Coordination of Retail Demand Response with Midwest ISO Markets

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Publication Date
2008-06-10

LBNL XXXXX

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BERKELEY NATIONAL LABORATORY

Coordination of Retail Demand Response with Midwest ISO Wholesale Markets

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May 2008

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability, Permitting, Siting and Analysis of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

LBNL-XXXXX

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Prepared for the
Office of Electricity Delivery and Energy Reliability,
Permitting, Siting, and Analysis
U.S. Department of Energy

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The survey effort was coordinated by the Midwest Demand Resource Initiative's (MWDRI) Steering Committee and implemented with the active involvement of state regulators throughout the Midwest ISO footprint. The authors would like to thank Frank Bodine and Gordon Dunn, Commissioner John Norris (Iowa Utilities Board), Commissioner Bob Lieberman and Sean Brady (Illinois PSC), Dave Johnston and Cathy Brewster (Indiana PSC), Greg Scheck (Ohio PUC), Jorge Valladares (Kentucky PSC), Mike Proctor (Missouri PSC), Burl Haar and Marshall Johnson (Minnesota PSC), Tim Texel (Nebraska PRB), John Feit (Wisconsin PSC), Monica Martinez (Michigan PSC), and Bryan Baldwin (Montana PSC)**.** We would also like to thank the OMS team, Bill Smith and Julie Mitchell, for their help in coordinating the survey process, and Larry Mansueti (DOE OE) for his support of the OMS MWDRI initiative. The authors would like to acknowledge the cooperation of utilities and their staff that participated in this survey as well as review comments on a draft of this report from Mary Beth Tighe (FERC), Bruce Sailers (Duke Energy, Indiana), Mark Williamson (DTE Energy), Greg Scheck (Ohio PUC), and John Feit (Wisconsin PSC).

Table of Contents

List of Figures and Tables

Acronyms and Abbreviations

A/C	Air Conditioners
CBL	Customer Baseline Load
CPP	Critical Peak Pricing
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
EIA	Energy Information Administration (DOE)
EDR	Emergency Demand Response
EEA	Electricity Emergency Alert
FERC	Federal Energy Regulatory Commission
IRC	ISO/RTO Council
ISO-NE	New England Independent System Operator
LMP	Locational Marginal Price
LBNL	Lawrence Berkeley National Laboratory
LSE	Load-Serving Entity
MISO	Midwest Independent System Operator
MP	Market Participant
MRO	Midwestern Reliability Organization
MWDRI	Midwest Demand Resources Initiative
M&V	Measurement & Verification
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PUC	Public Utility Commission
RAP	Regulatory Assistance Project
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SERC	Southern Electricity Reliability Council

Abstract

The Organization of Midwest ISO States (OMS) launched the Midwest Demand Resource Initiative (MWDRI) in 2007 to identify barriers to deploying demand response (DR) resources in the Midwest Independent System Operator (MISO) region and develop policies to overcome them. The MWDRI stakeholders decided that a useful initial activity would be to develop more detailed information on existing retail DR programs and dynamic pricing tariffs, program rules, and utility operating practices. This additional detail could then be used to assess any "seams issues" affecting coordination and integration of retail DR resources with MISO's wholesale markets.

Working with state regulatory agencies, we conducted a detailed survey of existing DR programs, dynamic pricing tariffs, and their features in MISO states. Utilities were asked to provide information on advance notice requirements to customers, operational triggers used to call events (e.g. system emergencies, market conditions, local emergencies), use of these DR resources to meet planning reserves requirements, DR resource availability (e.g. seasonal, annual), participant incentive structures, and monitoring and verification (M&V) protocols. This report describes the results of this comprehensive survey and discusses policy implications for integrating legacy retail DR programs and dynamic pricing tariffs into organized wholesale markets. Survey responses from 37 MISO members and 4 non-members provided information on 141 DR programs and dynamic pricing tariffs with a peak load reduction potential of 4,727 MW of retail DR resource. Major findings of this study area:

- About 72% of available DR is from interruptible rate tariffs offered to large commercial and industrial customers, while direct load control (DLC) programs account for ~18%. Almost 90% of the DR resources included in this survey are provided by investor-owned utilities.
- Approximately, 90% of the DR resources are available with less than two hours advance notice and over 1,900 MW can be dispatched on less than thirty minutes notice. These legacy DR programs are increasingly used by utilities for economic in addition to reliability purposes, with over two-thirds (68%) of these programs callable based on market conditions.
- Approximately 60% of DLC programs and 30% of interruptible rate programs called ten or more DR events in 2006. Despite the high frequency of DR events, customer complaints remained low. The use of economic criteria to trigger DR events and the flexibility to trigger a large number of events suggests that DR resources can help improve the efficiency of MISO wholesale markets.
- Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels averaged about $5/kW-month for interruptible rate tariffs and $6/kW-month for DLC programs. Few programs offered incentive payments that were explicitly linked to actual load reductions during events and at least 27 DR programs do not have penalties for non-performance.
- Measurement and verification (M&V) protocols to estimate load impacts vary significantly across MISO states. Almost half of the DR programs have not been evaluated in recent times and thus performance data for DR events is not available. For many DLC programs, M&V protocols may need to be enhanced in order to allow

participation in MISO’s proposed EDR schedule. System operators and planners will need to develop more accurate estimates of the load reduction capability and actual performance.

1. Introduction

The unusually hot summer of 2006 broke peak electricity demand records in most parts of the country, including the Midwest. The success of system operators across the nation in "keeping the lights on" despite record peak demands was partially due to the use of demand response (DR) resources (Hopper et al. 2007). The Midwest Independent System Operator (MISO) called on retail DR programs and tariffs to provide emergency operating reserves on both August 1 and 2, 2006. On these days MISO operators declared an Energy Emergency Alert (EEA) Level 2 and requested Load Serving Entities (LSEs) to interrupt non-firm load. A 3,000 MW drop in peak demand (see Figure 1) on August 1st and 2,000 MW on August 2nd were sufficient to avoid triggering scarcity pricing and helped minimize the possibility of outages.

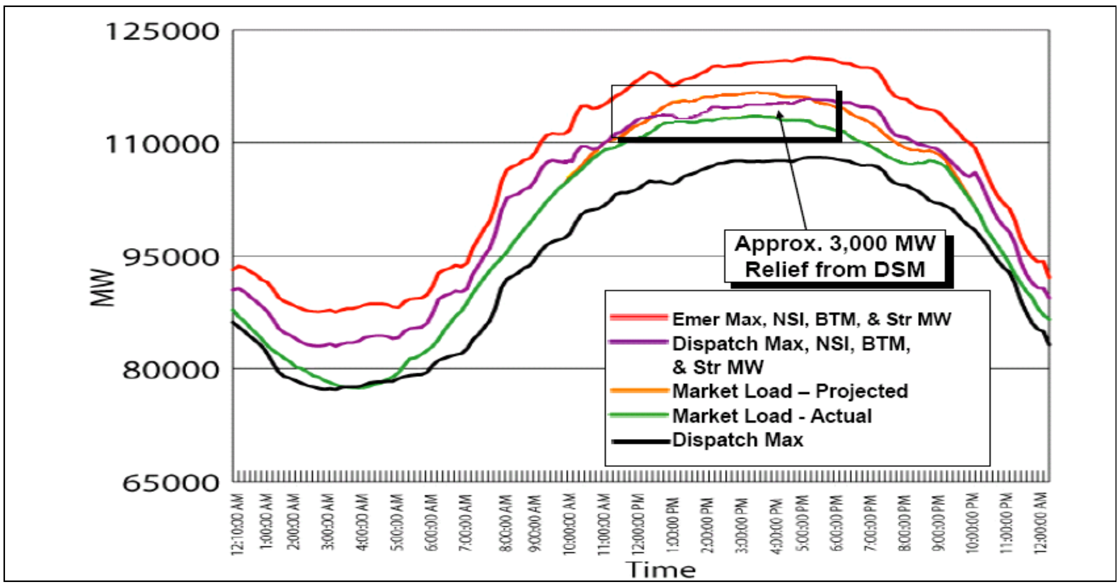

Figure 1: Midwest ISO August 1 2006 Generation and Load Summary (MISO, 2006)

