The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response

How did DR programs perform in 2006? For reliability programs, the resounding answer from industry participants was ''very well.'' However, the performance of economic DR programs and dynamic pricing tariffs received somewhat less glowing reports.

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I. Introduction

Throughout the United States, 2006 was a watershed year for demand response (DR).[1] Summer heat storms set new temperature and electrical peak demand records across the country, prompting utilities, independent system operators (ISOs), and regional transmission organizations (RTOs) to call on their DR resources to maintain electrical system reliability and mitigate high prices. In the five years since the last major heat storm struck in 2001, the need for DR has been the focus of rapidly growing attention by policymakers, ISOs, RTOs, utilities, and third-party aggregators. Their efforts have led not only to increased quantities of demand-side resources enrolled in DR programs and dynamic pricing tariffs, but—more fundamentally—to transitions in the types of DR programs and tariffs offered, and their treatment in relation to supply-side resources.

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How, then, did DR resources perform in 2006? Was 2006 really a turning point for industry acceptance and integration of DR resources? What lies ahead? We set out to shed some light on these questions, interviewing representatives of 15 utilities, six ISOs/RTOs, three load aggregators, and several regulatory staff and consultants. This article summarizes the results of those interviews, providing a ''status check'' for DR as of 2006, and highlighting future directions and challenges.

II. Summer 2006 DR Landscape

To begin, we provide a ''snapshot'' of the state of DR programs across the U.S. in 2006, with information on the types, size, and administration of DR resources in various regions, as well as a summary of the year's impactful events.

A. DR resource potential

Our interviews were conducted with representatives from entities in eight regions of the U.S. that have significant DR resources (**Table 1**).

Table 1: Entities Interviewed for This Study

Region	ISO/RTO/Agency	Utilities[a]/Third Parties
Northwest	• Northwest Power and Conservation Council (NPCC)	• Bonneville Power Administration (BPA) • PacifiCorp
California	• California ISO (CAISO)	• Pacific Gas & Electric (PG&E) • Southern California Edison (SCE)
Midwest	• Midwest ISO (MISO)	• Ameren • Duke Energy (Indiana/Ohio) • EON* • Exelon* • Kansas City Power & Light (KP&L)*
Texas	• Electric Reliability Council of Texas (ERCOT)	
New England	• ISO-New England (ISO-NE)	• National Grid • Northeast Utilities • United Illuminating
New York	• New York ISO (NYISO)	• Long Island Power Authority (LIPA) • Consolidated Edison (ConEd)
Mid-Atlantic	• PJM Interconnection	• PEPCO Holdings, Inc. • Public Service Electric & Gas (PSE&G)
Southeast		• Duke Energy (North Carolina) • Gulf Power
National	• Federal Energy Regulatory Commission (FERC) staff	• Apogee (consultant) • Comverge (third-party aggregator) • Constellation NewEnergy (retailer/third-party aggregator) • EnerNOC (third-party aggregator) • Summit Blue (consultant)

[a] Regional boundaries are approximate; not all of the utilities shown participate in the respective ISO or RTO (indicated by *).

We interviewed representatives of six ISOs and RTOs currently operating in the U.S. Four of them—ERCOT, ISO-NE, NYISO and PJM—offered a range of economic and reliability DR programs to large customers in their respective regions in 2006 (**Table 2**). CAISO maintains a resource of large customers that it asks to curtail on a voluntary basis in emergencies (without compensation), but otherwise it and MISO rely on pay-for-performance programs offered by the utilities (and retail suppliers in some states) in their control areas to provide DR when needed. In the Northwest and Southeast, regions without ISOs or RTOs, DR programs are administered and operated by utilities and power marketing authorities (e.g., BPA, TVA).

