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Demand Response in U.S. Electricity Markets: Empirical Evidence

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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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Abstract

Empirical evidence concerning demand response (DR) resources is needed in order to establish baseline conditions, develop standardized methods to assess DR availability and performance, and to build confidence among policymakers, utilities, system operators, and stakeholders that DR resources do offer a viable, cost-effective alternative to supply-side investments. This paper summarizes the existing contribution of DR resources in U.S. electric power markets. In 2008, customers enrolled in existing wholesale and retail DR programs were capable of providing ~38,000 MW of potential peak load reductions in the United States. Participants in organized wholesale market DR programs, though, have historically overestimated their likely performance during declared curtailments events, but appear to be getting better as they and their agents gain experience. In places with less developed organized wholesale market DR programs, utilities are learning how to create more flexible DR resources by adapting legacy load management programs to fit into existing wholesale market constructs. Overall, the development of open and organized wholesale markets coupled with direct policy support by the Federal Energy Regulatory Commission has facilitated new entry by curtailment service providers, which has likely expanded the demand response industry and led to product and service innovation.

1. Introduction

Demand response (DR) can be defined as: "Changes in electric usage by end use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." [1, 2][1] This concept of demand response can be traced to the beginnings of the U.S. electric power industry (circa early- to mid-1890s), where system engineers and utility executives debated the optimal pricing regime for this new found service: Hopkinson's demand charge or time-of-day differentiated rates [6]. The universe of time-based retail rates has expanded significantly from these early days of the industry to now include real-time pricing (RTP), critical peak pricing (CPP) and variations thereof [2, 3, 7, 8].

As our definition suggests, U.S. utilities have also utilized incentive-based programs, often based on reliability differentiation, to elicit demand response from customers [3]. Utilities implemented load management (e.g. direct load control) programs and interruptible/curtailable tariffs in the early 1970s, both of which were in essence call options in which the customer sold the right but not the obligation for the utility to curtail or shed some of the customer's load in exchange for an upfront payment (in $/kW-month or a bill credit for participation) or a per kWh discount for the non-firm electricity consumption [2]. The initial interest in load management was driven in part by the increasing penetration of air conditioning which resulted in needle peaks and reduced load factors. With the advent of integrated resource planning in the late 1970s and 1980s, utilities increasingly recognized the system cost impacts of meeting peak loads and began to view load management as a reliability resource.

In the mid-1990s, with the advent of electricity restructuring, policymakers and utilities interested in facilitating the development of regional, competitive wholesale (and, in some states, retail) electricity markets initially focused primarily on market design and structure, albeit with a supply-side focus (e.g., open access to transmission services, vertical de-integration, establishing independent system operators). However, the problems in many restructured electricity markets (e.g. electricity crisis in Western state power markets in 2000-2001, price volatility and spikes, perceived market power, reliability concerns during system peak demand conditions, and failure to produce expected benefits to consumers) led policymakers to conclude that demand response, in all of its different forms, is essential to the efficient functioning of wholesale electric markets [9]. The Energy Policy Act of 2005 (EPACT) codified that a key objective of U.S. national energy policy was to eliminate unnecessary barriers to wholesale market demand response participation in energy, capacity, and ancillary services markets by customers and load aggregators, at either the retail or wholesale level.

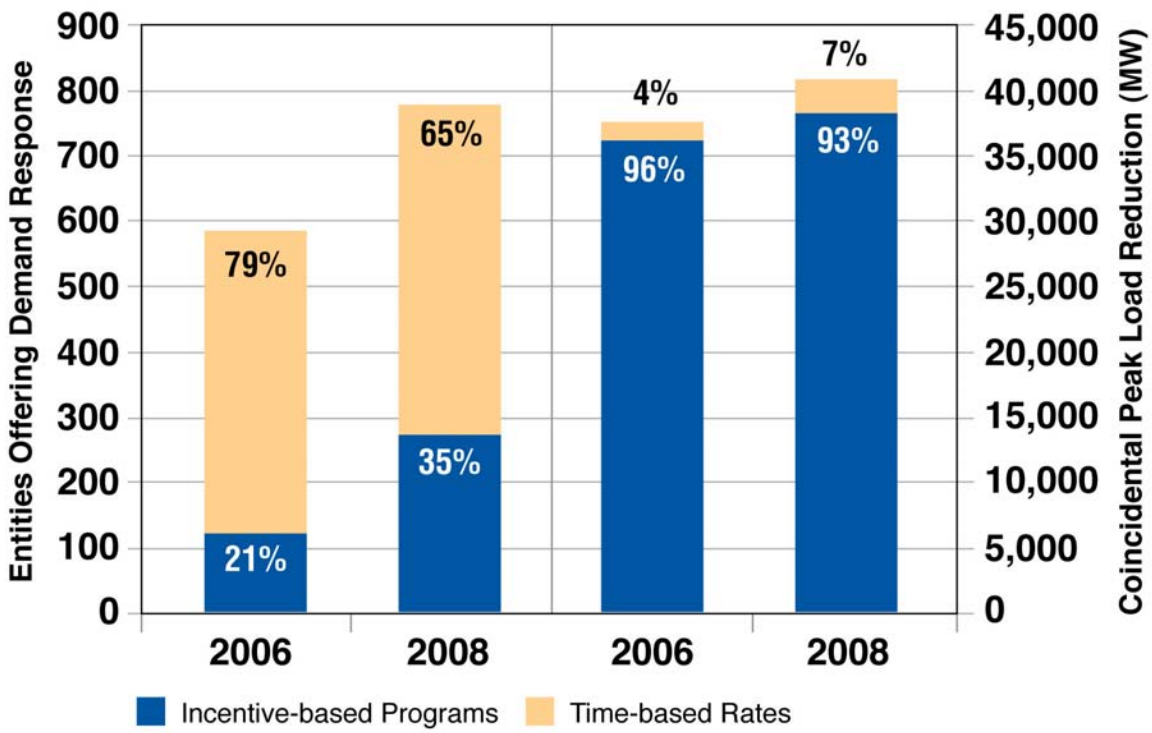
[1] Other studies have developed alternative typologies to characterize demand response resources [3, 4] which are linked to program objective (e.g., system reliability or price response) or resource planning (e.g. firm vs non-firm resources) Given our subsequent focus on the two Federal Energy Regulatory Commission reports on demand response, we have chosen to use the typology found therein [2, 5].

It is therefore critical to assess existing capabilities of DR resources among load serving entities and customers to provide load reductions in response to system emergencies and/or high market prices, and assess the actual performance of DR resources during recent periods. Empirical evidence of DR resources is needed in order to establish baseline conditions, develop standardized methods to assess DR availability and performance and to build confidence among policymakers, utilities, system operators, and stakeholders that DR resources do offer a viable, cost-effective alternative to supply-side resources. In this study, we summarize the existing contribution of DR resources in U.S. electric power markets (i.e., retail and wholesale), with a primary focus on enrollment and performance of incentive-based DR programs in organized markets (rather than time-based retail rates). Both types of DR resources are critical to the development of competitive electricity markets [10 - 12].

This paper proceeds as follows. First, it provides an overview of the types and magnitude of existing DR resources in the United States and then focuses on the evolution and maturation of incentive-based DR programs in organized markets in terms of enrollment and performance. Next, it discusses the evolution of legacy, existing load management programs and interruptible/curtailable tariffs offered by utilities within the new framework of organized wholesale markets, drawing on results of recent studies of the Midwestern Independent System Operator (MISO) and Southwest Power Pool (SPP) conducted by the authors. Finally, it explores the role that third party DR program providers (i.e. curtailment service providers) have played in expanding the scope of the DR industry, again drawing on the empirical evidence of recent activity.

2. Current Size and Scope of DR in the United States

As part of the Energy Policy Act of 2005, the U.S. Congress directed the Federal Energy Regulatory Commission (FERC) to develop a comprehensive national assessment of the size and scope of electricity DR resources and advanced metering as part of a national energy policy [2]. To accomplish this task, the FERC prepared and administered a comprehensive survey, first in 2006 [2] and then again in 2008 [5], to ~3300 organizations representing all aspects of the electric delivery industry (e.g., investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated DR providers) from all 50 states. About 55% of these organizations (~1850 responses) completed the DR section of the survey.



Source: [2] and [5].