Although an impressive demonstration of the value of demand response, these emergency operations revealed discontinuities between the needs of regional system operators and the organization of retail demand response programs. Since MISO did not have a regional emergency demand response program in place, load reductions were achieved according to the legacy retail program procedures of individual LSEs and states.[1] MISO was unable to predict or control the amount of DR resources needed to maintain system reliability, and the load reductions undertaken by LSEs and their customers could not be compensated by MISO.[2] Moreover, some LSEs and large customers were actually penalized for responding to the MISO dispatcher request for load interruptions during the August 1-2, 2006 emergency because of

[1] "Legacy" retail programs refer to those DR programs administered by LSEs that existed before the formation of MISO.

[2] In some cases utilities compensated retail customers for load reductions according to the tariffs (e.g. interruptible contracts).

MISO market rules governing departures from scheduled generation and deviations from accepted load offers at the balancing authority level.[3]

Inclusion of retail DR resources in resource adequacy planning and use of these resources in regional transmission operations requires coordination between wholesale and retail electricity markets. When MISO called for emergency demand response in August 2006, not much was known on a region-wide basis about the quantity and type of retail DR resources that could be expected to respond and under what conditions. These retail programs range from legacy interruptible contracts with large customers to load control programs for small residential and commercial customers.

This report describes a survey undertaken to inventory retail DR resources that can provide sufficient aggregated loads to be valuable as an emergency resource at the regional level. The survey collected detailed information regarding the operational capabilities and limitations of retail DR resources. An important objective of the study was to help identify issues that MISO members, state regulators and other stakeholders may need to address in incorporating legacy retail DR programs and dynamic pricing tariffs into MISO wholesale markets. The study is organized as follows. Section 2 provides an overview of the wholesale and retail electricity markets in the Midwest while Section 3 describes institutional arrangements and stakeholders in the Midwest ISO and Organization of Midwest States. Section 4 reviews the existing and future role of DR resources in MISO markets and operations. The DR program survey approach and scope is described in Section 5, while survey results are presented in Sections 6 and 7. Key findings and conclusions are discussed in Section 8.

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[3] FERC subsequently waived these penalties (also referred to as “uplift charges”) retroactively and proposes to eliminate them in its Notice of Proposed Rulemaking, “Wholesale Competition in Regions with Organized Electric Markets” (Docket Nos. RM07-19-000 and AD07-7-000), February 22, 2008.

2. Wholesale and Retail Electricity Markets in the Midwest

Established in 2001, MISO is one of nine independent and regional transmission organizations (RTOs) that the FERC has approved to carry out regional system and market operations. MISO extends over a broad reach of Midwestern North America, from eastern Montana and the Canadian province of Manitoba through the upper Midwest and south to parts of Kentucky and Missouri (see Figure 2). MISO is responsible for the reliable operation of nearly 94,000 miles of interconnected high voltage power lines serving more than 100,000 MW of demand and 40 million people throughout the Midwest, as well as administering one of the world's largest energy markets, and ensuring that the Midwestern bulk power infrastructure expands to meet the growing regional demand for power.

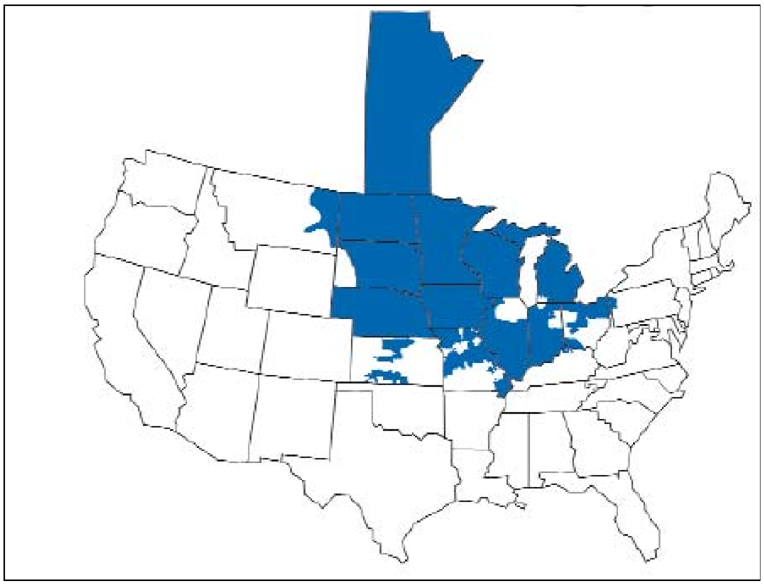

Figure 2: MISO Reliability "Footprint" (Source: ICF, 2007)

Development of a regional transmission operator and organized wholesale markets in the Midwest has taken a distinctive path compared to other RTOs such as New England or PJM. In 2005 MISO became the first multi-state RTO without a history of tightly-pooled power sharing arrangements to implement organized wholesale energy markets (day-ahead and real time) with centralized economic dispatch and locational marginal pricing. In doing so MISO and its stakeholders grappled with several complicated issues: (i) the need to accommodate the reliability rules of four different regional reliability entities (Mid-America Interconnected Network or MAIN, East Central Area Reliability Coordination Agreement or ECAR, Mid-Continent Area Power Pool or MAPP,; and SERC, or SERC Reliability Corporation); (ii) 16 retail jurisdictions with varying approaches towards retail competition and mix of electric utility ownership structures;[4] and (iii) the need for a single transmission tariff that could accommodate regional variations in marginal losses (Drom et al. 2005).[5]

MISO has subsequently developed ancillary services market designs that provide for Regulation, Spinning Reserves, and Supplemental Reserves to be acquired via bid and auction markets instead of bilateral procurement.[6] This new Ancillary Services Market, scheduled for a September 2008 launch, will allow co-optimization of energy and ancillary services provision and increased participation of demand response (MISO 2007a). A key element of the introduction of co-optimized Energy and Ancillary Services Markets is consolidation of the multiple (i.e. 23) Balancing Authorities now responsible for providing reliability services into a single regional Balancing Authority under the auspices of MISO (see Figure 2). Because of the vast territory contained within the regional footprint, MISO is also developing a zonal scheme for managing the procurement and provision of Operating Reserves.[7]

Although MISO does not operate a capacity market, it coordinates regional planning processes to ensure that sufficient generation and transmission capacity is added to meet the reliability and demand growth needs of the region (MISO 2007b).

