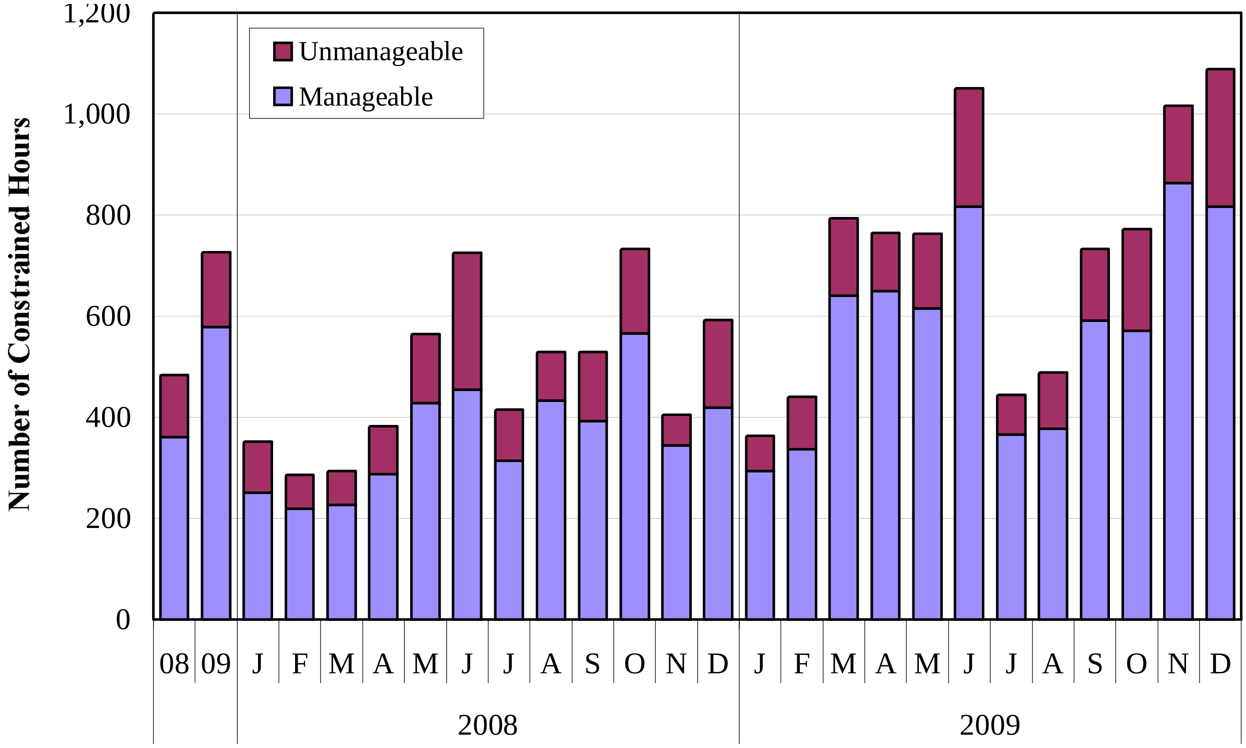
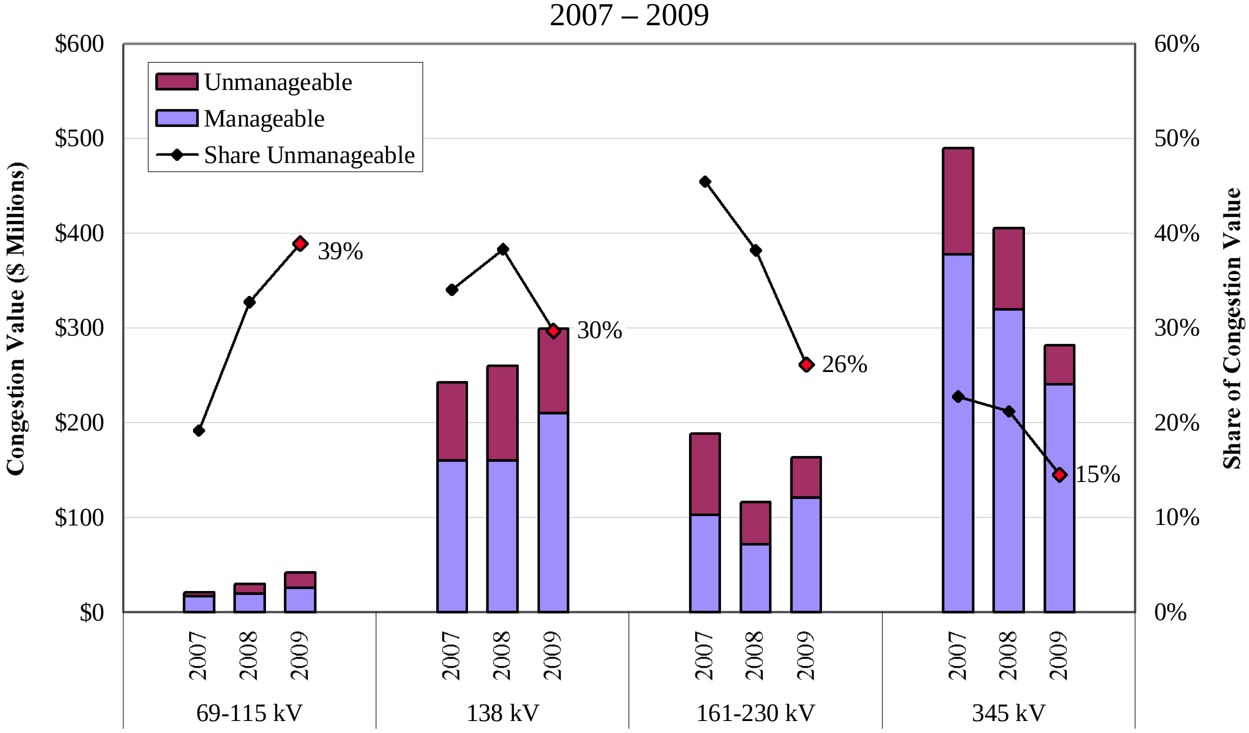


Figure 58: Value of Real-Time Congestion by Path
2007 – 2009



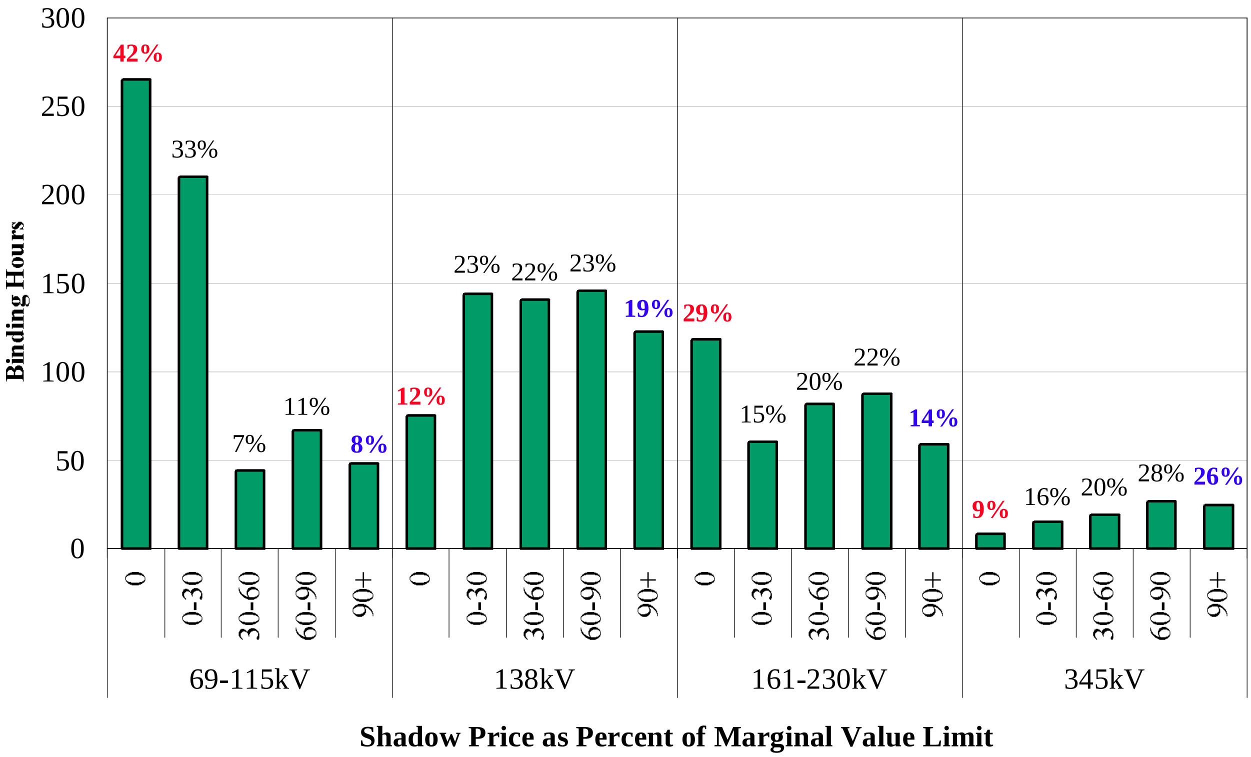
Due to the physical properties of electricity, more power tends to flow over higher-voltage lines, and a wider array of generators tends to affect these flows. Conversely, low voltage constraints typically must be managed with a smaller set of localized generating resources, making low-voltage constraints more difficult to manage. Figure 58 shows constraint manageability improved substantially at all voltages equal to or greater than 138 kV, which constitutes the vast majority of the congestion on the Midwest ISO system. These improvements are attributable to the changes discussed above.

Only the lowest voltage level exhibited worse manageability in 2009. Nearly 40 percent of low-voltage facilities (those rated 69 kV to 115 kV) were unmanageable in 2009, up from 33 percent in 2008). This suggests that the Midwest ISO accepted responsibility for facilities that it lacked the resources to effectively manage. We recommend that the Midwest ISO establish criteria for determining when it should secure these low voltage facilities and when they are more appropriately secured by local balancing authorities.

Given the frequency with which constraints are unmanageable, it is very important that the congestion be priced efficiently in the Midwest ISO's LMPs. Before we evaluate this, it is important to understand how the real-time market treats transmission constraints. The real-time market model utilizes "marginal value limits" ("MVL") that represent the value of managing the constraint. The MVL caps the cost (i.e., the shadow price) that the real-time market will incur to reduce the constraint flow to the limit. Hence, it is the maximum cost the Midwest ISO would be willing to incur to manage the constraint. Presumably, therefore, it should reflect the true reliability cost of violating the constraint. When the constraint is violated, the most efficient LMPs would be those that reflect the MVL of the violated constraint.

Figure 59 evaluates the pricing of violated constraints be showing how consistent shadow prices of the constraints have been with the MVLs. In this figure, the violated constraint hours are divided into tranches by the ratio of the shadow price to the MVL of the constraint. The ratio of the constraint shadow price to the MVL determines the extent to which the shadow price fully reflects the cost of the violated constraint. When the shadow price is close to 100 percent of the MVL, it accurately reflects the congestion on the violated constraint. When the ratio is significantly less than 100 percent, the congestion indicated in the LMPs is inefficiently muted.

Figure 59: Pricing of Unmanageable Congestion by Voltage Level
2009



Only 8 percent to 26 percent of violated constraints (depending on voltage level) are priced within 90 percent of the MVLs. Additionally, it shows that on all but the highest-voltage constraints, a substantial share of the violated constraints are priced at a zero shadow price, indicating that the LMPs include no reflection of the violated constraint. For example, 42 percent of the violated low-voltage constraints had a shadow price equal to zero. This raises substantial concerns regarding the efficiency of the LMPs under these conditions.

The reason the shadow prices can be far less than the MVL is that the Midwest ISO uses a constraint relaxation algorithm that essentially raises the limit for the constraint to allow the real-time market to achieve a feasible solution. The results above suggest that the algorithm often produces inefficient shadow prices that distort the associated LMPs and understates the reliability cost of violating the constraint. Hence, we continue to recommend that the Midwest ISO discontinue use of the relaxation algorithm and set prices based on the constraint penalty factors.

F. FTR Auction Prices and Congestion

As discussed in Subsection B above, the Midwest ISO administers a market for FTRs that allows participants to hedge the costs of congestion in the market. This subsection evaluates the performance of the FTR market. The Midwest ISO auctions the majority of transmission rights through seasonal and monthly auctions. A small percentage of rights are allocated directly to holders of Option B and Carve-Out FTRs. Prior to June 2008, most FTRs were allocated based upon physical usage of the system on an annual basis. Since June 2008, the majority of transmission rights have been auctioned (or self-scheduled via ARRs) on a seasonal basis.

A key indicator of the liquidity of the FTR markets is the profitability of FTR purchases. FTR profits are the difference between the costs to purchase the FTR and the payout on the FTR based upon the congestion in the day-ahead market. In a liquid FTR market, the profits should be low because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR holder. Our next analysis evaluates the profitability of FTRs purchased in the seasonal FTR auctions and the monthly FTR auctions. Figure 60 and Figure 61 show FTR profitability for seasonal and monthly FTRs, respectively, for the last three years.

Figure 60: FTR Profitability
Seasonal Purchases, 2007 – 2009

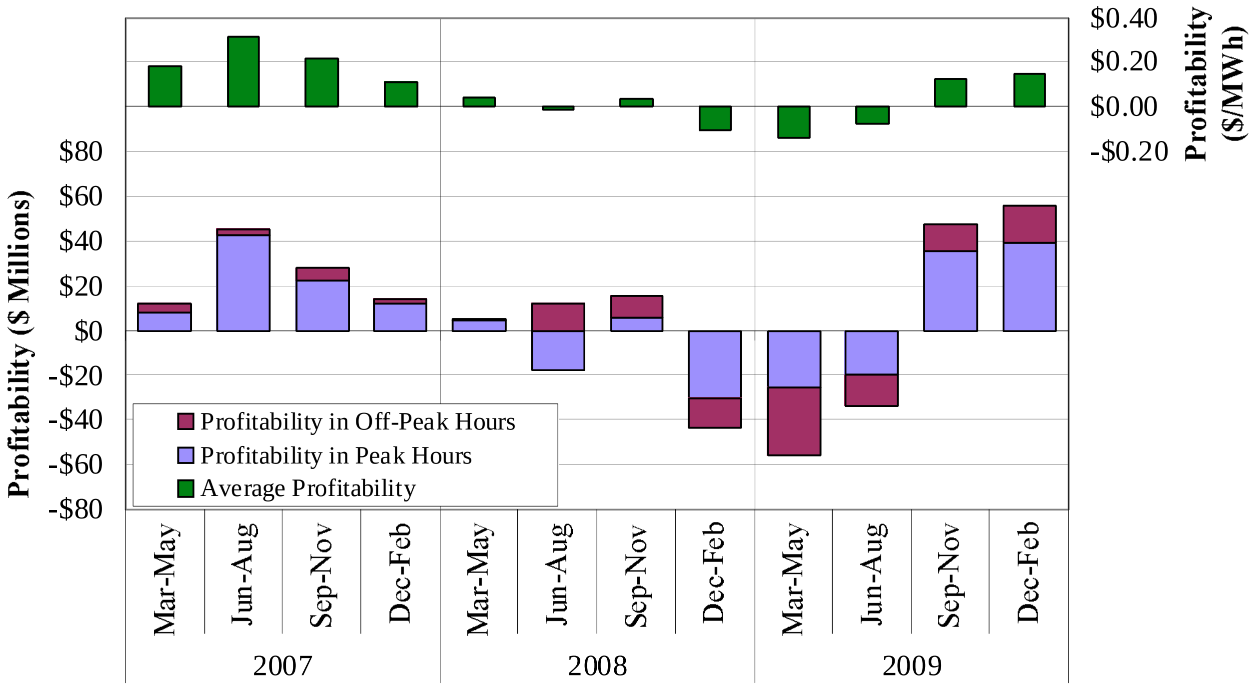
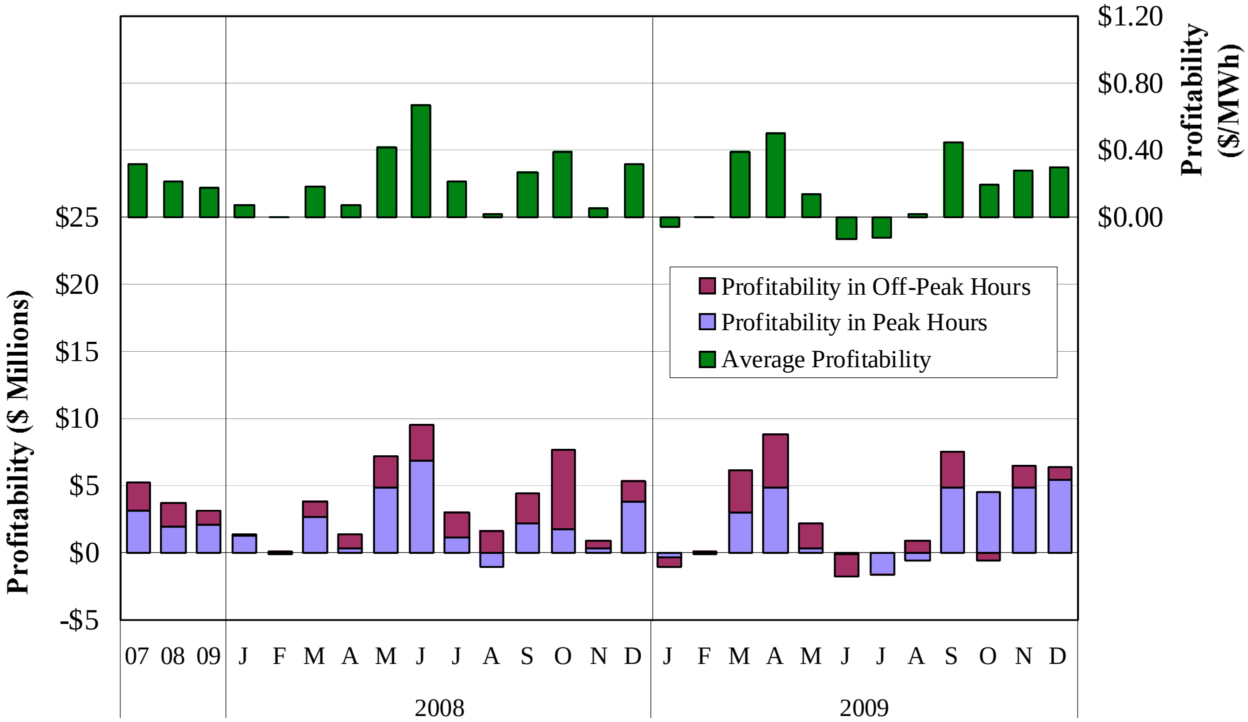


Figure 61: FTR Profitability
Monthly Purchases, 2007 – 2009



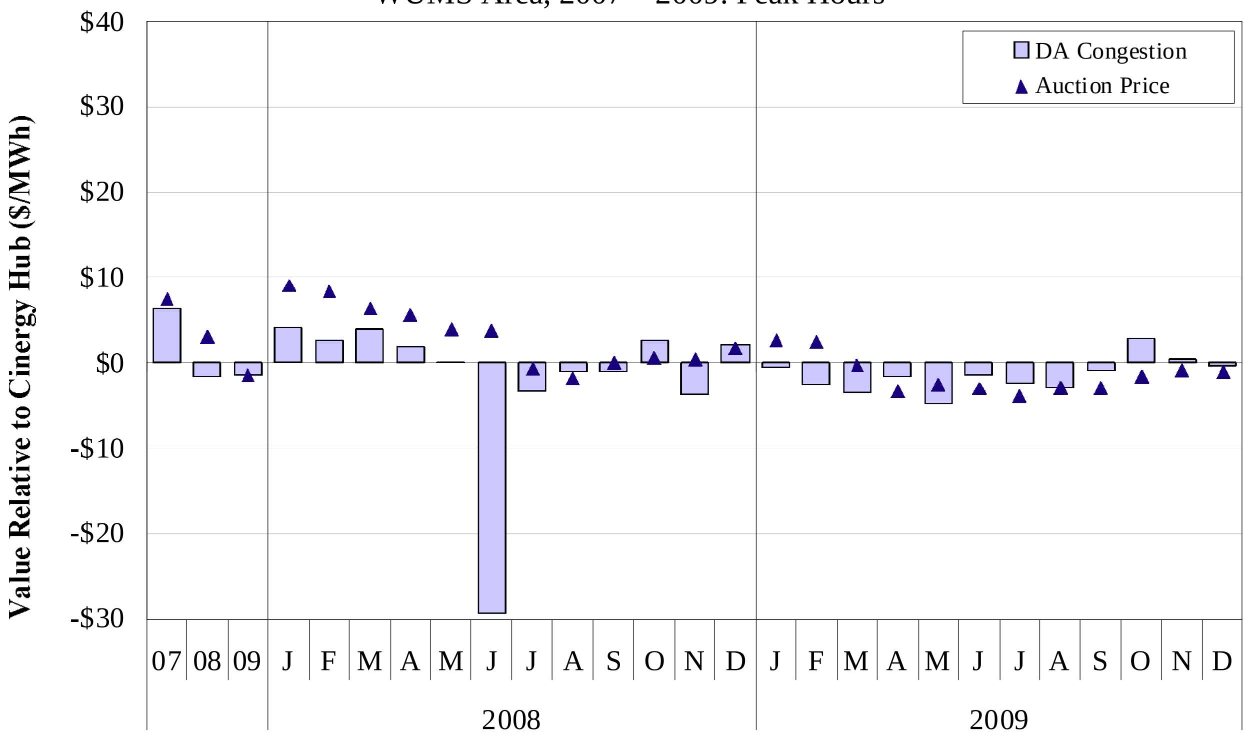
Average FTR profits in the seasonal auctions have declined from more than $1.50 per MWh when the markets were first introduced in 2005 to $0.21, -$0.02 and $0.01 per MWh in 2007, 2008, and 2009, respectively. The reduction in profitability indicates that the performance of the market has improved over time as liquidity has increased and participants have gained experience, causing FTR prices to more accurately reflect their value. Peak-hour FTRs were considerably more profitable in 2009 ($29.8 million) than off-peak-hour FTRs (loss of $15.2 million).