Figure 1. Estimated size of DR resources in the United States.

Among survey respondents, there has been a significant increase (117%) in the number of entities offering DR programs: 126 in 2006 vs. 274 in 2008 (Fig. 1) and about a 10% increase in the number of entities offering dynamic pricing tariffs to retail customers. Nationally, the potential size of peak load reductions from existing DR resources, relative to national peak demand, was about 5.0% in 2006 [2] and grew to 5.8% in 2008 [5].[2]

Many more entities offer some type of time-based retail rate as compared to incentive-based DR programs. However survey respondents indicated that these time-based retail

[2] In estimating existing DR Resource contribution, FERC staff drew upon FERC survey responses and other sources (e.g. Energy Information Administration Form 861, Independent System Operator (ISO) or Regional Transmission Operator (RTO) DR program data).

rates account for a small part of the total existing DR resource base. In 2008, customers enrolled in existing incentive-based DR programs were capable of providing ~38,000 MW of potential peak load reductions, while time-based retail rates were expected to produce another 2,700 MW (Fig. 1). In percentage terms, about 93% of the peak load reduction from existing DR resources in the U.S. is provided by various types of incentive-based programs (Fig. 1).

Given that peak loads vary significantly by region, it is also useful to characterize existing DR resources compared to a region's summer peak demand (see Fig. 2). Demand response resource potential ranges from 3 to 9% of a region's summer peak demand in most regions, with the notable exception of the Midwest Reliability Organization (MRO) region where DR resources represent a much higher percentage of summer peak demand.

Several factors may help to explain this result: (1) several states (Minnesota and Iowa) require utilities to invest a percentage of revenues from retail sales (1.5-2%) in demand-side management (DSM) programs, (2) utilities in the upper Midwest have historically had favorable resource adequacy rules that allow load management to be counted towards meeting reserve requirements, and (3) the customer base includes a significant fraction of industrial load that is amenable to interruption (e.g. steel plants) [5]. Among the existing DR resource base, residential customers account for ~6,000 MW while industrial customers account for ~14,800 MW. In the Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), and Reliability First (RF) regions, a significant portion of DR resources is attributable to programs offered by ISOs and RTOs (e.g., classified as wholesale). Elsewhere in the U.S., the majority of existing DR resource potential comes from more traditional DR programs: interruptible/curtailable rates for industrial customers and direct load control for residential and small commercial customers.

3. DR Resources in Eastern U.S. ISOs

3.1 Participation

Most of the growth in incentive-based DR resources has occurred in organized wholesale markets administered by ISOs/RTOs. Since 2001, FERC has required ISO/RTOs to file annual program evaluations or include a detailed discussion of their DR program enrollment and performance in annual state of the market reports. To illustrate trends in the development of DR resources in some organized markets, we focus on three ISOs located in eastern U.S. electricity markets: New York Independent System Operator (NYISO), ISO New England (ISO-NE), and PJM Interconnection (PJM).

The New York ISO has historically offered three different incentive-based DR programs: Emergency Demand Response Program (EDRP), Special Case Resource (SCR) program, and the Day-Ahead Demand Response Program (DADRP). EDRP is a voluntary program that pays strictly for energy; while SCR provides an up-front payment for capacity, a payment for load reductions when dispatched, but includes the threat of penalties for non-compliance with capacity obligations during declared program events.[3] The DADRP is an economic DR program that allows participants to submit load curtailment (i.e., supply) offers into the NYISO's Day-Ahead Market, where they compete side-by-side with generators. If a DADRP participant's offer is accepted, that participant is obligated to curtail the committed amount the following day, or else covers any open position it has at the higher of the real-time or day-ahead location-based marginal price (LBMP).

ISO-NE also offers three incentive-based DR programs: its Real-Time Demand (RT-Demand), Real-Time Price (RT-Price) and Day-Ahead Load Response (DALRP) program. There are three options for customers wishing to participate in ISO-NE's emergency (RT-Demand) DR program: the first two require participants to send near real-time meter data every 5-minutes to the ISO, but differ in terms of the length of notification prior to an event they require (i.e., RT-30 Minute or RT-2 Hour) and consequently the floor energy price paid for curtailments ($500/MWh and $350/MWh, respectively); the third option (RT-Profiled) requires neither communications devices nor interval meters to be installed in order to participate. In all the cases, enrolling participants are subject to non-performance penalties. The RT-Price program provides customers the opportunity to reduce load in real-time when a specific price point is exceeded, while the DALRP offers customers the opportunity to participate indirectly in the ISO-NE's Day-Ahead energy market.[4]

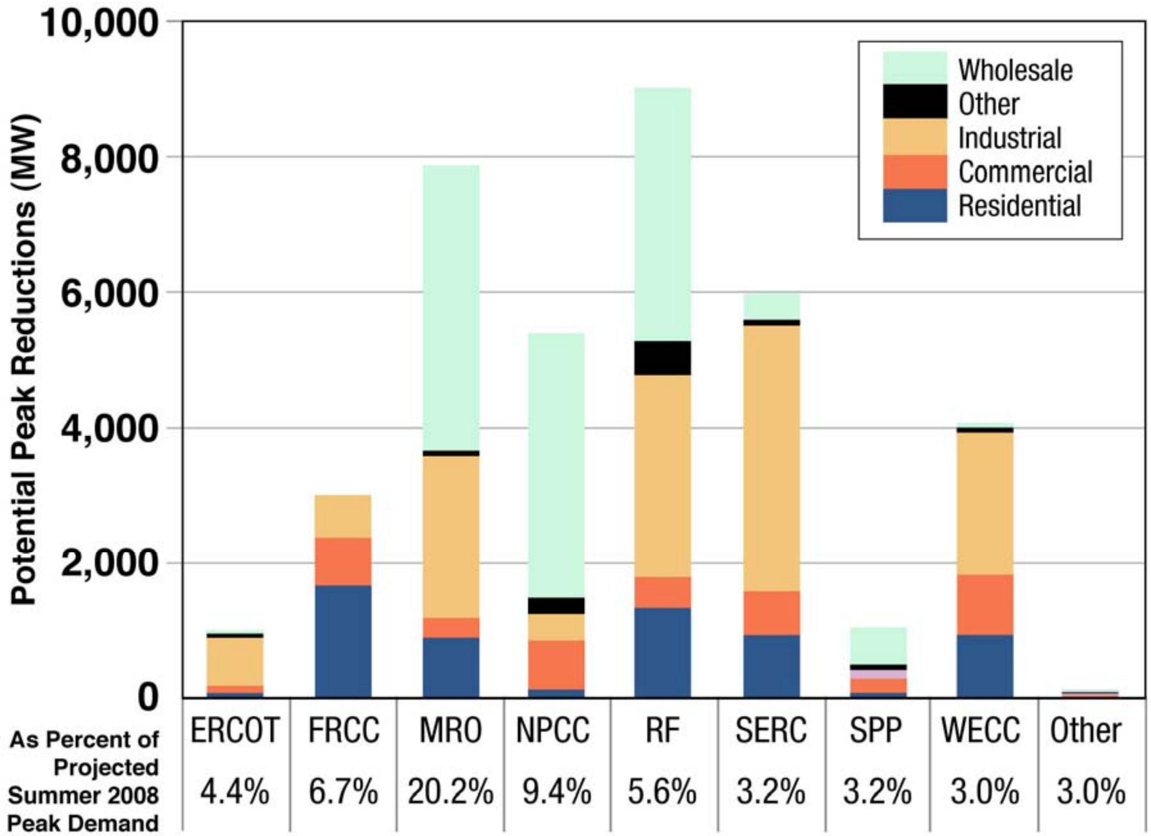
PJM provides its customers with three incentive-based DR programs: Emergency, Active Load Management (ALM), and Economic load response programs. The Emergency and ALM programs are dispatched under system emergencies, but differ in terms of the requirements for participation. As a result of the introduction of a forward capacity

[3] Prior to 2003, end-use customers had to enroll in both EDRP and SCR to receive both an up-front capacity payment and any energy payment that would be provided during program events.