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[4] Three states (Illinois, Michigan, and Pennsylvania) have implemented retail competition, eight states (Missouri, Kentucky, Iowa, Montana, Minnesota, North Dakota, South Dakota, Wisconsin) retain monopoly provision of retail electric service, one state (Ohio) allows retail competition for certain customer classes, and one state (Nebraska) is fully served by public power.

[5] ECAR and MAIN have ceased operations and the region they covered is not part of ReliabilityFirst Corporation or RFC. MAPP has been replaced by Midwest Reliability Organization or MRO.

[6] At present Transmission Customers must provide for their own Operating Reserves through: 1) self-supply; 2) bilateral contracts; 3) take cost-based service from the Balancing Authority in which their Load is located; or 4) as a last resort, request the Midwest ISO to procure the necessary Operating Reserves on their behalf.

[7] These Reserve Zones will allow transmission constraints and other physical limitations to be taken into account in meeting reliability requirements imposed by NERC. The Reserve Zones will also disperse the clearing of Operating Reserve on Resources throughout the Midwest ISO Balancing Authority Area. Separate requirements will be established for Regulating Reserve, Spinning Reserve and Supplemental Reserves.

3. Institutional Arrangements and Stakeholders

Since inception MISO has stressed close coordination among state regulators in the development and operation of the regional transmission grid and electricity markets. The Organization of Midwest ISO States (OMS) was formed in 2003 to advise MISO and the FERC and provide a technical resource to the individual state regulators.[8] The OMS coordinates electricity transmission and wholesale market policy and planning oversight among the states within the MISO footprint, provides recommendations to MISO, FERC, and other government entities, and intervenes in FERC proceedings. The OMS has a Board of Directors and an Executive Committee, and topical working groups that cover key issues including congestion management, market power mitigation, pricing, resource adequacy, demand response, market implementation, transmission planning, and seams issues.

In 2004 MISO formed a Demand Response Working Group (DRWG) within its Market Subcommittee. The DRWG consists of MISO staff and stakeholders including regulators and Market Participants (MPs) and develops recommendations to allow existing and potential DR resources full participation in MISO markets. The DRWG is responsible for developing new business practices, tariff language and protocols governing the participation of DR in day-ahead and ancillary services markets and for emergency purposes.[9]

In October 2006, the Organization of Midwest ISO States (OMS) launched the Midwest Demand Resource Initiative (MWDRI). The goal of the Initiative is to identify and develop remedies to retail barriers to the deployment of DR resources in the MISO region, including state and regional policies and market-enabling activities. MWDRI efforts are focused on retail DR programs and dynamic pricing tariffs and are intended to complement the ongoing efforts of MISO Working Groups that address demand response (e.g., DRWG and Resource Adequacy Working Group).

[8] URL: http://www.misostates.org/

[9] DRWG Charter and DRWG 2008 Management Plan. Both available at: http://www.midwestiso.org/publish/Folder//30a6c2_101ed99cd65_-7fe40a48324a

4. Status of Demand Side Management in Midwest ISO

There are two principal types of demand-side management (DSM) resources: energy efficiency (EE) and demand response (DR). While the objective of EE is to permanently reduce the demand for energy in intervals ranging from seasons to years, DR's objective is to change customer demand in intervals that range from minutes to hours during specific conditions (e.g., high demand, congested networks, or high prices). This study focused specifically on DR resources.

Figure 3 presents the main types of DR resources. DR resources can be characterized in terms of whether they are dispatchable by the system operator (or program administrator) or the customer alone decides when to reduce load (i.e. non-dispatchable). Customers enrolled in dynamic pricing tariffs (e.g. hourly pricing, critical peak pricing, and time-of-use pricing) would typically fall under the non-dispatchable DR resources category while direct load control, interruptible rate programs, and demand bidding programs would be under the dispatchable category - see NERC (2007) for a detailed discussion of DR program typology.

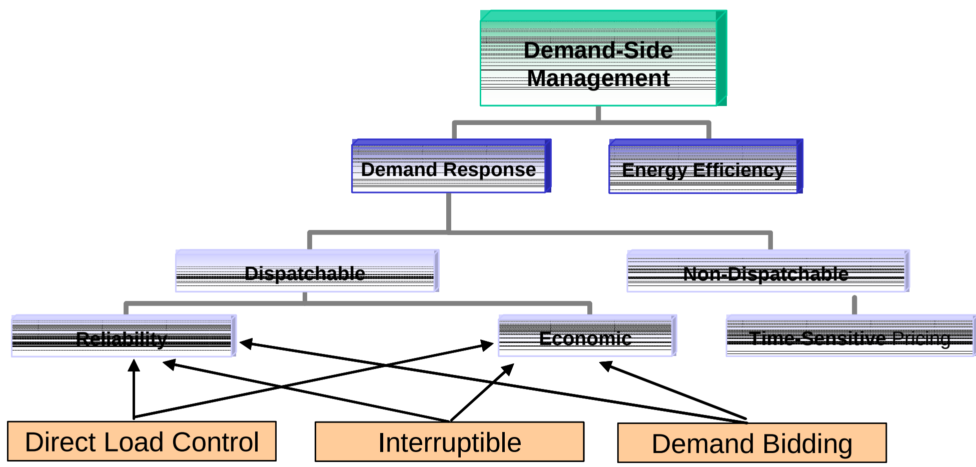

Figure 3: Types of Demand-Side Management Resources (Source: NERC, 2008)

MISO coordinates with utilities in their role as Balancing Area Authorities to dispatch demand response resources for the benefit of the entire MISO interconnected system (IRC 2007). The various ways (existing and future) in which DR resources can participate in MISO markets and operations are shown in Table 1.

Currently, DR resources formally participate in MISO operations through the wholesale energy market only. LSEs can offer DR resources, similar to generation resources, in the day-ahead or real-time energy market. In this case MISO decides whether to dispatch the DR resources or not. Alternatively, LSEs can also use DR resources as part of their price-sensitive demand curve. In this situation, the LSE decides whether to dispatch its DR resources or not in an effort to manage its wholesale market price risk.

In the future, DR resources will be able to participate in Ancillary Services Markets. Recently, FERC also approved MISO's proposal to allow DR resources to satisfy the resource adequacy requirements of LSEs as described in Module E of MISO's Transmission Tariff. DR resources would receive capacity credits comparable to those received by generators. DR resources receiving capacity credits would be dispatched during emergency conditions in accordance with business rules that are still under development. [10] Unlike several other RTOs, MISO does not directly administer DR programs at the present time.

Table 1: How DR resources can participate in MISO markets?

MISO Platform	Method of DR Participation
Non-Dispatchable by MISO	
Day-ahead and Real-time energy markets	Price-sensitive demand: LSEs indicate how much energy they will buy for a given price.[11]
Dispatchable by MISO	
Day-ahead and Real-time energy markets	DRR offers: LSEs can bid DR resources in the energy markets similar to generation resources. If offer is accepted then LSE must deliver the load reduction or pay a penalty.
Ancillary services market (ASM)	DRR offers: LSEs can bid DR resources in ASM similar to generation resources. During power system contingencies, LSEs must deliver load reductions. *(Note: ASM will begin operations in September 2008).*
Resource adequacy requirements (Module E)	LSEs can utilize their DR resources to meet their resource adequacy requirements. When EEA2 alert is issued, LSEs must reduce load as defined in Module E.
Emergency demand response program (Schedule 30)	DRR offers: LSEs can bid DRR in this program. During EEA2, if MISO has exhausted resources in energy markets, ancillary services market, and Module E then offers bid into Schedule 30 will be according to ascending order of offer prices. *(Note: FERC has not yet approved Schedule 30. However, MISO has begun the process of developing the business process manual.)*
Only for Planning Purposes	
Long-term planning	MISO has proposed that it would include DR resources formally in its planning process in future.