Because we interviewed only a subset of the electric utilities in each of the eight regions, we are unable to provide a complete picture of the amount and types of DR resources offered by all utilities. **Table 3**

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Table 2: Demand Response Programs Offered by ISOs/RTOs in 2006

ISO/RTO	Economic Programs	Reliability Programs
CAISO	–	• Voluntary Load Reduction Program
MISO	–	–
ERCOT	• Balancing Up Load (BUL)	• Load Acting as a Resource (LaaR)—non-spin & responsive reserves[a]
ISO-NE	• Real-Time Price Response (RTPR) • Day-Ahead Load Response (DALR)	• Real-Time 30-minute Demand Response • Real-Time 2-hour Demand Response • Real-Time Profiled Response • Demand Response Reserves Pilot[a]
NYISO	• Day-Ahead Demand Response Program (DADRP)	• Emergency Demand Response Program (EDRP) • Installed Capacity/Special Case Resources (ICAP/SCR)
PJM	• Economic Load Response Program: Real-Time (RT) • Economic Load Response Program: Day-Ahead (DA)	• Emergency Load Response Program: (Energy-only) • Full Emergency Load Response Program • Synchronized Reserve and Regulation Markets[a]

[a] DR program targeting ancillary services.

summarizes at a high level the types of programs offered by the utilities that were interviewed. Many of the utilities were also participants, either directly or indirectly, in wholesale market programs offered by ISOs or RTOs. A more comprehensive picture of current DR resource contribution across the U.S., including the types of programs offered, is afforded by data gathered by FERC for a recent staff report to Congress (see related article, this page).[2]

B. Events of 2006

Why was summer 2006 a bellwether data point for DR? Because it was the second-warmest June-to-August period in the continental U.S. since climate records were first logged in 1895—eclipsed only by the ''dustbowl'' summer of 1936.[3] In July, most of the country was hit by a sustained heat wave that broke more than 2,300 daily records and over 50 all-time-high temperature records; additional high-temperature records carried over into the beginning of August.

Not surprisingly, the hot weather had a strong impact on electricity demand—peak demand records were broken and demand forecasts were exceeded in most parts of the country. In California, forecasters determined that the heat and peak demands were a 1-in-57-years event. In many states, the unexpectedly high peak demands threatened grid operators' abilities to maintain system reliability. DR resources were called on to alleviate these conditions.

Table 4 summarizes the major events that triggered DR programs in 2006 among the entities that were interviewed.

Table 3: Types of DR Programs Offered by Interviewed Utilities in 2006

Region	Direct Load Control	Large Customer Reliability Programs	Large Customer Economic Programs	Dynamic Pricing
Northwest	✓	✓	✓	
California	✓	✓	✓	✓
Midwest	✓	✓	✓	✓
Texas[a]				
New England	✓			✓
New York	✓			✓
Mid-Atlantic	✓			✓
Southeast	✓	✓		✓

[a] No utilities in Texas were interviewed for this study.

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Table 4: Major Reliability and DR Program Events of 2006

Region	ISO/RTO	ISO/RTO Emergency Events	Utility Program Events
Northwest	–	–	• Several utilities[a] activated their DR programs on July 24
California	CAISO	• Stage 2 Alert: July 24	• PG&E: 20 days in June, July and Aug. • SCE: 24 days in June, July and Aug. • SDG&E: 12 days in June, July and Aug.
Midwest	MISO	• Energy Emergency Alert 2: Aug. 2 • Energy Emergency Alert 1: 3 days	• ComEd: July 31; Aug. 1, 2 • Duke: 4–6 events in different states • EON: 11 events • KCP&L: July 17, 19, 20, 31; Aug. 1, 2, 9, 10
Texas	ERCOT	• No events in mid-summer • DR events called due to generation outage (Apr. 17) and frequency aberration (Oct. 3)	–
New England	ISO-NE	• Region-wide event: Aug. 1, 2 • Local event: June 19	–
New York	NYISO	• Zonal events: July 18, 19; Aug. 1–3	• ConEd: July 17
Mid-Atlantic	PJM	• Zonal events: Aug. 2, 3	• PSE&G: 5 events
Southeast	–	–	• Duke: 1 event in the Carolinas • Gulf Power: 2–3 CPP events

[a] Utilities include Portland General Electric, Puget Sound Energy, Idaho Power, Snohomish PUD, Avista, PacifiCorp, and Chelan PUD.