Figure 61 shows average profits in the monthly auction have decreased from more than $1.30 per MWh in 2005 to $0.31, $0.21 and $0.18 per MWh in 2007, 2008, and 2009, respectively. These results confirm that the liquidity and overall performance of the FTR markets has improved over time, causing FTR prices to accurately reflect their value.

To provide further detail on the performance of the FTR markets, our next analysis compares the monthly FTR prices to day-ahead congestion that are payable to the FTR holders. As noted above, a well-functioning market should produce FTR prices that reflect a reasonable expectation of the day-ahead congestion. The profit earned by an FTR holder is the difference between the FTR price paid and the day-ahead congestion payment to the FTR holder.

The results in the following figures help explain the changes in FTR profitability shown in the analyses above. We analyze values for the WUMS area, the Minnesota Hub, and the Michigan Hub in both peak and off-peak hours. Figure 62 and Figure 63 show the results of our analysis for WUMS in peak and off-peak hours, respectively. All values in the figures are computed relative to Cinergy Hub, which is the most actively-traded location in the Midwest ISO.

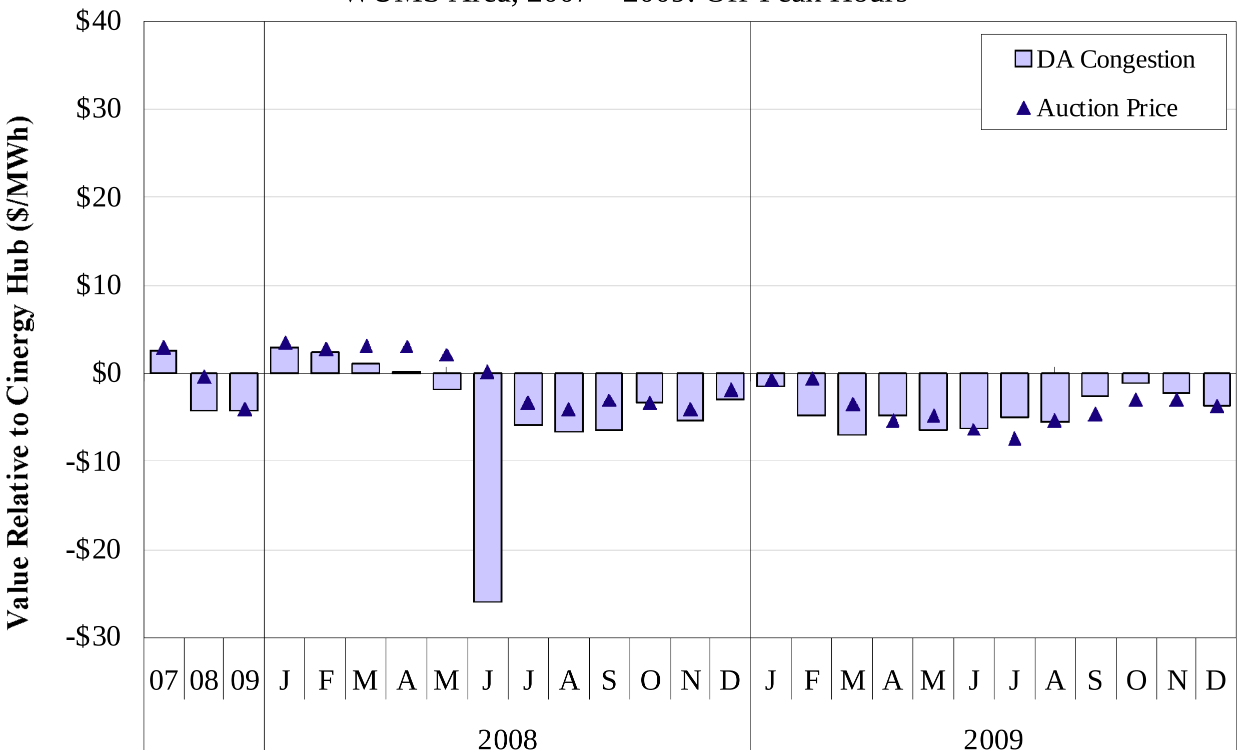
Figure 62: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2007 – 2009: Peak Hours



The value of congestion at WUMS relative to Cinergy was negative in most months in 2009. Convergence between FTR auction prices and congestion improved modestly in 2009 compared to 2008. The average absolute value of the monthly price difference between the auction price and the day-ahead congestion in 2009 was $2.23 per MWh, down from $2.90 in 2008 and $3.07 in 2007.[23]

Starting in the middle of 2008, the direction of the congestion in WUMS switched due to transmission upgrades in the region (particularly the new Arrowhead-Weston 345 kV line) and additional improvements in 2009. The average annual difference between the auction value and the day-ahead congestion (shown in the chart below) was near zero overall in 2009. This indicates that the FTR markets are performing well overall. Figure 63 shows the same analysis for the off-peak hours.

Figure 63: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2007 – 2009: Off-Peak Hours



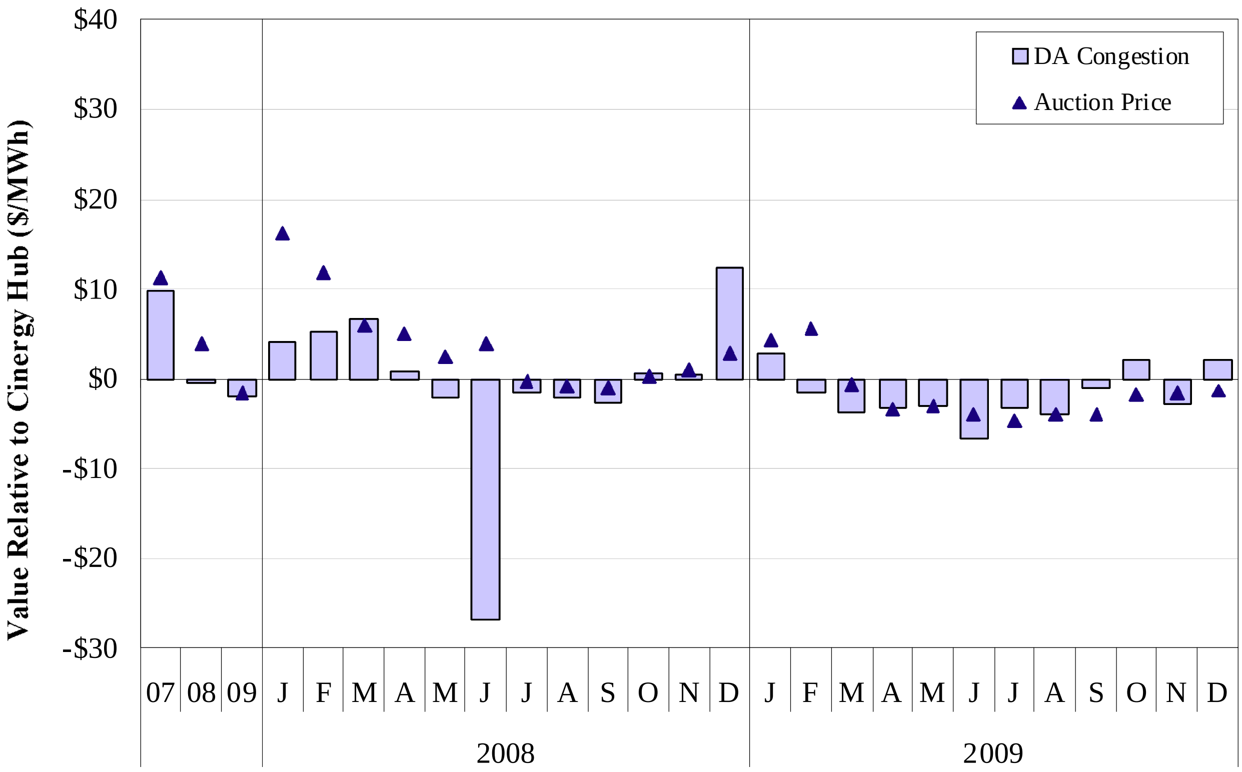
Congestion was consistently negative into WUMS during off-peak hours, averaging -$4.27 per MWh. Volatility is considerably lower during off-peak hours than during peak hours. The average absolute monthly price difference between the auction price and the day-ahead

23 June 2008 is excluded from all the annual statistics in this section. It was highly anomalous due to heavy storm-related transmission damage.

congestion in 2009 was $1.51 per MWh, down from $1.75 in 2008 (excluding June 2008). Similar to peak hours, the average annual price spread between the auction price and the congestion in off-peak hours was near zero in 2009, indicating that the FTR market performed well in off-peak hours.

Figure 64 and Figure 65 show the same analysis for the Minnesota Hub in peak and off-peak hours, respectively. As with WUMS, congestion variability at the Minnesota Hub has deceased markedly since 2007, and convergence between congestion values and FTR prices has improved. The monthly average of the absolute value of the spread between the FTR prices and the day-ahead congestion value was $2.26 per MWh in 2009, down 42 percent compared to 2008 (excluding June) and down 68 percent compared to 2007. This is likely due to the fact that the congestion patterns have become more predictable in 2009.

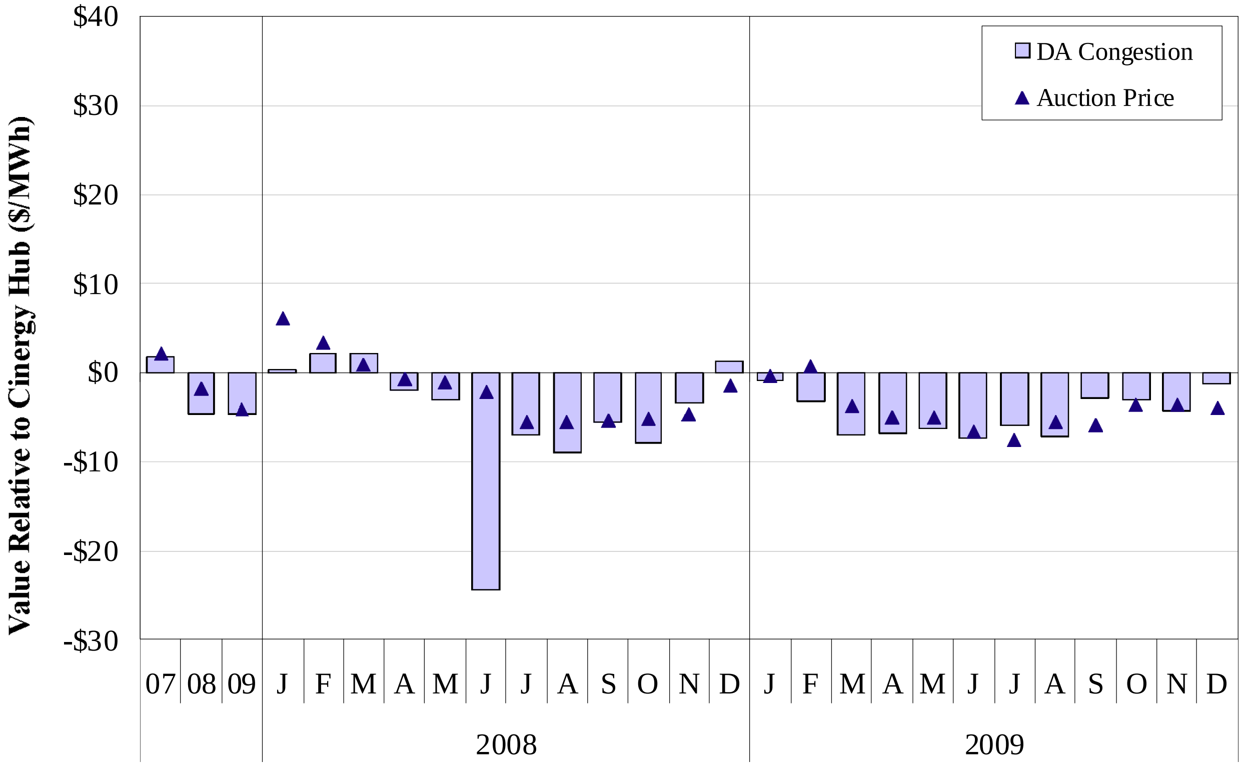
Figure 64: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2007 – 2009: Peak Hours



Off-peak congestion was similarly more uniform than peak congestion was in 2009 and reversed direction in the middle of 2008. This reversal was driven mainly by the increase in supply in the

West that resulted in more frequent west-to-east congestion, particularly in off-peak hours when load was low. Valuing FTRs can be difficult when congestion is changing directions. In 2007 and 2008, some months had negative congestion while others had positive congestion.

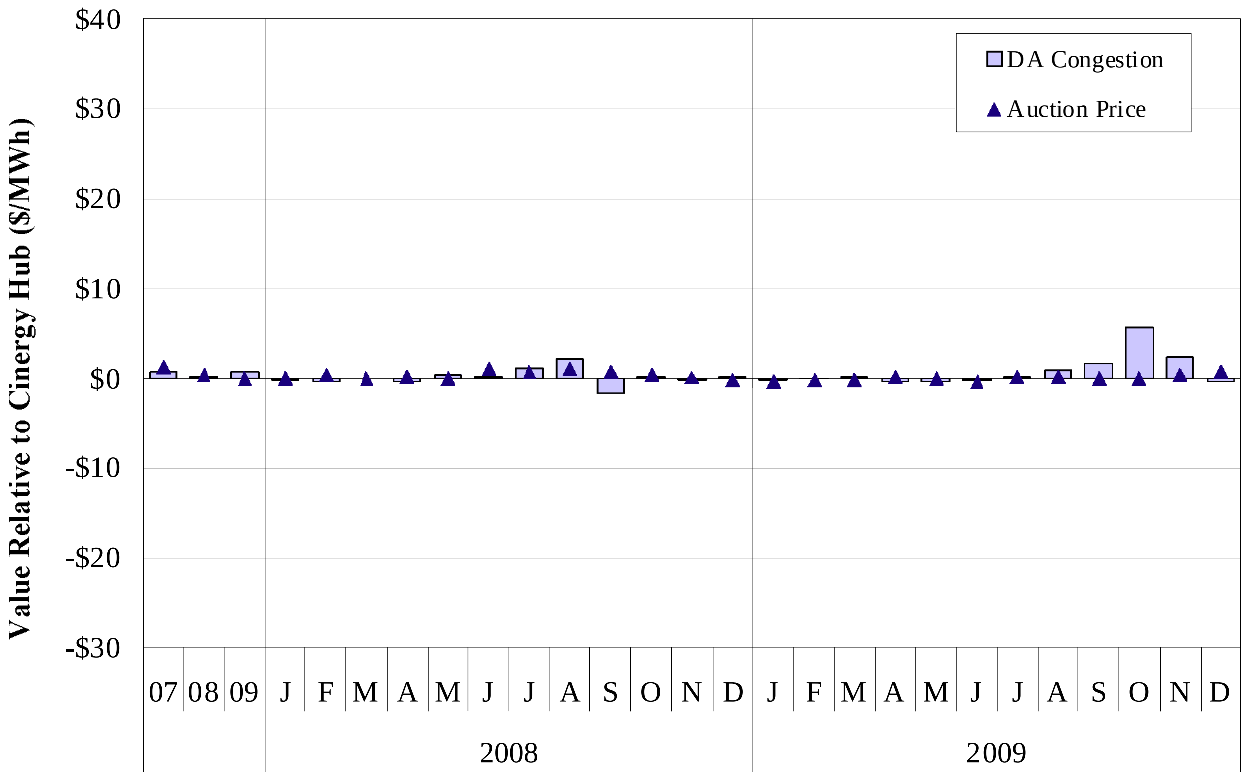
Figure 65: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2007 – 2009: Off-Peak Hours



Like the peak-hour results, convergence between the FTR markets and the day-ahead congestion improved in 2009. The monthly average off-peak spread between the two declined 14 percent from 2008 and 55 percent from 2007. Additionally, the Minnesota Hub the average annual price spread between the auction price and the congestion in both peak and off-peak hours was near zero. This indicates that the FTR markets performed well and produced prices that accurately reflected the congestion affecting this area.

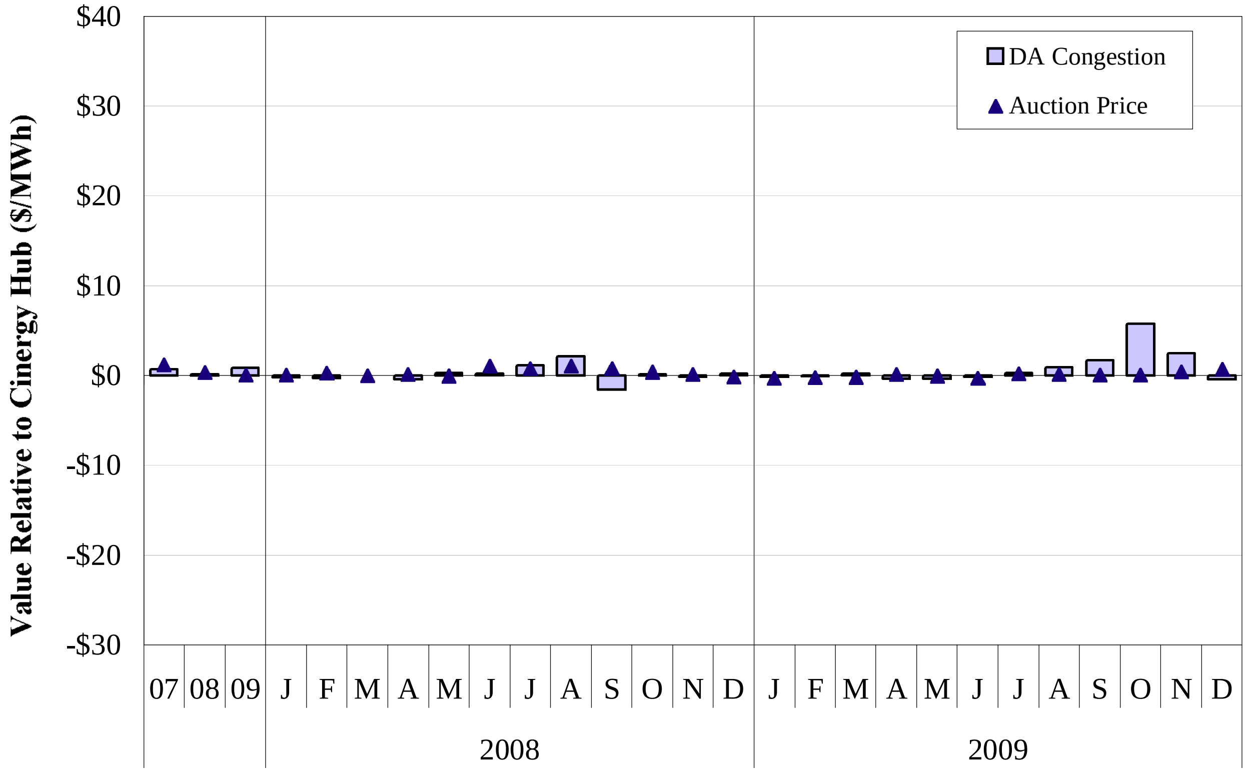
The final two figures of this subsection, Figure 66 and Figure 67, show our analyses of FTR prices into the Michigan Hub relative to Cinergy Hub in peak and off-peak hours. The value of congestion and FTR prices from Michigan to Cinergy are low relative to the magnitude of WUMS and Minnesota Hub FTR valuations net of Cinergy. In fall 2009, congestion increased due to transmission outages associated with a number of upgrade projects. This resulted in congestion that was not reflected in the FTR prices, which is not surprising because the FTRs are sold ahead of the month. Typically, FTR prices will respond with a lag. In this case, however, the FTR prices did not respond because participants understood that the outages were transitory and the elevated congestion levels were unlikely to persist.

Figure 66: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2007 – 2009: Peak Hours



Overall, these results for Michigan Hub indicate reasonably good convergence between FTR prices and the value of day-ahead congestion. Convergence can be challenging on the Michigan interface because the congestion frequently switches direction. In addition, Michigan congestion is often impacted by loop flows around Lake Erie. When the Phase Angle Regulators ("PARs") on the Midwest ISO-to-IESO interface are fully operational, convergence should improve. Of the four PARs currently designed to control the interface; one is in operation, two more are available but not in operation, and the fourth is being repaired. Additional agreements are still needed on PAR operation and scheduling.

Figure 67: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2007 – 2009: Off-Peak Hours



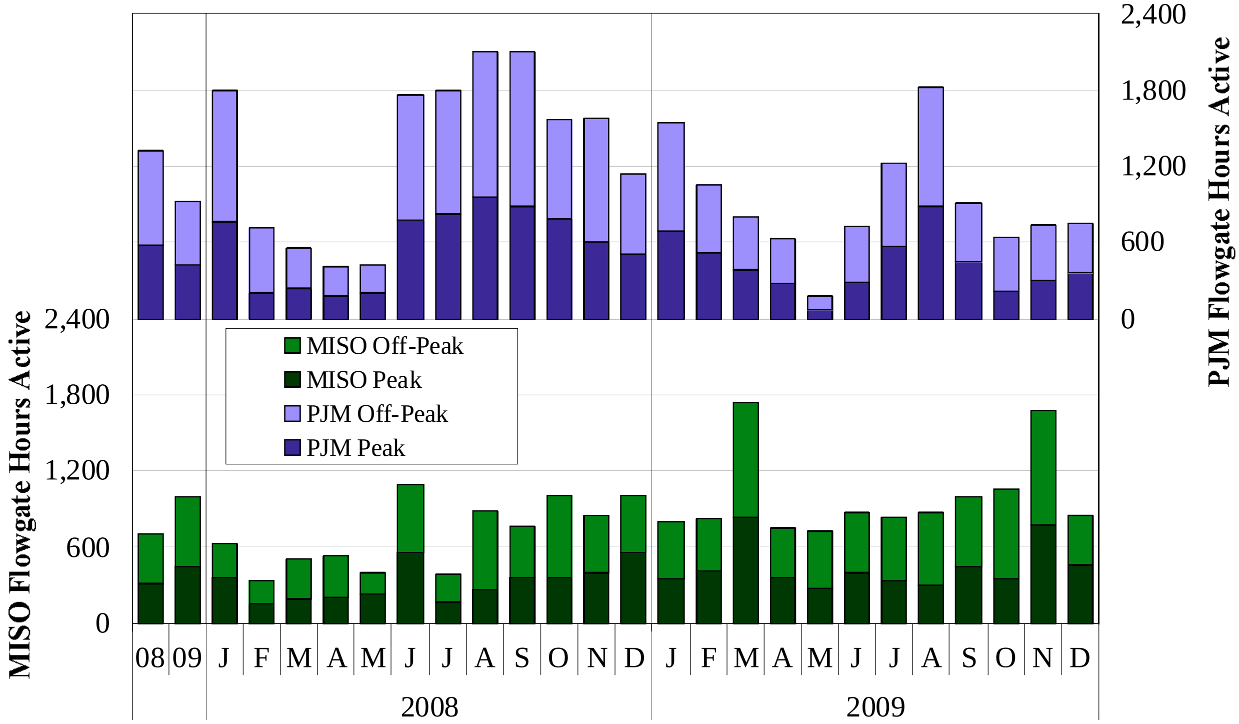
G. Market-to-Market Coordination with PJM

The next series of analyses evaluate the "market-to-market" process between the Midwest ISO and PJM, which is specified in the JOA between the RTOs. The market-to-market process is used by the Midwest ISO and PJM to coordinate the relief of transmission constraints that both systems affect. A market-to-market constraint is a constraint on a Midwest ISO-PJM coordinated flowgate located in either of the RTOs. When a market-to-market constraint is activated, the monitoring RTO that is responsible for coordinating reliability for the constraint provides its shadow price and the quantity of relief requested (the desired reduction in flow) from the other market. The shadow price measures the marginal cost of relieving the constraint.