Source: Mike Robinson, MISO 2008

On December 31, 2007, MISO filed a proposed Emergency Demand Response (EDR) Schedule 30 with FERC, which provides payments from MISO to load-serving Market Participants (MP) that curtail loads during emergency events (i.e., EEA2 and EEA3).[12] Only authorized MPs would be allowed to participate in Schedule 30, which would be the first DR program to be directly administered by MISO. In order to be compensated under this proposed program, participants will be required to submit an EDR offer to MISO at least 30 days ahead of the calendar month in which the offer is valid. Each offer must remain in force for one month and include: (1) minimum and maximum amounts of demand reduction; (2) minimum and maximum

[10] One issue of contention among stakeholders is the advance notice requirements for DR resources in order to qualify as a load-modifying resource under Module E.

[11] Anecdotal evidence suggests that currently, a significant portion of DR resources participates in the MISO market in this manner. LSEs adjust their daily load projections for expected DR reductions for those days they intend to use DR resources.

[12] On April 22, 2008 FERC conditionally approved MISO's Emergency Demand Response Schedule 30. However, FERC also directed MISO to address several issues not included in the proposal. Currently, MISO is working with various stakeholders to address the issues raised by FERC.

number of continuous hours of demand reduction; (3) any shutdown costs associated with the demand reduction; (4) number of hours of advance notice required before reduction and any time of day limitations; and (5) a firm offer price (subject to a $3,500/MWh cap). MISO will issue instructions regarding the start time, reduction amount, and necessary duration of curtailment during emergency events for accepted bids. Compensation would be based on the higher of the real-time LMP or the EDR Offer price for the amount of demand reduction included in MISO's instructions. In case of non-compliance, a penalty would be incurred.

In terms of operations during system contingencies, MISO will first dispatch the generation and DR resources offering bids in the Ancillary Services Market according to merit order. If ASM resources are unable to meet the demand, MISO will begin issuing sequential warnings and emergency alerts. When an EEA2 alert is issued, MISO will first ask LSEs to dispatch the resources accredited under Module E. If the Module E resources are not sufficient to meet the demand, MISO will dispatch the DR resources enrolled under EDR Schedule 30 according to merit order.[13]

[13] It should be noted that this order of dispatch may be revised in the future.

5. Purpose and Approach of the Survey

Market participants (MP) administering retail DR programs and state regulators are concerned whether the requirements that MISO includes in its EDR Schedule 30 and Ancillary Services market for DR resources are consistent with the requirements already embedded in legacy programs and tariffs. To better inform this discussion and assess differences and similarities among existing retail DR programs and dynamic pricing tariffs in the MISO footprint, MWDRI decided to conduct a detailed survey.

A team comprising the Lawrence Berkeley National Laboratory (LBNL) and the Regulatory Assistance Project (RAP) surveyed the retail DR programs and dynamic pricing tariffs administered by MISO member utilities as well as other utilities operating in OMS member states. The survey template was developed by the DR program design subgroup of MWDRI with input from OMS members. State regulatory commissions transmitted the survey to utilities in their states and requested their cooperation in describing their retail DR programs and dynamic pricing tariffs. The survey coverage generally included all load serving MISO MPs along with several utilities that are not MISO members but whose service territories are in OMS states. In some states, surveys were not sent to rural cooperatives and municipal utilities either because PUCs did not have jurisdiction or utility staff contacts. LBNL staff compiled the survey data, conducted follow-up interviews and consistency checks to ensure accuracy of the survey responses, supplemented survey data with information from other sources, and analyzed the data.

Utilities were asked to provide information on retail DR programs (e.g., interruptible, direct load control or DLC, emergency programs, and demand bidding programs where events are triggered by high prices), dynamic pricing tariffs (including Real Time Pricing, or RTP; and Critical Peak Pricing, or CPP), and voluntary DR programs (i.e., a program where customers voluntarily participate and make a "best efforts" attempt to curtail load when requested but are not compensated).

Interruptible rate programs provide a rate discount or bill credit to the customer for curtailing or shedding load upon request. Typically, interruptible programs are offered to larger industrial and commercial customers and often involve penalties if the customer fails to curtail load when requested to do so. DLC programs involve an end-user (typically, residential or small commercial) who agrees to allow their utility or a curtailment service provider to control an appliance or device within certain pre-set limits of frequency and duration. Participants in DLC programs typically receive compensation in the form of bill credits and/or payments based on performance during events. Customers enrolled in a Demand Bidding or economic DR program offer bids to curtail load based on market prices. These programs are mainly offered to large customers; however, some utilities also allow aggregation of small customer loads.

An RTP tariff provides variable hourly pricing for all hours of the year, while a CPP tariff provides variable pricing only for a relatively few number of hours per year when the utility calls a CPP event. A one-part dynamic pricing tariff assesses all volumetric (per kWh) charges based on variable hourly prices. A two-part dynamic pricing tariff incorporates a customer baseline (CBL) usage which establishes a long-term average hourly usage profile for each customer. Variable hourly prices are applied only to the differences between actual hourly load and the CBL. Two-part CBL-based real-time tariffs are a hedge against the implicit price-exposure risk of variable hourly prices as the bulk of a customer's consumption is billed on the customer's otherwise applicable tariff. Hourly prices can be indexed to wholesale energy market prices (i.e. either day-ahead or real-time) or utility marginal costs.

6. Survey Results: Overview of Existing DR Resources

Thirty-five utilities responded to the survey with information on 141 DR programs and dynamic pricing tariffs. Of these, four utilities (that reported information on 13 DR programs and 3 dynamic pricing tariffs) are not members of MISO but operate in states that belong to OMS. The analysis reported here includes all 141 programs.

The size of the DR resource is defined as the potential peak load reduction that the utility expects from the DR program or dynamic pricing tariff, which is consistent with the approach taken by FERC and EIA. The utilities reported retail DR resources totaling 4,727 MW, of which 757 MW are from MISO non-members (~16%).Response to the survey was quite good as MISO member utilities reported DR program resources of ~3,649 MW of DR resources, compared to the 4,099 MW reported in the latest FERC DR report (FERC 2007).

The distribution of DR resources by state is shown in Figure 4. States with the most DR resources include Minnesota (1,245 MW), Indiana (731 MW), and Michigan (822 MW). Note that OMS member states such as Illinois and Pennsylvania have large DR resources, although some utilities in these states were not sent or did not respond to the survey because they were not MISO members (e.g., Commonwealth Edison is a member of PJM).