CAISO, MISO, ISO-NE, NYISO, and PJM all called system emergency events in response to supply-demand imbalances during the heat waves. In some instances, ISO-NE, NYISO, and PJM called events for specific zones, rather than their whole footprint. Utilities' DR programs were either triggered by their control-area system conditions, or events declared by regional ISOs or RTOs. In several regions (e.g., New York, the Mid-Atlantic States, New England, the Midwest, California), DR operations were called on several consecutive days, testing the resilience of DR resources over sustained periods.

While electrical peak demand was higher than usual in the Southeast and Texas, these regions did not experience reliability concerns related to the heat waves. In Texas, ERCOT's two reliability events in 2006 were unrelated to the heat waves; rather, DR resources were called in response to unscheduled outages and electrical supply frequency aberrations.

III. Reliability Programs Performed Well in 2006

How did DR programs perform in 2006? For reliability programs, the answer we heard resoundingly was "very well."[4] Across the board, we were told that reliability-based DR resources—such as direct load control (DLC), large customer emergency and capacity programs, and interruptible/curtailable (I/C) rates—produced as (or better than) expected, with load response in some places as high as 80 percent or more of enrolled resources.[5] Moreover, despite back-to-back events on very hot days, utility representatives reported very few customer complaints. Most individuals felt that coordination issues between the various entities involved in notification of events and dispatching of DR programs (e.g., ISOs/RTOs, utilities, third-party aggregators),

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though somewhat prevalent in earlier years, had largely been worked out. Overall, the impression was that DR programs were executed smoothly in 2006. However, some ISOs/RTOs had limited capacity to observe and confirm DR impacts in real time.

Several utilities and third-party aggregators attributed the healthy response of reliability programs to a large degree of customer ''handholding,'' at least for large customer programs, noting the high cost of maintaining customer relationships. A number of respondents described multiple ways of getting the message across to their large customers when events were called—in addition to the standard event notifications, utilities and third-party aggregators telephoned individual customers to remind them of events. In some cases, they were able to identify customers that weren't responding as expected and call them to address the problem; this was made possible by near-real-time information systems that provided quick feedback on customer response.

Representatives of several utilities and ISOs remarked that they could directly see reductions in hourly system load as DR resources came online, and noted this as an important factor in boosting confidence in DR among stakeholders. **Figures 1** and **2** demonstrate this ''observability'' in relation to system load data for the most dramatic DR event days in the ISO-NE and CAISO control areas. In both cases, the actual load closely followed the day-ahead forecast until the early afternoon, when it visibly tapered off as DR resources were called. DR program impacts, subsequently calculated by the ISOs, are shown in the graphs to illustrate the ''projected'' load that likely would have occurred in the absence of DR resources; customer load curtailments reduced expected system demand by ~1.7 percent and 2.3 percent, respectively, for ISO-NE and the CAISO. For the ISO-NE example, only reliability programs were included in the DR impacts. CAISO's data includes the impacts of both reliability and economic programs.

The California investor-owned utilities' (IOUs') demand response programs provide a more specific example of actual program performance on July 24 for three statewide large-

