The Brattle Group

Demand Response in the Midwest ISO

An Evaluation of Wholesale Market Design

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I. EXECUTIVE SUMMARY

The Midwest ISO (MISO) commissioned *The Brattle Group* to conduct an independent assessment of its progress in integrating demand response (DR) into its wholesale markets. This whitepaper reports our findings in the areas of resource adequacy, energy and ancillary services markets, and emergency DR. We also report progress relative to the goals set out in MISO's 2009 Incentive Plan[1] and identify opportunities for further improvement, which MISO and its stakeholders can consider in establishing future goals.

MISO has made significant progress in integrating demand response (DR) into its wholesale market structures. Foremost, MISO has incorporated a large amount of DR into its resource adequacy construct. During the first planning year 2009/2010, the share of DR as a planning resource exceeded the share of DR in other markets, such as PJM, ISO New England (ISO-NE), and New York ISO (NYISO). Another significant achievement was the launch of the MISO's centralized ancillary services market in early 2009, which allowed DR to provide regulation and contingency reserves. Uniquely among Regional Transmission Organizations (RTOs), MISO has an active DR participant in its regulation market.

On the other hand, MISO's integration of DR has lagged in certain other areas. Aggregators of Retail Customers (ARCs) currently do not participate in any of its markets, and thus MISO has not seen the growth in new DR that ARCs have generated in other markets. There are several major barriers that have excluded ARCs, including real-time metering requirements that raise the cost of participation and the lack of a settlement mechanism to compensate ARCs. These barriers, in combination with relatively low market prices, have resulted in limited direct DR participation in the energy and ancillary services markets. (It should be noted that there may have been indirect participation through utility use of legacy DR programs to reduce load when prices were relatively high, but without MISO or the authors knowing about it. Such DR is beneficial, but full integration and coordination of such DR with the wholesale market would be more efficient.)

However, barriers to ARCs and other DR barriers that stakeholders identified during the Federal Energy Regulatory Commission (FERC) Order No. 719 compliance process will be removed if MISO's recent FERC filing (its "ARC Proposal") is implemented. ARCs will be able to participate in resource adequacy, as well as in the energy and ancillary services markets. The ARC Proposal establishes a compensation mechanism for ARCs that will be comparable to generation and will promote economic efficiency. Ultimately, however, ARC participation will depend largely on the states. ARC participation in non-restructured states will be subject to approval by the state retail regulatory authorities. In addition, small customers will be able to participate (through ARCs) only if states approve cost recovery for distribution companies to invest in advanced metering infrastructure (AMI).

Although most of the major barriers will be addressed when the ARC Proposal is implemented, there are some remaining concerns. These barriers are more minor, and include (1)

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1 For Incentive Plan goals, see pp. 8-9, MISO (2009a).

incomparable treatment of Load Modifying Resources (LMRs) and Demand Response Resources (DRRs) relative to generation in terms of disqualification from resource adequacy and revenue sufficiency guarantee (RSG) payments; (2) lack of capacity price transparency, which is especially important for ARCs; (3) undetermined rules regarding LMR deliverability; and (4) some bidding and modeling issues such as the lack of Price-Responsive Demand (PRD) bidding in the real-time energy market, the inability of DRR-Type I resources to set real-time prices, and insufficient bid parameters in regulation offers to fully accommodate the special characteristics of DR.

Going forward, as market conditions improve, it is likely that new DR will become economic, especially in those areas of the MISO footprint that have not yet developed much DR. Although ultimate participation levels will depend primarily on retail regulatory action to allow ARCs, introduce a Smart Grid, and provide dynamic retail rates, we recommend that MISO consider the following additional actions to maximize the potential of DR:

1. Implement the ARC Proposal, especially the ARC compensation mechanism, in its current form (pending FERC acceptance).

2. Conduct stakeholder discussions on identified concerns regarding the ARC Proposal and prepare a cost-benefit analysis of removing the remaining minor barriers to DR.

3. Continue to coordinate with states on regulatory policy toward DR.

4. Provide market participants with more training and a coherent manual regarding DR market participation opportunities.

II. STUDY OBJECTIVES AND APPROACH

A. PURPOSE

MISO has commissioned *The Brattle Group* to conduct an independent assessment of its progress in integrating DR into its wholesale markets. This whitepaper reports the results of that assessment, focusing on resource adequacy, energy and ancillary services markets, and emergency DR. This whitepaper also evaluates the progress MISO has made in integrating DR, relative to the goals outlined in its 2009 Incentive Plan.[2] The purpose of this assessment is to assist MISO and its stakeholders in establishing appropriate goals for the future.

B. *THE BRATTLE GROUP* EVALUATION CRITERIA

The primary criterion used by *The Brattle Group* in evaluating the MISO market design is economic efficiency. In the context of DR, this means facilitating the use of lowest-cost resources to reliably meet load, provide ancillary services, and satisfy resource adequacy targets. Efficiency would be reduced by barriers that prevent DR from competing freely with generation in resource adequacy, energy, and ancillary services markets. Elimination of existing barriers could include reasonable accommodation of the special characteristics of DR resources similar to the accommodation of generators' characteristics, but it should not include additional special incentives for DR unless they are economically justified. The overall result of economic efficiency could mean greater participation of DR, but only to the extent that DR can provide a comparable product at a lower cost.

C. APPROACH

The Brattle Group authors incorporated extensive stakeholder input and review into this assessment, and systematically examined each component of MISO's market design relevant to DR through the following process:

– Reviewed MISO's compliance filings with FERC, stakeholder comments, and FERC orders.

– Reviewed current tariff modules, current business practices manuals, historic working group materials, and market results to date.

– Solicited stakeholder input through question and answer sessions, and written comments. This stakeholder feedback was gathered through meetings with the Supply Adequacy

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[2] For Incentive Plan goals, see pp. 8-9, MISO (2009a).

Working Group (SAWG), the Demand Response Working Group (DRWG), and individual focus group meetings with each of the nine stakeholder sector groups.

- Compared the MISO market against other RTOs in both best practices and common difficulties.

- Evaluated each market design component, including progress to date and opportunities for improvement, as reported in the body of this document.

- Presented draft findings to stakeholders at DRWG and solicited comments on draft versions of this report.

- Assessed whether the specific goals in the 2009 Incentive Plan have been met.

While stakeholder input has been an invaluable source of information and insight, the product of this undertaking represents the findings of *The Brattle Group* authors alone. This report does not attempt to represent stakeholder positions or resolve conflicts among these positions.

III. INTRODUCTION

A problem with traditional electricity markets is that the demand side is not dynamic -- retail customers' consumption decisions are detached from the marginal cost of serving their load. Customers on fixed retail rates have no incentive to reduce their usage even during peak periods that drive capacity needs and have very high spot prices. The concept of DR is to reduce load when doing so is more economic than purchasing additional supply, both in the short-term (energy and ancillary services markets) and in a planning sense (resource adequacy). DR can thus improve economic efficiency while also increasing the competitiveness of wholesale electricity markets and supporting reliability.

Although enabling DR largely depends on state-level initiatives to install AMI and to establish dynamic and interruptible retail rates (and/or to allow ARCs), there are several things the ISO must do to integrate DR into its resource adequacy construct and energy and ancillary services markets. ISO integration is necessary for DR to efficiently displace generation and for DR providers to be able to capture the value of their actions.

A. APPROACHES TO INTEGRATING DR AND ROLE OF THE RTO

RTOs can choose from two, not mutually exclusive, general approaches to DR integration: (1) the demand-side approach; and (2) the supply-side approach.

Under the demand-side approach, the RTO conveys wholesale market prices, and market participants adjust their consumption in response to those prices. The consumer has the option to buy less energy when energy prices are high, eliminating or shifting energy consumption to lower-priced periods. Under the demand-side approach, the RTO needs to develop a mechanism that translates price-responsive demand into a demand curve in the wholesale markets.

Under the supply-side approach, customers remain on a fixed retail rate but are able to sell load reductions as "negawatts" measured from a hypothetical customer baseline (CBL), subject to measurement and verification (M&V) protocols; DR can therefore be treated as if it were a supply-side resource. The value of such load reductions can only be recognized in the wholesale markets if the RTO establishes a compensation mechanism for DR, whereby other customers pay the DR provider for supplying negawatts. The primary role of the RTO under the supply-side approach is to provide participation opportunities for DR comparable to generation's opportunities. "Comparable treatment" means that a DR resource capable of providing the same product as generation is allowed to participate under comparable conditions. It does not mean equal treatment. For example, if participation requirements were developed to accommodate the specific characteristics of generation resources, requiring DR to meet the same requirements does not constitute comparable treatment.