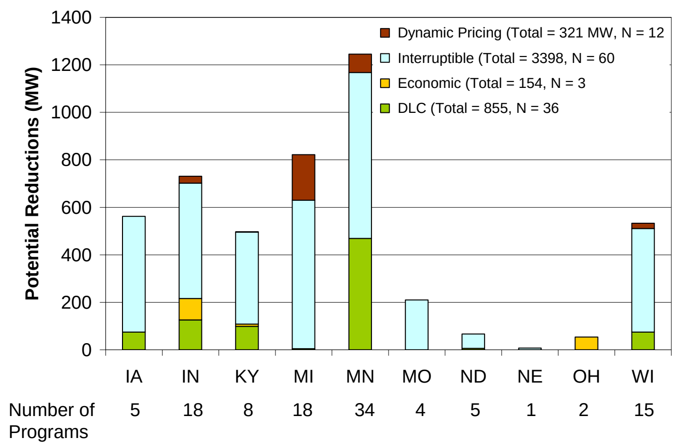

Figure 4: State-Level Distribution of DR Resources

Figure 5 shows how survey respondents characterized their retail demand response program offerings. Interruptible tariffs account for ~72% of the DR resource, while DLC programs account for ~18%, and economic programs account for ~3% of existing DR resources. Interruptible tariffs and DLC programs are offered in almost all OMS member states, however, economic programs were offered by LSEs only in Indiana and Ohio.

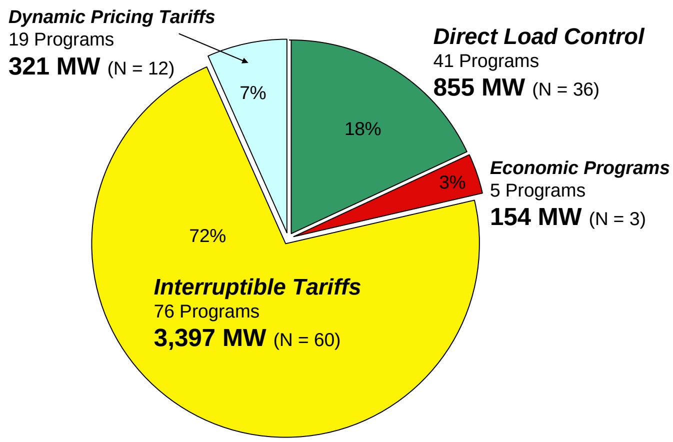

Figure 5: Distribution of DR resources by program type

Dynamic pricing tariffs account for ~7% of the total DR resource. Fifteen entities reported that they offer 19 dynamic pricing tariffs in their service territories. However, utilities reported information on potential peak load reductions for only 13 dynamic pricing tariffs. Survey respondents estimated that customers enrolled in these dynamic pricing tariffs could provide 321 MW of potential load reductions in aggregate. It is important to note that customer enrollment (and potential load reductions) for dynamic pricing tariffs vary significantly across utilities with five utilities accounting for 92% of the potential load reductions (see Table 2). CPP tariffs accounted for only 7 MW of DR resources. Only one utility called its CPP tariff in 2006 (approximately 60 events) that yielded ~4 MW of actual load reductions.

Table 2: Dynamic Pricing Tariffs: Top five utilities ranked by potential load reduction and peak demand of enrolled customers.

Utility	Potential Peak Load Reductions (MW)	Peak Demand of Enrolled Customers (MW)
Utility A	150	360
Utility B	72	84
Utility C	29	60
Utility D	25	25
Utility E	20	40
Remaining utilities	25	229
TOTAL	321 MW	798 MW

Almost 50% of the RTP tariffs (all two-part tariff design) rely on the utility's marginal cost to determine the hourly component of the price, while the remaining RTP tariffs are indexed to either MISO's real-time or day-ahead energy market price. The RTP tariffs primarily target non-residential customers. With one exception, the design of dynamic pricing tariffs involves an "opt-in" approach as customers must voluntarily choose to enroll on a dynamic pricing as opposed to an "opt out" approach where dynamic pricing tariff is designated as the default tariff. None of the potential load reductions from the dynamic pricing tariffs are currently bid into the

MISO wholesale energy markets. Six utilities count the potential load reductions from their dynamic pricing tariffs towards their planning reserves.

Eighteen utilities reported that they operate voluntary, emergency DR programs that do not offer compensation for load curtailments. Approximately ~61% of these programs recruit customers actively through public appeals, advertising, customer education, and targeted marketing to large customers. Five utilities reported that they have enrolled ~138 customers in these voluntary DR programs. Only four utilities have called these programs in recent years and six utilities periodically contact enrolled customers to see if they are willing to participate in the program in future.

7. Survey Results: Retail DR Program Characteristics

The survey requested detailed information about a range of DR program characteristics, including operational triggers, frequency of events, advance notice provided, program duration, participation requirements (e.g. size thresholds, market segments, etc.), communications arrangements, monitoring and verification protocols, and others. This section discusses these DR resource characteristics and their potential implications for participation in MISO markets by DR resources.

7.1 Operational Triggers

Respondents were asked to describe what triggered the operation of DR programs. The most-frequent uses of DR programs reported were maintaining system reliability, reducing the cost of procuring power during high price periods, maintaining system demand below contracted levels, and addressing local reliability or congestion problems (see Table 3).

Table 3: Operational Triggers for DR Programs

Program Type	System Emergency	High Prices	Maintain demand below contracted levels	Local/utility reliability/ congestion
DLC	28	25	21	16
Economic	1	5	0	1
Interruptible	66	49	35	42
TOTAL	95	79	56	59

Approximately ~81% of programs and ~87% of potential peak load reductions are triggered for system emergencies. Interestingly, over two-thirds (~68%) of all DR programs (~70% of enrolled load reductions) are triggered for economic reasons. This result is somewhat surprising as historically DLC and interruptible rate programs were justified primarily for reliability purposes and dispatched only during system emergencies. These results suggest that many Midwest utilities have found additional benefits in dispatching DR programs in response to market conditions (e.g. high day-ahead or real-time market prices) and system conditions (manage contracted demand to lower overall utility system costs, relieve congestion). Some survey respondents noted that regulators have given them additional flexibility in recent years to decide how DR resources are deployed and the number of times they can be deployed. LSEs also reported an increase in DR events triggered by economic conditions since MISO markets began operating.

Respondents indicated that 79 DR programs can be triggered for economic reasons (i.e. high prices); however, only 13 DR programs (9 interruptible and 3 DLC accounting for ~580 MW) actually bid into MISO's day-ahead energy market. It appears that many LSEs are acting as "price-takers" instead of having to commit to reduce a specific amount of load if their bid is accepted.

Most DR programs have more than one operational trigger: 83% of DR programs which account for 94% of enrolled load reductions. Figure 6 and Figure 7 show the potential load reductions respectively for DLC and interruptible rate programs for each type of operational trigger. The Venn diagram representation allows one to readily see the use of multiple triggers.

For example, about 47% of potential load reductions from DLC programs are dispatched for both reliability (system-wide and/or local) and economic purposes. Potential DLC load reductions triggered for purely economic reasons (i.e., high prices) account for ~37% of the total load reductions while DLC programs triggered for purely reliability purposes account for ~17% of the total load reductions.