When the reciprocating RTO receives the shadow price and requested relief, it incorporates these values in its real-time market to provide as much of the requested relief as possible at a cost less than the shadow price. From a settlement perspective, each market is entitled to its FFE on each of the market-to-market constraints. Settlements are made between the RTOs based on its actual flow over the constraint relative to its entitlement. This market-to-market process is essential for ensuring that generation is efficiently re-dispatched to manage these constraints, and that prices in the two markets are consistent.

Figure 68 summarizes the frequency that Midwest ISO market-to-market and PJM market-to-market constraints were active and binding in 2008 and 2009. The top panel represents coordinated flowgates located in the PJM system and the bottom panel represents flowgates located in the Midwest ISO. The darker shade in the stacked bars represents the total number of peak hours in the month when coordinated flowgates were active. The lighter shade represents the total for off-peak hours.

Figure 68: Market-to-Market Events
2008 – 2009

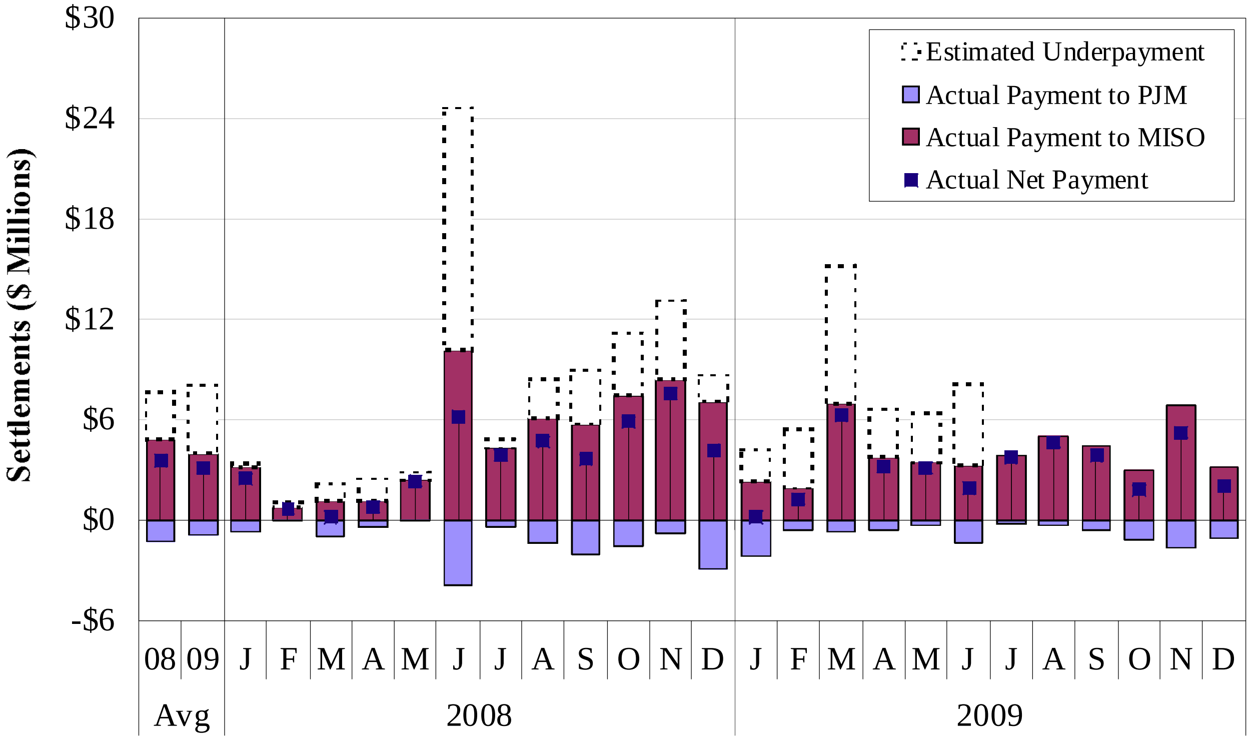


Activity on PJM market-to-market constraints decreased 31 percent from 2008 to 2009, to 916 hours per month. However, activity on Midwest ISO market-to-market constraints increased by 44 percent in 2009 to over 1,000 hours per month. The Midwest ISO market-to-market constraints that were coordinated most frequently were west-to-east constraints impacted by Commonwealth Edison exports. These constraints occurred most often during off-peak hours.

The number of hours with market-to-market coordination on Midwest ISO flowgates spiked in March and November due to seasonal planned outages on transmission lines that resulted in reduced limits and more frequent west-to-east congestion. PJM market-to-market constraint coordination occurred most frequently during the summer and periods of high load.

Figure 69 summarizes the financial settlement of market-to-market coordination. The market-to-market settlement is based upon the reciprocating RTO's actual market flows compared to its FFE. If the reciprocating RTO's market flow is below its FFE, then it will receive a payment for the unused portion of its entitlement at its internal cost of providing that relief. Alternatively, if the RTO's flow is above its FFE it will make a payment at the cost of the monitoring RTO's congestion for only the flow in excess of its FFE. In the figure, the positive values represent payments made to the Midwest ISO on coordinated flowgates and the negative values represent payments made to PJM on coordinated flowgates. The drop line shows the net payment to (or from) the Midwest ISO in each month.

Figure 69: Market-to-Market Settlements
2008 – 2009



Payments from PJM to the Midwest ISO decreased by 12 percent in 2009, while payments from the Midwest ISO to PJM decreased nearly 30 percent. Payments were more uniform in 2009 than in 2008. As in 2008, net payments were made by PJM to the Midwest ISO in each month in 2009, even though more PJM constraints than Midwest ISO constraints are active in a number of the months. These settlement results are due in part to the fact that the Midwest ISO generally provides more flow relief on PJM constraints than PJM does on Midwest ISO constraints.

In April 2009 the Midwest ISO identified an issue with PJM's market flow calculations that understated PJM's market flows and affected settlements from 2005 until June 2009. Though PJM did not retain the data necessary to correct the settlements for the entire period, PJM and the Midwest ISO agreed on a methodology using an available data and PJM estimated the underpayment of the most recent two years, which totaled $65 million. Figure 69 above shows the monthly values using this methodology, which peaked at close to $15 million in June 2008.

The Midwest ISO and PJM stakeholders met and attempted to reach a settlement of this issue but were unable to do so. The Midwest ISO and then PJM each filed complaints on this and other market-to-market issues and these matters are now before the Commission. At the same time, the RTOs are improving their processes to provide additional auditing and validation of the market-to-market settlements to minimize future errors, but there is still room for improvement.

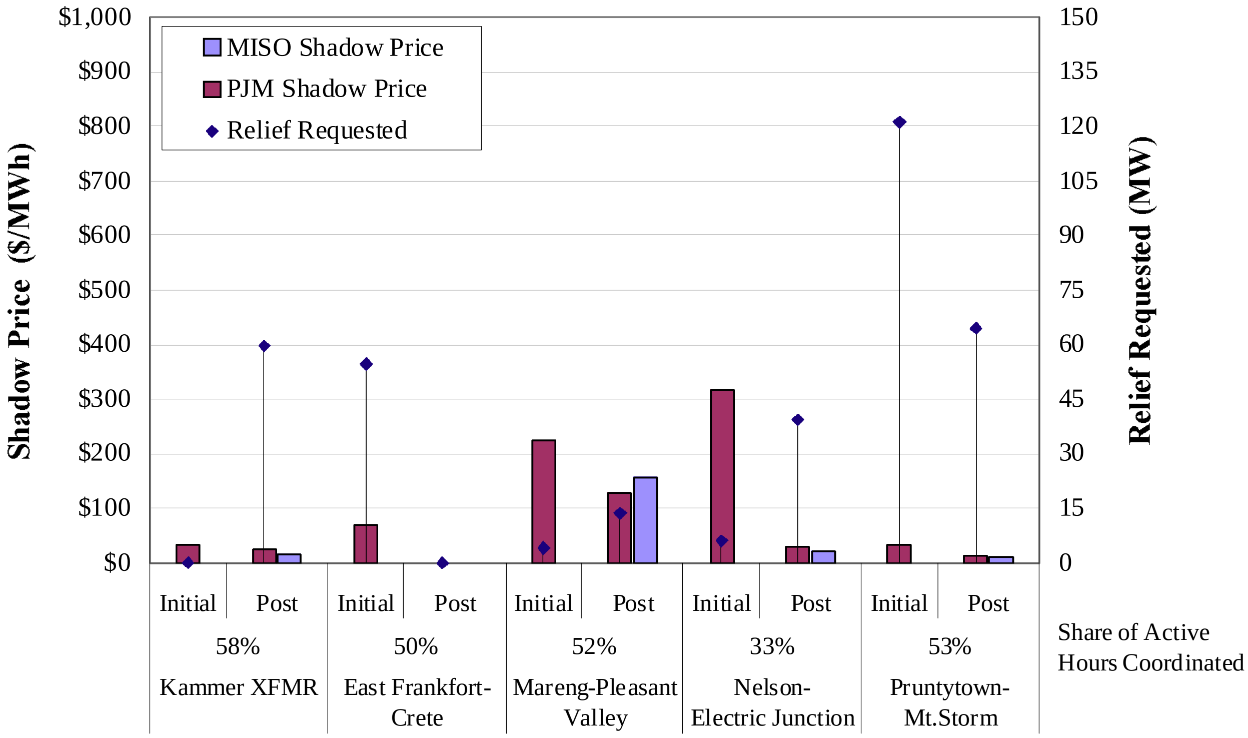
In addition to this error, other issues regarding coordination under the JOA have arisen. We have made two tariff compliance referrals to FERC regarding PJM's implementation of the JOA since the JOA is a tariff attachment in both RTOs. Additionally, the JOA lacks clarity in a number of areas that have resulted in disagreements between the RTOs on the obligations and settlements under the JOA. We recommend that the RTOs work together to clarify the JOA in these areas, including:

- Use of the monitoring RTO's marginal value limits during coordination;
- Pre-positioning on coordinated constraints;
- Use of proxy flowgates;
- The obligation to activate a coordinated constraint; and
- The obligation to test new constraints.

Since the market-to-market process plays such an important role in the pricing and management of congestion in both areas, we continue to evaluate its effectiveness and recommend improvements. To this end, Figure 70 and Figure 71 examine the five most frequently activated market-to-market constraints on the PJM and Midwest ISO systems. The analysis is intended to show the extent to which the shadow prices on coordinated constraints converge between the two RTOs. We calculate average shadow prices and the amount of relief requested during market-to-market events, including:

- An initial shadow price as the average shadow price of the monitoring RTO that was logged prior to the first response from the reciprocating RTO.
- Post-activation shadow prices for both the monitoring RTO and the reciprocating RTO. The post shadow price is the average price in each RTO after the requested relief associated with the market-to-market process is provided.
- The share of hours the constraint was activated and relief was being provided by the reciprocating RTO.[24]

Figure 70: PJM Market-to-Market Constraints
Relief Requested and Shadow Prices, 2009



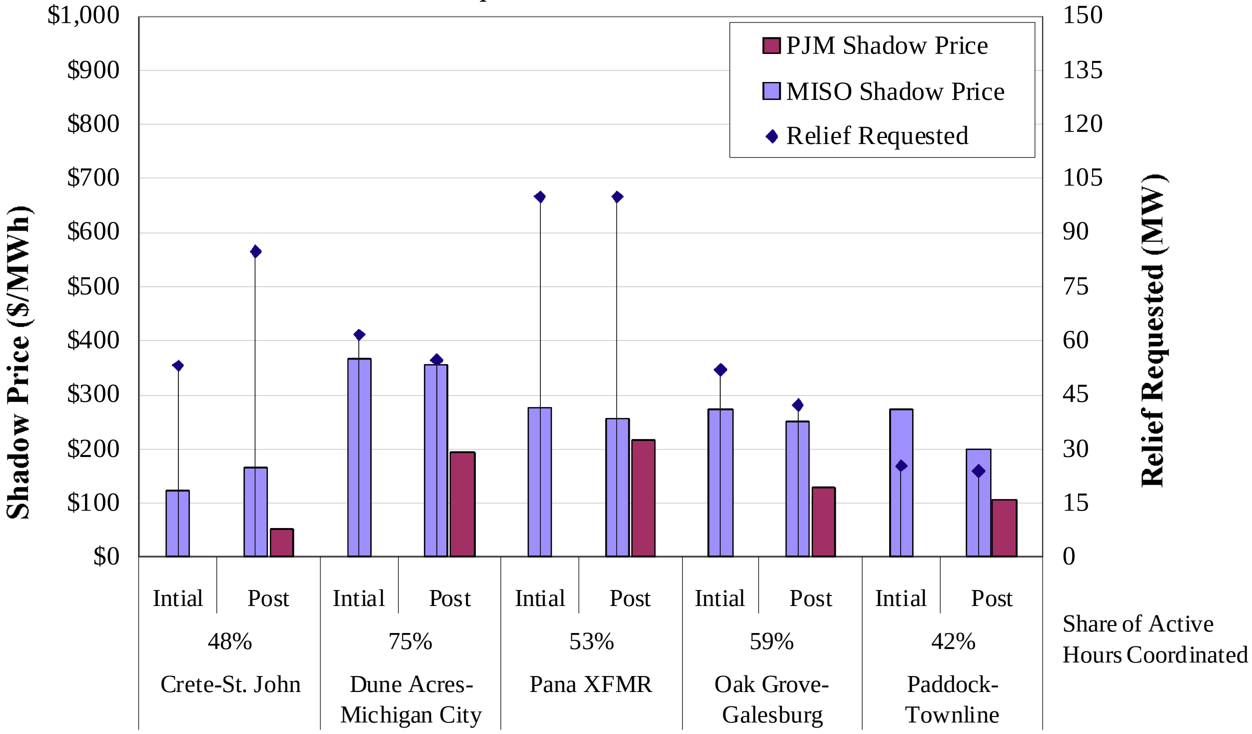
24 The statistics for the post-initialization period exclude the periods when the reciprocating RTO was not actively responding.

Shadow prices on most constraints decreased and move toward convergence over the duration of an event, indicating that the market-to-market process is achieving its objective. In a well functioning market-to-market process, the shadow prices of the two RTOs should converge after a coordinated constraint is activated. In most cases, the shadow prices should decrease from the initial value as the two RTOs collaborate to manage the constraint.

The percentage of active intervals coordinated is lower than in prior years. The amount requested varies considerably by constraint, as well as over the course of each coordinating event. In 2009, both the Midwest ISO and PJM used automated software to determine dynamically the appropriate relief request based on market conditions. However, the software has not always provided reasonable relief values, and work is underway by both RTOs to improve the software. Nevertheless, the Midwest ISO's response to PJM relief requests has contributed to large reductions in PJM's shadow price in the period that the RTOs are coordinating.

Figure 71 shows the same analysis for the most frequently called market-to-market constraints on the Midwest ISO system.

Figure 71: Midwest ISO Market-to-Market Constraints
Relief Requested and Shadow Prices, 2009



The three most common flowgates for market-to-market coordination are those that limit flows from west to east: (1) Crete-St. John, (2) Dune Acres–Michigan City, and (3) Oak Grove–Galesburg. PJM has made changes that have allowed it to provide substantially more relief than in prior years when the Midwest ISO activates a market-to-market constraint. PJM's response to Midwest ISO constraints is now comparable the Midwest ISO's response to PJM's constraints.

The figure also shows the shadow prices tend to decrease and move toward convergence over the duration of the event. However, in comparing these results to those for the PJM constraints, we find the reductions in the Midwest ISO's shadow prices have been much smaller, and the shadow prices do not converge as well after the coordination is initiated. This suggests that additional cost-effective relief may be available from PJM. The improvement to the relief software may improve these results, although we recommend that the RTOs work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief.

Finally, the Midwest ISO and PJM have recently responded to a number of past recommendations which should improve the performance of the JOA process in 2010. We recommend the following additional changes to improve the market-to-market process:

- The Midwest ISO should institute a process to monitor more closely the information exchanged with PJM to quickly identify when the process is not operating correctly.
- The Midwest ISO should discontinue the constraint relaxation algorithm, even on market-to-market constraints that cannot be resolved by the monitoring RTO.
- The RTOs should work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief.
- The RTOs should clarify the JOA in the following specific areas:
  1. Use of marginal value limits;
  2. Pre-positioning on coordinated constraints;
  3. Use of proxy flowgates;
  4. Obligation to activate a coordinated constraint;
  5. Obligation to test new constraints; and
  6. Flowgate definitions and the thresholds used to identify new coordinated constraints.
- We continue to recommend that the RTOs expand their market-to-market process to optimize interchange between markets.

VI. Competitive Assessment

This section assesses the competitive structure and performance of the Midwest ISO markets in 2009. The competitive assessment seeks to determine whether market power exists and, if so, whether it has been exercised. This type of assessment is particularly important for LMP markets because LMP markets can provide opportunities for the exercise of local market power in congested areas.

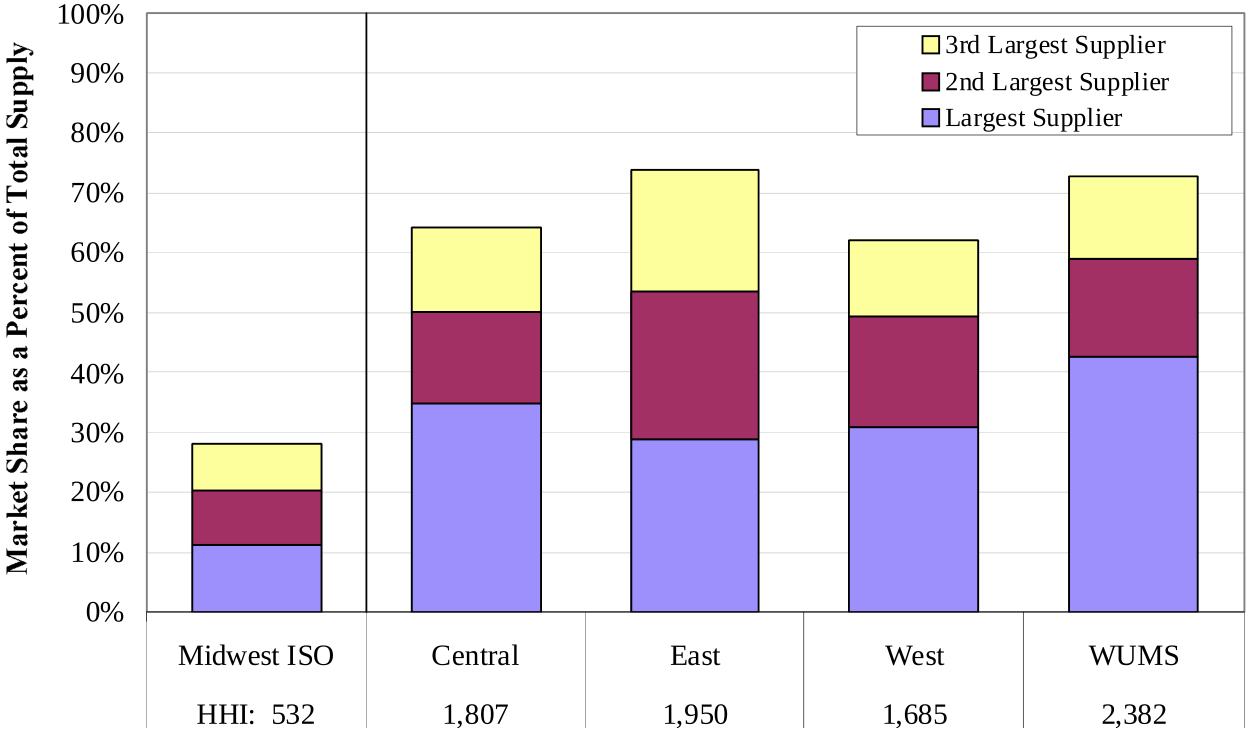
A. Market Structure

This first subsection provides three structural analyses of the market. The first is an overview of the concentration of both the Midwest ISO as a whole and the various regions within it. The remaining two analyses address the frequency with which suppliers in the Midwest ISO are "pivotal" and needed to serve load reliably or resolve transmission congestion. In general, the latter analyses provide much more reliable indicators of potential market power than the structural market concentration analysis does.

1. Market Concentration

The first analysis of market structure evaluates the market's concentration using the Herfindahl-Hirschman Index. The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share. Antitrust agencies generally characterize markets with HHIs greater than 1,800 as highly concentrated while markets with HHIs less than 1,000 are not considered to be concentrated. The HHI is only a general indicator of market concentration, not a definitive measure of market power. The most significant shortcomings of the HHI for identifying market power concerns are that it does not account for demand, network constraints, or load obligations. In wholesale electricity markets, these factors can have a profound effect on the competitiveness of the market. Figure 72 shows market shares and HHI calculations for the Midwest ISO as a whole and within each region.