The demand-side approach is theoretically preferable to the supply-side approach because it does not rely on burdensome and contested measures, such as customer baseline definitions, measurement and verification (M&V) protocols, and compensation mechanisms. However, its applicability is limited. The fact is that most customers are on fixed rates, and many are likely to remain so (for simplicity and price stability) in spite of the nascent introduction of dynamic pricing in some jurisdictions.[3] Only the supply-side approach can provide such customers with efficient economic signals to consume less energy when spot prices are high. In addition, the supply-side approach is the only way for DR to be dispatchable for ancillary services (the demand-side approach would work only if individual customers could “consume” less ancillary services, which they can not). Finally, supply-side DR resources are easier to count toward resource adequacy since they provide controllable reductions. Demand-side DR is not controllable and thus can contribute to meeting resource adequacy requirements only to the extent that it reduces the load forecast itself. Several years of experience might be needed to accurately incorporate the effects of dynamic pricing into the forecast.

For all of these reasons, ISOs must enable the supply-side approach in spite of its difficulties. Moreover, the supply-side approach is the only way to admit ARCs (which do not themselves own retail load). ARCs have expertise in load management technology and protocols that are superior to that of some LSEs. ARCs also lack the disincentives that some LSEs face for helping their customers to reduce their loads, due to the potential undercollection of transmission and distribution revenues.

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3 Aligning retail rates with wholesale market prices through dynamic pricing can only be done by LSEs and state retail regulatory authorities, not the ISO. The ISO’s role is to ensure that wholesale prices are determined in an economically efficient manner, which includes enabling participation by all types of resources. Recent FERC policy has indicated that ISOs should play a more active role in integrating DR into their markets, in response to comments and observations that an inadequate amount of DR was present in the wholesale markets (see FERC 2008b).

IV. CURRENT DR PARTICIPATION OPPORTUNITIES IN MISO

This section includes a summary of current demand response participation opportunities in MISO markets, a timeline of DR development to date, and a description of current participation levels in resource adequacy, day-ahead and real-time energy markets, ancillary services markets, and emergency demand response.

MISO currently enables both demand-side and supply-side participation options for DR, but there are several major barriers that have limited direct participation in the energy and ancillary services markets. Table 1 summarizes current DR participation opportunities, as well as gaps that have been identified in this review.

Table 1
DR Participation Opportunities in MISO

	Resource Adequacy		**Energy**				**Ancillary Services**			**Emergency**
	LMR	DRR	Day-Ahead		Real-Time		Regulation	Spinning Reserves	Supplemental Reserves	
Approach	Demand-Side	Supply-Side	Demand-Side	Supply-Side	Demand-Side	Supply-Side	Supply-Side	Supply-Side	Supply-Side	Supply-Side
Existing DR Opportunities	LMR	DRR	PRD	DRR Type I DRR Type II		DRR Type I DRR Type II	DRR Type II	DRR Type II	DRR Type I DRR Type II	EDR
Missing DR Opportunities	ARCs*	ARCs*		ARCs*	PRD		ARCs*	DRR Type I**; ARCs*	ARCs*	

*Most of the missing opportunities with ARCs will be solved by the ARC Proposal
** There is an ongoing initiative to allow DRR Type I resources to provide spinning reserves

Both supply- and demand-side participation options are available to DR in the resource adequacy construct. As an LMR, DR may be used by an LSE to reduce its capacity obligation, or alternatively the LSE may designate the resource as a DRR which is treated as a supply-side resource. There are some differences between the treatment of LMRs and DRRs as discussed further in Section IV.B.

Economic DR can currently participate in the energy market as either DRR or as PRD.[4] A DRR is treated as a supply-side resource, and DRR offers can be submitted both in the day-ahead and the real-time energy markets. In contrast, PRD bidding is only available day ahead. There are two types of DRRs, depending on the dispatchability and controllability of the resource, as discussed in more detail in Section IV.C.[5]

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4 MISO tariff uses the term Price Sensitive Demand Bid for a PRD bid.

5 DRR-Type I includes DR that can provide a given amount of energy through physical interruption. DRR-Type II includes resources that are dispatchable over a range of different output levels.

Because ancillary services, including regulating, spinning, and supplemental reserves, are centrally procured for the system (not procured for or used by individual customers), only the supply-side participation options are possible. Only DRR-Type II can currently provide regulation and spinning reserves. DRR-Type I resources are excluded from the regulation market because they are not sufficiently controllable. The exclusion of DRR-Type I resources from the spinning reserve market is a gap that MISO is currently working on to remedy. Both types of DRRs are eligible to provide supplemental reserves. Current DR participation levels in the ancillary services markets are discussed in Section IV.D.

As an Emergency Demand Response (EDR) resource, DR can offer to be curtailed and receive compensation during emergency events defined by the North American Electric Reliability Corporation (NERC) as Energy Emergency Alert 2 (EEA2) and Energy Emergency Alert 3 (EEA3) events. EDR resources are dispatched based on their daily offers. When called, they receive the higher of the real-time locational marginal price (LMP) or their EDR offer, including shutdown costs. EDR participation is discussed briefly in Section IV.E.

The lack of ARC participation is the most apparent gap in MISO. As discussed in Section V.B.1, existing barriers currently prevent ARCs from participating in any of the MISO markets. MISO has recently submitted a tariff revision to FERC that would eliminate most of those barriers.[6]

A. Timeline and Development of DR in MISO

From the inception of the MISO wholesale energy markets in 2005, DR has been able to participate in the market to some extent. Since then, MISO has implemented several improvements to its operating agreement and business rules to improve the incorporation of DR.

April 2005 — Launch of the "Day2" MISO Energy Market. DR participation as DRR and PRD was part of the original day-ahead and real-time energy market design.[7] DRR participation was allowed both in the day-ahead and real-time energy markets, while PRD participation was limited to the day-ahead energy market only.

December 2007 — DR Included in Module E.[8] MISO filed changes to Module E of its tariff in order to constitute a long-term resource adequacy construct. The proposed design would allow DR participation in resources adequacy. Although not all details had been worked out, MISO requested approval of the overall structure to help narrow down the focus of the stakeholder process.

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6 MISO (2009c).

7 MISO (2004).

8 MISO (2007a).

December 2007 — MISO Files Emergency Demand Response (EDR) Initiative.[9] In response to FERC's comment urging MISO to establish procedures for deploying and compensating DR during emergencies, MISO submitted a new Schedule 30 to its Open Access Transmission and Energy Markets Tariff.[10] The proposal would establish a compensation for DR during emergency events.

May 2008 — Launch of the EDR Initiative.[11] After FERC conditionally approved the EDR filing, MISO launched EDR, which provides additional DR participation opportunities during emergency events defined by the NERC as EEA2 and EEA3 events. In the initial phase, EDR resources were not allowed to submit offers later than 30 days prior to the start of the operating month due the inadequacy of MISO systems to accommodate more flexible bidding. In its order, FERC directed MISO to make changes to its systems that would enable day-ahead EDR offers, without committing it to a specific deadline for accepting such offers, but requiring MISO to provide quarterly status updates.

August 2008 — FERC Order No. 719.[12] After observing a lack of progress in integrating DR in most organized wholesale markets, FERC directed RTOs, subject to certain conditions, to: (1) permit ARCs to bid DR on behalf of retail customers; (2) accept bids from demand resources to provide ancillary services; (3) eliminate deviation charges during emergencies for voluntary load reductions; and (4) assess whether there are any remaining barriers to comparable treatment of DR. FERC's primary objective in enacting these reforms was to ensure that demand resources are treated comparably to generation. Order No. 719 reflects the FERC's view that the wholesale electric power markets work best when demand has the ability to respond directly to the wholesale market price. Details of the following issues had been left to the RTOs to determine:

- *Comparable treatment* – FERC declined to provide a definition, arguing that because each RTO is unique, it should not impose a uniform definition.
- *Technical parameters for DR participation* – FERC declined to define minimum technical parameters and directed RTOs to develop their own standards in conjunction with their stakeholder processes.
- *Baseline methodology and compensation for DR* – FERC encouraged RTOs to coordinate on developing a standardized M&V methodology.[13]

January 2009 — Ancillary Services Market (ASM) Launch. In February 2008, FERC conditionally accepted MISO's proposal to establish a single balancing authority across

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[9] MISO (2007b).

[10] MISO (2007b).

[11] FERC (2008a).

[12] FERC (2008b).

[13] In response, RTOs and stakeholders have been working with the North American Energy Standards Board (NAESB) to develop and adopt DR measurement and verification standards for the wholesale electric markets.

its footprint.[14] In that order, FERC directed MISO to evaluate whether DR was treated comparably to generation. In December 2008, FERC accepted MISO's compliance filing that proposed revisions to remove barriers to the comparable treatment of DR.[15] On January 6, 2009, MISO commenced its ancillary services market and integrated the procurement of regulation and contingency reserves into the energy market. Qualified DR was allowed to submit offers to provide ancillary services.

April 2009 — MISO Submits FERC Order No. 719 Compliance Filing. Primarily within the Demand Response Working Group (DRWG), MISO stakeholders identified potential barriers to DR. A list of identified barriers, including MISO's response, were submitted as part of the FERC Order No. 719 compliance filing.[16]

October 2009 — MISO Submits the ARC Proposal.[17] The most significant provision of Order No. 719 affecting MISO was the requirement that RTOs must enable ARC participation. Existing barriers effectively excluded ARCs from participating in the MISO markets. The ARC Proposal contains revisions to the tariff to remove most barriers identified during the Order No. 719 compliance process, and establishes a compensation mechanism for ARCs.