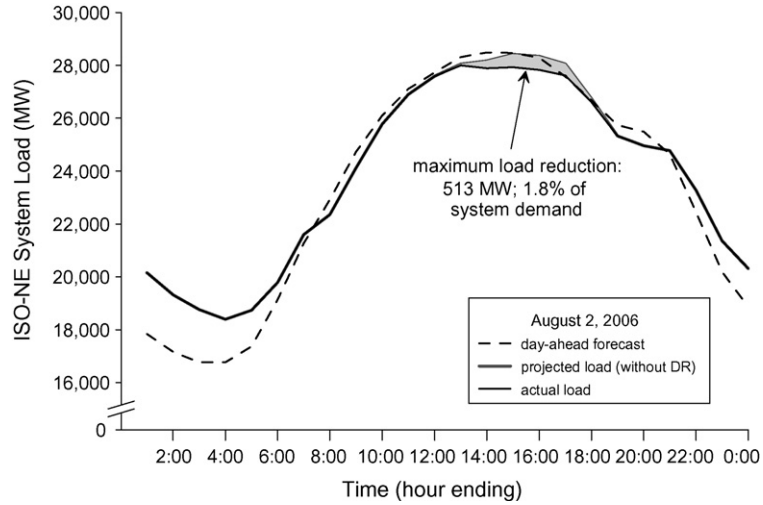

Figure 1: Impact of Reliability DR Programs on ISO-NE System Load (**Source:** www.iso-ne.com, Yoshimura and Corcoran (2007))

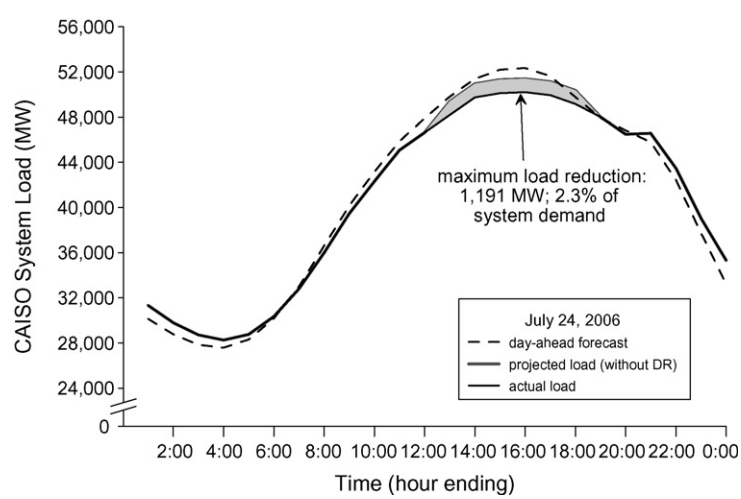

Figure 2: Impact of Reliability and Economic DR Programs on CAISO System Load (**Source:** www.caiso.com)

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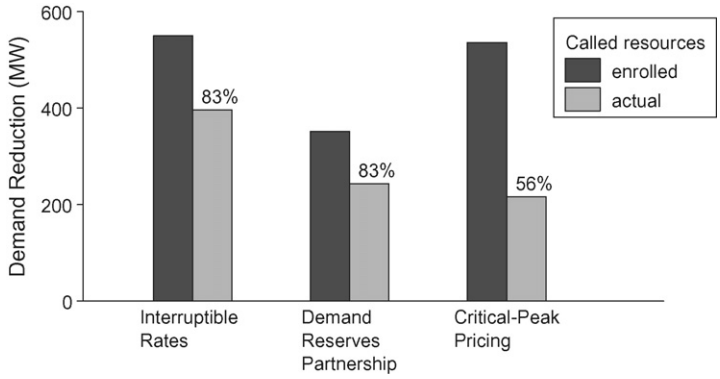

Figure 3: Performance of California IOUs' Large Customer DR Resources: July 24, 2006 (**Sources:** PG&E (2006), SCE (2006), SDG&E (2006))

customer programs (**Figure 3**). For both interruptible rates and the Demand Reserves Partnership—programs that impose significant penalties for not responding when called—the actual response was 83 percent of enrolled resources. Resources in the large-customer critical-peak pricing (CPP) rate (which can be triggered by either economic or reliability criteria and does not have strict penalties) were somewhat less responsive; actual load curtailments were 56 percent of the subscribed load on July 24.[6]

NYISO's two emergency programs—EDRP and ICAP/SCR—provide an example of targeted, locational dispatch of DR resources (**Figure 4**). In each event, only a subset of the NYISO load zones' DR resources were dispatched—on average, about half of the total enrolled load in the ISO control area for each program. The programs were called most frequently in New York City and Long Island, the most obviously transmission-constrained areas of the state, with more widespread events occurring on July 18 and Aug. 2. The performance of these resources varied, but the percent of called enrolled load that responded was consistently higher in the ICAP/SCR program—which offers reservation payments and levies penalties for non-performance—than for EDRP, a voluntary program that compensates customers for load reductions only during events. On average, actual load reductions were 62 percent of called resources for ICAP/SCR and 43 percent for EDRP.