Figure 72: Market Shares and Market Concentration by Region
2009



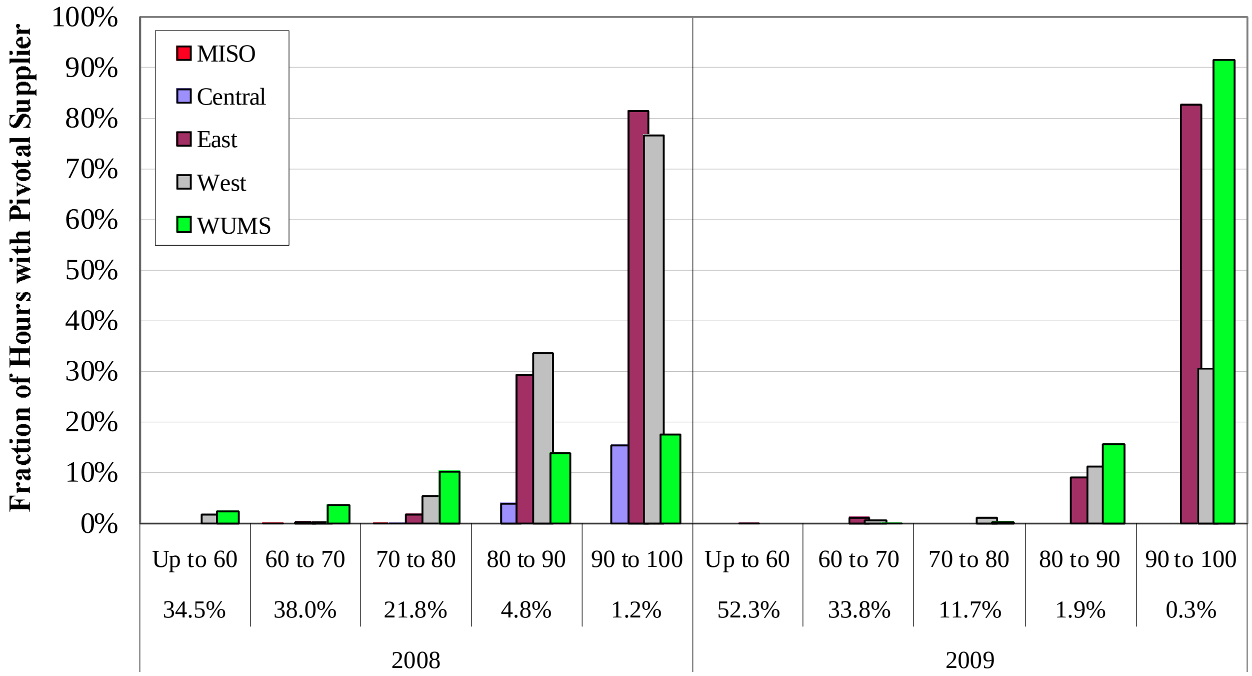
The HHI in the entire Midwest ISO area of operation is 532, which is low and indicative of a competitive market. The largest three suppliers combined have a total market share of less than 30 percent. This metric indicates that generation ownership in the Midwest ISO as a whole is not concentrated. Each of the four regions is much more concentrated than the Midwest ISO as a whole. The East region and WUMS area are highly concentrated: the top three suppliers control over 70 percent of the market in both of these regions. Investment has reduced the HHI from 2,089 to 1,685 in the West. The regional HHIs are higher than those in the comparable zones of other RTOs because vertically-integrated utilities in the Midwest ISO that have not divested generation tend to have substantial market shares. Divestitures of generation in other RTO zones generally reduce market concentration because the assets are typically sold to a number of smaller entities.

2. Residual Demand Index

As noted above, the HHI market concentration calculation is a commonly used measure of market power. However, the HHI does not allow one to draw reliable inferences regarding the competitiveness of electricity markets because it ignores factors particularly relevant to the study of power markets. The next two analyses more accurately reveal potential competitive concerns in the Midwest ISO energy markets.

The first metric is the Residual Demand Index ("RDI"), which measures the portion of the load in an area that can be satisfied without the resources of its largest supplier. The RDI is calculated using all import capability into the area, not just the imports actually scheduled. In general, the RDI decreases as load increases. An RDI greater than 1 means that the load can be satisfied without the largest supplier's resources. An RDI less than 1 indicates that a supplier is "pivotal" and a monopolist over a portion of the load. Figure 73 shows the portion of total hours with a pivotal supplier by region and load level, measuring the percentage of hours when the RDI is less than one. The percentages shown below the x-axis indicate the percent of hours falling into each load-level tranche.

Figure 73: Pivotal Supplier Frequency by Load Level
2008 – 2009



As expected, the frequency with which a supplier is pivotal rises sharply as load rises. Furthermore, prices are most sensitive to withholding under high load conditions, which explains why market power concerns are the greatest when load is highest. The figure shows a substantial year-over-year improvement in the competitive conditions of all regions. The total number of hours when a supplier was pivotal decreased by at least 70 percent in each region. No supplier was pivotal during any hour in the Central region or the Midwest ISO as a whole during 2009. Suppliers were rarely pivotal at load levels below 80 GW (97.8 percent of all hours). These improvements are likely due to increases in transmission capability and reduced congestion into many of these areas. Although the frequency was high in WUMS during the highest load hours, this only comprises 0.3 percent of all hours and does not pose a substantial concern. Additionally, WUMS is designated as an NCA and, thus, subject to tighter mitigation thresholds. In all, the figure shows a modest improvement in 2009 as a result of investments in generation, transmission, and lower overall load.

3. Constraint-Specific Pivotal Supplier Analysis

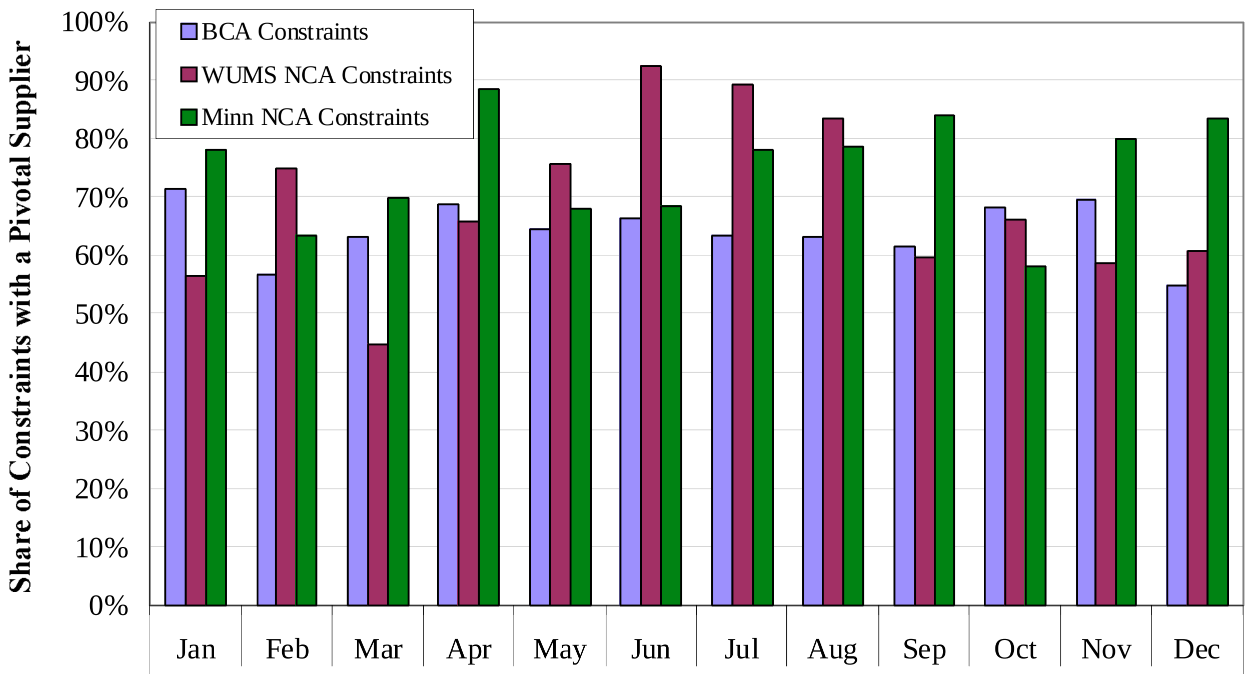
While the RDI pivotal supplier analysis in the prior subsection is useful for generally evaluating the competitiveness of the market, accurately identifying local market power requires a more detailed analysis that focuses on specific transmission constraints that can isolate locations on the transmission grid. The analyses in this subsection seek to detect potential local market power concerns by identifying when a supplier is pivotal relative to a particular transmission constraint.

A supplier is pivotal for a constraint when it has the resources to overload that constraint to an extent that all other suppliers combined cannot relieve the constraint. This is frequently the case for lower-voltage constraints because the resources that most affect the flow over the constraint are those that are near the constraint. If the same supplier owns all of these resources, this supplier is likely pivotal to maintaining reliability. Although overall congestion was modestly lower in 2009 compared to 2008, an increasing share of binding intervals occurred on low-voltage constraints.

We focus particular attention on the two types of constrained areas that are defined for purposes of market power mitigation: Broad Constrained Areas and Narrow Constrained Areas. The definition of BCAs and NCAs is based upon the electrical properties of the transmission network that can lead to local market power. NCAs are chronically-constrained areas where one or more suppliers are frequently pivotal. Hence, they can be defined in advance and are subject to tighter market power mitigation. The three NCAs currently defined are the Minnesota NCA, the WUMS NCA, and the North WUMS NCA.

Market power associated with non-NCA constraints can still be severe. If the constraints are not chronic, however, they generally raise less competitive concerns. Due to the vast number of potential constraints and the fact that the topology of the transmission network can change significantly when outages occur, it is neither feasible nor desirable to define all possible BCAs in advance. Therefore, BCAs are defined dynamically when non-NCA constraints bind on the transmission network. A BCA includes all of the generating units that have a significant impact on the power flows over a constrained interface. Figure 74 shows the portion of active NCA and BCA constraints that have at least one pivotal supplier.

Figure 74: Percentage of Active Constraints with a Pivotal Supplier
2009

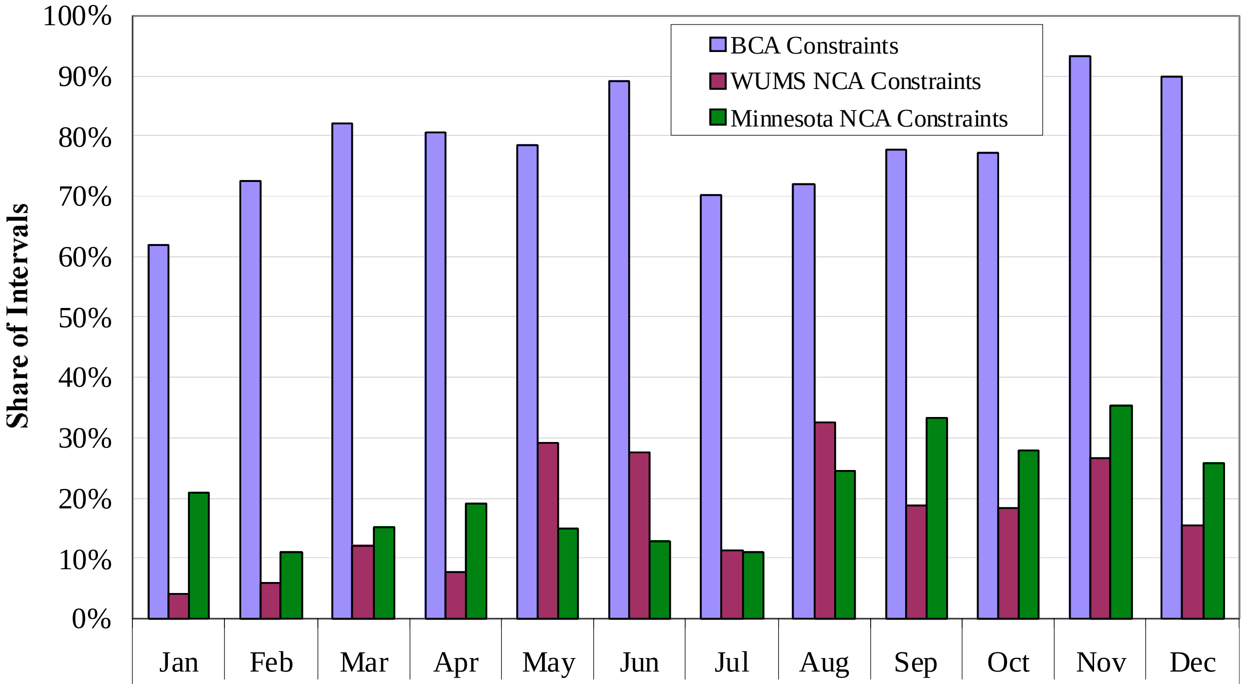


In most months of 2009, active constraints in each of the constrained areas had a pivotal supplier in the majority of hours. During the year, 69 percent of the active NCA constraints into WUMS had a pivotal supplier, down from 79 percent in 2008. During each of the three summer months, however, this percentage exceeded 80 percent. For the Minnesota NCA, 75 percent of active constraints had a pivotal supplier, up from 69 percent in 2008. For BCA constraints, 64 percent of active constraints had a pivotal supplier, up from 59 percent in 2008. In all, these results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2009 raised potential local market power concerns as well.

The prior analysis showed that a supplier was frequently pivotal when a BCA constraint or NCA constraint was active. Figure 75 shows the percentage of all market intervals when at least one supplier was pivotal for such a constraint. This analysis varies from the prior analysis because it incorporates how frequently BCA and NCA constraints are active. Therefore, it measures how frequently local market power may be a problem within the Midwest ISO.

Figure 75: Percent of Intervals with at Least One Pivotal Supplier

2009



There was an active BCA constraint with at least one pivotal supplier in 79 percent of the hours during 2009, up 13 percentage points from 2008. As in prior years, the regional distribution of BCA constraints varied by month, with the Central region experiencing more constraints than the other three regions. The monthly frequency ranged from 62 percent to more than 90 percent. NCA constraints had a pivotal supplier in substantially fewer hours than BCA constraints did because there were fewer NCA constraints. There was an active NCA constraint with a pivotal supplier in only 17 and 21 percent of hours in WUMS and Minnesota, respectively. These statistics represent a decrease of 13 percentage points from 2008 for WUMS and an increase of 15 percentage points for Minnesota. The decrease in WUMS is consistent with the fact that congestion into WUMS has become less frequent due to key transmission upgrades. Overall, however, the results indicate that BCA and NCA mitigation continues to be essential. The next section evaluates participants' conduct during 2009 to determine whether participants with market power attempted to exercise it.

B. Participant Conduct

In this section, we analyze participant conduct to determine whether it is consistent with competitive behavior or whether it is consistent with attempts to exercise market power. We begin this section with a Price-Cost Markup analysis. Then we test for two types of conduct: economic withholding and physical withholding. Economic withholding occurs when a participant offers resources substantially above competitive levels to raise market clearing prices or RSG payments. Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output. This is usually accomplished by claiming an outage or by derating the resource.

1. Price-Cost Markup Analysis

Our first analysis estimates the "markup" of real-time market prices over suppliers' competitive costs. In this analysis, we compare the system marginal price that would result under two different sets of assumptions: we estimate the SMP first assuming that suppliers offer at prices equal to their reference levels and second using suppliers' actual offers. The difference in the estimated SMPs under the two different sets of assumptions is the markup. We then calculated a yearly load-weighted average of the estimated system marginal price. This analysis does not account for physical restrictions on the units and transmission constraints, or potential changes in the commitment of generation, both of which would require re-running the market software.

This metric is useful in evaluating the competitive performance of the market. A competitive market should produce a small mark-up because suppliers should have incentives to offer at close to their marginal cost. Our estimated average annual markup was approximately 1.2 percent in 2009, down from an estimated 2.0 percent for 2008. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so we would not expect to see a markup exactly equal to zero. Markups of such low magnitude indicate that the markets have performed competitively over the timeframe studied.

2. Economic Withholding

An analysis of economic withholding requires a comparison of actual offers to competitive offers. Suppliers lacking market power maximize profits by offering resources at marginal costs, which is a generator's competitive offer price. A generator's marginal cost is the incremental cost of producing additional output. Marginal cost includes inter-temporal opportunity costs, incremental risks associated with unit outages, fuel, additional O&M, and other incremental costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by their variable production costs (primarily fuel costs, labor, and variable O&M costs). However, at high-output levels or after having run for long periods without routine maintenance, outage risks and expected increases in O&M costs can create substantial additional incremental costs. Generating resources with energy limitations, such as hydroelectric units or fossil-fuel units with output restrictions due to environmental considerations, must forego revenue in a future period to produce in the current period. These units incur inter-temporal opportunity costs associated with producing that can cause their marginal costs to be much higher than their variable production costs.

Establishing a proxy for units' marginal costs as a competitive benchmark is a key component of analyses that seek to identify economic withholding. The proxy is necessary to determine the quantity of output that is potentially economically withheld. The Midwest ISO's market power mitigation measures include a variety of means to calculate a resource's "reference levels", intended to reflect the resource's marginal costs. We use these reference levels for the analyses presented below. The mitigation measures also include a threshold that defines how far above the reference levels that the supplier would have to offer before potentially warranting mitigation. This threshold is used in the market power mitigation "conduct test."

To identify potential economic withholding, we calculate our "output gap" metric, based upon resources' startup, no-load, and incremental energy offer parameters. The output gap is the difference between a unit's output that is economic at the prevailing clearing price and the amount that is actually produced by the unit. In essence, the output gap shows the quantity of generation that a supplier may be withholding from the market by submitting offers above competitive levels. Therefore, the output gap for any unit would generally equal:

$Q_i^{econ} - Q_i^{prod}$ when greater than zero, where:

Q_i^{econ} = Economic level of output for unit i; and

Q_i^{prod} = Actual production of unit i.

To estimate Q_i^{econ}, the economic level of output for a particular unit, it is necessary to look at all parts of the unit's three-part reference level: startup cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time.

We employ a three-stage process to determine the economic output level for a unit in a particular hour. In the first stage, we examine whether the unit would have been economic for commitment on that day if it had offered its true marginal costs. In other words, we examine whether the unit would have recovered its actual startup, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP (constrained by its EcoMin and EcoMax) for its minimum run time. If a unit was economic for commitment, we then identify the set of contiguous hours during which the unit was economic to dispatch. Finally, we determine the economic level of incremental output in hours when the unit was economic to run. In hours when the unit was not economic to run and on days when the unit was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment is based upon day-ahead market outcomes for non-quick-start units and based upon real-time market outcomes for quick-start units.

Because our benchmarks for units' marginal costs are inherently imperfect, we add a threshold to the resources' reference level to determine Q_i^{econ}. This ensures that we will identify only significant departures from competitive conduct. The thresholds used are based on the thresholds defined in the tariff for BCAs and NCAs. The thresholds are described in more detail below.

Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers would indicate due to transmission constraints, reserve considerations, or other changes in market conditions between the unit commitment and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. Hence the output gap formula used for this report is:

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:

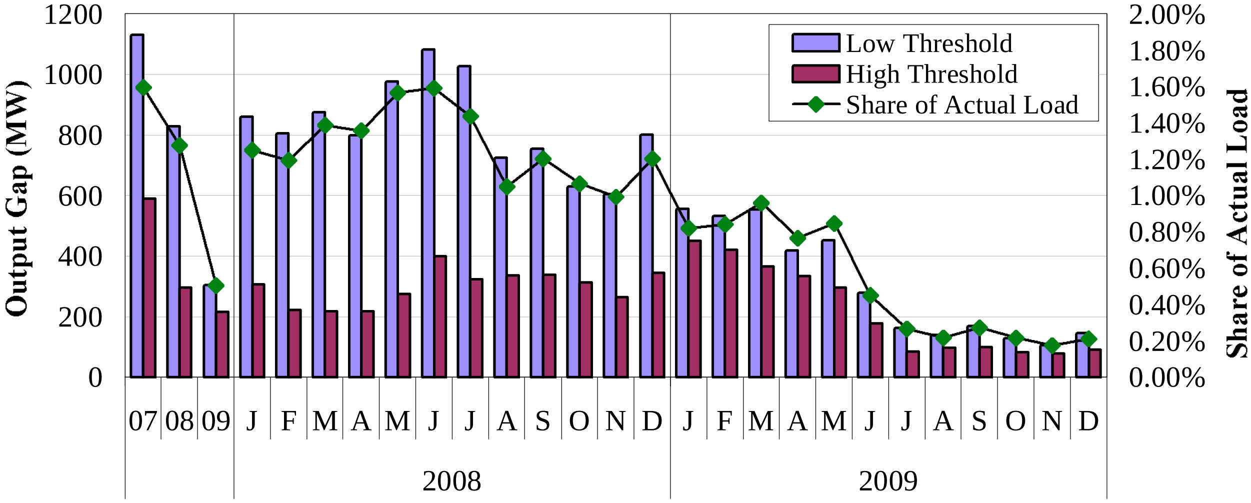
Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, units that are subject to ramp limitations are excluded from the output gap.

Figure 76 shows monthly average output-gap levels for the real-time market for 2008 and 2009. The output gap shown in the figure includes two types of units: 1) online and quick-start units available in real time, and 2) offline units that would have been economic to commit. The data is arranged to show the output gap using the mitigation threshold (defined above) in each area (the "high threshold"), and one-half of the mitigation threshold ("low threshold"). Resources located in NCAs are tested at the NCA conduct thresholds and resources outside NCAs are tested at BCA conduct thresholds.