B. DR Participation in Resource Adequacy

Module E of MISO's tariff establishes a platform that allows demand resources to compete with generation in meeting resource adequacy requirements (RAR). Prior to the beginning of each month, LSEs must satisfy their Planning Reserve Margin Requirement (PRMR), which specifies the amount of capacity that each LSE needs in excess of its forecasted monthly peak load. In order to demonstrate that they meet their PRMR, LSEs must designate sufficient Planning Resource Credits (PRCs), which represent the tested and verified capacity of eligible planning resources.

Module E defines DR as a planning resource. DR may qualify as either of the two types of planning resources: (1) Capacity Resources; or (2) Load Modifying Resources (LMRs). Capacity Resources include Demand Response Resources (DRR), which are treated as supply-side resources and are subject to the same requirements as generating capacity. In particular, DRRs are required to submit offers into the MISO day-ahead energy market, all pre-day ahead and the first post day-ahead Reliability Assessment Commitment (RAC), except when the resource is unavailable due to a forced or scheduled outage.[18] In contrast, LMR obligations are

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14 FERC (2008c).

15 FERC (2008d).

16 MISO (2009b).

17 MISO (2009c).

18 MISO (2009d); Module E, Section 69.1.3. In other RTOs (*e.g.*, PJM and ISO-NE) which treat DR as a supply-side planning resource, the must-offer obligation is not extended to DR.

less extensive, requiring emergency interruption capability at least five times during the planning year. LMRs include Demand Resources and Behind-the-Meter Generation (BTMG). Demand Resources provide capacity by reducing their consumption during emergencies, and may include resources such as interruptible load or direct load control (DLC). Unlike DRRs and BTMG, Demand Resources can be directly deducted from the LSE's PRMR,[19] *i.e.*, they follow the "demand-side" approach discussed in Section III.A. Thus, while the underlying nature of DR may be the same, obligations under the RAR are determined by whether the resource is designated under Module E as DRR or LMR.

The establishment of PRCs has been a significant achievement for MISO. PRCs represent a fungible capacity product, since one megawatt of PRC represents one megawatt of unforced capacity (UCAP), independent of whether it was derived from generation or a demand resource. To account for locational differences of planning resources, Capacity Resources and LMRs are subject to a deliverability test.[20] The result of the deliverability test determines whether the resource can be used to meet PRMR anywhere in the MISO footprint or only within a local balancing area (LBA). Based on deliverability, MISO distinguishes three types of PRCs: (1) aggregate PRCs (APRCs); (2) local PRCs (LPRCs); and (3) external PRCs (EPRCs). APRCs represent the capacity of planning resources that are deemed fully deliverable within the MISO footprint and can be used by any LSE toward meeting its PRMR. Local PRCs can be designated at any commercial pricing node (CPNode) within the same Local Balancing Area (LBA). Capacity of external resources can be converted into External PRCs (EPRC) and may be designated at any CPNode within the LBA into which the owner of the resource has acquired firm transmission service.[21]

Table 2 below summarizes total PRCs from demand response and other traditional capacity resources, based on LSE designations for the forecasted peak month of the first planning year. Total DRRs and LMRs were 8,515 MW which represents 6.8% of total PRCs. DRRs form a negligible portion of the planning resource mix. The majority of LMRs were PRCs from behind-the-meter generation with a total capacity of 4,818 MW, while Demand Resources (*i.e.*, demand response as a "demand-side" planning resource) amounted to 3,620 MW.[22]

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[19] Demand Resources can either be converted into LPRCs, or subtracted directly from the PRMR, but not both. See p. 4.25; MISO (2009f).

[20] MISO uses system impact studies to determine the aggregate deliverability of generation resources, however it has not established a similar method for assessing the aggregate deliverability of LMRs. The FERC has required MISO to develop such a procedure. Recently, MISO has proposed extending its generator deliverability methodology to LMRs. MISO plans to file its proposed permanent solution to LMR deliverability studies with the FERC by early 2010; MISO (2009e).

[21] For first planning year, some LPRCs and EPRCs have been allowed to be designated at any CPNode within the LBA. For future planning years, the EPRC can only be used at the CPNode where the firm transmission rights sink. See pp. 4.34, 5.42-5.43, MISO (2009f).

[22] Note that the amount of DRRs and LMRs may vary by month, reflecting variation in forecasted monthly peak loads. For example, for October 2009, total PRCs from LMRs were 6,245 MW, of which 3,772 MW were from behind-the-meter generators and 2,473 MW were Demand Resources; MISO (2009g).

Table 2
Qualified Planning Resources by PRC Category
During the Forecasted Peak Month of July, 2009[23]

Resource Type	UCAP, MW	Fraction of Resource Mix
DRR	78	0.1%
DR (LMR)	3,620	2.9%
BTMG (LMR)	4,818	3.9%
LPRC (Non-LMR)	7,390	5.9%
APRC (Non-DRR)	103,180	82.7%
EPRC	5,696	4.6%
LMRs and DRRs	**8,515**	**6.8%**
Total	**124,781**	**100%**

Notes:
Resource types shown are mutually exclusive categories.
Quantity of DR resources reflects load reductions at the customer meter grossed up for transmission and distribution losses but not grossed up for planning reserve margins.

The share of DR in MISO's capacity resource mix is comparable, albeit somewhat higher, than in other RTOs. For the 2009/2010 planning year, DR represented 5.6% of the total committed capacity in PJM[24] and 6.4% in New York ISO.[25] In ISO New England, cleared DR represented 6.7% of all cleared capacity in the first Forward Capacity Auction held for planning year 2010/2011.[26]

While MISO's resource adequacy construct has incorporated large amounts of DR, most of it came from legacy utility programs. New DR has not developed significantly. In other RTOs, the development of new DR was largely driven by ARCs, which have been particularly active in capacity markets. For example, ARCs provided as much as 77% of DR enrolled in NYISO's

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23 Data provided by MISO (2009h).

24 In the Base Residual Auction held for the 2009/2010 delivery year, 893 MW of demand resources cleared; PJM (2007). In addition, 6,481 MW of Interruptible Load for Reliability (ILR) was certified; PJM (2009a). The combined total 7,374 MW of DR represents 5.6% of the 132,232 MW of capacity that cleared in the BRA.

25 In the summer of 2009, Special Case Resources represented 2,138 MW, which was 6.4% of the peak load forecast of 33,452 MW; (NYISO (2009)).

26 For the 2010/2011 planning year, 2,279 MW of demand resources cleared in ISO-NE's first Forward Capacity Auction, out of the total cleared capacity of 34,077 MW. Thus, demand response represents 6.7% of total capacity (see ISO-NE (2009a), Table 1-1), but about one third of that is provided by energy efficiency and is not responsive to prices (see ISO New England (2009a), p. 30). Larger amounts of demand response cleared in subsequent forward auctions.

emergency and capacity DR programs, compared to their 44% share in 2003.[27] In ISO New England, ARCs provided an estimated 70% of all new DR that cleared in the first Forward Capacity Auction.[28]

Participation in resource adequacy does not exclude DR from participating in other markets, such as the energy and ancillary services markets. In addition, LMRs that must respond during emergency events under the RAR may also participate as Emergency Demand Response (EDR) under Schedule 30 of the tariff, which also requires response only during emergency events.

C. Day-Ahead and Real-Time Energy Markets

MISO allows economic DR to participate in the energy market on the supply side as a DRR, or on the demand side as PRD. DRRs can be either DRR-Type I or DRR-Type II. The DRR-Type I category includes demand resources that are able to provide a pre-specified amount of load curtailment through physical load interruption, but their output is not fully controllable. This category was created primarily to integrate legacy interruptible and DLC programs into the wholesale energy market. DRR-Type II includes resources that are dispatchable and controllable over a range of different output levels and are either backed by behind-the-meter generation or controllable, typically industrial, load. By using PRD bids, wholesale market buyers can specify a maximum price at which they desire to purchase the designated amount of energy. If the market clears at or below that price, the customer receives the desired amount of energy; otherwise it must curtail its load.

For LSEs, DRR and PRD offer similar market participation opportunities. The main advantage of DRR over PRD is that DRR offers include operational limits of the asset and, like generators, DRRs are eligible for Revenue Sufficiency Guarantee (RSG) make-whole payments if energy market revenues are insufficient to cover the whole DRR offer. Therefore, one might expect LSEs to prefer DRR over PRD; however this is not what we observe in the day-ahead energy market. For reasons we have not been able to determine, DRR participation has not significantly exceeded PRD participation.

In the real-time energy market, MISO does not enable PRD, and therefore DRR is the only option to participate. Enabling real-time PRD bidding would make the market more efficient than LSEs responding to real-time prices, as discussed in Section III.A. (The subsequent sections summarize actual DRR and PRD participation in the MISO day-ahead and real-time energy markets.)

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27 Cappers et al. (2009), p. 23-24.