[4] The methodology for triggering an RT-Price event has evolved over the past several years. At the program's inception, customers were able to curtail anytime between 7 a.m. and 6 p.m. if the day-ahead locational marginal price (LMP) or forecasts of real-time LMP exceeded $100/MWh. Starting in 2005, the event start time was scaled back to include only afternoon hours. More recently, the ISO has altered the trigger price to better track economic conditions in the wholesale market.

market in 2007, the design of the Emergency and ALM programs was altered to accommodate these respective resources in the Reliability Pricing Model (RPM).[5] The Economic program has given customers the opportunity to participate in the Real-Time energy market, either through direct or indirect scheduling.

In addition, these three ISO/RTOs have recently developed opportunities for DR resources to participate in ancillary service markets. Both the NYISO and PJM allow DR resources to participate in regulation, 10-minute and 30-minute operating reserves markets. ISO-NE is offering a pilot program for customers to participate in providing operating reserves.



Source: [5].

Figure 2. Estimated size of DR resources by NERC region and customer sector

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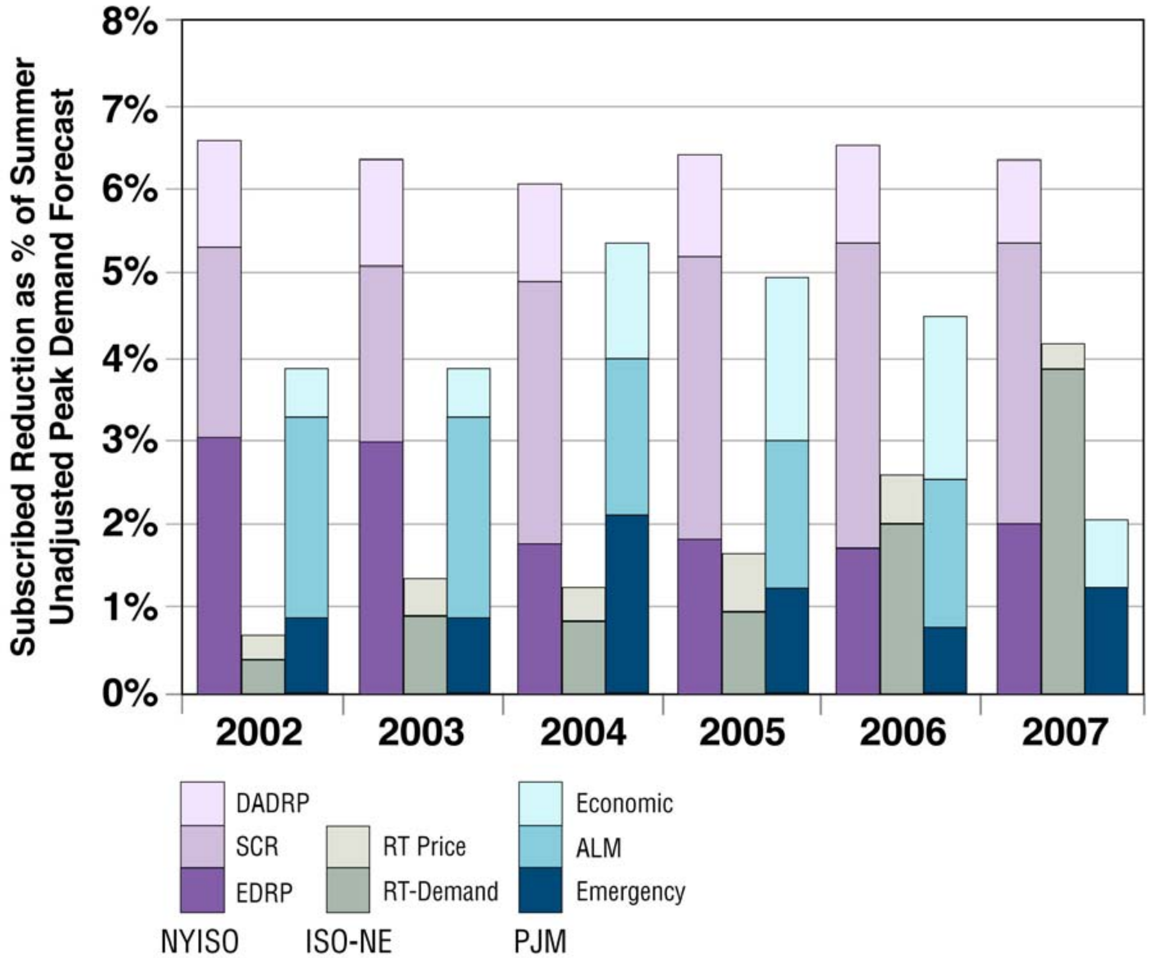
5 The participation figures in 2007 for the Emergency program represent the enrollment in the "Energy Only" option, which is consistent with the voluntary nature of the Emergency program prior to that year. For reporting purposes, we have chosen to include all participants in the "Full" and "Capacity Only" options of the current Emergency program under the ALM category. This characterization is consistent with the historic ALM program, which included mandatory performance with the possibility for penalties and offered some form of a capacity payment.



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 3. Comparison of Northeastern ISO incentive-based DR program enrollment

Fig. 3 illustrates how DR program enrollment has evolved in these three ISO/RTOs from 2002 through 2007. In New York, the total size of the DR resource portfolio has not changed dramatically over the past six years, although there have been significant changes in the mix of individual programs.[6] Since 2003, when joint participation in EDRP and SCR was no longer allowed, there has been a clear migration away from EDRP towards the more lucrative but demanding SCR program.[7] The up-front reservation payment provided in the SCR program provides an ongoing revenue stream that is crucial to the financial viability of load aggregators and attractive to customers.

In interpreting results for PJM, it is important to recognize that PJM significantly expanded its footprint (and summer peak demand) since 2005 and 2007 as new utilities from the Midwest joined PJM. Enrollment in PJM's DR programs has grown significantly from 2002 to 2007 from ~2100 MW to 4600 MW, although in percentage

[6] Enrollment in the NYISO DR program increased dramatically from 775 MW in 2001 (not shown in Fig. 2) to 2,025 MW in 2002.

[7] The subscribed load reductions prior to 2003 associated with participants jointly in EDRP and SCR were assigned to SCR, as that program has the threat of penalty for non-compliance.

terms it is lower because PJM's footprint has expanded. PJM has also seen a major shift in its pool of program participants over time.

Significant changes in the designs of the Emergency and ALM programs were undertaken as part of Reliability Pricing Model (RPM), development process, in order to allow as many resources as possible to participate in that forward capacity market. Such alterations in the programs' designs appear to have elicited an exodus from the purely voluntary Emergency program option (i.e., Energy-Only) towards the capacity-based (Full and Capacity-Only) options, the latter labeled as ALM in Fig. 2.

During this period, participants enrolled in PJM's economic DR programs increased their subscribed peak load reductions from 335 MW in 2002 to ~2500 MW in 2007. Customers in two zones, Commonwealth Edison (ComEd) and Baltimore Gas & Electric (BGE), account for nearly 65% of this increase in the economic program's capabilities. Since joining PJM, ComEd has enrolled and transitioned its existing DR assets into PJM's economic DR programs and also expanded its offering of DR programs (i.e., Early Advantage, Rider 32 and Voluntary Load Reduction Programs) [13]. Enrollment in economic DR programs in the BG&E zone almost tripled in 2007 compared to 2006 (140 to 393 MW), which may have been a response to very large rate increases in Maryland and aggressive marketing by curtailment service providers (CSPs).

In ISO-NE, the RT-Demand response program increased in size from 0.4% of forecasted system peak demand in 2002 to 3.9% in 2007, nearly an 800% increase in just 5 years. Since 2007, the introduction of the Forward Capacity Market (FCM) in New England has also contributed to the continued growth in DR resources, as estimated peak load reductions associated with the RT-Demand response program increased by 51% between 2007 and 2008.

Enrollment in DR programs provides system operators with an indication of the size of the customer resource base that is willing to curtail or shift load in response to system contingencies or high market prices. However, because participation is voluntary in some of these DR programs and because the utility often does not have physical control of the customer's load response (as in a direct load control program), information on the actual performance of DR resources during system emergencies or in response to high prices is crucial to assessing the long-term viability of DR resources. In order for these resources to be treated comparably to "iron-in-the-ground" generation assets, system operators must be confident that DR resources will perform in a consistent and predictable fashion. Performance metrics offer all market participants, and especially system operators, the opportunity to tangibly recognize the value of DR.