The high threshold for resources in BCAs is $100 per MWh above the reference or 300 percent of the reference, whichever is lower. The threshold effective during most of 2009 was $22.11 per MWh in the WUMS NCA, $22.11 per MWh in the North WUMS NCA, and $42.97 per MWh in the Minnesota NCA. The low threshold is set to 50 percent of the applicable high threshold for a given resource. For example, a resource in WUMS, the low threshold would be $11.06 per MWh. For a resource's unscheduled output to be included in the output gap, its commitment cost per MWh or incremental energy offer must exceed the given resource's reference plus the applicable threshold. The lower threshold would indicate potential economic withholding of output that is offered at a price significantly above its reference yet within the mitigation threshold.

Figure 76: Monthly Average Output Gap: Real-Time Market
2008 – 2009



Low Threshold Results by Commitment Status (MW)

Off-Line	93	102	31	35	35	47	91	89	112	130	102	84	146	126	222	66	57	35	7	44	41	18	4	56	16	1	26
On-Line	1039	727	105	825	771	828	708	888	971	897	625	671	484	479	579	491	472	441	412	407	238	144	136	113	113	105	120

High Threshold Results by Commitment Status (MW)

Off-Line	42	55	11	17	10	25	16	31	26	73	79	65	124	83	110	57	38	4	3	0	1	2	1	19	0	1	7
On-Line	548	242	199	289	213	194	203	244	373	250	257	273	189	181	235	394	381	305	331	296	176	84	96	81	84	77	85

The output gap continued to decline in 2009. Output gap levels were considerably lower in the second half of 2009 as a result of sustained low load levels and prices and surplus generation. These levels are relatively low and generally raise limited competitive concerns. However, we monitor these levels continually and have investigated many specific output gap issues. In nearly all cases, output gap can be explained by specific operating conditions and other competitive factors.

Despite the low output gap levels shown above, it is useful to make a further examination. Because any measure of potential withholding will inevitably include quantities that can be justified, we generally evaluate not only the absolute level of the output gap but also how it varies with factors that can cause a supplier to have market power. This allows us to test whether a participant's conduct is consistent with attempts to exercise temporal market power. The most important factors in this type of analysis are the size of the participant and the load level. Larger suppliers generally are more likely to be pivotal and will tend to have a greater incentive to increase prices than relatively smaller suppliers. Load level is important because the sensitivity of price to withholding generally increases as the load increases. This is due, in part, to the fact that rivals' resources will be more fully-utilized serving load under these conditions, leaving only the highest-cost resources to respond to the withholding.

The effect of load on potential market power was evident earlier in this section in our pivotal supplier analyses. Accordingly, Figure 77 through Figure 80 below show the output gap results by load level and size of participant for each of the four regions within the Midwest ISO. The average output gap quantities are shown for the largest two suppliers in each region versus the other suppliers. The figures also show the average output gap at the mitigation thresholds and at one-half of the mitigation thresholds (the high and low thresholds discussed previously).

Figure 77: Real-Time Market Output Gap
Central Region – 2009

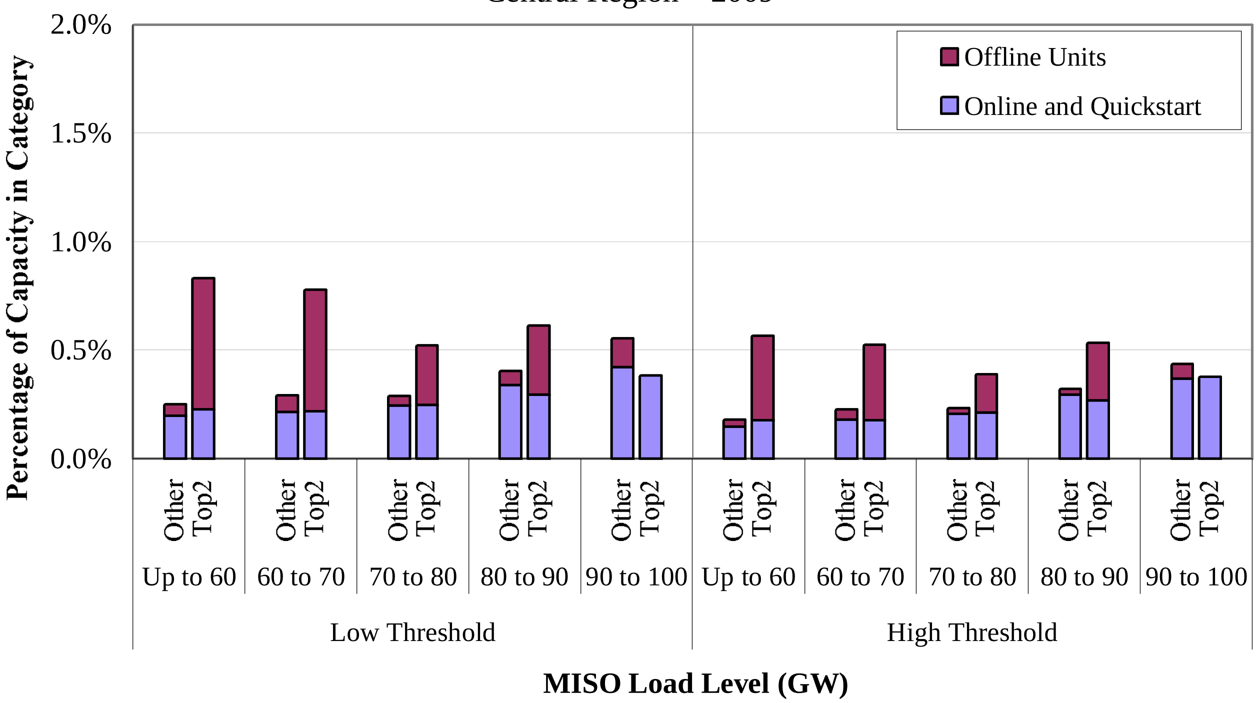


Figure 78: Real-Time Market Output Gap
East Region – 2009

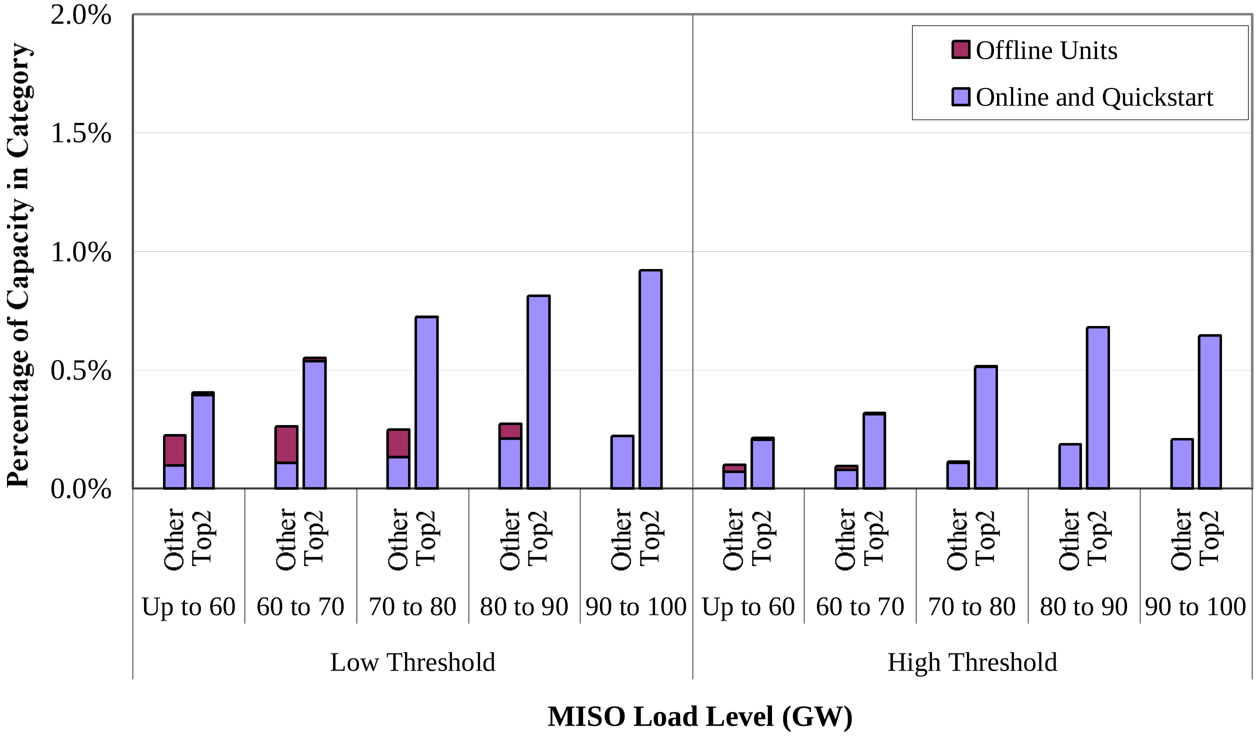


Figure 79: Real-Time Market Output Gap
West Region – 2009

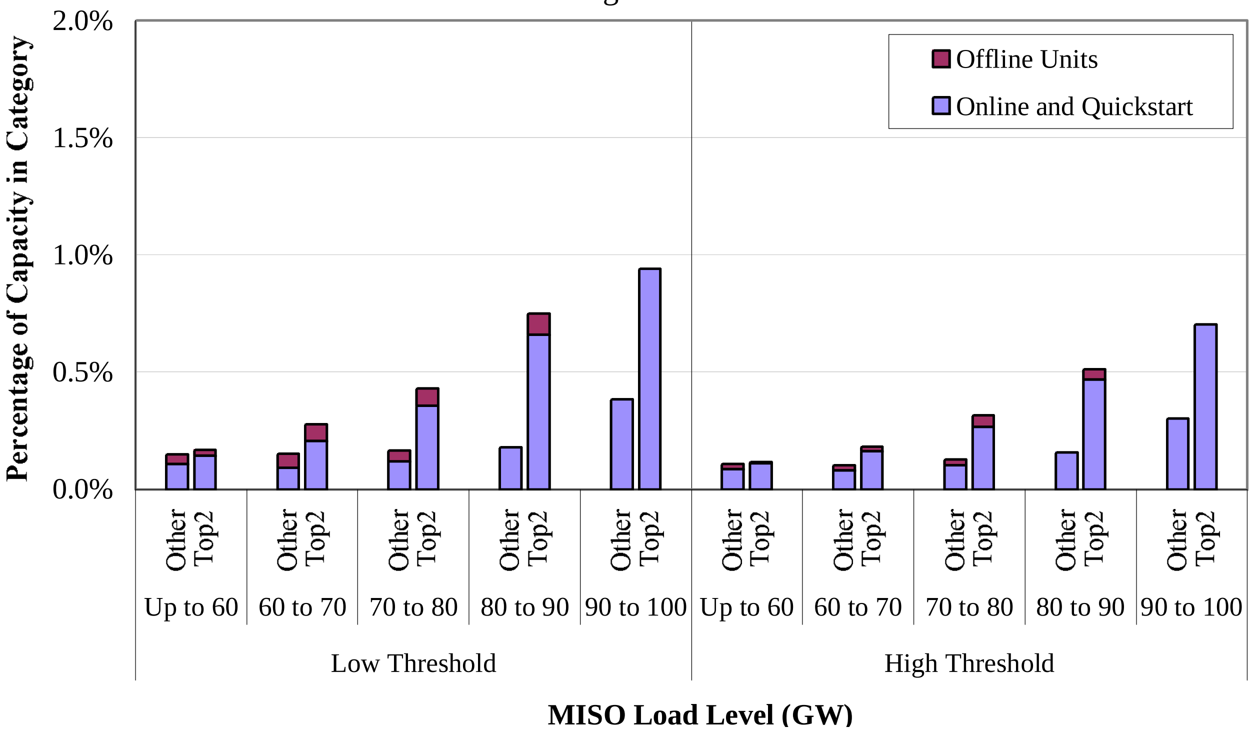
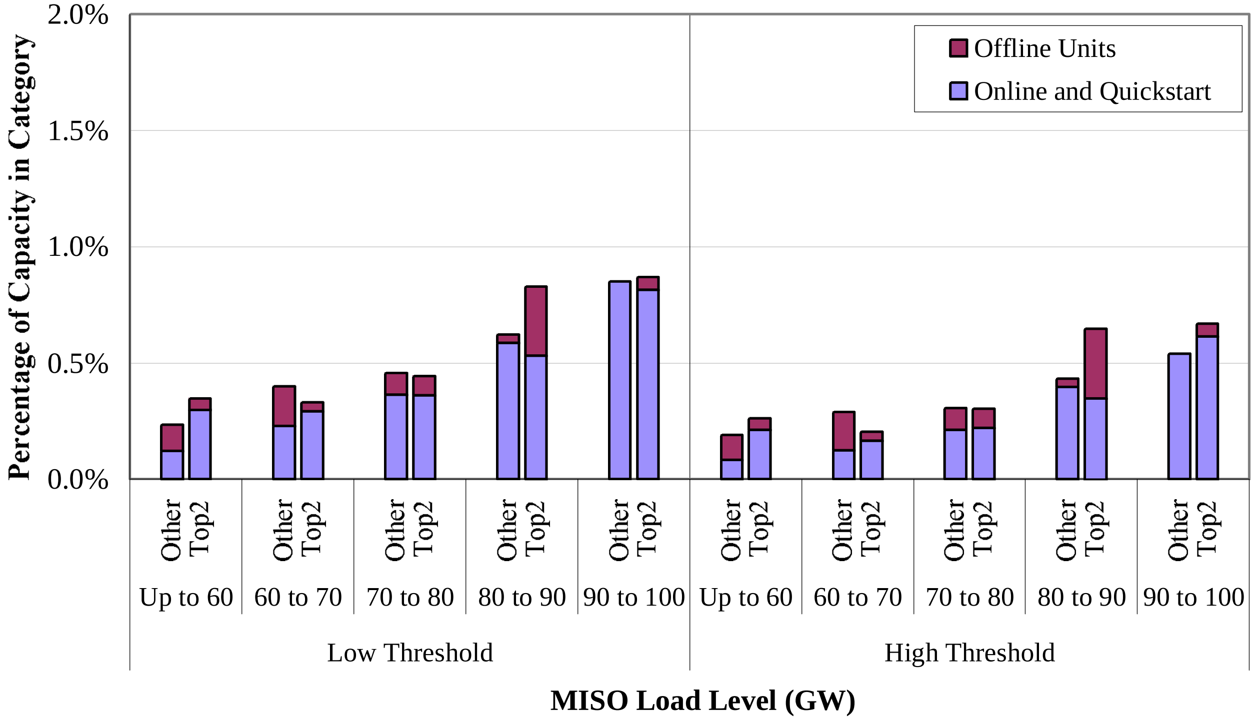


Figure 80: Real-Time Market Output Gap
WUMS Area – 2009

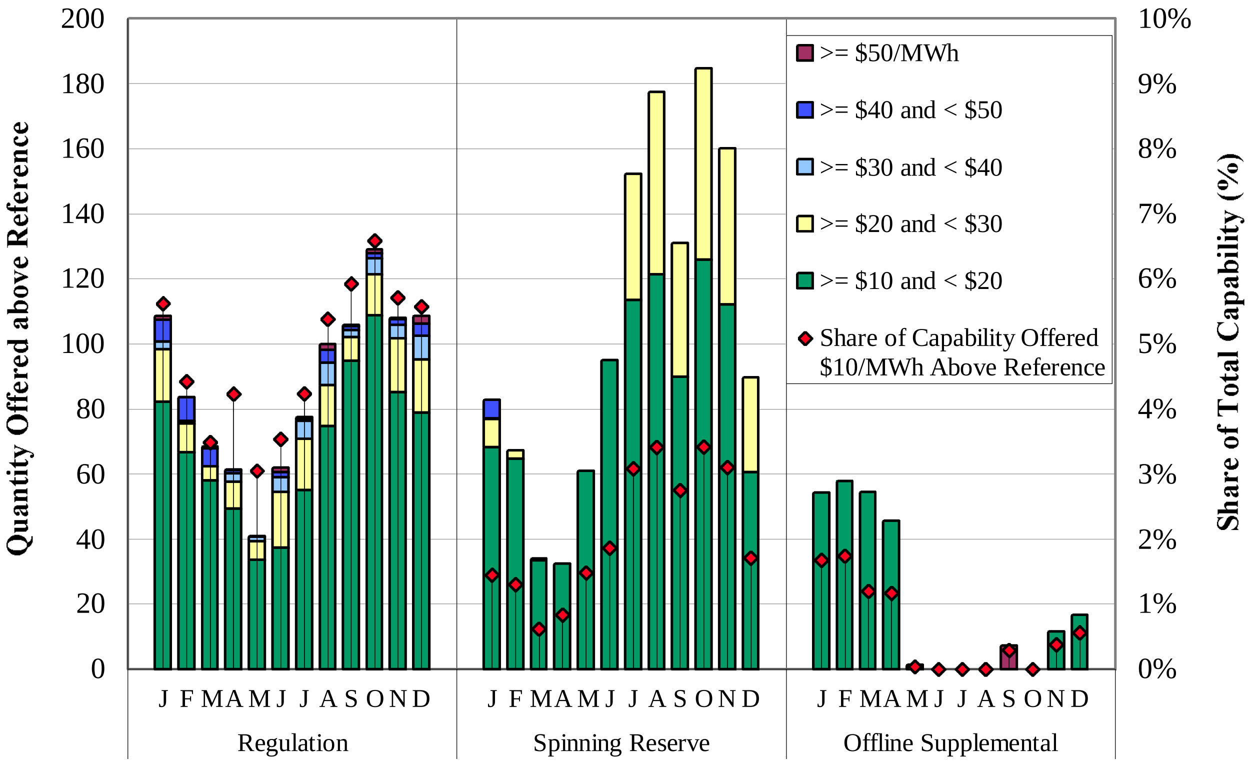


Our analysis indicates that the output gap quantities at both threshold levels are generally below one percent of the total capacity at all locations and load levels. In general, the output gap increases with load levels because the high prices that occur at high-load levels cause a much greater share of resources to be economic. However, because this could also signal a rise in anticompetitive conduct, we investigate increases in output gap levels at higher-load levels on an ongoing basis. These investigations did not raise material competitive concerns in 2009. Finally, the figures also show that the output gap quantities for the largest two suppliers are generally comparable to or only moderately higher than for other suppliers.

Overall, these analyses and our ongoing monitoring of hourly results indicate that the supply offers in the Midwest ISO were generally very competitive in 2009. The competitive offer patterns observed in 2009 are likely due to both the market conditions and structural characteristics of the market. Surplus generation and lower load in 2009 reduced the incentive to economically withhold supply. Additionally, many of the largest suppliers in the Midwest ISO are also large LSEs, which reduces their incentive to withhold.

Next we summarize the offers for ancillary services. Figure 81 shows the monthly average quantities of regulation and operating reserves offered at varying price levels (ranging from $10 to $50/MWh) above each unit's reference level.[25] A reference level is an estimate of the competitive offer level for the service (i.e., the unit's marginal cost of supplying the service). This is information that we had previously published in quarterly reports reviewing the conduct in the ancillary services markets.

Figure 81: Ancillary Services Offers
2009



Offers for ancillary services were generally competitive in 2009. On average, 88 MW of regulation capability (or 4.8 percent of the online regulation capability) was offered at more than $10 per MW above its reference level, while only 19 MW was offered at more than $20 per MW above its reference level. Similarly, 105 MW of spinning reserve capability (or 2.1 percent of the total capability) exceeded reference levels by at least $10 per MW. Very few offers for

25 These thresholds are below the BCA mitigation threshold, which is the lesser of 300 percent or $50 per MWh (for offer prices greater than $5 per MWh).

supplemental reserves exceeded reference levels by more than $10 per MW. Lastly, there were only two instances of ASM mitigation in 2009. Given the relatively small share of the total capability represented by these offers and the fact that some resources naturally have higher perceived costs or risks associated with selling ancillary services, we conclude that the offers in the ASM in 2009 were competitive.

3. Physical Withholding

While the prior analyses assessed offer patterns to identify potential economic withholding, the next analyses seek to identify potential physical withholding. Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output due to a non-economic parameter or condition. For instance, this may be accomplished by the supplier unjustifiably claiming an outage or derating the resource. Although we analyze broad patterns in outages and deratings for this report, we also monitor for potential physical withholding on a day-to-day basis and audit outages and deratings when they have a substantial affect on market outcomes.

Figure 82 through Figure 85 show average share of capacity unavailable to the market in 2009 due to forced outages and deratings in each of the four regions of the Midwest ISO. Like the output gap analysis above, this conduct may be justifiable or may represent physical withholding. Therefore, we evaluate the conduct relative to load levels and participant size to detect patterns consistent with potential withholding. Attempts to withhold would likely occur more often at high-load levels when prices are most sensitive to withholding. We also focus particularly on short-term outages and partial deratings because long-term forced outages are less likely to be a profitable withholding strategy. This is because taking a long-term forced outage of an economic unit would cause the supplier to forego profits on the units during hours when the supplier does not have market power.