Several other ISOs provided more aggregate information on the actual performance of DR resources during system emergencies. For example, PJM reported load curtailments of 799 and 832 MW on Aug. 2 and 3, respectively, for their Full Emergency Load Response program, which was called only in the Mid-Atlantic zones.[7] MISO, which does not operate its own programs, surveyed the utilities in the MISO footprint, and found overall load reductions of 2,651 MW on Aug. 1 and 1,982 MW on Aug. 2 from voluntary public appeals, demand-side management, utility load conservation, voltage reduction, interruptible loads,

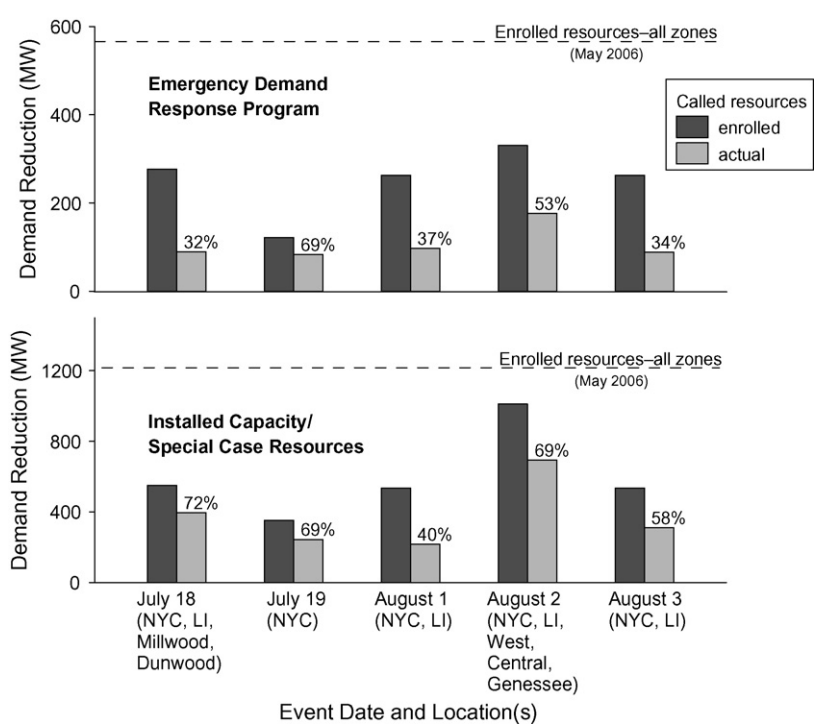

Figure 4: NYISO Reliability DR Program Performance in 2006 (**Source:** NYISO (2007))

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and behind-the-meter emergency generation.[8]

IV. Economic DR Program Results Varied

The performance of economic DR programs and dynamic pricing tariffs received somewhat less glowing reports in our interviews. In some areas of the country (e.g., the Southeast and the Northwest), economic DR programs either were not called or did not garner much customer response because wholesale market prices were not very high or spiky during summer 2006. Although dynamic pricing tariffs, such as real-time pricing (RTP) and CPP, are offered by at least 50 utilities nationally, most of the individuals we spoke with had little information on their performance in 2006, and information on load impacts was not available.[9]

Nonetheless, a number of economic DR programs did generate considerable activity in 2006. **Table 5** summarizes available data on enrollment and activity from January through August in five programs offered by ISOs, RTOs, and utilities. Cumulative energy reductions throughout this period ranged from a few thousand to almost 80 thousand MWh. Most of the energy reductions for the PJM and ISO-NE programs (over 80 percent) occurred between May and August. In contrast, only 7 percent of the load reductions in the NYISO day-ahead market DR program occurred during this time period, demonstrating the potential for economically driven DR to provide load curtailments year-round.