3.2 Performance

Two different performance metrics have been proposed by evaluators of the NYISO DR programs: Subscribed Performance Index (SPI) and Peak Performance Index (PPI) [14]. SPI compares the actual load reduction to what was initially subscribed to a DR program, while PPI estimates the customer's actual DR load curtailment compared to their peak demand. Given the infrequent reporting of the PPI by ISOs and the difficulty of producing the PPI independently, we focus on the SPI. For consistency of reporting, we focus on the portfolio level metric, whose definition was taken from [14]:

$$SPI_p = (E_d / E_s) \cdot 100\% \,, \quad (1)$$

where

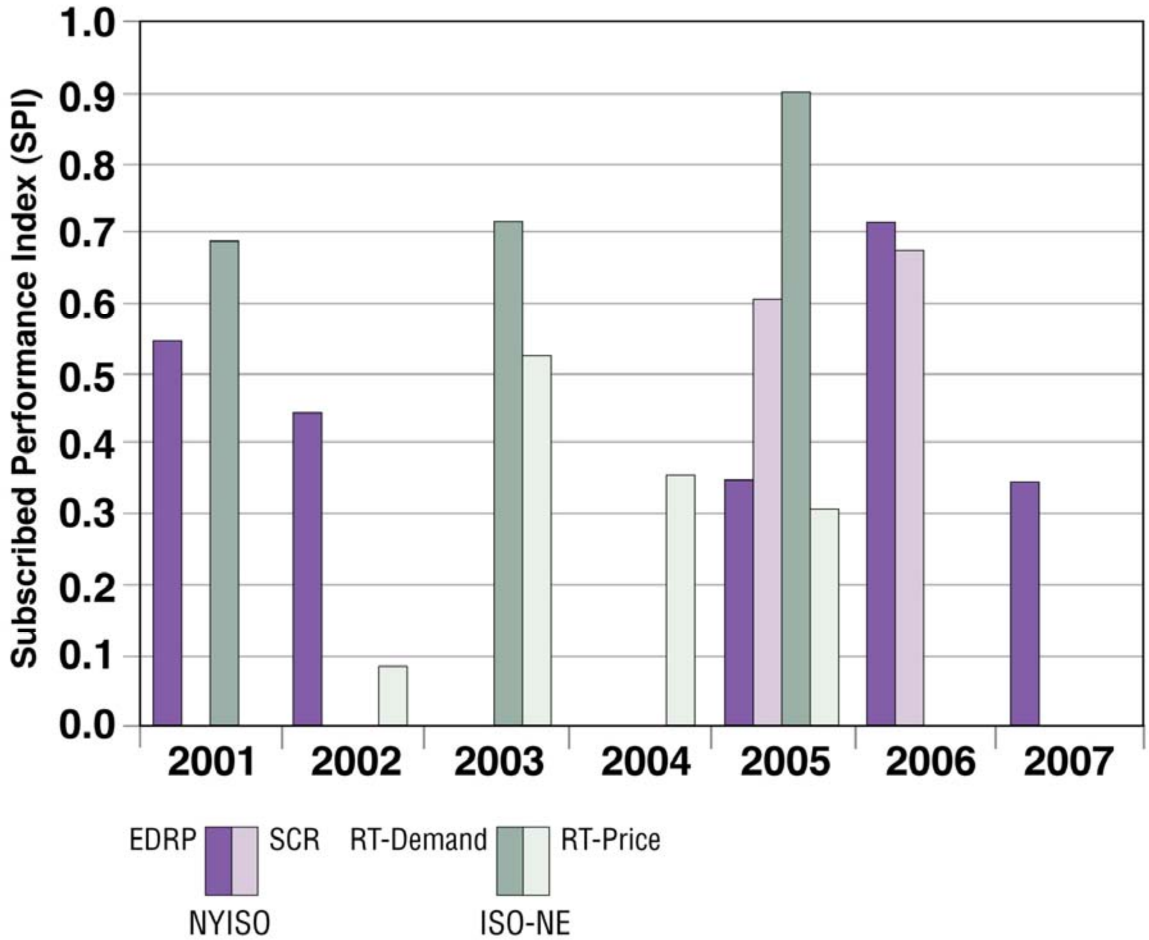
$$E_d = \sum_{i=1}^{M} \left(\sum_{t=1}^{N} (CBL_{i,t} - E_{i,t}) \right), \quad (2)$$

$$E_d = \sum_{i=1}^{M} \left(\sum_{t=1}^{N} (CBL_{i,t} - E_{i,t}) \right), \quad (3)$$

and

E_d = the total electric energy curtailment <u>delivered</u> by all customers in a program,
E_s = the total electric energy curtailment <u>subscribed</u> by all customers in a program,
CBL_t = the customer baseline of customer *i* in hour *t* (MWh),
$E_{i,\,t}$ = the electric energy of customer *i* in hour *t* (MWh),
M = the total number of customers in a program,
N = the number of hours per curtailment event, and
$E_{sub,i}$ = the subscribed load curtailment of customer *i* (MWh).

We were able to derive SPI values in Fig. 4 from ISO-NE and NYISO DR programs for several years based on the evaluation results or reported program performance. In some cases, the lack of a reported metric in certain years is either because no events were declared (e.g., 2004) or conditions surrounding a declared event would not produce an accurate assessment of performance relative to subscription (e.g., 2003 Northeast Blackout).



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 4. Comparison of Northeastern ISO program performance

The average SPI for ISO-NE's Economic program is 0.32 for four years with program data, which suggests that program participants' load curtailments were only about 32% of their subscribed load commitment during high price events. The SPI varied considerably from one year to the next – ranging between a low of 9% (2002) and a high of 53% (2003), illustrating how highly variable performance is of these enrolling participants.

The relatively low and highly variable SPI for the ISO-NE Economic DR program is not too surprising, given the fact that this program was new to participants (who may have been unsure about how much load curtailment to "subscribe"), there were no penalties for non-performance, and participants had complete discretion concerning when and how much of a load reduction to undertake based on an economic analysis of the opportunity cost of consuming load. In our view, this type of performance metric can provide useful information over time (as customers obtain more experience with measurement and verification protocols used to estimate curtailed load during events) and if training and technical assistance are provided to customers to help them quantify the amount of discretionary load that they can and are willing to curtail or shed during events.

The two DR capacity market programs (NYISO SCR and ISO-NE RT-Demand) provided 64% (SPI=0.64) and 77% (SPI=0.77) of their expected curtailments, respectively. The voluntary emergency DR program (NYISO EDRP) produced an overall average SPI of 0.52. These results suggest that the actual performance of DR programs with non-compliance penalties will be closer to their committed load curtailment compared to economic or voluntary emergency DR programs (that do not have penalty provisions). In terms of consistency, the NYISO SCR and the ISO-NE RT-Demand programs' performance index also varies considerably less than the SPI for EDRP. The variability in SPI over time is also very important to system operators who have the responsibility for maintaining grid reliability.

If DR is to play an increasing role in wholesale markets as an economic or reliability resource, system operators and resource planners must be able to accurately predict what DR resources can provide during system events in order to maximize their contribution to market efficiency and system stability while minimizing overall system costs. Recent efforts by system operators to manage and integrate intermittent generation resources provide an instructive example. Intermittent generation resources, like DR, are playing an increasing role in the bulk power system. As wind generation has grown over the past several years, ISO/RTOs have been forced to not just rely on these resources' accepted offers in forward markets to predict real-time performance but have also developed internal forecasts of their output in order to ensure sufficient reserves are in place to maintain reliability. For example, in September 2008, the NYISO brought on-line a new state-of-the art wind forecasting system that feeds wind-power forecasts based on meteorological data and historical operating characteristics directly into NYISO operational systems to better maintain the requisite balance of load and generation and predict wind power output on an hourly basis [15].

4. Integration of Existing Utility DR Programs in Wholesale Markets

As part of the transition to competitive, organized wholesale markets, it is necessary for the wholesale market rules and requirements to accommodate and facilitate a transition of existing DR resources into these new markets. Initially, the design of organized wholesale markets focused primarily on developing market rules that worked for supply-side assets. The FERC and state regulators in a number of states have placed increasing emphasis on ensuring that market rules provide an opportunity for existing DR assets enrolled in legacy incentive-based programs to participate in organized wholesale markets.