Figure 82: Real-Time Deratings and Forced Outages
Central Region, 2009

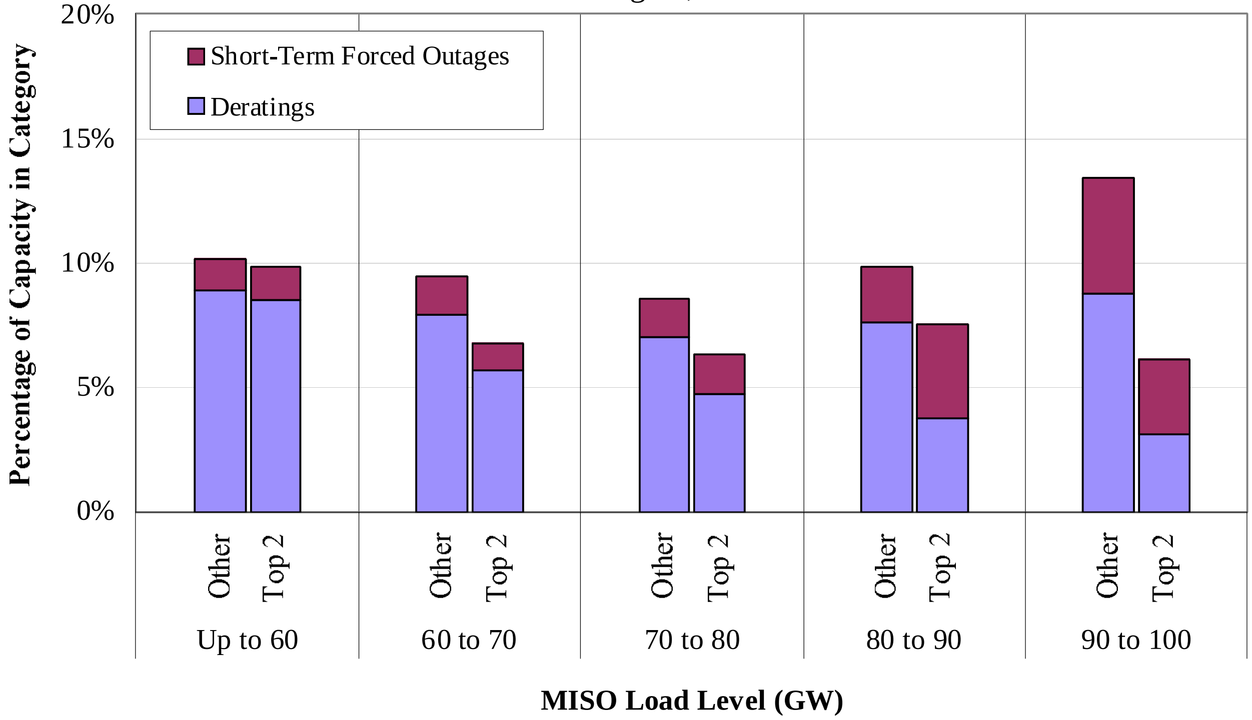


Figure 83: Real-Time Deratings and Forced Outages
East Region, 2009

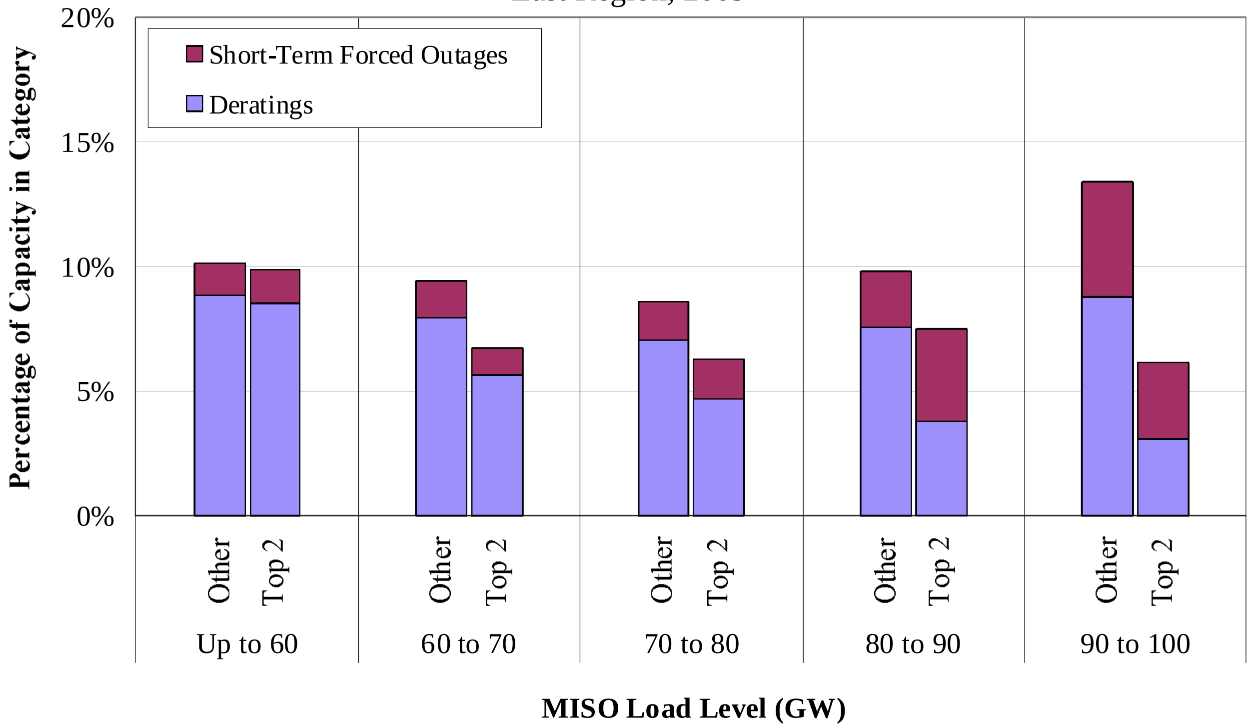


Figure 84: Real-Time Deratings and Forced Outages
West Region, 2009

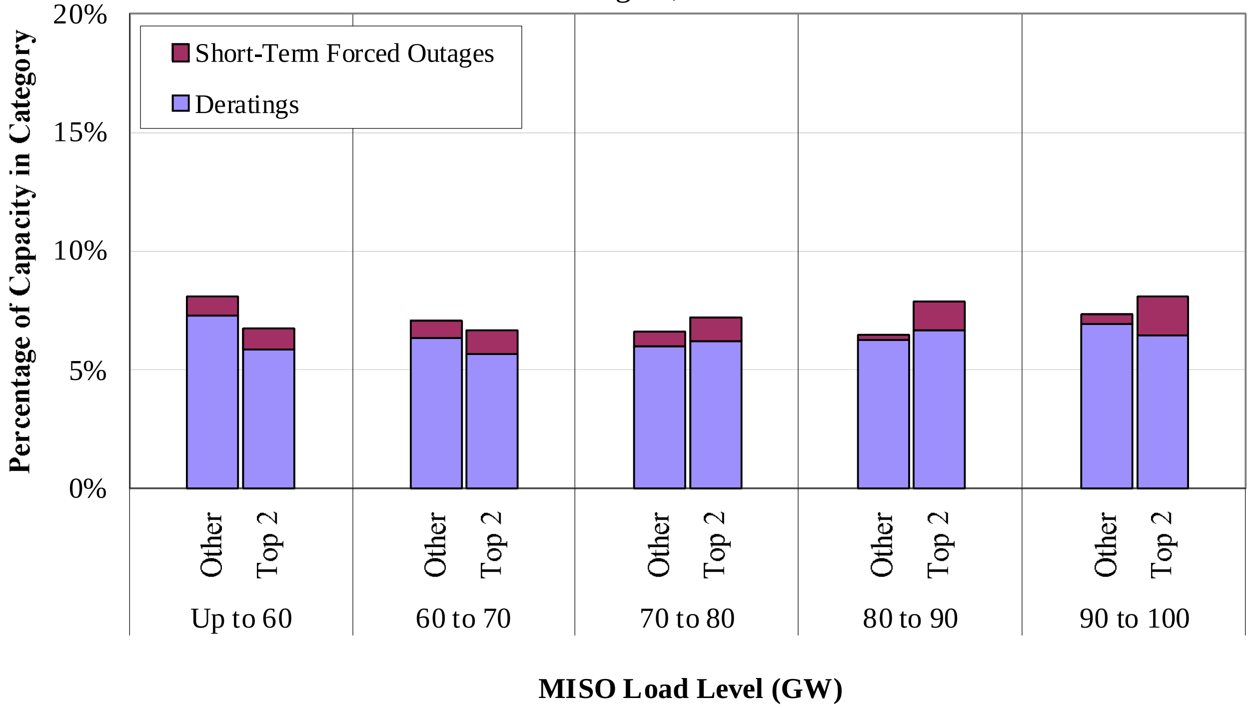
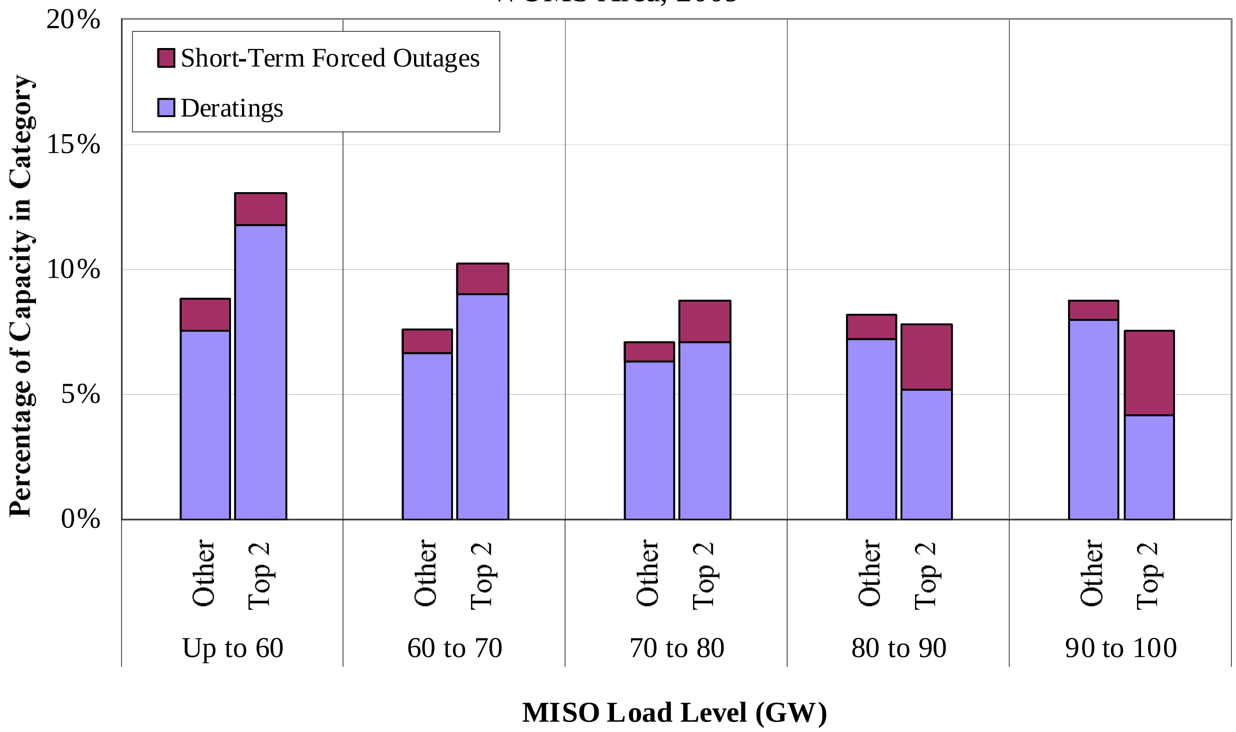


Figure 85: Real-Time Deratings and Forced Outages
WUMS Area, 2009



The data in the figures do not raise substantial competitive concerns. In the Central and East regions, deratings and short-term forced outage rates are slightly lower for the largest two suppliers than for all other suppliers. In the WUMS and West regions, deratings and outages are comparable across all load levels (generally ranging from 8 to 13 percent). While short-term forced outage rates are higher for the top suppliers in these regions at the higher load levels, the combined outage rates are lower. Overall, short-term outages were less prevalent in 2009 than in 2008. Although these results do not raise competitive concerns, we continue to investigate any outages or deratings that create substantial congestion or other price effects.

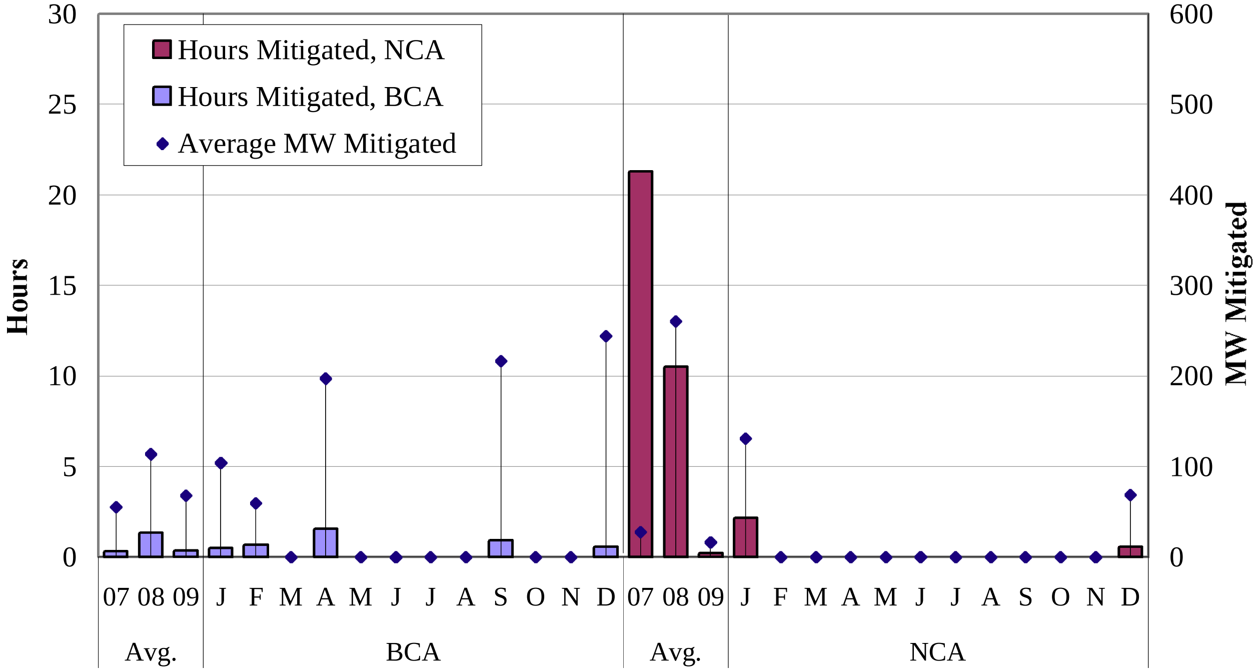
C. Market Power Mitigation

In this subsection, we examine the frequency with which market power mitigation measures were imposed in the Midwest ISO markets. The mitigation measures are contained in Module D of the Midwest ISO's Tariff. They are intended to preclude abuses of locational market power while minimizing interference with the market when the market is workably competitive. The Midwest ISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds *and* when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas. The Midwest ISO has almost completely automated the mitigation process.

Market participants are subject to potential mitigation specifically when transmission constraints that are binding can result in substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in a position to exercise market power due to a lack of competitive alternatives. As discussed previously, the mitigation thresholds differ based on the two types of constrained areas that may be subject to mitigation: BCAs and NCAs.

Because the market power concerns associated with NCAs are higher due to their chronic nature, the conduct and impact thresholds for NCAs are substantially lower than they are for BCAs. The chronic nature of the NCAs and the lower mitigation thresholds generally lead to more frequent mitigation in the NCAs than in the BCAs, even though there are many more BCAs. Figure 86 shows the frequency and quantity of mitigation in the real-time market by month. Very little mitigation was imposed in the day-ahead market. This is expected because the day-ahead market is much less vulnerable to withholding due to the presence of virtual traders.

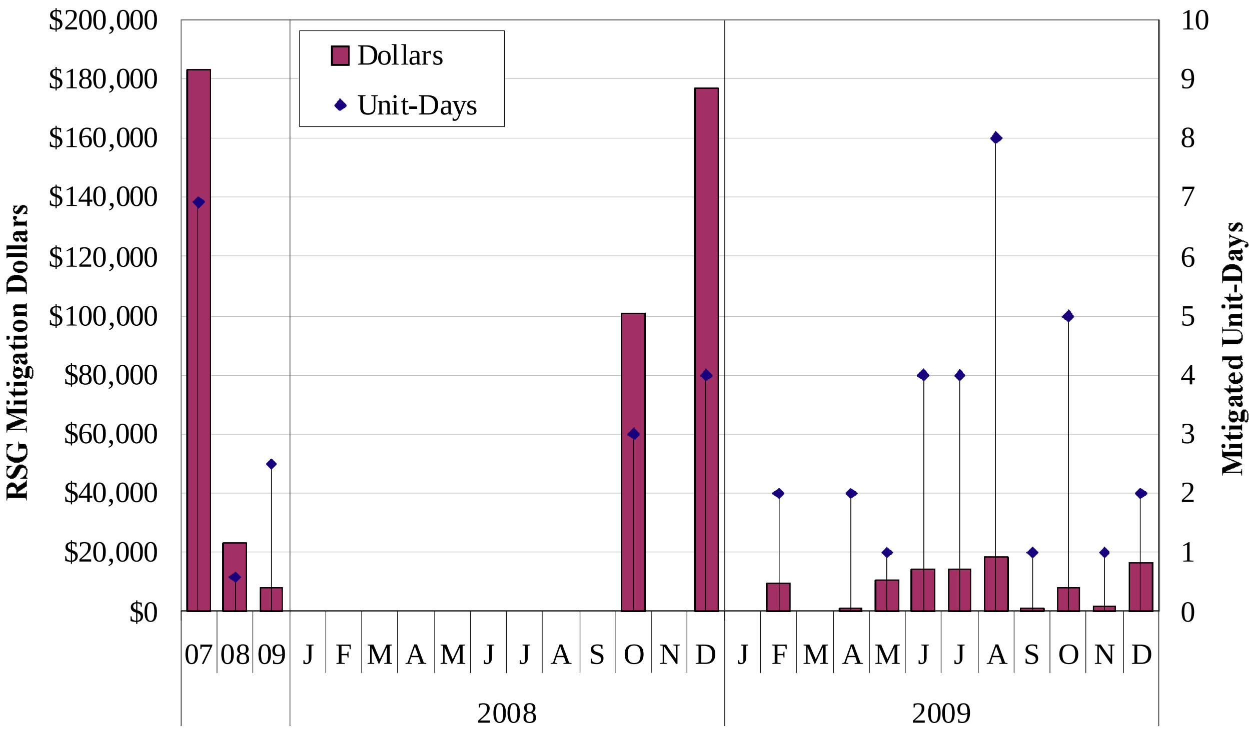
Figure 86: Real-Time Mitigation by Month
2008 – 2009



Real-time NCA and BCA mitigation was exceedingly rare in 2009, dropping 98 percent and 74 percent respectively from 2008. Only 5 BCA and 3 NCA unit-hours of mitigation occurred, down from 17 and 122 unit-hours in 2008. This was generally due to lower levels of congestion, particularly into the NCAs. When mitigation did occur, the quantities mitigated were still substantial, averaging 193 MW and 73 MW per unit-hour for NCA and BCA mitigation respectively. Although mitigation was infrequent during 2009, the pivotal supplier analyses discussed earlier in this section continue to indicate that local market power is a significant concern. If exercised, local market power could have substantial economic and reliability consequences within the Midwest ISO market. Hence, market power mitigation measures remain essential.

The previous analysis focused on mitigation of economic withholding in the real-time energy market. Participants can also exercise market power by raising their offers when their resources must be committed to resolve a constraint or to satisfy a local reliability requirement. This can compel the Midwest ISO to make substantially higher RSG payments. The Midwest ISO designed mitigation measures to address this conduct. These mitigation measures are triggered when the following three criteria are met: 1) the unit must be committed for a constraint or a local reliability issue; 2) the unit's offer must exceed the conduct threshold; and 3) the effect of the inflated offer must exceed the RSG impact threshold (i.e., to raise the unit's RSG payment by $50 per MWh). Figure 87 shows the frequency and amount by which RSG payments were mitigated in each month of 2008 and 2009.

Figure 87: Real-Time RSG Payment Mitigation by Month
2008 – 2009



RSG mitigation occurred for 30 unit-days in 2009, up from 7 in 2008. However, the dollar amount mitigated dropped by 65 percent to $96,000. Since RSG payments are a function of both as-bid production costs and LMPs, lower fuel and energy prices in 2009 led to a reduction in the dollar amount mitigated. These figures remain substantially below the totals for prior years.

Although mitigation of RSG payments was modest, this does not indicate a lack of locational market power.

VII. Demand Response Programs

Demand response consists of actions taken during certain hours that reduce consumption from normal levels when the value of consumption is less than the marginal cost to supply the electricity. DR allows for participation in the energy markets by end users and contributes to:

- Reliability in the short-term;
- Least-cost resource adequacy in the long-term;
- Reduced price volatility and other market costs; and
- Reduced supplier market power.

Additionally, price-responsive demand has great potential to enhance wholesale market efficiency. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the need to facilitate DR through wholesale market mechanisms and transparent economic signals.

DR resources can broadly be categorized as either “emergency DR”, which respond to capacity shortages, or “economic DR”, which respond to high energy market prices. Emergency DR resources are callable by the ISO in advance of a forecasted system emergency and thus can play an important role in supporting system reliability. However, emergency DR is not price-responsive and does not participate directly in Midwest ISO markets. Economic DR resources respond to energy market prices not only during emergencies but any time the energy price exceeds the marginal value of the consumer’s electricity consumption.

The real-time market is significantly more volatile than the day-ahead market due to physical restrictions and contingencies that affect the real-time market. Given the high value of most electricity consumption, DR resources will tend to be most valuable in the real-time during abrupt periods of shortage when prices spike. In the day-ahead market prices are less volatile and there is a much wider array of supply alternatives. Consequently, DR resources are generally less valuable in the day-ahead market. On a longer-term basis, however, consumers can make strategic shifts in their consumption patterns in response to day-ahead prices (from the peak to off-peak period, flattening the load curve). This increases the overall efficiency and reliability of the system.

A. DR Resources in the Midwest ISO

At year-end 2009, the Midwest ISO had over 12,000 MW of demand response capability. Most of this is through legacy "reliability" DR programs locally administered by LSEs, either through load interruption (known as Load-Modifying Resources, or "LMR") or through Behind-the-Meter Generation ("BTMG"). These resources are beyond the control of the Midwest ISO and effectively reduced the overall load that the system met. DR resources under the control of the Midwest ISO are classified as Demand Response Resources ("DRR") and participated in all Midwest ISO markets in 2009, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff. The launch of ASM provided additional avenues for DR participation in Midwest ISO markets.

1. Types of DRR

The Midwest ISO characterizes DRR that participate in the Midwest ISO markets as either DRR-Type I or DRR-Type II resources. Type I resources are capable of supplying a fixed, pre-specified quantity of energy or contingency reserves through physical load interruption. Conversely, Type II resources are capable of supplying varying levels energy or operating reserves on a 5-minute basis, such as through controllable load or behind-the-meter generation.