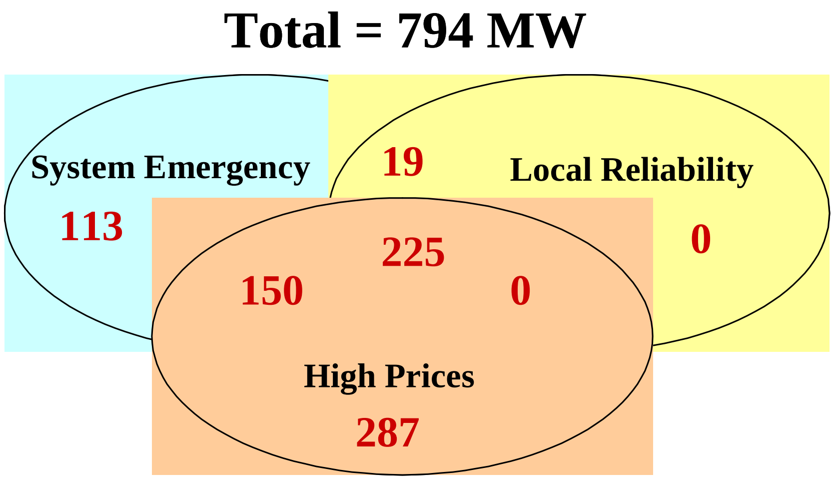

Figure 6: Overlap of operational triggers for DLC programs

In contrast, the potential load reductions from interruptible programs that are triggered purely for economic reasons account for only ~1% of the total potential load reductions. Approximately 33% are triggered for purely reliability purposes and ~65% for both reliability and economic purposes. A much larger portion of potential load reductions (~52% compared with ~28%) from interruptible rate programs are triggered for all three purposes as compared with those from DLC programs.

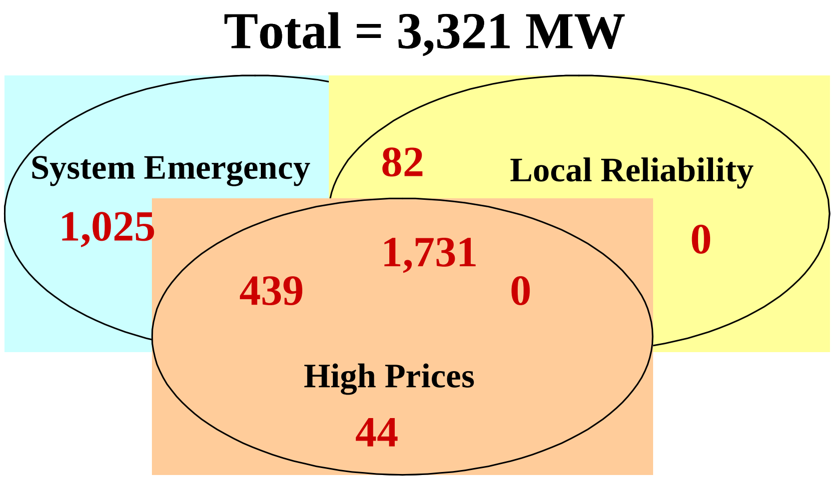

Figure 7: Overlap of operational triggers for interruptible rate programs

This wide-spread use of DR resources for economic reasons suggests that program operators are capable of valuing the resource purely in economic terms as opposed to using it as a last resort for ensuring system reliability. For participation in MISO's energy markets or the proposed EDR schedule (and possibly future ancillary services market), program administrators will need to develop an offer price for their DR resources. Past experience in monetizing the value of DR resources should make it easier for program administrators to develop offer prices.

7.2 Frequency of DR Events

Respondents were asked to provide information on program operating limits as well as operational experience in recent years. More than one-third (~36%) of respondents reported that their DR programs did not have any limits on operational frequency.

Survey respondents also indicated that more than 60% of DLC programs and 30% of interruptible rate programs were called ten or more times in 2006 (see Figure 8). Follow-up discussions with some utilities suggest that the large number of DR events is a consequence of using economic criteria as operational triggers. Utilities also indicated that there were not many customer complaints despite the high frequency of DR events.

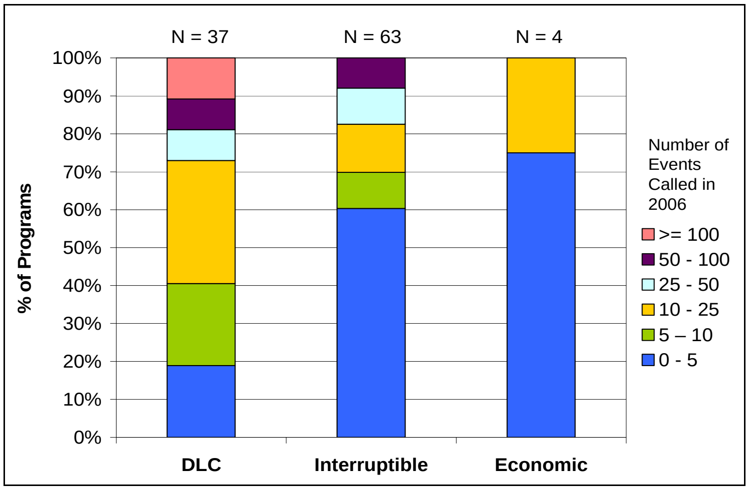

Figure 8: Frequency of DR Program Operations (2006)

The lack of annual limits on maximum number of events called or maximum hours of load reductions coupled with the fact that LSEs do not report significant customer satisfaction issues suggests that many LSEs may have the flexibility to continue calling and relying on DR resources for a variety of needs (e.g., emergency, economic, local congestion).

7.3 Advance Notice Requirements

The proposed EDR Schedule 30 calls for participants to specify the number of hours of advance notice required before demand can be reduced. Therefore, the advance notice requirements for existing retail DR programs are of interest. As shown in Table 4, 83% of DR programs (representing 89% of potential load reductions) require less than 2 hours advance notice. Nearly all DLC programs provide either no or less than 30 minutes of advance notice to customers, which is not surprising given that equipment (e.g. air-conditioning unit, water heater) is cycled directly by the utility. Surprisingly, over one-third (~36%) of interruptible programs provide relatively short notice (i.e., less than 30 minutes advance notice) to customers. Utilities reported that over ~1900 of customers were on interruptible rate programs that provide 30 minutes to 2 hours notice. The majority of economic programs are "day-ahead" programs, bidding load curtailments into the day-ahead energy market.

Table 4: Advance Notice Requirements for DR Resources

Program Type	Potential Enrolled Load Reductions (MW)				
	Less than 30 minutes	30 minutes – 2 hrs	2 - 4 hrs	4 - 12 hrs	Day-ahead
DLC	740	10	0	0	0
Economic	0	0	0	0	154
Interruptible	1,221	1,927	202	7	31
TOTAL	1,961	1,937	202	7	185

The survey results suggest that over 90% of the existing DR resource could provide load curtailments with two hours or less of advance notice. A significant amount of that load (1960 MW) is available on just 30 minutes notice. One of MISO's challenges in implemented EDR Schedule 30 will be "stacking" the DR resource offers for dispatch according to the relative merit order of advance notice and other characteristics. The proposed Schedule 30 language notes that dispatch instructions will be sent to accepted offers in the event of EEA2 and EEA3 alerts, but does not specify exactly when the alerts are initiated and dispatch instructions sent to the DR resources.

7.4 DR Resource Availability

Over the past two years MISO has called on DR resources to provide operating reserves in both the summer (danger of demand exceeding supply) and the winter (equipment failure).[14] This suggests that access to DR resources throughout the year has value for MISO system operators. Although certain DR resources will always be available only seasonally (e.g., air-conditioner load control), it is possible to develop a portfolio of DR programs that provides operating reserves year-round.