Working with the Lawrence Berkeley National Laboratory, the Organization of Midwest's Demand Response Initiative (MWDRI)[8] and the Southwest Power Pool each commissioned a detailed survey of the design features, operational triggers used to call events (e.g., system emergencies, market conditions, local emergencies), DR resource availability (e.g. seasonal, annual), participant incentive structures, and historic performance of existing DR programs and dynamic pricing tariffs offered by load serving entities in each ISO/RTO [16 - 17]. Although the timing of the surveys differed by roughly a year, they shared common goals:

- To inventory the existing set of retail incentive-based DR programs and dynamic pricing rates;
- To assess differences and similarities among existing retail incentive-based DR programs and dynamic pricing rates; and
- To help inform the debate at MISO and SPP concerning how to best make use of existing retail DR assets at the wholesale level.

The survey for SPP was fielded to 52 different cooperatives, municipal utilities, investor-owned utilities (IOU), state agencies, independent power producers (IPP), power marketers and transmission companies. Thirty entities, all municipal utilities and IOUs returned completed surveys; 14 of these entities offered some form of DR to their customers. In the MWDRI survey project, 35 utilities completed the survey with information on 141 DR programs and dynamic pricing tariffs; survey response was very good (~80%).[9]

In terms of wholesale market design, SPP administers an Energy Imbalance Service (EIS) market: participation is mandatory for load serving entities and generators and all real-time resources where imbalances are settled using the EIS market. MISO administers a day-ahead and real-time energy market with centralized economic dispatch and locational marginal pricing as well as ancillary services markets for regulation, spinning reserves and supplemental reserves. At the time of the survey, neither ISO/RTO had explicit wholesale DR programs that the ISO/RTO administered.

[8] MWDRI was an initiative of the Organization of Midwest States (OMS) that resides primarily in the Midwest ISO (MISO) footprint.

[9] Four utilities were not members of MISO but operate in states that are part of OMS. Their responses were included in the study to provide a more comprehensive view of DR programs in the Midwest.

Table 1 – Overview of SPP and MWDRI survey results

	SPP			MWDRI		
	Incentive-based programs	Time-based rates	Voluntary response	Incentive-based programs	Time-based rates	Voluntary response
Survey Respondents	26	5	4	99	12	N/A
No. of Programs	36	5	6	122	19	N/A
Potential Coincident Peak Demand Reduction (MW)	1,352	200	N/A	4,406	321	N/A
Distribution of DR Resources	87%	13%	N/A	93%	7%	N/A

Source: [16] and [17]

As Table 1 illustrates, both SPP and MISO have a robust existing set of DR resources capable of reducing RTO system peak demand, roughly 4% and 5% respectively. Specifically, the SPP survey revealed that in 2008 there were a total of 47 different retail DR initiatives currently being offered in that RTOs footprint: 36 incentive-based DR programs, five time-based retail rates, and six voluntary response programs.[10] Retail DR as a whole in SPP is estimated to provide 1,552 MW of potential coincident peak demand reduction, 13% of which comes from customers on time-based rates while the remaining 87% is associated with incentive-based DR programs.[11] The MWDRI study indicated that as of late 2007 there were over 122 different retail incentive-based DR programs being offered to customers, and 19 different time-based retail rates in the region's utility tariffs. Collectively, DR is forecasted to reduce coincident peak demand in MISO by 4,367 MW, again the vast majority (93%) of which is coming from incentive-based DR programs.

The surveys also provided insights into how utilities in SPP and MISO are utilizing their DR resources. Respondents were asked to characterize the conditions (i.e., improving local reliability, mitigating system emergency conditions, and/or reducing exposure to high market prices) under which they chose to invoke load curtailments.

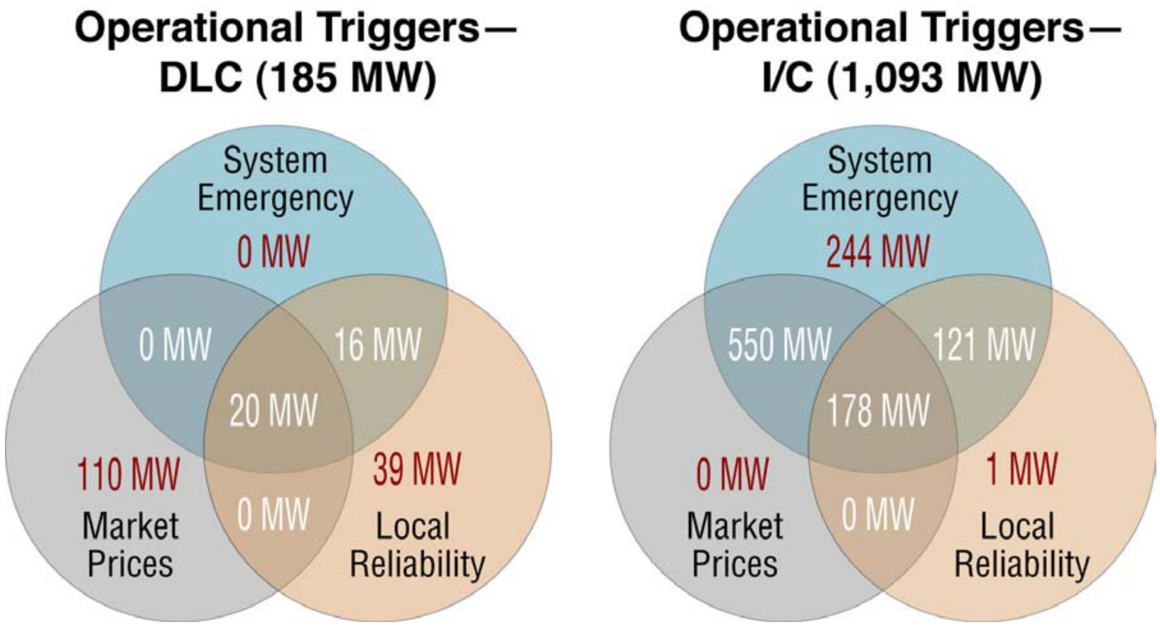
Historically, interruptible/curtailable (I/C) and direct load control (DLC) programs were justified primarily for reliability purposes and dispatched only during system emergencies. However, as competitive wholesale markets have developed and with the formation of MISO and SPP, most DR programs in these two regions currently have more than one operational trigger. A Venn diagram illustrates the universe of different conditions under which program administrators are invoking their DR resources and the expected load reductions associated with each combination of conditions.[12] The dark

[10] Incentive-based DR programs were defined to encompass interruptible/curtailable rates, direct load control programs, and economic (e.g., demand-bidding, demand buy-back) programs. Time-based retail rates include real-time pricing and critical peak pricing. Finally, voluntary response programs were defined to represent any program where customers provided their "best-effort" to reduce consumption when requested but were not provided any compensation for doing so.

[11] Although five of the voluntary response programs had been called at least once, none had been evaluated at the time the survey was administered and thus respondents had no estimates of the programs' likely contribution to reducing peak loads.