Because Type I resources are inflexible – they either provide no response or their "Target Demand Reduction Amount" – they cannot set prices in the Midwest ISO markets. In this respect, the Midwest ISO treats Type I resources in a similar fashion as generation resources that are block-loaded for a specific quantity of energy or operating reserves. The Midwest ISO is pursuing an initiative to develop an appropriate pricing methodology to allow Type I and other so-called "fixed block" offers to establish market prices. Although 17 units were capable of providing almost 2.4 GW of total Type I capacity in 2009, peak participation totaled just 340 MW. The capacity dropped substantially after September 1, 2009 because pumped storage resources that had been the largest provider of DRR Type I stopped participating as such.

Most other Type I capacity is in the form of interruptible load programs catered toward large industrial end-users. Enrollment typically requires a minimum size of load reduction and a minimum level of peak demand. In an interruptible load program, customers agree to reduce consumption by (or to) a predetermined level in select ISO-determined instances in exchange for a small per-kWh reduction in their fixed rate. The Midwest ISO does not directly control this load – such programs are therefore ultimately voluntary, although penalties exist for non-compliance. Direct Load Control ("DLC") programs are targeted toward residential and small commercial and industrial ("C&I") users. They often require certain equipment end-uses, such as air conditioners or water heaters. In the event of a contingency, the LSE will manually reduce the load of certain equipment to a predetermined level.

Type II resources can set prices because they are capable of supplying energy or operating reserves over a dispatchable range and respond to five-minute set-point instructions. They are therefore treated comparably to generation resources. These price-based resources are referred to as "dynamic pricing" resources. Dynamic pricing is the most efficient form of DR because rates formed under this approach provide customers with accurate price signals that vary throughout the day to reflect the higher cost of providing electricity during peak demand. In turn, customers can alter their usage accordingly. There are significant barriers to implementing dynamic pricing, including a minimum size requirement, extensive infrastructure outlays and potentially retail rate reform. Only 4 units totaling 111 MW of capacity participated in 2009. Peak participation was 65 MW.

Module E of the Midwest ISO's Tariff allows all DR resources except those that qualify only for EDR to count toward the fulfillment of an LSE's capacity requirements. DR resources can also be included in the ISO's long-term planning process as comparable to generation. Currently only DRR units can participate in the VCA, and do so just like generation resources. LMR will soon be able to participate as well, pending the approval of the Commission and certification by their LSE. The ability for all DR resources to provide capacity under Module E goes a long way toward addressing economic barriers to DR and ensuring comparable treatment with the Midwest ISO's generation.

2. Recent DR Initiatives

a. DRR Participation in Ancillary Services Markets

ASM markets launched in January 2009 allow LSEs to offer DRR for operational reserve purposes similar to generation resources. Type II resources can currently offer all ancillary services products, whereas Type I units are prohibited from providing regulating reserves. This is because the physical requirements required of regulating reserve-eligible units are too demanding for Type I resources – they need to be able to respond to small changes in generation within 4 seconds. Type I units were also prohibited from providing spinning reserves until February 2, 2010. Table 4 below shows the participation rates for DRR in energy and ancillary service markets in 2009.

Table 4: DRR Participation in Midwest ISO Markets
Average quantities in MW, 2009

Resource	Day-Ahead				Real-Time			
	Energy	Ancillary Services			Energy	Ancillary Services		
		Reg	Spin	Supp		Reg	Spin	Supp
DRR Type I	1	–	–*	51	1	–	–*	52
DRR Type II	17	15	13	0	17	15	14	0

* DRR Type I resources became eligible for spinning reserves on February 2, 2010.

DRR participated in nearly all eligible markets in 2009. Type I resources offered only supplemental reserves, whereas Type II resources offered energy, regulation and spinning reserves. Quantities between day-ahead and real-time did not change substantially. DRR provided on average 1.6 percent (spinning reserves) to 5.3 percent (supplemental reserves) percent of the total cleared amounts for the AS products. Cleared quantities were largely constant across all months of 2009, except for Type II spinning reserves. These quantities averaged just 2 MW prior to September 1, 2009 and 36 MW thereafter.

b. Emergency DR

The Emergency DR Initiative began in May 2008 and allows the Midwest ISO to directly curtail load in specified emergency conditions if DRR dispatched under ASM and LSE-administered DR programs are unable to meet the demand. EDR is supplementary to existing DR initiatives and requires the declaration of a NERC Energy Emergency Alert (“EEA”) 2 or EEA 3 event. Resources that do not qualify as DRR or DRR units that are not offered into energy or operating reserve markets are still eligible to reduce their load and be compensated as EDRs. EDR-qualified resources totaled 242 MW in 2009. EDR was never deployed in 2009 due to low peak demand conditions.

As of July 2009, EDR offers are submitted on a day-ahead basis, rather than on a monthly basis, which allows for more accurate availability of such resources. During emergency conditions, the Midwest ISO will select offers on a merit basis based on the provided curtailment prices (subject to a $3,500 per MWh cap). EDR participants that reduce demand in response to a dispatch instruction will be compensated at the greater of the prevailing real-time LMP or the offer cost (including shutdown costs) for the amount of verifiable demand reduction provided. EDR resources are not yet eligible to set prices due to their inflexibility, but we have recommended that the Midwest ISO investigate changes that would allow them to set prices when they are needed.

c. Aggregators of Retail Customers

FERC in August 2008 directed RTOs to improve their DR participation in wholesale electricity markets. Orders 719 and 719-A specifically require comparable treatment of DR resources to existing generation. In response, the Midwest ISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements. The largest such barrier is the limitation of direct market participation to resources greater than 1 MW. The pooling of small resources through ARCs, which serve as an intermediary between the Midwest ISO and retail customers that can reduce their consumption[26],

[26] An ARC is by definition a market participant sponsoring a DRR resource provided by customers that it does not serve at retail. An ARC can also be an LSE sponsoring a DRR that is the retail customer of another LSE.

has been successfully implemented in neighboring RTOs (see Table 5). The Midwest ISO filed Tariff revisions on October 2, 2009 to allow ARCs to participate in all Midwest ISO markets. ARCs were scheduled to be eligible to participate beginning June 1, 2010, although as of this writing FERC has not yet approved the Tariff revisions.

ARC-sponsored resources will be treated comparable to LSE-owned resources, with one notable difference. For settlement purposes, an ARC-operated resource cleared for energy will be paid the LMP minus the predetermined Marginal Foregone Retail Rate, which is a proxy for the cost the retail customer providing the DRR would have incurred to consume. This is an economically efficient payment because reducing load provides the retail customer savings for foregoing consumption. This payment to the ARC for foregoing consumption is assessed to the LSE at the retail rate, resulting in a net payment to the retail customer equal to the LMP. ARCs providing other products such as capacity or ancillary services are still paid just the MCP for that particular product because there is no retail rate associated with it.

B. Inter-ISO Comparison of DR Programs

In this section, we provide a comparison of the DR programs run by the Midwest ISO, NYISO, ISO-NE and PJM in Table 5 below. The Midwest ISO has an initiative for emergency DR and allows for direct participation of DR resources in all markets. The Midwest ISO's total DR resources exceed 12,500 MW, far more than neighboring RTOs. These resources comprise 6.8 percent of the Midwest ISO's resource mix, which is comparable to other RTOs. Only a quarter of this is in the form of ISO-controlled resources, however, with the balance being load that is interruptible by LSEs. Other RTOs are ahead of the Midwest ISO in implementing economic DR, which is discussed in the subsequent section.

Table 5: Comparison of DR Programs Across RTOs.
2009

	Program/Resource	Quantity in MW	Pct of Resource Mix
MISO	**TOTAL**	**10,197**	6.8%
	DRR Type I	2,353*	
	DRR Type II	111	
	Load-Modifying Resources	4,860	
	Behind-The-Meter Generation	4,984	
	Emergency	242	
ISO-NE	**TOTAL**	**2,554**	7.4%
	Real Time Demand Response	873	
	Real Time Emergency Response	875	
	Energy Efficiency	700	
	Load Management	105	
NYISO	**TOTAL**	**2,387**	7.7%
	Day-Ahead Demand Response	331	
	Demand Side Ancillary Services	2	
	Emergency Demand Response	323	
	Targeted Demand Response	536	
	Installed Capacity - Special Case Resources	2,061	
PJM	**TOTAL**	**7,374**	5.6%
	Economic	893	
	Emergency	6,481	

* Type I capacity for Planning Year 2010 is only 210 MW due to certain pumped storage resources no longer offering their capacity when pumping as Type I (effective September 1, 2009). As of February 2010, Type I resources can also offer spinning reserves, subject to a 10 percent participation cap.

Notes: Non-Midwest ISO resources are not all mutually exclusive. Due to various operating characteristics of each program or resource, specific program-to-program comparisons are not readily feasible.

Sources: Midwest ISO; The Brattle Group, "Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design", January 29, 2010.

C. Improving DR Integration in Midwest ISO Market

The Midwest ISO has made significant efforts to reduce the barriers to integrating DR resources into existing markets. As the quantities of DR resources increase, one can expect that they will be deployed much more frequently to satisfy peak loads and respond to system contingencies. Therefore, it will be increasingly important to ensure that the real-time markets produce efficient prices and other market outcomes when DR resources are deployed.

In prior State of the Market reports, we showed that when the Midwest ISO has called for load curtailments under emergency conditions, prices have generally been understated and have not efficiently reflected the shortage (or the value of the foregone consumption). One such event occurred on August 1-2, 2006, when extremely high temperatures throughout the Midwest ISO region resulted in record electricity demand. Emergency procedures were invoked by the Midwest ISO that resulted in voluntary load reductions of close to 3,000 MW. Prices during peak hours on August 1, however, ranged from $50 to $150 and were less than $100 in the highest demand hour. These prices did not reflect the conditions that triggered the load curtailments.

When DR resources do not set prices, as in the example above, a key component of the economic signals needed to support investment in generation, transmission, and demand-side management is undermined. Hence, it should be a high priority of the Midwest ISO to permit all such resources to set energy and ancillary services prices at efficient levels when DR is implemented. This will improve the markets economic signals by accurately reflecting the value of the energy provided. Further integrating this capability into the market will be challenging. In its most recent compliance filing with the Commission on the matter, the Midwest ISO stated that "current systems are not adequate to permit this because such resources are not able to move incrementally in response to small changes in conditions."[27]

The same issue prevents peaking resources from setting prices when they the marginal resources, but are being dispatched at their economic minimum or economic maximum. The Midwest ISO has been working on a means to set prices that would reflect the marginal offer costs of peaking resources when they are needed.[28] This work is encouraging and we believe that it may be possible to utilize this approach to allow DR resources to set prices as well. Hence, we recommend the Midwest ISO consider this approach or others that would allow DR resources to set prices in the real-time energy market when they are the marginal resources, notwithstanding their general lack of flexibility.

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27 Midwest Independent Transmission System Operator (2009). "EDR Quarterly Report Filing," filed before the Commission, October 21, 2009. Docket No. ER08-404-000.

28 Generally referred to as "Convex-Hull Pricing".

D. Conclusions

With more than 12,500 MW of existing potential DR capability, the Midwest ISO has significant potential for more fully integrated DR. The Midwest ISO's existing programs and proposed initiatives address many of the barriers to DR. One change that will be particularly important is a modification to the price-setting methodologies to allow emergency actions and all forms of DR to contribute to setting efficient shortage prices in energy and AS markets. Failure to set efficient shortage prices when DR resources or other emergency actions clear the market under shortage or near shortage conditions can serve as a material economic barrier to the development of new DR resources.

This report raises the potential that the EDR initiative could be expanded to include economic DR resources, which would address the regulatory/economic barrier posed by fixed retail rate regimes at the state level. However, substantial work would need to be done to determine whether this kind of initiative would be feasible and beneficial.

Finally, we believe the stakeholder process that the Midwest ISO has established to identify and respond to more specific barriers related to market rules, settlement provisions, and operating requirements will be an effective means to address these barriers. In developing the new rules and requirements, however, it is important to adhere firmly to sound principles of economic efficiency. One area where this is particularly important is in the area of compensation for DR resources when they curtail in the energy market. Real-time economic DR resources should be provided the same incentives that they would have under a dynamic retail pricing regime. This can be accomplished by structuring the energy settlements to pay the wholesale LMP at the DR resource's location less the retail rate they save by not consuming. This is consistent with the settlement procedures proposed for ARCs that are currently pending at the Commission. However, it is not consistent with the current settlements for other DR resources, which the Midwest ISO should consider revisiting. The Commission has been considering these issues more broadly in its recent Notice of Proposed Rulemaking on compensation for DR resources.

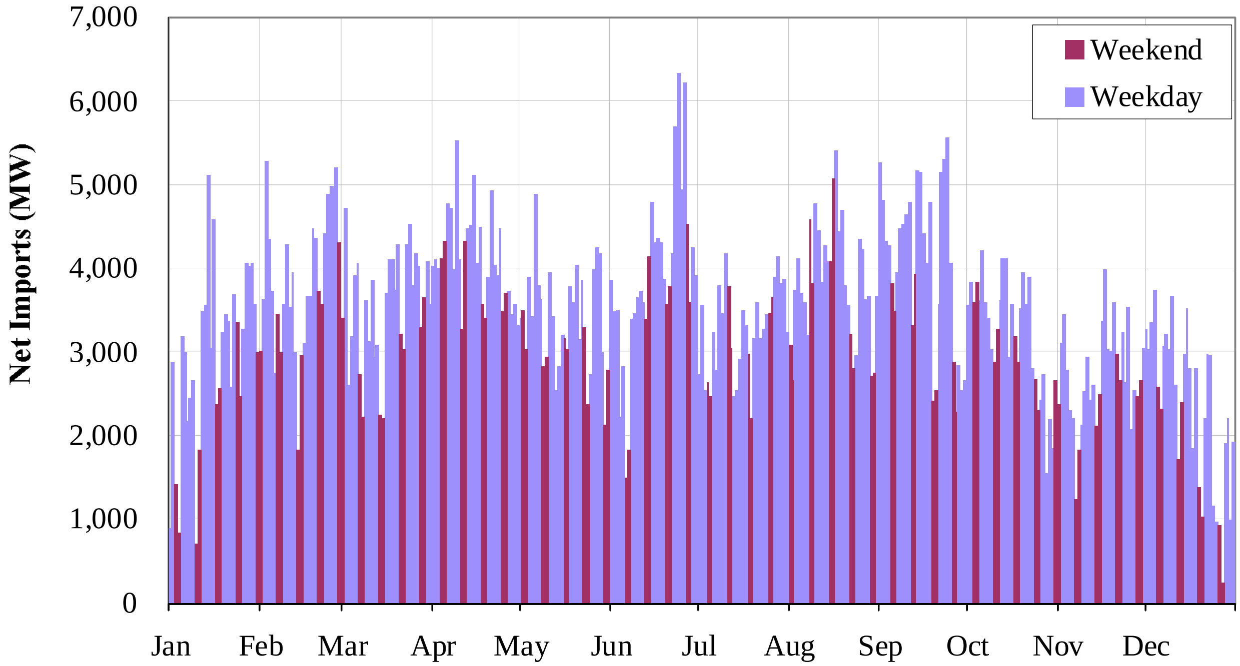
VIII. External Transactions

As in prior years, the Midwest ISO continued to rely heavily on imports to serve its load and meet its operating reserve requirements. In this section, we evaluate the interchange between the Midwest ISO and adjacent areas. In particular, we summarize the quantities of external transactions and the efficiency of the transaction scheduling processes.

A. Import and Export Quantities

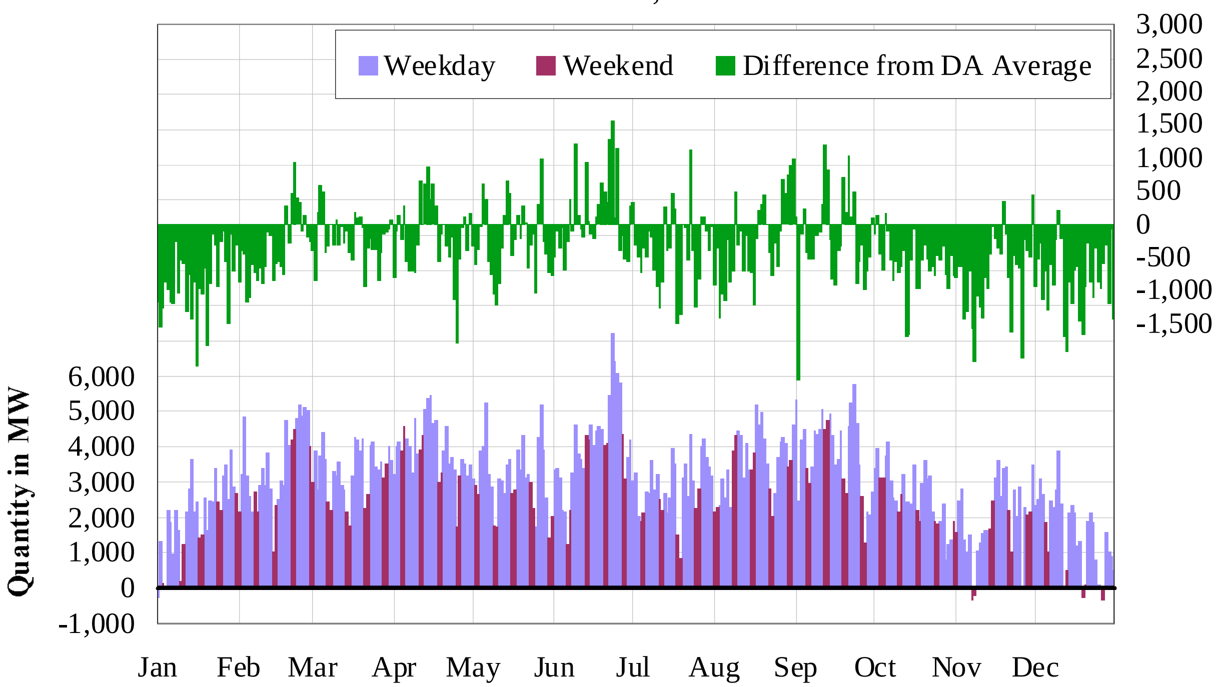
Figure 88 shows the daily average of hourly net imports scheduled in the day-ahead market. The Midwest ISO is on the whole a net importer of power in both peak and off-peak periods due to its reliance on large imports from the West and Manitoba. In 2009 there was no discernible seasonal pattern to net imports with high levels of imports throughout the year. Day-ahead imports averaged 3.4 GW in 2009 indicating substantial reliance upon net imports to satisfy the demands of the market. This average import level was a slight decrease from 3.6 GW in 2008.

Figure 88: Average Hourly Day-Ahead Imports
All Hours, 2009



Net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 89 shows the average hourly net imports scheduled in the real-time market each day over all interfaces, and the deviation of real-time imports from the day-ahead imports. In the real-time market in 2009, the Midwest ISO imported an average of 3.0 GW, a slight decline from the average of 3.1 GW in 2008. PJM (1.1 GW) and Manitoba Hydro Electric Board ("MHEB") (0.9 GW) continued to be the two largest sources of imports to the Midwest ISO in the real-time market, comprising over two-thirds of net imports.

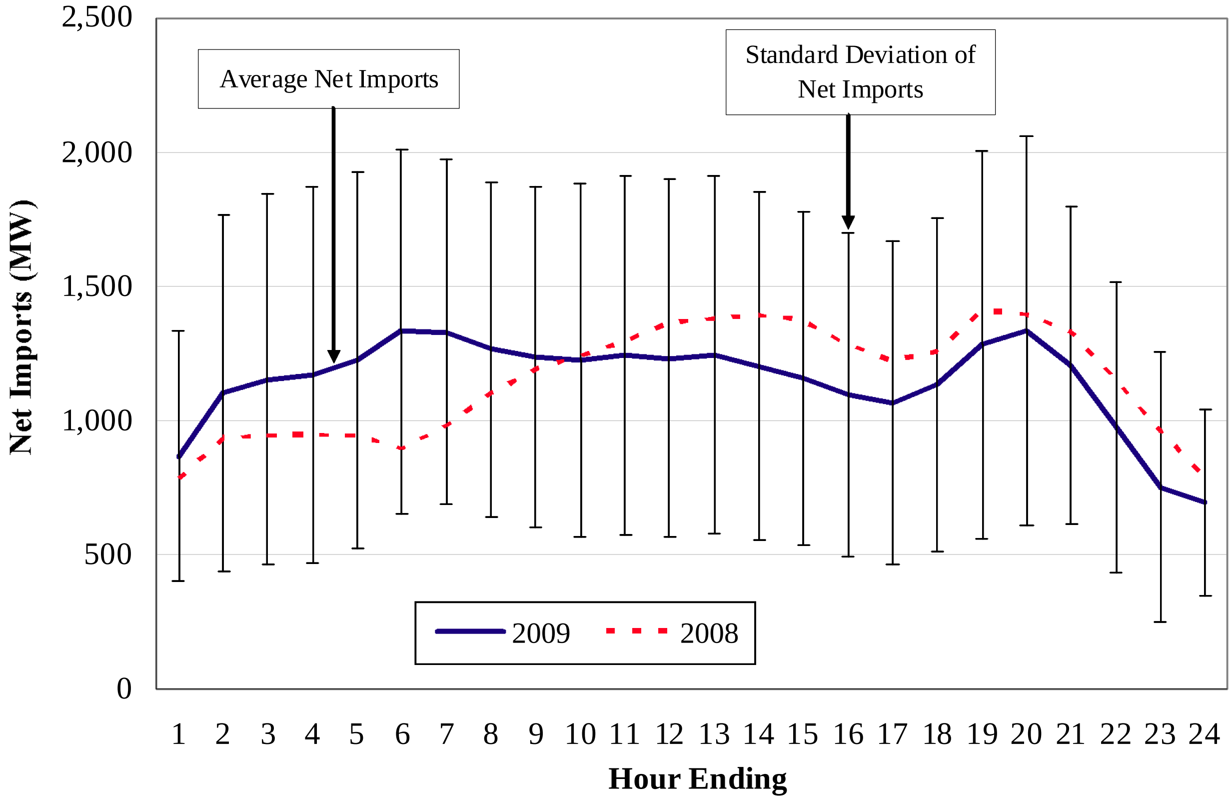
Figure 89: Average Hourly Real-Time Imports
All Hours, 2009



Real-time net imports generally decreased from those scheduled in the day-ahead market. On 49 days, the average net imports decreased by more than 1,000 MW, which can create reliability issues that the Midwest ISO must manage. Large changes in net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources. The figure shows changes in net imports from day-ahead to real time occurred with greater frequency in late fall and in winter. The largest shares of the reduced real-time imports are on the western interfaces with WAUE and MHEB, though all the major interfaces show reduced real-time imports.