The maximum capacity impacts calculated for economic DR programs were not insignificant (~50–450 MW) and for most programs occurred on days when system emergency events were declared or system demand was high. Average energy payments for curtailed load ranged from roughly $100 to $175 per MWh for the ISO/RTO market-based programs, while the customer incentive for the California Demand Bidding program was fixed at $350/MWh.

V. DR is Maturing into a Dependable Resource—At Least for Reliability Programs

Most of the parties we interviewed shared the view that reliability-based DR had matured in the last five years and was increasingly recognized, by multiple parties (including grid operators), as a viable resource. For many of the utilities we spoke with that engage in integrated resource planning (IRP),[10] DR was being viewed through this lens.[11] In regions with organized

Table 5: Performance of Economic DR Programs: Jan.-Aug. 2006

	Enrollment		Energy Impacts (Jan.–Aug.)		Maximum Capacity Impacts	
Program	Assets/ Resources[a]	Load (MW)	Load Reductions (MWh)	Energy Payments ($1,000)	Load Reduction (MW)	Date/Time
ISO-NE Real-Time Price Response	572	168	19,952	2,863	116	Aug. 2/5 – 6 p.m.
NYISO Day-Ahead Demand Response	19	389	3,479	120	–	–
PJM Economic Load Response Program: Day-Ahead	276	1,195	13,353	905	50	Aug. 1/8 – 9 p.m.
PJM Economic Load Response Program: Real-Time	–	–	79,460	8,344	463	Aug. 1/5 – 6 p.m.
CA Utilities' Demand Bidding	2048[b]	274[b]	4,684[c]	880	52	July 25

Sources: Yoshimura and Corcoran (2007), NYISO (2007), Covino (2006), SCE (2006), PG&E (2006), SDG&E (2006)
[a] Assets or resources may be individual customers or load aggregators representing many customers.
[b] Enrollment was ongoing throughout the summer; data are shown for August 2006.
[c] Event duration data was not available for PG&E; we assumed the same eight-hour window as for SCE's program.

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wholesale markets, the concept of DR as a viable resource is manifested through efforts to facilitate participation by customer loads in wholesale markets for capacity, reserves, and energy.

Respondents in regions with ISO-administered programs also noted an evolution in DR program enrollment. For example, in New York and New England, enrolled load declined or remained level in voluntary DR programs (NYISO EDRP and ISO-NE RTPR) between 2003 and 2006, while increasing significantly in reliability-based programs that are linked to capacity markets (NYISO ICAP/SCR) or provide capacity credits (ISO-NE RTDR) (**Figure 5**). Customers appear to have ''cut their teeth'' in voluntary ISO programs that offer incentives to curtail load during system emergencies or high wholesale market prices. These penalty-free programs provided a risk-free opportunity for customers to test out load response strategies and build confidence. Over time, as reservation payments in ISO capacity market programs have increased due to tighter supply/demand conditions and capacity market rule changes that have increased prices (and bolstered in some cases by state incentives[12]), customers have migrated toward these programs. A number of utilities and third-party aggregators noted that customers find the steady stream of payments from capacity and reserves market programs