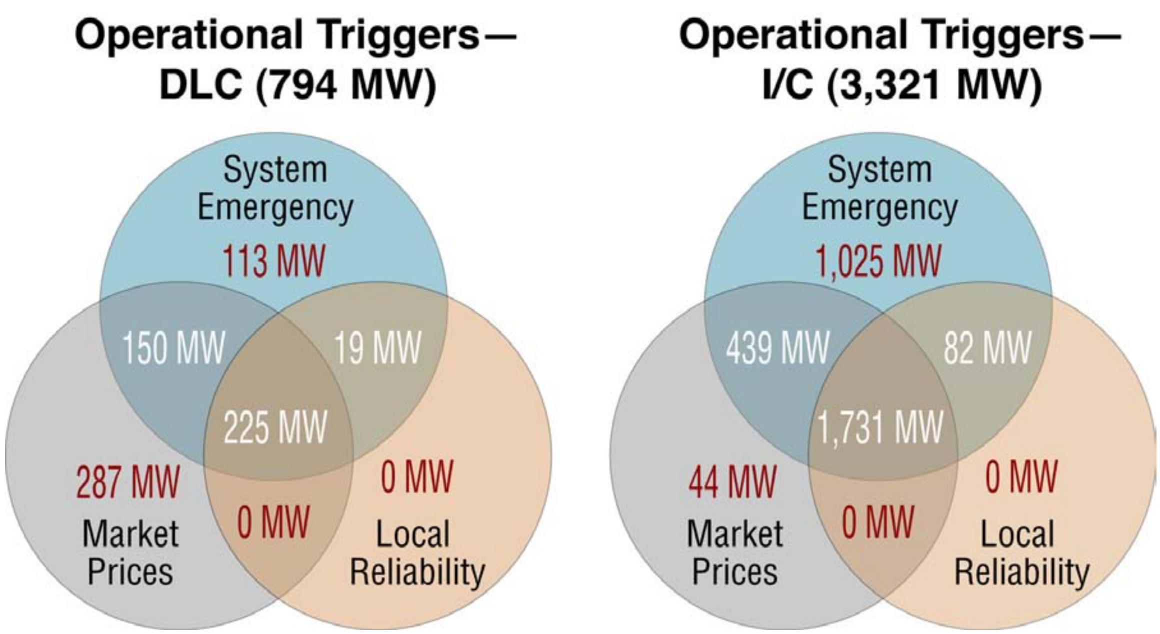
[12] In Figs 5 and 6, the different sets (circles) in the Venn diagram represent the different dispatch conditions (i.e., system emergency, local reliability, or market price) and the indicated MW values represent the magnitude of committed load reductions from enrolled participants for the indicated set of conditions based on program administrators' estimates. Parts of the sets that overlap each other represent committed load reductions that can be dispatched for the different indicated dispatch conditions. For example, 20 MW of

intersections in Figs 5 and 6 shows that in SPP and OMS states, about 69% and 64% respectively of survey respondents' enrolled DR (in MW), can be called for multiple conditions. An increasing number of utilities are now recognizing the flexibility these tariffs provide in the new wholesale market environment by also allowing for economic dispatch of these DR programs.



Source: [17]

Figure 5. Peak load reduction by operational trigger for DLC and interruptible DR programs in SPP



Source: [16]

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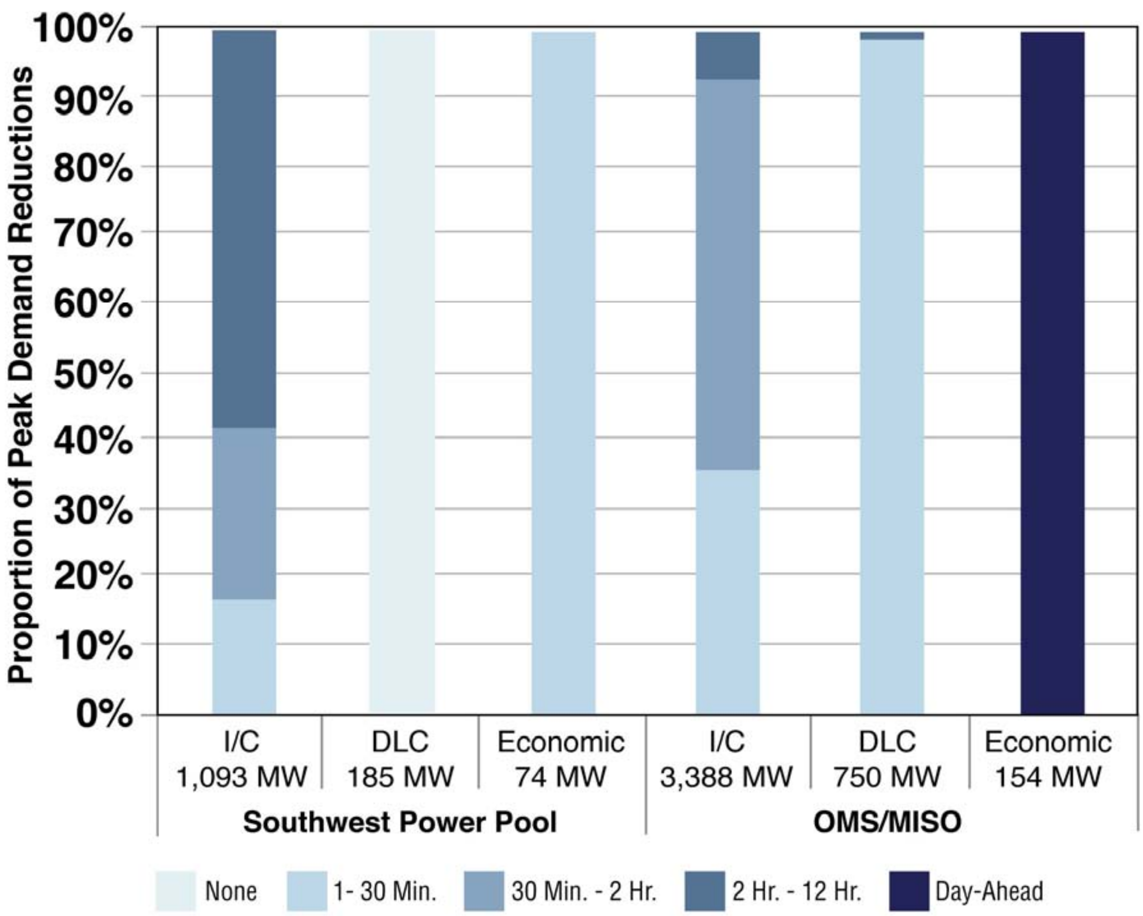
demand response in an SPP DLC program can be dispatched for any of the three conditions, whereas 39 MW can only be dispatched for local reliability reasons.

Figure 6. Peak load reduction by operational trigger for DLC and interruptible DR programs in OMS states

When utilities see or expect high prices, at least 66% of the peak demand reductions associated with a DR program (i.e., DLC or I/C) in SPP and OMS can be (or have been) dispatched (see Figs. 5 and 6). Utilities in OMS indicated that they wanted to reduce their exposure to high energy market prices but were reticent about bidding these resources into MISO's day-ahead market directly. So instead, the utilities themselves dispatched these programs closer to real-time when energy market prices rose above a certain level. In contrast, the distribution cooperatives in SPP who responded to the survey invoked their DLC programs for flattening out their load shape in order to minimize coincident transmission system peaks, thereby achieving substantial savings in their demand charge.



Source: [16] and [17]

Figure 7. Advance notification requirements for DR Programs

The surveys also requested that respondents specify the number of hours of advance notice required before demand can be reduced for each DR program. Advance notice requirements vary considerably across DR programs and by region (see Fig. 7). For example, DLC programs were uniformly reported to have no or very short notice requirements, which is not surprising given that equipment is cycled directly by utilities. In contrast, for interruptible/curtailable tariffs in MISO, ~90% of the enrolled load could be curtailed in less than 2 hours of advance notice with a significant amount of that load (1960 MW) available on just 30 minutes notice. However, among SPP member utilities, survey respondents reported that only 40% of the enrolled interruptible/curtailable load could be curtailed within 2 hours (see Fig. 7). Economic DR programs do not have significant amounts of enrolled load in either SPP or MISO, although notice requirements are much shorter in SPP (1-30 minutes) compared to MISO (day-ahead).

The relatively short event notification requirements associated with DLC programs make them perfect candidates to participate in wholesale real-time ancillary services markets, when such opportunities arise. If emergency and/or capacity DR programs are developed at SPP and/or MISO, then the vast majority of I/C resources could participate under existing retail program and tariff structures.