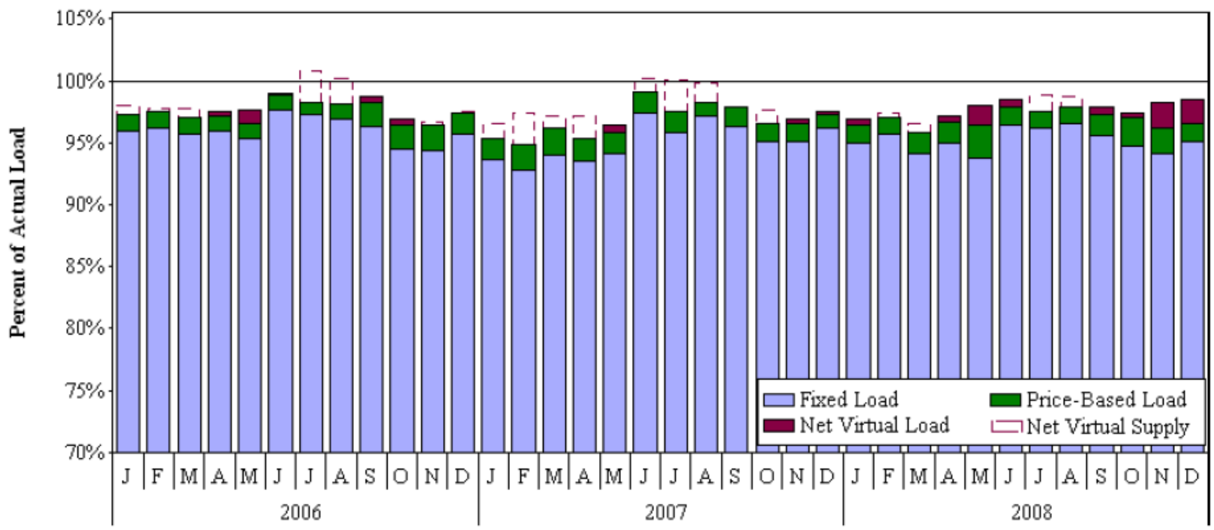
28 Cappers et al. (2009), p. 26. In the first Forward Capacity Auction, 2,279 MW of demand resources cleared. By the third Forward Capacity Auction, total cleared demand resources increased to 2,898 MW. We do not have reliable data regarding how the share of ARCs changed; ISO-NE (2009a) and ISO-NE (2009b).

It should be noted again that market participants other than LSEs and direct wholesale customers can not yet participate in the energy markets until the ARC Proposal is implemented later this year. Until then, ARCs can not participate as DRR due to the existing barriers discussed in Section V. Nor can they participate as PRD. PRD is a “demand-side” approach that can never work for market participants such as ARCs that do not own load.

PRD Participation in the Day-Ahead Energy Market

Since the start of MISO's day-ahead energy market in 2005, there has been limited demand-response participation through PRD. As illustrated in Figure 1,[29] most load in the day-ahead market clears through fixed demand bids rather than through PRD bids. In 2008, for example, PRD bids accounted for less than 2% of total cleared demand. Although there has been some regional variation, cleared PRD bids did not exceed 9% of total load in any parts of the footprint.[30]

Figure 1
Demand Bidding in MISO[31]



It should be noted that the PRD data presented in Figure 1 excludes LSE load reductions that occur without being bid into the day-ahead market, including some retail-level direct load control (DLC) and interruptible programs, as well as some industrial customers on dynamic prices. When load curtailments occur at the LSE's distribution level, they may not be visible to MISO. Nevertheless, there is strong evidence that such load reductions are significant. For example, a

29 Taken from the 2008 State of the Market Report of the Independent Market Monitor for MISO; Figure 24, Potomac Economics (2009).

30 Source: 2008 SOM, page 36: "Price-sensitive physical load accounts for less than two percent of total load scheduled market-wide (it peaks regionally in WUMS at nine percent)."

31 "Fixed Load" represent load bids that clear irrespective of the market price. "Price-Based Load" represents PRD bids that clear only if the market clearing price is less than the bid price. "Virtual Load" and "Virtual Supply" shown on the figure are not PRD bids. Virtual bids are speculative or hedging financial positions that do not result in an overall purchase or sale of energy, instead energy is purchased (or sold) day-ahead with the same quantity sold back (or purchased back) in real time.

recent survey for the Midwest Distributed Resources Initiative (MWDRI) found that, although utilities historically used DR programs for reliability, the development of the MISO wholesale energy market has led many utilities to modify their legacy programs to include market price as an operational trigger.[32] The survey found that 70% (2,876 MW) of all DR in MISO on interruptible rates or DLC programs, included in the survey, could be triggered by the LSE in response to high market prices. LSEs responding to the survey also indicated that, although they wished to reduce their exposure to high energy market prices, they were reluctant to use PRD bidding in the day-ahead energy market, and instead preferred to dispatch the interruptible and DLC programs themselves when they anticipated high prices. This sentiment among utilities was confirmed by the responses we received to our survey questions as well as through interviews that we conducted with MISO market participants.

1. DRR Participation in the Day-Ahead and Real-Time Energy Markets

DRR participation in MISO's energy markets was very small prior to the launch of the ASM in January 2009, but it has significantly increased since then. As of the end of September 2009, 23 resources were actively participating as DRR in the MISO real-time or day-ahead energy markets, of which 19 resources were DRR-Type I and four resources were DRR-Type II.[33] The number of resources participating in the day-ahead energy market exceeded the number of resources in the real-time energy market by five. The total capability of all active DRR resources was 1,390 MW, of which DRR-Type I resources provided 1,282 MW, and DRR-Type II resources contributed 108 MW. Both groups of DRR resources were dominated by a single resource: over three-quarters of total DRR-Type I capability was provided by one facility, and over half of total DRR-Type II capacity was from one resource.

On average, 80 MWh of real-time DRR offers and 22 MWh of day-ahead DRR offers cleared from the start of the ASM in January through the end of September, 2009. Cleared DRR-Type II offers were about 20 MWh on average and virtually all of them represent sales in support of regulation offers. Current rules require DRR-Type II resources that do not normally buy energy in the wholesale market to purchase day-ahead energy in order to be able to submit regulation offers. Such purchases of day-ahead energy are subsequently offset by sales in the real-time market, and therefore, they do not represent a true load reduction.

Apart from the two large DRR-Type I and DRR-Type II facilities mentioned, active participation of DRRs in the energy market has been limited. Low market prices of energy have not been conducive to the development of active DR. Another reason limiting DR participation may be that existing barriers raise the cost of participation and exclude ARCs, as discussed in Section V.

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32 Bharvirkar *et al.* (2008).

33 Data provided by MISO (2009i).

D. DRR PARTICIPATION IN THE ANCILLARY SERVICES MARKETS

DRR participation has been allowed since the launch of the ASM in January 2009, but only DRR-Type II resources have been allowed to provide regulation and spinning reserves. To date, only a single resource offered regulation and spinning reserves, although MISO is the only RTO that has attracted active DR participation in the regulation market. Average cleared regulation from DRRs was 16 MW in the real-time market, and 17 MW in the day-ahead market.

On average, only about 3 MW of DR offers to provide spinning reserves cleared, which is much less than in other RTOs. For example, PJM has much more widespread DR provision of spinning reserves. In PJM's Mid-Atlantic subzone, DR provided all spinning reserves in 32 percent of the hours in 2008, when the Tier 2 synchronized reserve market cleared.[34] PJM's spinning reserve prices during those hours were much lower than in the rest of the hours, likely due to the low opportunity costs of providing spinning reserve with DR.

Both DRR-Type I and Type II resources are allowed to offer supplemental reserves, however during 2009, virtually all cleared offers were from Type I resources alone. Between January and September, 2009, an average of 157 MW DRR-Type I resources cleared in the real-time market, and 53 MW in the day-ahead market. Since MISO carries about 1,050 MW of supplemental reserves, DR has represented 5% to 15% of the total supplemental reserve requirement.

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[34] Monitoring Analytics (2009), pp. 331.

E. EMERGENCY DR INITIATIVE PARTICIPATION

Emergency DR, launched in 2008, is a special initiative of MISO that compensates registered resources for curtailments during NERC EEA2 and EEA3 events. Approximately 300 MW of DR is registered as EDR. It is somewhat surprising that compared to RAR participation, EDR registrations are relatively small. The performance requirements between the two participation opportunities are similar, and DR is allowed to participate in both concurrently. One possible explanation may be that since EEA2 and EEA3 events are relatively rare, market participants are unwilling to incur the initial costs to participate in EDR as compensation is only provided when a resource is called during an emergency.

An initial concern with the EDR initiative was that EDR offers were accepted by MISO only on a monthly basis. Effective July 1, 2009, MISO allows participants to submit daily offers. However, EDR offers (capped at $3,500/MWh) cannot set the LMP. In its October 21, 2009 informational filing[35] MISO stated that its current systems are not adequate to permit LMP-setting by EDR resources because such resources are not able to move incrementally in response to small changes in conditions. MISO will continue to work to allow EDR resources to set the LMP as part of its efforts to accommodate all fixed-block resources.