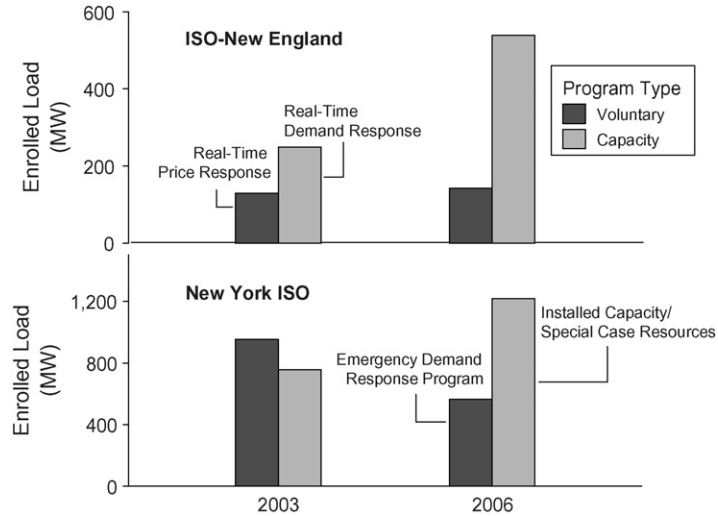

Figure 5: Transitioning from Voluntary to Capacity Programs: Two Examples (**Sources:** RLW Analytics and Neenan Associates (2003), ISO-NE (2006), NYISO (2003, 2007))

attractive, even though penalties are levied for non-compliance. This suggests that an increasing number of customers, supported by load aggregators, are willing to increase the ''firmness'' of their DR resource commitments.

However, a number of utility representatives indicated that they did not yet regard economic DR programs (e.g., demand bidding) or dynamic pricing (e.g., RTP, CPP) as ''firm'' resources based on their experience to date.[13] In interviews, some described these options as fulfilling a different role than reliability programs: improving the overall efficiency of electricity markets, rather than providing a specific demand response resource. Others were simply more comfortable with their ability to count on reliability options—particularly for more traditional programs such as I/C rates and DLC programs—to provide load reductions that could compete with (and supplant) supply-side peaking resources.

VI. A Growing Role for Third-Party Aggregators

Our interviews revealed that third-party aggregators are emerging as a viable business model in selected markets. These companies aggregate customer loads to participate in both ISO and utility DR programs across the country. Most of their activity, however, is in programs where capacity payments or energy incentives are high relative to the rest of the country. In New York, for example, third-party aggregators have enrolled about 90 percent of the customers in the NYISO ICAP/SCR program, equating to approximately 74 percent of the enrolled load. In some other parts of the country, however, utility and ISO representatives told us that third-party activity is either

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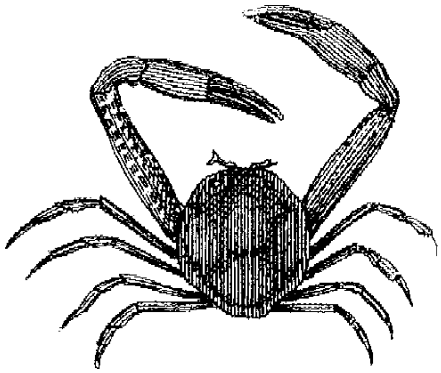
non-existent or limited to the very largest customer market segments, in part due to the limited financial incentives currently available or the lack of capacity markets in their areas.

Some companies perform DR aggregation as a standalone business; others are part of national energy marketing firms or companies that produce and distribute DR-enabling technologies. The three third-party aggregators we interviewed reported that in 2006 they were able to coordinate the simultaneous dispatch of DR resources they control in various markets at a national level. This was the first time that DR resources were called almost concurrently across the country, and these companies were proud of their ability to handle large dispatch volumes with their centralized data management and control systems. One company representative claimed to have responded to 39 events in 25 programs across the U.S. in 2006.

Among energy retailers, there is also increasing interest in DR and dynamic pricing, and they are aggressively building DR capability. Retailers are viewing DR as an important component of retail supply products that can help manage their price and volume risk.[14]

VII. Mixed Opinions on the Significance of 2006

While 2006 was recognized across the board as an unusually hot summer that tested DR resources, there were mixed opinions about its implications for the future. For some, the 2006 heat storm was viewed as an anomaly.[15] A few likened it to Hurricane Katrina—an unusually bad experience, but one that is now behind us. Adherents to this view did not expect 2006 to result in changes to their organizations' load forecasting or resource planning processes although, for many, 2006 did raise the level of attention to DR issues, with more focused efforts being undertaken to examine the potential for DR to address peak demand conditions.