5. Role of Curtailment Service Providers in Wholesale Market DR Programs

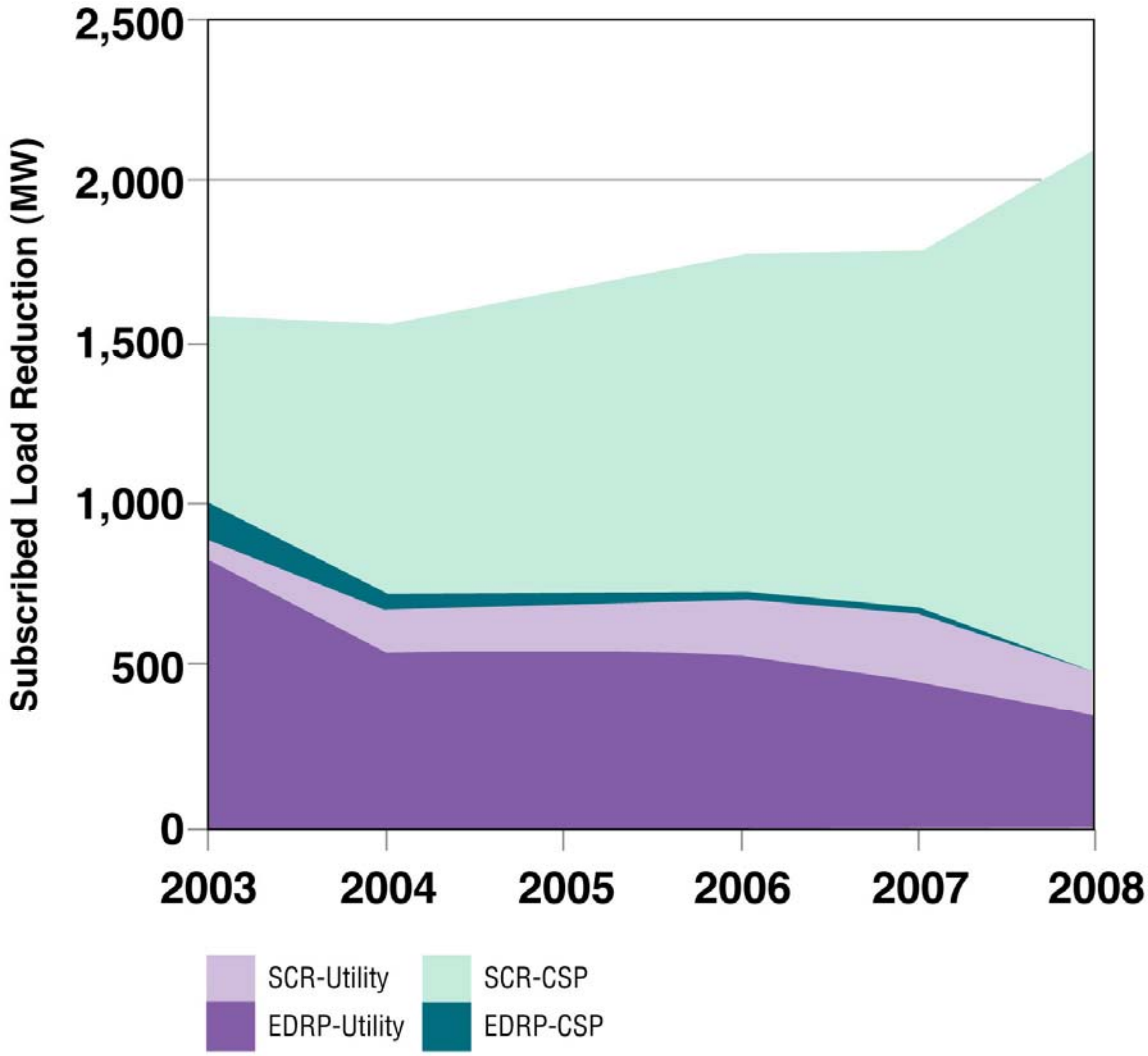
One of the arguments and intended benefits of competitive wholesale markets was service and product innovation. The emergence and increasing role of curtailment service providers provides an interesting case study that illustrates how strong public policy support by FERC and stakeholder support in organized wholesale markets created opportunities for new entrants to obtain a significant foothold and thus expand the DR industry.

In virtually all ISO/RTOs, "legacy" incentive-based DR programs offered by utilities were the initial participants in wholesale market DR programs. In states with retail competition, it was not long before competitive (non-utility) entities began offering customers similar opportunities. Each of the Eastern ISOs (ISO-NE, NYISO, and PJM) that developed opportunities for end-use customers to participate in their wholesale markets had to develop market and program rules for load aggregators that proposed to offer a customer's load reduction capability as a paid resource but were not the customer's load serving entity (LSE).

Program design and implementation issues that had to be addressed in order to facilitate participation by CSPs included: (1) a more sophisticated registration process for load aggregators (e.g., ensuring that customers' sites were not enrolled by multiple program providers), (2) notification procedures (e.g., notifying load serving entities that customers were enrolling in a incentive-based wholesale market DR program by a CSP), (3) metering and telemetry requirements (e.g., access by CSPs to customer's interval meter data) and (4) back-office software modifications at the ISO and incumbent utility in order to ensure timely and accurate processing and transmission of the interval data to CSP and ISO.

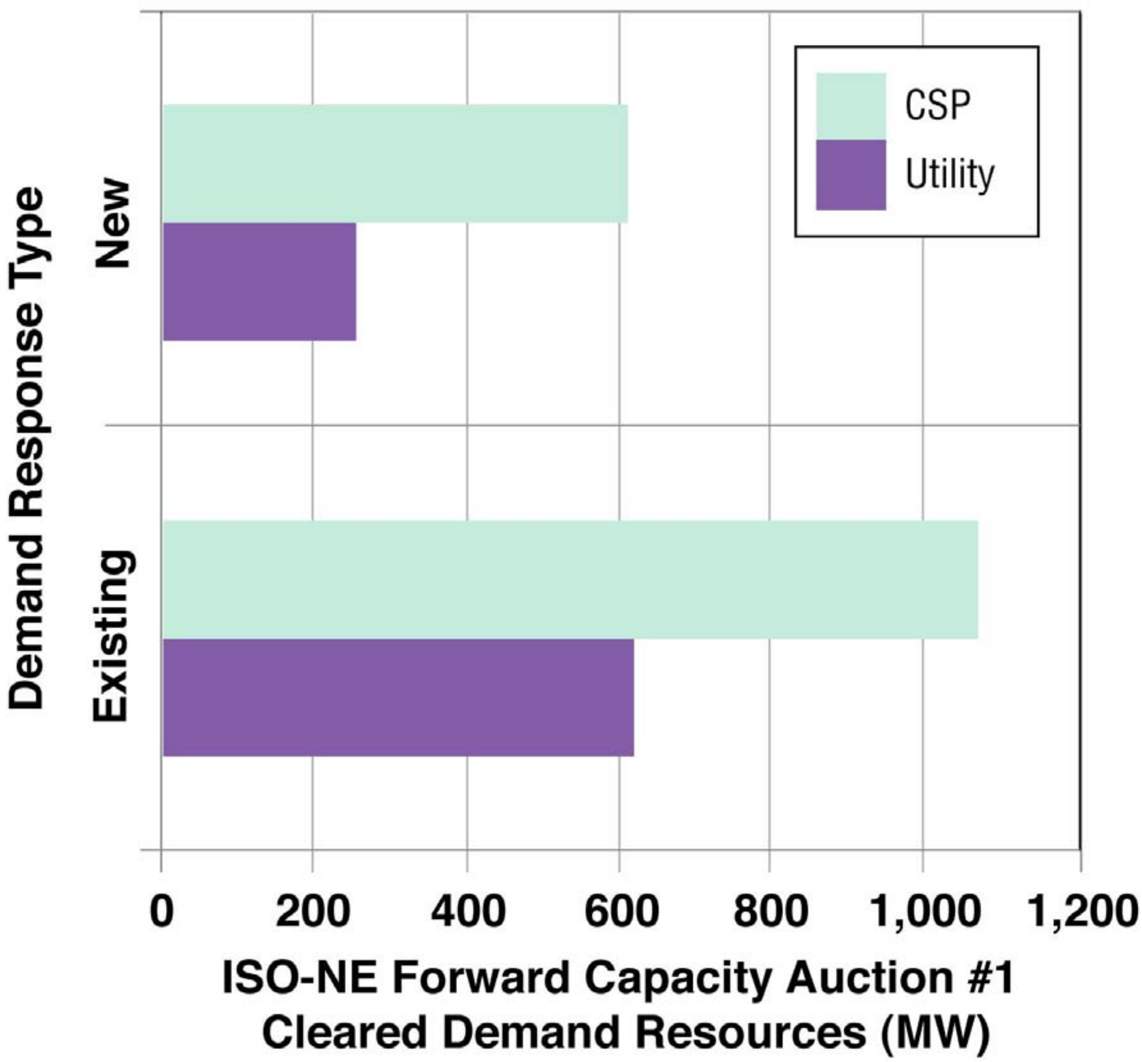
As new entrants, CSPs incurred substantial up-front costs which included marketing costs to enroll customers in a DR program, back-office and communications network infrastructure costs, and design, installation, financing, and maintenance of enabling technology at customer facilities (e.g. controls, onsite generation). CSPs required a source of revenue to make program participation a viable business opportunity. Energy payment for verified load reductions achieved by enrolled customers was an option, although CSPs would have to rely on the likelihood that events would be called by an ISO, which could be problematic. In contrast, utilities were typically allowed to recover program administration costs directly into retail rates.