[35] MISO (2009j).

V. OVERVIEW OF MISO'S PROGRESS IN ELIMINATING IDENTIFIED BARRIERS TO DR

Following an extensive stakeholder process to identify barriers to DR, MISO submitted a report on the remaining barriers to DR in its compliance filing to FERC Order No. 719 on April 28, 2009.[36] As discussed below, the April Compliance Filing was largely a roadmap of how to remove the identified barriers, while the recent ARC Proposal[37] is a significant step in implementing tariff changes necessary to remove those barriers. This section first summarizes the current status of each identified barrier, and then discusses in more detail the potential concerns with respect to the ARC Proposal and the remaining barriers to DR.

A. MISO'S PROGRESS IN ELIMINATING STAKEHOLDER-IDENTIFIED BARRIERS TO DR

The April Compliance Filing identified ten barriers that MISO and its stakeholders determined were the most significant to DR. This section describes the nature of each identified barrier and evaluates whether the ARC Proposal (or other provisions) will eliminate the barrier.

1. Barrier #1: DRR is not treated as an independent resource

The MISO tariff requires a DRR to be linked to a host load that is owned by the same market participant. In other words, the DRR provider and the LSE must be the same entity. This requirement restricts the pool of potential DRR providers to LSEs and direct wholesale customers. Furthermore, the requirement to have a one-to-one relationship between the DRR asset and host load creates a barrier for ARCs because they cannot make DRR offers without an offsetting bid to purchase energy. The strong link between DRR and host load was in part necessary because MISO does not have a conventional customer baseline methodology[38] or a compensation mechanism that could treat DRR as an independent resource.

The recent ARC Proposal will eliminate the requirement to link the DRR and host load to the same market participant for all types of DRRs.[39] It will eliminate the requirement to link DRR to a host load for all but regulation-qualified DRR-Type II resources. MISO argues that maintaining the strong link between DRR-Type II assets and host load is necessary for regulation-qualified resources, because due to the nature of regulation service, more rigorous load forecasting and metering requirements are warranted. Thus, if approved, the proposed tariff

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36 MISO (2009b), Attachment D: Report on Barriers to Comparable Treatment for DR Resources.

37 MISO (2009c).

38 MISO uses the Load Zone Dispatch Interval Demand Forecast, which is a 5-minute forecast of the host load, to measure the output of DRRs.

39 MISO (2009d), Sheet No. 793.

revisions in the ARC Proposal will remove this barrier for all DRRs except regulation-qualified DRR-Type II resources.

2. Barrier #2: Metering requirements for real-time telemetry or one-minute interval-metering is cost-prohibitive

Stakeholders have expressed that current metering requirements are unreasonable for resources that provide energy. For smaller resources, the cost of real-time telemetry may be prohibitive. Alcoa, which participates as a DRR-Type II resource, reported that the cost of installing new telemetry, an energy management system, a bidding interface, and a new database system to facilitate interactions with the market cost more than $750,000.[40] At this cost, participation is economically feasible only for large industrial customers such as Alcoa. Furthermore, MISO's current metering requirements are unreasonable in comparison with other RTOs. PJM, NYISO, ISO-NE do not require real-time telemetry in the energy market, and the required metering interval is generally longer than one minute.

The ARC Proposal will change the metering requirements, allowing hourly metering measurements for energy provision and five-minute metering measurements for contingency reserve provision. Metering requirements will remain unchanged for DR offering regulation. The new metering requirements would remove a significant barrier to small DR participation and will put MISO's metering standards in line with the practices of other RTOs. The new metering requirements seem appropriate and are more accommodative than in other RTOs.

3. Barrier #3: Forecasting requirements of host load (Load Zone Dispatch Interval Demand Forecast) is a barrier to participation

Under current rules, DRRs are required to submit a load forecast for the host load zone for each five-minute interval of the hour in which the resource is dispatched. Energy and ancillary services market penalties for non-performance are based on the deviations between metered consumption and the five-minute interval load forecast. Since anyone other than the LSE serving the host load would find it difficult to provide an accurate load forecast on a five-minute basis, this requirement constitutes a significant barrier to DRR providers that do not act as an LSE.

The ARC Proposal includes a new measurement and verification methodology based on a historical customer baseline that will remove this barrier for all DRR-Type I resources, as well as all DRR-Type II that are not regulation-qualified. Conditional on successful implementation of a new customer baseline-based M&V methodology, we believe that the ARC Proposal may eliminate this barrier. The success of the of the ARC Proposal depends on the details of the M&V methodology which are not yet known, although they should be developed by June 1,

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[40] Alcoa (2008).

2010, when the ARC Proposal is implemented. Another remaining concern is that the ARC Proposal will not eliminate this barrier for regulation-qualified DRRs, although we recognize the need for more rigorous load forecasting requirements for resources that provide regulation.

4. Barrier #4: Credit requirements for ARCs should not be too high

Some MISO stakeholders expressed concern that if the credit requirements for ARCs are set at an inappropriately high level, it may act as a barrier to DR. Under MISO's credit policy,[41] market participants must establish unsecured credit to cover their potential exposure to market losses and penalties.

The ARC Proposal would amend Attachment L of the ASM tariff[42] to calculate potential exposure for ARCs as the product of: (a) the maximum MW capacity of the resource; (b) 345 hours; (c) the average historical day-ahead price for the preceding three months; and (d) five percent (5%). The same formula applies for generators, except 720 hours are used instead of 345 hours.

This proposed credit limit for ARCs reflects the assumption that a DR resource is expected to operate less frequently than a comparable generator. During the drafting phase of the ARC Proposal, some stakeholders expressed concern that the use of 345 hours to calculate total potential exposure for ARCs was too high, and that the assumed operating hours for DR should be based on actual experience with those resources. Given the very limited experience with DRR participation in MISO market, we find that it is too early to tell whether the use of 345 hours in the total credit exposure formula is too high. Furthermore, under MISO's current credit policy, total potential exposure is calculated the same way for all types of generators, including peaking units that are expected to operate much less often than 720 hours per month.

An additional concern raised by stakeholders was that requiring a minimum credit amount from ARCs, irrespective of the size of their portfolio, may be unreasonable. The minimum credit requirement for ARCs is the greater of (a) \$414 per MW; or (b) the minimum credit requirement applicable to load, which is a function of recent LMPs.[43] The credit floor may be a barrier for smaller resources if it results in a per-MW credit requirement that significantly exceeds that of larger ARCs or generators. Since the minimum credit limit is a function of LMPs, this may become a more serious concern if prices rise in the future.

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41 MISO (2009d), Attachment L.

42 MISO (2009d), Tariff Sheet No. 2476.

43 As of November 1, 2009 the minimum credit limit applicable to load was \$17,265.

5. Barrier #5: Demand resources have strict limits in their ability to transact business as part of Module E requirements

Under current rules, capacity associated with demand resources can only be traded bilaterally within the Local Balancing Area. This deteriorates the value of the capacity of the resource and creates a situation where demand resources are not treated comparably to generation resources. It also prevents ARCs from offering capacity directly in the MISO Voluntary Capacity Auction. Since issuing its FERC Order No. 719 compliance filing, MISO has proposed a long-term approach for determining the aggregate deliverability of LMRs.[44] MISO proposes to utilize the existing generator deliverability study methodology specified in Business Practices Manuals (BPM) to evaluate whether each LMR is aggregate deliverable. This approach would allow the use of system impact studies for multiple resources in close proximity, which could reduce the study cost for each individual resource. It remains to be seen whether the cost of system impact studies will significantly raise the cost of market participation and become a significant barrier for DR.

6. Barrier #6: DRR-Type I Demand Resources cannot offer spinning reserve service

Until recently, MISO applied Reliability*First* Corporation's (RFC) default reliability standard which excludes DRR-Type I resources from offering spinning reserves.[45] The RFC actually allows RTOs to develop their own methodology regarding the types and amounts of reserves needed for their footprint. The RFC default requirement is that no more than 25% of Contingency Reserves-Supplemental and 0% of Contingency Reserves-Spinning can be obtained from interruptible load. In contrast to MISO, PJM, also a member of RFC, has allowed DR to provide synchronized reserves (PJM terminology for spinning reserves) since 2006.

In response to FERC Order No. 719, MISO indicated in its April Compliance Filing that it would move away from its current implementation of the RFC standard and started a stakeholder process to investigate the possibility of allowing DRR-Type I resources to offer spinning reserves. It indicated that the total amount of spinning reserves from DR would be capped at 10%.[46] Integrating DRR-Type I resources into the spinning reserve market requires a change in MISO's software. MISO is currently implementing the necessary changes, and expects full integration of DRR-Type II resources in the near future.

In its Order No. 719, FERC required RTOs to incorporate bidding parameters allowing DR to specify limits on the frequency and duration of service in their ancillary service bids. These

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44 Such implementation must take place by May 1, 2010; MISO (2009e).