The survey results suggest that almost all of the DR programs and tariffs are available during summer months (either because the programs require year round or summer availability), when the probability of a DR event is higher (see Table 5). Surprisingly, more than two-thirds of all DR programs and tariffs, at least on paper, can be operated year-round (~50% of DLC programs, and ~75% of interruptible rate programs). However, it is likely that some DR programs never get called during off-peak months (e.g., air conditioner or agricultural pump load control). Consequently, the potential load reductions available during non-peak months (e.g. winter season in lower Midwest region) could be much lower than reported.

Table 5: Seasonal availability of DR resources

Program Type	Number of Programs				
	Summer only	Summer & Winter	Winter only	Year-round	TOTAL
DLC	16	3	2	20	41
Economic				5	5
Interruptible	15	2	2	57	76
TOTAL	31	5	4	82	122

[14] Hopper et al. (2007).

The proposed MISO EDR Schedule 30 requires market participants to specify their offers one month in advance and to provide one months notice if the offer is to be changed. The offer must describe the restrictions on the availability of the DR resource (i.e. minimum and maximum hours, times during the day, days during month when the load reduction is available). Hence, DR program administrators will have to develop resource availability estimates by month in order to develop appropriate offers for participation in the MISO EDR program.

7.5 Participation Requirements

Some DR programs establish eligibility or threshold criteria for enrollment, or target specific customers. For example, DLC programs are targeted to residential and small commercial customers while interruptible rate programs are targeted to large industrial and commercial (including government, educational institutions, and others) customers. Respondents indicated that other types of eligibility criteria were also employed in lieu of or in addition to market segment.

The most commonly cited criteria were the minimum size of load reduction offered by customer, minimum level of customer peak demand, presence of specific types of equipment or appliances (e.g., air conditioners) and access to onsite generation (see Table 6). The category "other" referred to contracts negotiated between an individual customer and the utility. Approximately 25% of DR programs explicitly indicated that they had no specified eligibility criteria. About 48% of DR programs allow participating customers to meet their program commitments using onsite generators in lieu of load reductions.

Table 6: DR Program Participation Requirements (MW)

Program Type	Certain End-uses Required	Min. Size of Load Reduction	Minimum Customer Demand	Other
DLC	191			301
Economic		154		
Interruptible	8	841	1,008	247
Total	199	995	1,008	548

The survey results indicate that minimum size thresholds for curtailable load and customer maximum demand are most commonly used as program eligibility criteria. These eligibility criteria allow LSEs to target larger customers whose participation is easier to administer. However, if aggregation is allowed, then a load aggregator may be able to enroll many smaller customers in these programs. The proposed MISO EDR Schedule 30 does not include any eligibility criteria or aggregation rules; hence, potentially all existing DR resources may be able to participate.

7.6 Measurement and Evaluation

Participation in MISO's proposed EDR schedule or in MISO energy markets requires the ability of the LSE to accurately measure and evaluate the actual load reduction. However, survey respondents indicated that barely half (~54%) of retail DR programs have been evaluated in the last 2-3 years. Many of these LSEs may be relying on older evaluations or engineering estimates of load reductions, rather than evaluation of actual load reduction results from recent DR events. A robust measurement and evaluation (M&E) protocol is necessary to estimate actual load reductions.

Only half (~50%) of the respondents provided detailed information on measurement and evaluation (M&E) protocols for their DR programs. Of these responses, the great majority (~80%) used interval meter data for evaluating the load impacts from interruptible programs. Customer baselines for measurement of actual load reduction were defined as part the M&E protocol.

The most common M&E method used for DLC programs (~77%) used substation level SCADA data to measure aggregate load impacts during DR events. This technique does not measure or estimate actual load reduction for each participating customer. Exclusive reliance on this method might prove to be a barrier in aggregating these loads for participation in MISO's proposed EDR Schedule 30, where compensation depends on actual and verifiable load reduction from participating customers.

Less than one-quarter (~19%) of the DLC programs used load research or other statistical methods to improve the accuracy of their load reduction estimates.[15] These methods are commonly used for non-interval metered participants in ISO DR Programs in other regions (e.g., ISO-NE, NYISO, and PJM).

Overall, the survey response suggests that M&E protocols vary quite a bit across the MISO foot-print. MISO does not include a specific M&E protocol in its proposed EDR schedule; rather, the proposed EDR Schedule 30 provides for MISO review and approval of M&E protocols on a case-by-case basis. Although this approach may expedite initial approval of the program, in the long-run, MISO needs an M&E protocol that is applied uniformly and yields comparable results.

7.7 Program Incentive Design and Compensation Levels

The survey also requested information on DR program incentive design, the type and size of incentives provided, and the basis for determining incentive levels. The results show considerable variability in incentive design and compensation levels across LSEs, states, and program types. Incentives were provided via bill discounts (i.e. $/month, $/season, $/year), capacity payments (i.e. $/kW offered per month or season or year), performance payments ($/kWh paid according to a single event), and capacity-performance payment combinations.

The most commonly offered incentive design is the capacity or reservation payment with or without a pay-per-event performance payment. MISO proposed EDR schedule 30 offers only a performance payment for load curtailed as its incentive. Hence, for many DR programs, LSEs and state regulators may need to address the issue of aligning the compensation received by LSEs from MISO for curtailing load during emergency events with the actual incentives currently paid to the end-use customer through the existing retail tariff.

[15] This methodology consists of extrapolating the measured actual load reductions for a sample of participants to the population of participants in a DLC program using various statistical methods and data analysis techniques.

Figure 9 and Figure 10 present the monthly capacity payments provided for interruptible rate programs and DLC programs, respectively. Reported capacity payments were converted to a common metric -- $/kW-month - in order to compare incentives across programs. The average incentive was $5/kW-month for interruptible rate programs, although there is significant variation across utilities (e.g. incentives ranged from $1 to $12/kW month).

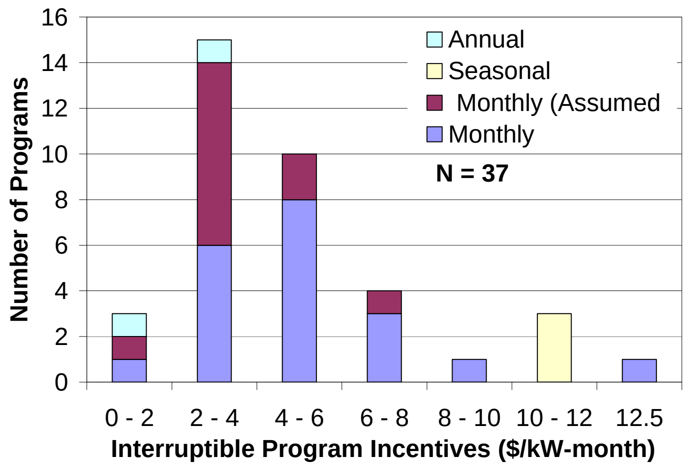

Figure 9. Distribution of incentives offered to interruptible tariff customers

Figure 10 segments the DLC program incentives in terms of the end-use appliance targeted by the program (i.e., air conditioners, and water heaters). The average size of the incentive provided to customers is $6/kW-month for the 22 DLC programs that provided this information. The variation in incentive levels across DLC programs is less than that observed among interruptible tariffs. For example, ~77% of the programs provide incentives between $4/kW-month to $8/kW-month. Incentives offered to customers in water heating DLC programs are relatively lower than those offered to customers in air-conditioning (A/C) programs. About 55% of A/C DLC programs provide incentives greater than $6/kW-month, while ~88% of water-heater DLC programs provide incentives less than $6/kW-month.