CSPs soon gravitated towards incentive-based DR programs (e.g., capacity market, requests for emergency resources) that provided an upfront and ongoing reservation payment for committed load reduction by load aggregator (or customer). These programs provided a significant opportunity for CSPs to aggregate individual customer's willingness to curtail into a load curtailment resource, negotiate and share reservation payments with customers, provide energy payments to customers for performance during events, and allow CSP to compete on the basis of price and not just service. For example, Fig. 8 shows enrollment by the type of service provider (i.e., CSP or utility) in several DR programs administered by the NYISO. From 2003 to 2008, CSPs increased their share of subscribed load of DR resources from 44% to 77% in the emergency (EDRP) and capacity markets (Installed Capacity/Special Case Resources – ICAP/SCR). The ICAP/SCR program has been the main area of growth for CSP, accounting for well over 80% of the enrolled capacity in 2008. CSPs have heavily marketed the SCR program to customers by developing customized service packages and enabling technology that help customers to manage the risks associated with participation. Enrollment in the voluntary EDRP program has steadily eroded (i.e., 956 MW in 2003 but only 365 MW in 2008) as CSPs have shunned the EDRP program that provides energy payments only during events. The market share of utilities has steadily declined over this period.



Source: FERC filings, annual State of the Market reports, working group presentations.

Figure 8. NYISO DR program enrollment: utilities vs. CSP



Source: [19]

Figure 9. Distribution of cleared demand-side capacity in ISO-NE FCA #1

CSPs also have been successful in attracting new customers to enroll and participate as DR resources in wholesale market DR programs. Results from ISO-NE's Forward Capacity Market auction illustrate this phenomenon. In 2007, ISO-NE filed with FERC its approved Forward Capacity Market (FCM) rules, which would allow any resource, both supply and demand, to commit three years ahead of time to provide capacity to the system [18]. Demand resources in the FCM included both DR and energy efficiency, and load aggregators had to identify if the resource already existed (e.g., generator currently producing electricity, end-use customer currently enrolled in a DR program) or was new (e.g., planned generation addition, expected future enrollment in a DR or energy efficiency program). The results of the first Forward Capacity Auction (FCA #1) were made public in March 2008 [19].[13] Across the six New England states, CSPs were

[13] ISO-NE did not reveal the name of entities that submitted offers in the FCA#1 in the public results; however project names were provided. Based on project names, which were often descriptive enough to

responsible for attracting over 60% (1,681 MW) of the total demand-side capacity (2,553 MW) that cleared in the FCA #1 and 70% of the new demand-side resources (see Fig. 9). These results suggest that CSP were more aggressive in marketing and/or willing to take the business risk that they could deliver demand resources three years hence.

CSP still face significant institutional and regulatory barriers in many regions of the United States. For example, some states (e.g., Indiana) have precluded third party program providers or customers from directly participating in wholesale market DR programs. Many Public Utility Commissions (PUCs) also limit the share of program benefits that may be retained by the utility, opting to give the bulk of them back to consumers (e.g., New York). With CSP, the sharing of benefits is typically part of the contract negotiation process. PUCs are also concerned about the erosion of their authority to regulate the business and operations of incumbent monopoly utilities and its infrastructure. Some states have argued that they have a legitimate reason for not opening up their retail sector to aggregators of retail customers (or "ARCs") and such decisions should be respected. The FERC has attempted to finesse this issue in its recent Order 719 [20] in which the FERC agreed with the principle that load aggregators must be allowed to participate in ISO/RTO markets unless prevented under state law or regulation. However, FERC did not make it clear who was responsible for notifying the ISO/RTO that a state precluded customers from participating in wholesale DR programs with a non-utility entity.[14]

Traditionally, DR vendors provided load control and communication/notification technologies to utilities on a fee-for-service basis in load management programs. In recent years, encouraged (or required) by their state regulators, an increasing number of utilities have issued requests for proposals for "negawatts" to be provided by CSP on a pay-for-performance basis. These efforts are often characterized as a move toward "outsourcing" provision of DR services, which in some cases are driven by the utility's need to meet aggressive demand-side reduction goals established by a state PUC. For example, California's investor-owned utilities (e.g., Southern California Edison, Pacific Gas and Electric, San Diego Gas& Electric) have signed long-term contracts with CSP in order to meet aggressive goals established by the California Public Utility Commissions (CPUC). As more utilities consider "outsourcing" DR programs, existing and new CSPs are now competing to provide this service and many CSPs now have dedicated "utility" sales staff to develop retail market leads by convincing utilities that CSPs can do it "cheaper, faster, and better."

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identify the submitting party, we were able to develop estimates of DR resources provided by a utility or CSP.

[14] PJM decided to put the onus on the enrolling customer's electric distribution company (EDC). The proposed tariff changes indicate once PJM receives a new customer registration, that customer's EDC will be notified and requested to submit within 10 days a copy of the relevant legislative or regulatory statute or decision expressly barring end-use customer participation [21]. This tariff language was approved by the PJM Members Committee on January 22, 2008 and will go to FERC for final approval and subsequent formal inclusion in PJM's Open Access Transmission Tariff (OATT).

6. Conclusion

This paper provides empirical evidence on the evolution of DR resources in U.S. electric power markets. This evidence shows that DR is a growing industry in the United States, as evidenced by the increasing number of entities that offer DR programs and dynamic pricing tariffs and the emergence of wholesale market DR programs. Based on data reported by utilities, ISOs and CSPs, the currently existing DR resource contribution, in terms of potential peak load reduction, has increased since 2006 by about 10%.

The vast majority of entities offering DR do so in the form of time-based retail rates; although, this type of DR accounts for a small share (<10%) of the total potential peak load reduction of all DR resources. The relative contribution of time-based retail rates among all DR resources is expected to increase over time as more utilities install interval meters for residential and small commercial customers that enable these types of rates as part of Advanced Metering Infrastructure (AMI) deployments.[15]

The existing DR resource potential ranges from 3 to 9% of a region's summer peak demand in most regions, with the notable exception of the Midwest Reliability Organization region where DR resources represent ~20% of summer peak demand.

With respect to assessing the accuracy of DR resources' expected performance, participants in energy market DR programs substantially overestimated their expected performance during declared program events, while participants in capacity market DR programs were much better at assessing their likely performance.

DR resources that participate in capacity markets typically face penalties for non-compliance, which is often not the case for DR resources that participate in wholesale energy markets. Thus program design (e.g. compensation levels, penalties for non-performance, aggregation rules for small customers) can significantly influence the accuracy of DR resources' predicted performance.

There is significant year-to-year variability in DR performance at the portfolio level, particularly for economic DR programs. Over time, as customers gain experience and more ISOs (and utilities) offer economic DR programs, system operators will be in much better position to develop a "supply curve" that predicts the level of customer response over a range of different prices. This will be increasingly important if DR resources play a more substantial role in wholesale electricity markets.

However, the lack of standardized reporting practices and metrics for DR programs hinders reliability assessments. The North American Electric Reliability Council (NERC) has recognized this as a significant problem and has formed a Demand Response Data Task Force (DRDFT) to develop a system and protocol to collect DR event and market participation data to facilitate development of performance metrics [22].

[15] In the future, the relative contribution of dynamic pricing as a DR resource also depends on policy choices of state regulators (e.g. optional vs default tariffs), customer preferences and acceptance, marketing and education by utilities, and development and deployment of enabling technologies that facilitate price response.

Comprehensive surveys of utilities in recently formed organized markets (e.g. Midwest ISO and Southwest Pool Power) suggest that utilities are creating more flexible DR resources by adapting legacy load management and interruptible/curtailable DR programs to respond not only just to reliability concerns but also to reduce exposure to high market prices.

Finally, organized wholesale markets and policy support by the Federal Energy Regulatory Commission have facilitated new entry by curtailment service providers, which have expanded the DR industry and led to some product and service innovation.

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