45 Standard BAL-002-RFC-02. RFC (2007).

46 In the stakeholder discussions (DRWG) this number was supported by an estimated 15% potential DR participation in the spinning reserve market, however to our knowledge, no study was prepared to support the 10% cap.

bidding parameters must include maximum duration for dispatch (in hrs), a maximum number of times per day that DR resources could be called, or a maximum amount of energy per day or week that a resource can produce. These bidding parameters are intended to mitigate the DR "fatigue effect," or DR customers' reduced desire to participate when they are more frequently called upon. FERC declined to establish regional minimum requirements for the DR bidding parameters. The current status of bidding parameters in MISO is included in the discussion of Barrier #8 that follows.

Overall, MISO has taken a significant step by incorporating all DR resources into its ancillary services market, however, it should monitor the effects of the 10% cap on DR participation and raise the cap in the future if necessary. Other RTOs have established significantly higher upper limits (25% in PJM[47] and 50% in ERCOT[48]), and their experience can provide valuable lessons to MISO.

7. Barrier #7: Demand resources cannot currently specify limits to product selection

Under the current tariff, DRRs must submit offers for all products and services that a given resource is qualified to provide. For example, if a resource qualifies to provide regulation and energy, it is not allowed to make an offer for energy without an offer for regulation. In its April Compliance Filing, MISO argued that this restriction applies to all market participants (*i.e.*, generators), and that the "elimination of this requirement would result in major modifications to MISO's system logic with little concomitant benefit. MISO commits to continue to review and analyze any appropriate modifications to these design requirements."

The FERC's Notice of Proposed Rulemaking (NOPR)[49] preceding Order No. 719 contained a provision that DR providers should be allowed to sell into the ancillary services markets without being required to offer into the energy market. This provision was later removed from the final order. FERC argued that allowing DR resources to bid into the ancillary services markets without also bidding into the energy markets could upset certain market efficiencies in co-optimized markets. FERC also stated that as long as a DR is allowed to specify limits on the frequency, duration, and the amount of its offers for each energy and ancillary service product, the resource should be able to indirectly select the resource it wishes to offer. Therefore the RTO must either establish sufficiently flexible offer parameters that allow implicit product selection, or it has to provide demand resources the option to explicitly choose the product they intend to supply. As discussed in the next section, MISO has not yet modified its bidding parameters to specify limits separately for each type of energy and ancillary service offer.

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47 PJM (2009c), pp. 79.

48 Load Acting as Resource (LaaRs) are allowed to provide up to 50% of the total ERCOT Responsive Requirement for any given hour; ERCOT (2009).

49 FERC (2008e)

8. Barrier #8: Demand resources should be allowed to specify limits to use of their resources

In Order No. 719, FERC stated that DR should have the ability to specify limits on the frequency, duration, and amount of each product they offer into the wholesale market. During the compliance process, MISO stakeholders identified the lack of appropriate DRR offer parameters as a potential barrier to DR. In the Transmittal Letter to its April Compliance Filing, MISO responded that its market design allows DRR-Type II resources to specify such limits both on their day-ahead[50] and real-time offers[51] into the energy and operating reserve markets. In particular, Minimum and Maximum Run Time parameters limit the number of hours that a unit may be dispatched per day. The Maximum Start-Up Limit allows DR to specify the highest daily frequency of its dispatch, and the Hourly Economic Minimum and Maximum Limits cap the amount that the resource can offer. DRR-Type I resources can specify limits on the duration of their service through the Minimum and Maximum Interruption Duration offer components in both the day-ahead[52] and real-time markets.[53]

In the April Compliance Filing, MISO also recognized that bidding parameters specifying limits on the frequency and the amount of services offered by DRR-Type I resources were not in place. To rectify this deficiency, it amended the tariff to include two new offer components for Type I resources: (1) Maximum Interruption Limit (maximum number of times DR may be called upon); and (2) Maximum Daily Energy (maximum amount of energy DR offers to supply). The new tariff provision became effective on June 27, 2009. With these modifications, the current tariff language should provide sufficient flexibility to DR resources to limit the duration, frequency, and the amount of their service, as required by FERC. However, DRR offers include joint offers for both energy and ancillary services, and they do not contain sufficient parameters to limit duration and frequency separately for each offered product. Therefore, in our view Barrier #8 is no longer a significant impediment to demand resource participation; however, Barrier #7 related to product selection still remains a concern.

9. Barrier #9: Comparable compensation of DRR-Type II assets

Alcoa, an active provider of DDR-Type II resources in the MISO ancillary services market, has argued that as a supplier it does not receive compensation comparable to generators providing the same regulation service. Most of Alcoa's load is served by its behind-the-meter generators. In order to provide ancillary services, it is not allowed to offer these units into the market as generators, but must purchase energy in the day-ahead energy market in order to be able to submit offers for regulation. As a result, Alcoa incurs additional costs and risks that

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[50] MISO (2009d), Section 39.2.5.

[51] MISO (2009d), Section 40.2.5.

[52] MISO (2009d) Section 39.2.5A.

[53] MISO (2009d), Section 40.2.6.

interconnected generators providing regulation do not face, including: a requirement to purchase load to offset DR curtailments; price risk relative to day-ahead and real-time markets associated with having to purchase load in day-ahead market and resell load in the real-time market; administrative charges associated with buying and selling load; inability to specify limits for participating in various markets; and inability to access capacity markets.

Alcoa claims that these issues create a 20-30% impact on the daily profitability of its DRR-Type II resource when compared with a generator providing the same services. In its April Compliance Filing MISO argued that it does not see this as a barrier, since the same requirements apply to all other resources. MISO raised as a possible solution the integration of behind-the-meter generators into its wholesale markets. It has not yet addressed this barrier, which may continue to discourage some DR resources from supplying regulation. MISO should consider implementing changes that allow these resources to offer regulation only, without having to purchase energy in the MISO energy markets.

10. Barrier #10: ARCs are not clearly defined in the MISO Tariff, and a specific BPM that designates requirements for aggregated DRRs to participate in MISO markets does not exist

This was a significant barrier, as it created uncertainty regarding the role that ARCs could play in providing DR in the MISO market. The recent ARC Proposal has sufficiently addressed this issue by defining ARCs as a market participant[54] and defining the role and responsibilities of ARCs, the registration requirements, and the relationship between ARCs and LSEs.[55]

B. Remaining Barriers and Concerns

1. Assessment of the Likely Overall Efficacy of Current ARC Proposal

MISO's current treatment of DR accommodates only DR offered by LSEs and large, controllable industrial loads. LSEs do not always have the incentive or the capability to develop new DR, which is the primary reason why other RTOs provided access for ARCs early on.[56] The ARC Proposal has the potential to attract DR from aggregated, smaller resources. Although ARCs could contract directly with LSEs to provide their services to aggregate customers and administer the program on behalf of the LSEs (a practice that is common in some markets such as

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54 MISO (2009d), Module A, as amended by the ARC Proposal.

55 MISO (2009d), Module C, as amended by the ARC Proposal.

56 For discussion, see *The Brattle Group* (2008).

California), we do not know of any ARCs providing such aggregation service to any LSE in the MISO footprint. Other RTOs that enabled direct wholesale market participation by ARCs, such as PJM, ISO New England, and NYISO, have managed to successfully integrate large amounts of new, ARC-enabled DR into their markets.

In developing its ARC Proposal, MISO was guided by the minimum requirements that FERC established in Order No. 719, including that: (1) DR bids of ARCs must be verifiable; (2) M&V methodology should be comparable to the M&V methodology applicable for other providers of DR, such as LSEs; (3) DR bids of ARCs and large industrial customers must not be treated differently; (4) an individual customer may be an ARC of itself; (5) RTO membership may be required; and (6) aggregated bids may be restricted to a single area, reasonably defined. MISO's ARC Proposal meets these minimum requirements. Furthermore, the ARC Proposal clearly states that it applies to all aspects of the MISO wholesale markets, and thus opens up a range of participation opportunities for aggregated DR.

Furthermore, the ARC Proposal establishes a compensation mechanism for energy provided by DR from ARCs. Net compensation received by ARCs would equal the LMP reduced by the Marginal Foregone Retail Rate (MFRR), which is a proxy for the curtailed customer's retail rate. MISO proposes to recover this payment through a charge to the host LSE. As discussed in Section V.B.2, this is the most economically efficient approach to DR compensation, and there are several examples from other RTOs that have chosen less efficient approaches to compensating DR.

Overall, we find that the ARC Proposal is a positive step forward. If approved by FERC, it will enable ARCs to participate in the MISO markets starting in June 2010. However, this does not mean that ARC activity will increase rapidly and immediately. ARC penetration will still depend on the action taken by state retail regulatory authorities regarding whether and to what extent ARCs will be allowed to participate. Further, if the current low prices for capacity and energy persist due to depressed economic conditions, actual ARC participation may not occur until some time after that date.