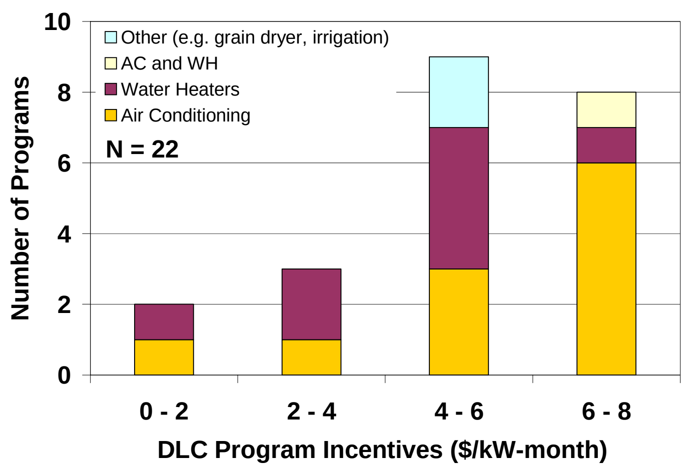

Figure 10. Distribution of incentives offered to DLC program customers

Approximately 30% of the 122 DR programs indicated that they have some type of penalty provision if customers do not curtail load during a DR event. Utilities use a variety of approaches to ensure that enrolled customers actually curtail during events: 25 programs include a monetary penalty for non-performance; four programs include mandatory “buy-through” provisions (i.e., the customer is required to pay the real-time market price for load not reduced), and seven programs include provisions that remove enrolled customers from future participation in the program (and loss of incentives) for failure to perform. Survey respondents indicated explicitly that there were no adverse consequences for non-performance in 27 DR programs. The penalty described in MISO EDR schedule is of the form $/MWh.

The most commonly used valuation basis for determining the size of incentives is the cost of a peaking unit (e.g., a natural gas-fired combustion turbine). As shown in Figure 11, more than 80% of DLC programs and more than 60% of interruptible rate programs use this valuation basis. About 17% of interruptible programs report using wholesale energy prices and ~12% used avoided costs (i.e. these include avoided transmission and distribution costs in addition to generation costs) to set incentive levels.

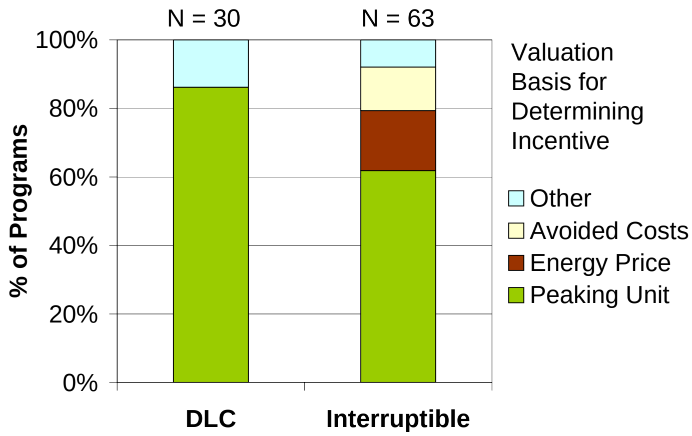

Figure 11. Valuation basis for DR program incentives

Many retail DR programs were approved prior to the formation of MISO and were justified primarily on reliability grounds. However, although “emergency” DR programs are increasingly being utilized for economic reasons, this reality is not fully reflected in cost-effectiveness screening practices used in some MISO states. Anecdotal information also suggests that many LSEs provide “price-sensitive demand bids” in MISO day-ahead energy markets and use high prices from energy markets to trigger their DR programs. Going forward, state regulators may want to direct utilities to consider and assess the full range of DR program applications in MISO markets in cost-effectiveness screening and in setting appropriate incentive levels.

8. Findings and Conclusions

This study provides the first comprehensive assessment of legacy DR resources in the MISO foot-print. The size of the DR resource that responded to this survey is 4,727 MW of which ~84% is available in the MISO service territory through 141 DR programs and dynamic pricing tariffs. Interruptible programs account for ~72% of the DR resource, while DLC programs account for ~18%. Almost 90% of the DR resources included in this survey are provided by investor-owned utilities.

Approximately 87% of the DR resource utilizes an operational trigger linked to system emergency conditions, although most programs allow for multiple triggers. Surprisingly, about 70% of the DR resource can also deployed by LSEs for economic reasons. The frequency of use of DR programs for economic reasons has increased since MISO markets began operating. Approximately 60% of DLC programs and 30% of interruptible rate programs called ten or more DR events in 2006. Despite the high frequency of DR events, customer complaints remained low. The use of economic criteria to trigger DR events and the flexibility to trigger a large number of events suggests that DR resources can help improve MISO wholesale markets.

Approximately, 90% of the DR resources are available with less than 2 hours advance notice and over 1,900 MW are available with less than 30 minutes notice. Almost all of the DR resources are available in summer and 67% of the programs throughout the year. However, the fact that a program operates throughout the year does not mean all potential load reductions from the program are available in each month. System planners will have to develop estimates of DR resource availability by season (or month) instead of using the existing estimates.

M&V protocols vary across MISO foot-print. For many DLC programs, M&V protocols may need to be enhanced in order to allow participation in MISO’s proposed EDR schedule. MISO is in the process of developing M&V protocols that are consistent across its service territory. Almost half of the DR programs have not been evaluated in recent times. Hence, data on performance during DR events is not available. System operators and planners will need to develop more accurate estimates of the load reduction capability and actual performance.

Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels were about $5/kW-month for interruptible rate programs and $6/kW-month for DLC programs. Most utilities indicated that the avoided cost of a peaking unit was used as the valuation basis in cost-effectiveness screening and in setting incentive levels. Few programs offered incentive payments that were explicitly linked to the actual load reduction during an event and at least 27 DR programs do not have penalties for non-performance.

If MISO’s proposed revisions to its emergency procedures are approved by FERC, it is unclear to what extent utilities will actually enroll their customers in this new MISO DR program. LSEs and participating customers would receive additional incentive payments during emergency events (up to $3,500/MWh), but LSEs will incur additional transaction costs, and LSEs and participating customers will face penalties for non-performance. For example, an LSE will have to specify the minimum and maximum amounts of curtailed load, the number of hours of advance notice required and whether such reductions are limited to certain hours, periodically bid and update offer prices for curtailed load, accurately estimate load curtailments or be subject to penalties, and develop and negotiate an acceptable M&V protocol with MISO.

Participation and enrollment of legacy DR resources in the MISO emergency DR protocols may ultimately hinge on whether it is made a requirement for LSEs that want to take resource adequacy credit for their DR resources as part of the MISO reliability planning process. At a minimum, utilities and state regulators may have to rethink and possibly revise some provisions of legacy DR programs that relate to customer's obligations and incentives for curtailing load during system emergencies, penalties for non-performance, periodic testing of existing DR assets, and more consistent M&V protocols.

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