Our next analysis shows net imports by interface to better show where the Midwest imports and exports originate. The interface between the Midwest ISO and PJM, both of which operate LMP markets over wide geographic areas, is one of the most significant Midwest ISO interfaces. Accordingly, Figure 90 shows the average net imports scheduled for the Midwest ISO-PJM interface in each hour of the day.

Figure 90: Hourly Average Real-Time Net Imports from PJM
2009

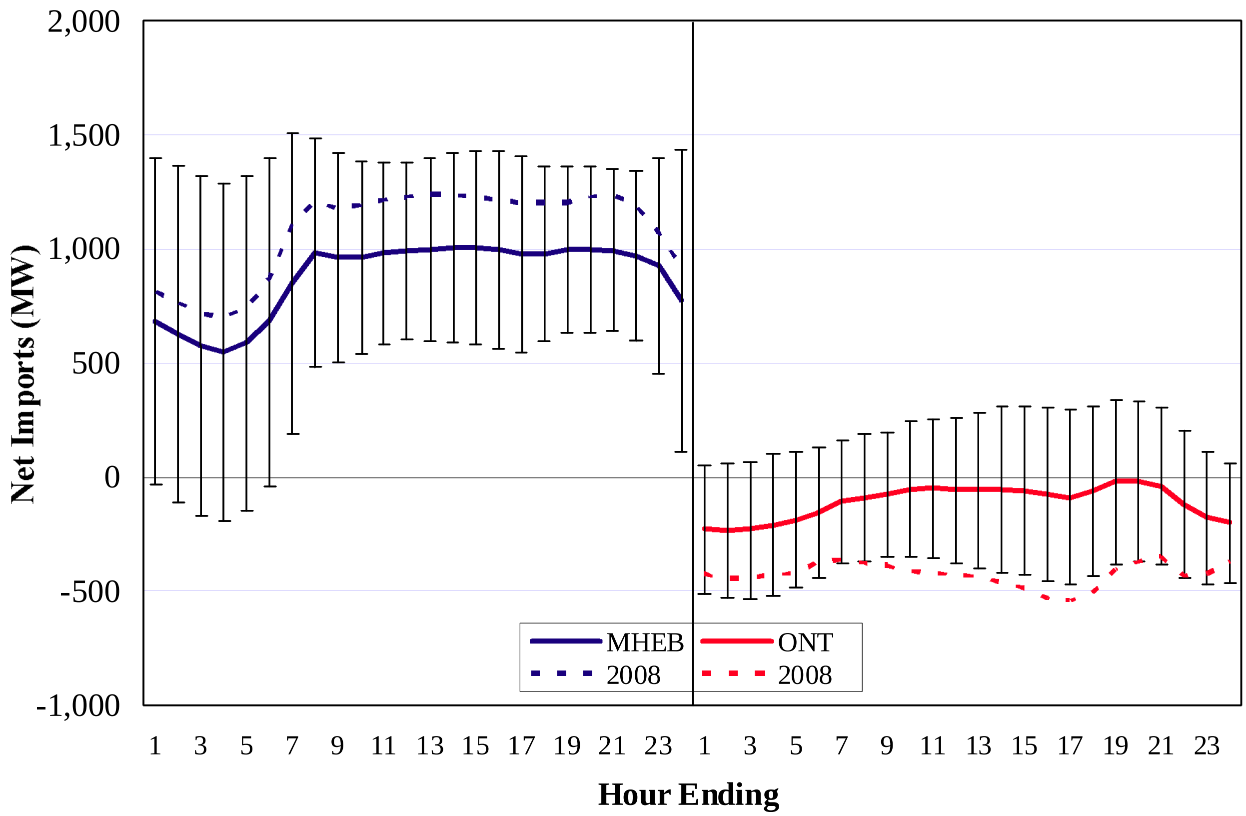


Midwest ISO is a net importer of power from PJM during each hour of the day. More imports are scheduled during peak hours than off-peak hours. The fluctuation in hourly net imports is less pronounced in 2009 than it was in 2008. In 2008, the Midwest ISO imported comparatively less during morning hours and more during afternoon and evening hours.

The standard deviation of the net imports declined in 2009 compared to 2008. However, it remains large, indicating that the magnitude and direction of the flows between the two markets is highly variable. This is due to the similarity of the generating resources in PJM and the Midwest ISO. Hence, the prices in the two areas tend to move in similar ranges. Because the relative prices in the two areas govern the net interchange between them, movements in these prices will cause the incentives to import or export to oscillate.

Figure 91 shows hourly real-time net imports across the Canadian interfaces. The Midwest ISO exchanges power with Canada through interfaces with MHEB (left panel) and the IESO (right panel). The Midwest ISO is typically a net importer from MHEB through the 500 kV Forbes-Dorsey line, which is the single largest contingency in the footprint. Net imports from MHEB are generally higher in the peak hours (averaging 960 MW) and lower in the off-peak hours (averaging 712 MW). Average hourly imports from MHEB were 200 MW lower in 2009 than they were in 2008.

Figure 91: Hourly Average Real-Time Imports from Canada
2008 – 2009

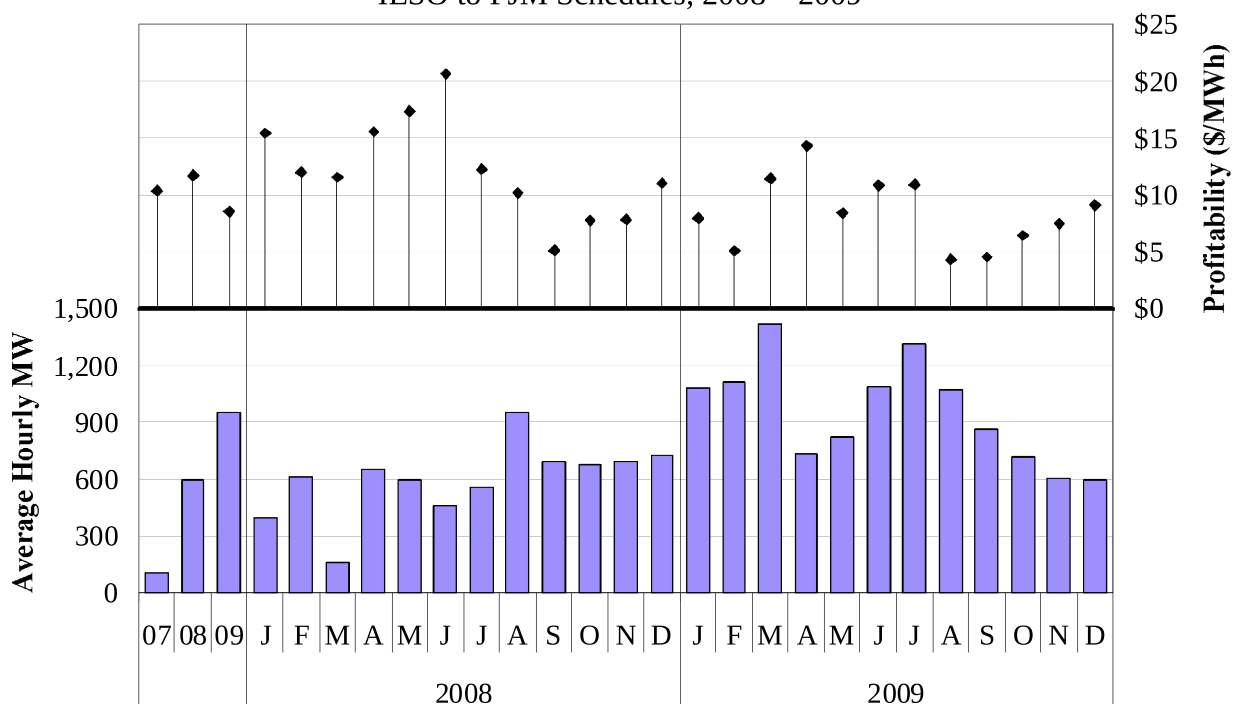


Conversely, the Midwest ISO is on the whole a net exporter to IESO, although the direction of the flows changes periodically. Exports to IESO are generally lower during peak and ramping hours. The wide standard deviation, which averaged 636 MW in 2009, shows the Midwest ISO is an importer from IESO during many hours (particularly peak hours). Average hourly exports to IESO were approximately 300 MW less in 2009 than in 2008.

B. Lake Erie Loop Flow

The issues surrounding "contract path" transaction scheduling by the four RTOs around Lake Erie persisted throughout 2009. The adverse affects of this scheduling was primarily related to the congestion it caused in the New York ISO market. The underlying problem in each of the cases was that settlements occur based upon the scheduled path (i.e., the "contract path"), but the actual power flows also occur on other paths (the flows that result from the schedule that are not part of the contract path are generally referred to as "loop flows"). The scheduling path does not alter the physical flow of the power between generation and load. The extents to which the physical flows differ from scheduled flows are loop flows that must be accounted for by the RTO operators. Furthermore, inconsistencies between the physical flows that result from a transaction and the scheduled path of the transaction can distort participants' incentives and can lead to inefficient scheduling.

Figure 92: Actual Flows Around Lake Erie
IESO to PJM Schedules, 2008 – 2009



Circuitous schedules were banned by NYISO in July 2008. Schedules from the IESO to PJM (across the Midwest ISO) increased thereafter. Figure 92 shows the quantity and profitability of these transactions from 2006 to early 2009. Relatively high volumes of circuitous transactions continued in 2009 and can be explained by their consistent profitability. Since the beginning of 2007, these transactions have netted average profits over $10 per MWh, and occasionally over $20 per MWh. The profitability of these transactions has declined over time and tends to be inversely correlated with the volumes. Profitability is calculated based on the prices in PJM and IESO minus the Midwest ISO's wheeling charge. It does not include costs allocated by IESO, which would reduce the profitability. These transactions may not always be efficient, even though they are generally profitable.

If these transactions had to pay for the congestion they caused in New York, many would be unprofitable. This raises efficiency concerns. Additionally if PJM priced the transactions at its Midwest ISO interface (instead of its current pricing method for IESO), the average profitability would drop to -$1.30 per MWh. The large difference between the PJM's IESO and Midwest ISO prices may create incentives to combine other transactions with these wheels to acquire that difference. The expanded use of PARs could help improve the consistency between the schedules and flows. However, this has been significantly delayed by the lack of necessary agreements between the relevant transmission owners and operators, and the Midwest ISO is limited in its ability to facilitate these agreements.

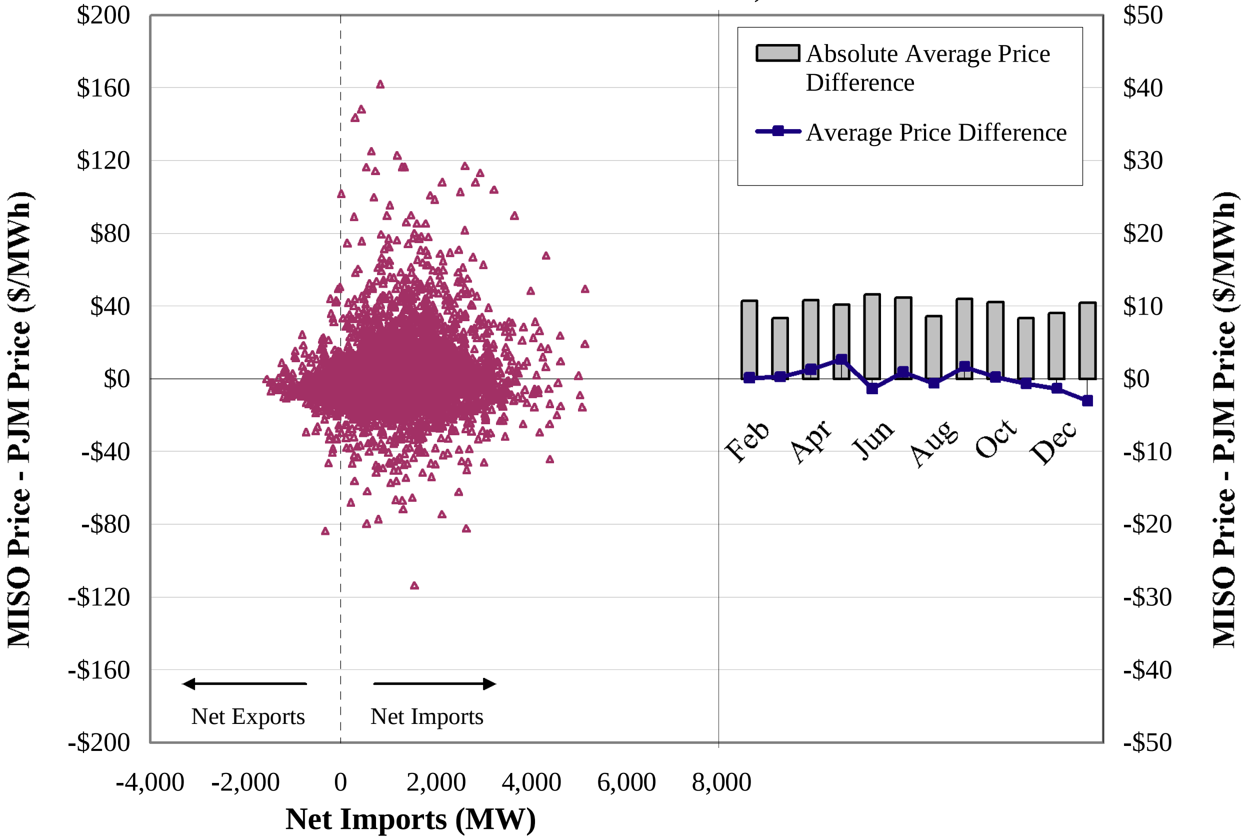
In addition, we have recommended that the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements. These modifications should substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers. Over the past year, the Midwest ISO has worked with these RTOs to develop the BRM Initiative, which addresses many of these issues. The outline of the BRM proposals were conditionally accepted by the Commission on July 15, 2010, and work should continue to implement them.

C. Convergence of Prices between the Midwest ISO and Adjacent Markets

Our next analysis evaluates the price convergence and net imports between the Midwest ISO and adjacent markets. Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to cause prices to converge between markets. Given the uncertainty regarding the difference in prices (because the transactions are scheduled in advance), one should not expect perfect convergence.

Our analysis is presented in a series of figures, each with two panels. The left panel in each is a scatter plot of the real-time price differences and the net imports in unconstrained hours. We expect to find imports into the Midwest ISO when the Midwest ISO prices are higher than prices in neighboring markets. The right side of each figure shows the monthly averages for hourly real-time price differences between the adjacent regions and the monthly average magnitude of the hourly price differences (average absolute differences). In an efficient market, prices at the interface should converge when the interfaces between the regions are not congested.

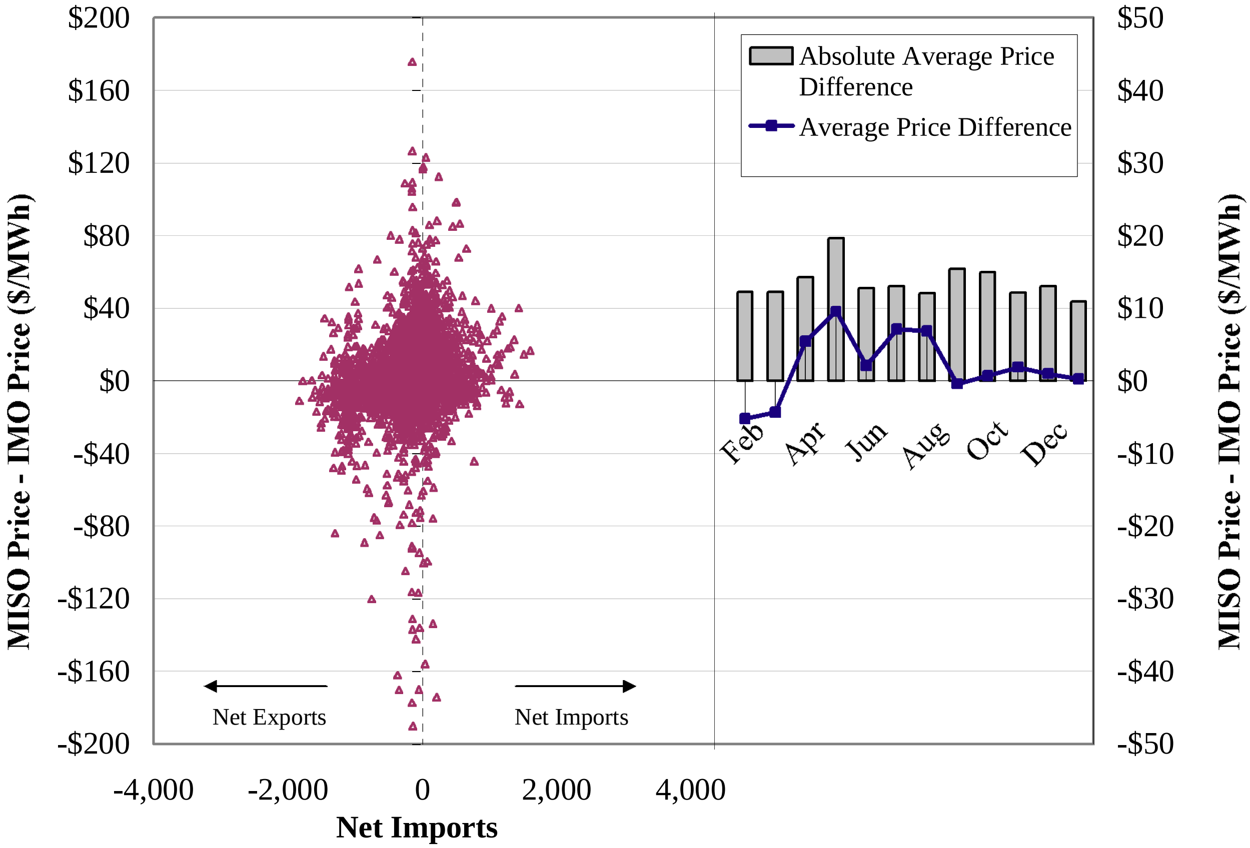
Figure 93: Real-Time Prices and Interface Schedules
PJM and the Midwest ISO, 2009



Midwest ISO interface prices in 2009 tended to be slightly higher than PJM's, except in the fourth quarter. The absolute average price difference was just over $10 per MWh in 2009, down from almost $18 per MWh in 2008. The left-hand-side panel in the figure shows participants have not been fully effective at arbitraging the prices between the two areas. The import and export quantities remain widely scattered relative to the price differences. Additionally, power is often scheduled from the higher-priced market to the lower-priced market – in 59 percent of the hours, power is scheduled in the wrong direction.[29]

We next analyze the external transactions with the IESO. Figure 94 shows the analysis of real-time prices and schedules between the Midwest ISO and IESO.

Figure 94: Real-Time Prices and Interface Schedules
IESO and the Midwest ISO, 2009



The pattern in the left-hand side of the figure confirms that the Midwest ISO was a net exporter of power to IESO in 2009, exporting an average of 100 MW. This is down from 400 MW in 2008. On average, Midwest ISO prices exceeded the IESO prices. Absolute average price differences averaged $13.57 per MWh, down from nearly $21 per MWh in 2008. Average price

29 The lower right quadrant indicates PJM prices are higher, yet imports are positive.

differences were more volatile during the first half of 2009. IESO premiums of approximately $5 per MWh prevailed during the first two months of the year, while Midwest ISO premiums averaged $6.25 per MWh from March to July. The dispersion of prices shows the schedules over this interface are relatively slow to respond to price differences.

Interpreting these results is complicated by the fact that the IESO does not have a nodal market, so the IESO price may not fully reflect the true value of power imported from the Midwest ISO. Internal constraints in the IESO can cause such imports to be more or less desirable than the price would indicate. Given the current market design in the IESO, there are limited options for improving the external transactions over this interface.

However, to achieve better price convergence with PJM, we continue to recommend that the RTOs consider expanding the JOA to optimize the net interchange between the two areas. The BRM initiatives contemplate a number of possible enhancements to coordination of inter-RTO transaction scheduling. One of these is to move to 15-minute scheduling as a first step. Another is an enhancement that would allow market participants to submit a single transaction bid corresponding to the spread of real-time prices between the RTOs that would be evaluated by the scheduling ISOs in a coordinated intra-hour scheduling process. We strongly support this proposal because it would improve the efficiency of the interchange between control areas, which would lower overall production costs across the four ISOs. This change would allow the markets to be more fully arbitraged and likely achieve the vast majority of potential savings associated with jointly dispatching the generation in the two regions.

D. Resource Adequacy and External Transactions

This section shows that the Midwest ISO relies on a high level of net imports to meet its energy needs. Therefore, it is reasonable to expect that it will rely on comparable levels of external capacity to meet its resource adequacy needs under Module E. However, our review of the Module E requirements indicates potential problems both with participants' ability to import capacity from external areas and to export capacity to PJM. Capacity prices will only be efficiently determined if participants are able to freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Therefore, it is critical to identify and eliminate barriers that inefficiently hinder such transactions.

With regard to imports, the current requirement that a deliverability study be performed in advance of participation by an external entity in the capacity market is an onerous, time-intensive requirement that creates an effective barrier to entry. Hence, we recommend the Midwest ISO modify its deliverability requirement for external resources to establish a maximum amount by interface that can be utilized to satisfy LSEs' capacity requirements under Module E.

With regard to exports to PJM, relatively little capacity has managed to be exported to PJM, despite the current price differences. This may be due to a number of factors, including deliverability requirements, operational requirements, or other market obligations. We believe it is important for the Midwest ISO and PJM to work together to identify inefficient barriers to capacity transactions and develop solutions to eliminate those barriers.