Going forward, there are some relatively minor concerns with the ARC Proposal, including (a) potential for disputes over the MFRR between LSE and ARC may act as a barrier; (b) details of M&V methodology are yet unknown; and (c) Relevant Retail Regulatory Authority (RERRA) response to the ARC Proposal.

a. Potential Disputes between ARCs and LSEs Over the Marginal Foregone Retail Rate

The ARC Proposal stipulates[57] that ARCs serving retail customers of LSEs that had prior-year sales exceeding four million MWh will be able to determine their own MFRR. The corresponding LSE will have the opportunity to accept or reject the MFRR proposed by the

[57] 38.6.2 (a).

ARC. If the LSE objects, the dispute will be resolved through the dispute resolution procedures under Attachment HH of MISO's tariff. If MISO is unable to resolve these disputes in a timely manner, the mediation delay may act as a potential barrier to ARC participation.

b. Undetermined Measurement and Verification Methodology

MISO has not yet defined its M&V methodology, which makes it difficult to evaluate. The ARC Proposal states that details of its new M&V methodology will be specified in a new Business Practices Manual. Customer baselines are an important factor in determining the appropriate compensation for DR. Customer baselines should be designed to depict, as accurately as possible, a customer's normal, uncurtailed load on a given day. Establishing a customer baseline helps the RTO to measure and verify load reductions. A flawed M&V methodology could undermine the success of the entire ARC Proposal. A well-structured baseline should be based on: (1) historical load, so that the DR customer does not have the ability to change it after the fact; (2) sufficiently recent data, so that it reflects current baseline load.

Even following these general guidelines may not guarantee success. For example, in 2008 ISO-NE realized that it was paying compensation for non-existent load reductions under its Day-Ahead Load Response Program. Even though the customer baseline load (CBL) was based on a rolling 10-day average load, program participants were able to freeze their baselines by bidding into the day-ahead energy market. As a result of higher energy prices, DR offers cleared almost every day, despite the minimum offer price of $50/MWh for DR. Since days when DR offers clear are considered event days and excluded from the CBL, market participants could freeze their baselines at levels that did not accurately represent what their consumption would have been absent the DR. ISO-NE requested FERC to approve a revision to its CBL methodology.[58] Similarly, in 2008 PJM identified a flaw in the CBL methodology used for its economic DR program.[59]

c. RERRA Response to ARC Proposal

Some stakeholders have expressed a concern that RERRAs, may impose a barrier to DR integration through ARCs by specifically prohibiting the aggregation of retail customers. However, in their joint comments to FERC most members of the Organization of MISO States

58 ISO-NE (2008), pp. 82-83.

59 Monitoring Analytics (2009), pp.105-111.

(OMS) have expressed support for MISO's ARC Proposal.[60] It remains to be seen what course of policy individual states will follow with respect to ARCs.[61]

2. Wholesale Market Compensation of DR

Determining the amount of compensation that ARCs should receive for providing energy from DR is a controversial issue in most RTOs. One line of argument is that one MWh of energy from DR provides the same service as dispatching one additional MWh of generation, and since the two services are apparently identical, both resources should receive the same compensation at the LMP. However, this level of payment is not efficient because the decision not to purchase energy *is not* the same as physically supplying energy. The efficient payment to DR is the LMP minus the customer's retail rate. This achieves the same outcome as if the customer had to first purchase energy at the retail rate (analogous to buying fuel or purchased power) before being able to sell unused energy into the market at the market price. Since the customer does not in fact pay for energy not consumed, reducing load provides the customer savings equal to the retail rate. If that customer also receives a payment equal to the LMP minus the retail rate, the total savings from foregoing consumption is the full LMP.

Any compensation to DR higher than the LMP minus the retail rate distorts consumption decisions to inefficiently low levels.[62] To illustrate this point, consider a consumer that has a behind-the-meter generator (BTMG) with a variable cost of $250/MWh.[63] Assuming the retail rate is $120/MWh, the consumer would be willing to run its generator if it receives compensation of at least $130/MWh (*i.e.*, the difference between the generator variable cost and the retail rate). If the LMP is $140/MWh and the consumer were entitled to receive the full LMP for its BTMG-based DR, the customer would want to run its generator. The effect would be to replace $140/MWh marginal generation in the wholesale market with $250/MWh generation, which would be economically inefficient and a waste of fuel. If the customer were instead entitled to receive only the LMP minus the retail rate, or $10/MWh, it would be unwilling to run its own generator, and the last MWh of load would be efficiently served from the lowest-cost resource.

MISO's ARC Proposal would establish an efficient DR compensation mechanism that is similar to the approach currently in effect in PJM. In the PJM market, DR receives the LMP less the retail rate, and the payment is recovered from the host LSE. Before the end of 2008, PJM had a DR subsidy in place. When the LMP exceeded $75/MWh, DR received the full LMP; below the

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60 The Illinois Commerce Commission abstained from the vote on joint OMS comments; OMS (2009).

61 The Indiana Utility Regulatory Commission (IURC) has recently started an investigation into matters related to IURC approval of participation by Indiana retail customers in MISO's demand response programs. The case is still pending; IURC Cause No. 43566.

62 For a more detailed discussion of the distortionary effects of inefficient DR compensation see Chao (2009).

63 The same argument applies to a customer without a BTMG who values energy consumed at $250/MWh and has the operational flexibility to reduce its load.

$75/MWh threshold the compensation was LMP less the retail rate. The rationale for the subsidy was to provide an extra incentive to DR and to partially fund metering infrastructure costs.[64] Other RTOs (*e.g.*, ISO-NE, NYISO) continue to pay the full LMP to DR.

Many DR providers argue that DR creates positive externalities that justify paying more than the LMP.[65] This argument faces several challenges. First, although DR may potentially reduce wholesale market prices, these price reductions are not technically an "externality" but a wealth transfer from suppliers to DR customers. It is not the RTO's job to promote such transfers by subsidizing DR, just as the RTO should not subsidize new generation or uneconomic dispatch to depress wholesale prices. Further, the price-reducing effects of DR may be small and transient if short-run price reductions cause generation to exit the market, creating an offsetting price effect. Another category of potential externalities is environmental. Nevertheless, DR is not likely to produce large environmental benefits since it generally has a small effect on the total energy consumed. Perhaps one exception is that DR can reduce NO_X emissions on critically high-demand, high-ozone days in non-attainment areas.

Compensation of DR for providing energy remains a hotly debated topic. Even without overcompensating DR, the RTO must recover payments to DR through a separate charge in order to remain revenue-neutral. This charge should be allocated to those market participants who benefit from the load reduction. The host LSE benefits through the avoided cost of the energy no longer needed as a result of the DR. Other market participants may also potentially benefit, if DR affects market prices, but those benefits are likely to be smaller than the savings that accrue to the LSE. Allocating charges to the host LSE, as MISO proposed, is non-distortionary and probably the most fair. If the LSE funds the DR payments but still receives the retail rate through the ARC, its net cost is the same as if the customer had not reduced (*i.e.*, as if the customer consumed its baseline and not provided DR). Furthermore, the load reduction reduces the need for generation, which achieves savings equal to the LMP for each MWh of load reduced. These savings free up just the right amount of funds (that are now not being paid to generators) to compensate both the ARC and the LSE. The ARC receives the LMP minus the retail rate, and the LSE receives the retail rate, for a total payout equal to the LMP. Most of this is presumably passed on to the customer, although some would be retained by the ARC to cover its administrative costs.

Even if the LSE is held harmless, it will still be concerned about DR to the extent that it affects its day-ahead demand bidding and its exposure to real-time prices and RSG charges. The LSEs may also be concerned that customers could possibly game their baselines and get paid without providing real load reductions. Thus, some other RTOs have chosen to allocate charges for DR payments more widely than MISO has, to all LSEs within a constrained area or all LSEs in the

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[64] On August 26, 2009, PJM made a filing at FERC to re-introduce incentive payments for DR customers that provide load reductions in the top 9% of high-priced hours. The proposal includes a sunset provision and is currently awaiting FERC approval (see PJM (2009d)).

[65] The positive externalities may include a dampening effect on wholesale market prices and environmental benefits.

market.[66] These cost allocation options might be justified if there are widespread externalities to other customers. However, the existence of such externalities is questionable, as discussed above.

Compensation to DR for providing capacity, ancillary services, and emergency DR is more straightforward because these products are distinct from energy and are not consumed by anyone under a retail rate. Therefore there is no lack of alignment between retail rates and wholesale prices. Consequently, the right amount of compensation to DR for providing any of these products is to pay the relevant product-specific market-clearing price.

3. Remaining Barriers to DR Integration

Although MISO has addressed all of the primary barriers to DR in its markets, there remain a few more minor barriers. The remaining barriers are categorized as follows: (1) treatment of DR not fully comparable to generation in some areas; (2) lack of capacity price transparency; (3) uncertain or yet undetermined future rules and protocols; and (4) bidding and modeling issues.

a. Treatment of DR Not Fully Comparable to Generation in Some Respects

There are some aspects of the MISO market design where the treatment of DR is still not fully comparable to generation, including the treatment of LMRs in RAR, as well as RSG payments to DRRs. Although the treatment of DR may not be fully comparable to generation, these are not likely to be significant barriers to DR.

Under the resource adequacy construct, LMRs may be disqualified for one planning year after failing to perform on two separate occasions. This does not apply to generating capacity and DRRs, and thus, constitutes unequal treatment between different capacity resource types.

As discussed earlier, DRRs are treated as supply-side resources and are eligible for RSG make-whole payments in the same manner as generators. These make-whole payments are designed to ensure that suppliers offering their resources receive the full offer price if market revenues are not sufficient. Currently, any make-whole payments must be fitted into generator make-whole mechanisms that do not fit demand resources. For instance, a demand resource must submit fuel, operating and maintenance, and start-up costs. Stakeholders commented that there is no clear guide to translating DR production costs into equivalent generation costs.

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[66] For example, NYISO and ISO-NE.

b. Capacity Price Transparency

In other RTOs, ARCs rely on capacity payments as their primary source of revenue. Therefore ARCs require price signals that reflect the market value of capacity. The Voluntary Capacity Auction administered by MISO is a residual market to meet short-term capacity needs, and as such it produces highly volatile prices at low cleared volumes. Most capacity transactions in the MISO footprint are made in the bilateral capacity market. Bilateral markets do not have a transparent market value of capacity since most transactions are made between private parties. The bilateral capacity market appears to be sufficiently liquid, although it is possible that the limited capacity price transparency may discourage ARCs.

Other RTOs that have attracted significant amounts of new DR through ARCs (*e.g.*, PJM, ISO-NE) operate centralized, mandatory capacity markets with very transparent pricing. These RTOs do not preclude bilateral trading of capacity. In fact a very large fraction of capacity transactions involve bilateral contracts. However, since the RTO-administered capacity market is mandatory, one can expect the capacity prices in the bilateral market and the RTO capacity auctions to converge. Therefore, ARCs can gauge the market value of capacity by examining the RTO auction-clearing prices. Price discovery in these markets entails a trivial cost to ARCs, while in bilateral-only markets they may have to expend greater resources to find the market value of capacity. A centralized, mandatory capacity market is not the only way to achieve price transparency. MISO should form a focus group with ARCs and other market participants to determine what options are available to increase capacity price transparency across its footprint.

c. Uncertainty about LMR Deliverability

There is considerable concern about how the deliverability of LMRs and the future capacity value of DR will be determined as part of the resource adequacy construct. The Supply Adequacy Working Group (SAWG) has been trying to develop a permanent policy for LMR deliverability, and MISO has put forward a proposal regarding the deliverability of LMRs. Some stakeholders are concerned that DR would have to pay for the deliverability study, which may create a barrier especially for smaller resources. MISO should strive to establish permanent rules for DR deliverability as soon as possible.

d. Bidding and Modeling Issues

There are some relatively minor issues related to DR bidding and modeling, including: (1) lack of PRD bidding in the real-time energy market; (2) inability of DRR-Type I resources to set real-time prices; and (3) bid parameters in regulation offers.

MISO currently does not allow PRD bids in the real-time energy market. This could limit participation and price-setting ability, although real-time participation is enabled for DR acting as a DRR supply-side resource. Given that price-responsive bids are not allowed and DRR participation is limited, real-time market demand is very inelastic. PRD bidding is the best way to integrate existing utility programs into the wholesale market. These programs were initially developed for reliability purposes and dispatched only during system emergencies. However, as the MISO competitive wholesale markets have developed, most utility demand programs in its footprint have incorporated additional operational triggers, including market prices. A recent survey[67] of utility DR programs in the MISO footprint found that two thirds of the utility-administered interruptible and direct load control programs, representing about 2,214 MW of DR capability, can be triggered in response to high market prices. Utilities in the survey indicated that they are reluctant to bid their DR into MISO's day-ahead market directly, but instead dispatch these programs closer to real-time if prices are high. It must be noted that real-time PRD bidding is not yet implemented in any other RTO. Implementation poses significant technical challenges, and therefore we recommend that MISO evaluate whether the benefit of introducing real-time PRD bidding outweighs the cost of implementation.

Currently DRR-Type I resources cannot set the LMP in the MISO energy markets. This is not necessarily a barrier to DR integration; however, full benefits of DR integration cannot be reaped if DR is not part of the price-setting process. MISO has recognized this problem and is currently working on implementing the necessary software changes. A resolution to this problem is expected in 2010.

Currently, regulation limits are defined as the same amount in both directions (regulation up and down), and demand resources do not have the option to offer regulation in only one direction or to specify different limits in each direction. In its April Compliance Filing, MISO stated that it does not perceive this as incomparable treatment or as a barrier because all resource types face the same constraint on their regulation bids. Demand resources by their nature may be better able to regulate up (by reducing load) than down (by increasing load). Therefore, although DRRs are treated equally to generators, the treatment may not be comparable. We recommend that MISO evaluate the options to modify regulation offer parameters to better accommodate DR.

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[67] Cappers *et al*. (2009).

VI. EVALUATION OF MISO PROGRESS ON GOALS IN 2009 INCENTIVE PLAN

Table 3 below presents the MISO Board goals set forth in its 2009 Incentive Plan and summarizes the progress made on these goals.[68] As illustrated, each of the MISO board goals, except having active ARC participation, has been met.

Table 3
MISO Board DR Goals

Goal	***How Goal Has or Has Not Been Met***
File timely MISO response to FERC Order No. 719 (DR and Retail Aggregator integration)	Filing was made on April 28, 2009, and October 2, 2009.
Evaluate and file (if required) tariff, system and other modifications required to mitigate the barriers to entry for DR in the MISO wholesale market	The ARC Proposal, filed on October 2, 2009, addressing most of the remaining barriers, however implementation will not be complete until mid-2010.
One Aggregator becomes a MISO Market Participant and is enabled to offer in the MISO wholesale market	This goal has not been met, but it is likely to be met in 2010 after MISO implements its ARC Proposal.
Provide a report to MISO Board of Directors and stakeholders on increased incorporation of DR via DA/RT, ASM, EDR, RAR and MTEP - included in this report will be the remaining barriers to entry of DR in the MISO wholesale market.	MISO met this goal through the completion of this report and the prior distribution of preliminary findings to stakeholders and The Board.

68 For Incentive Plan goals, see pp. 8-9, MISO (2009a).

VII. RECOMMENDATIONS

It is likely that MISO's ARC Proposal and its removal of other barriers will allow new, cost-effective DR to develop as market conditions improve. However, we recommend that MISO consider taking the following additional actions to maximize the potential of DR:

1. The ARC Proposal is a major step forward. The final step is to implement its provisions, especially the ARC compensation mechanism, and to do so in 2010 (pending FERC acceptance).

2. Section V.B identifies remaining (relatively minor) DR barriers and concerns regarding the ARC Proposal. We recommend that MISO facilitate stakeholder discussions and prepare a cost-benefit analysis of removing the remaining barriers.

3. Ultimate DR participation levels will depend primarily on retail regulatory action to allow ARCs, introduce a Smart Grid, and provide dynamic retail rates. Hence, we recommend that MISO continue to coordinate with states on regulatory policy toward DR.

4. We heard from stakeholders that the complexity of market rules across multiple products and types of resources is difficult to navigate. We agree with their assessment and their suggestion that MISO provide market participants with more training and a coherent manual regarding DR market participation opportunities.

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List of Acronyms

AMI	Advanced Metering Infrastructure
APRC	Aggregate PRC
ARC	Aggregator of Retail Customers
BPM	Business Practices Manual
BTMG	Behind-the-Meter Generation
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CBL	Customer Baseline
CPNode	Commercial Pricing Node
DLC	Direct Load Control
DR	Demand Response
DRR	Demand Response Resource
DRWG	Demand Response Working Group
EDR	Emergency Demand Response
EEA2	Energy Emergency Alert 2
EEA3	Energy Emergency Alert 3
EPRC	External PRC
ERCOT	Electric Reliability Council of Texas
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
ICAP	Installed Capacity
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	ISO New England
IURC	Indiana Utility Regulatory Commission
kW	Kilowatt
LBA	Local Balancing Area
LMP	Locational Marginal Price
LMR	Load Modifying Resource
LPRC	Local PRC
LSE	Load-Serving Entity
M&V	Measurement and Verification
MFRR	Marginal Foregone Retail Rate
MISO	Midwest Independent System Operator
MW	Megawatt
MWh	Megawatt-hour
MWDRI	Midwest Demand Response Initiative
MRO	Midwest Reliability Organization
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NYISO	New York ISO
OMS	Organization of MISO States
PJM	PJM Interconnection
PRC	Planning Resource Credit

PRD	Price-Responsive Demand
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
RA	Resource Adequacy
RAC	Reliability Assessment Commitment
RAR	Resource Adequacy Requirement
RERRA	Relevant Retail Regulatory Authority
RFC	Reliability*First* Corporation
RPM	Reliability Pricing Model
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
SAWG	Supply Adequacy Working Group
UCAP	Unforced Capacity
VCA	Voluntary Capacity Auction