However, in a few regions, the events of 2006 were viewed as a wake-up call. Most notably, California saw peak demands in 2006 that they had not forecast until 2011. Policymakers regarded 2006 as having erased five years off their planning horizon, and the California Public Utilities Commission (CPUC) is setting more aggressive DR goals for the state's investor-owned utilities.[16]

In New England, too, the notion of losing time until new capacity is needed was pervasive. ISO-NE was already in the process of designing a forward capacity market with fully integrated demand-side resources (energy efficiency as well as DR). The combination of high gas prices and higher-than-forecast peak loads in 2006 spurred additional demand-side initiatives by the region's legislatures and regulators.[17]

At the other end of the spectrum are market participants in the Southeast and ERCOT. Interviewees in both of these regions did not feel that peaking conditions in 2006 were all that severe—ERCOT in particular did not have to call DR resources to address peak demand conditions—and do not see 2006 as a particular turning point for DR in their regions.

VIII. New Directions for DR

Going forward, most of the ISO and utility representatives we spoke to agreed that they would like to see more DR—and a more diversified portfolio of DR resources—provided that the resource can live up to expectations.

In the three eastern ISOs/RTOs, there is a continuing push to improve the design and performance of capacity markets. Stakeholders in New England are in the process of designing a forward capacity market that will hold auctions for future capacity, beginning in 2008 for delivery in 2010, and which allows demand-

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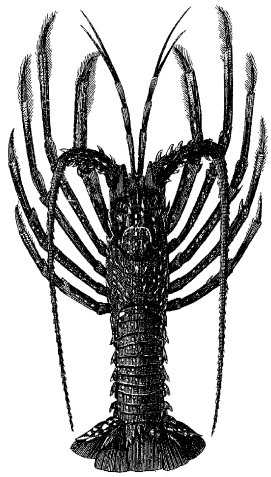
side resources (DR and energy efficiency) to compete. FERC also recently approved PJM's new Reliability Pricing Model (RPM).[18]

ISOs and RTOs are also developing rules for loads to participate more fully in reserves markets: ERCOT, PJM, and CAISO already allow load participation, ISO-NE has a pilot in place, and NYISO is in the process of designing similar rules. A number of interviewees, particularly third-party aggregators, saw the potential for high DR value in these markets, and hoped to see more efforts that utilize automated DR strategies to participate in ancillary services markets (including spinning reserves).

Based on our interviews with third-party aggregators, we expect to see continued growth in the role of third parties in aggregating load for DR, particularly if forward capacity markets develop and expand. All three aggregators (as well as other respondents) identified small to medium-sized commercial and institutional customers as a source of large untapped potential and the next up-and-coming market for DR load aggregation.

More widespread dissemination of the concept of fully automated DR—strategies to shed loads automatically in commercial buildings that have shown promise in pilot studies—can play an important role in supporting the above activities, improving the reliability and sustainability of DR while minimizing the impact on customer comfort, convenience and productivity.[19]

For mass market (small commercial and residential) customers, a number of utilities that have traditionally offered DLC programs involving simple radio-communicating switches to control specific pieces of equipment (e.g., air conditioners,



water heaters) are considering a transition to programmable communicating thermostats (PCTs). Many see the potential for PCTs to support dual reliability and price-response functions: remote control by the utility or grid operator (similar to a DLC program but with lower installation costs and lower disengagement rates than for switches used in DLC programs)[20]; and, combined with dynamic pricing rates such as CPP, support for automated price-responsive demand.[21]

Several utilities, ISOs/RTOs, and other agencies were also interested in advanced metering infrastructure (AMI) initiatives that facilitate dynamic pricing and demand response among mass market customers. Regulators in several states have directed utilities to estimate DR value as part of their AMI business cases.

IX. Challenges Ahead

The individuals we interviewed identified a number of challenges ahead for DR resources. We selected and summarized the most common themes to highlight here.

A. Providing access to real-time information

A number of individuals identified information barriers that limit DR potential. One issue is a lack of real-time customer-level load data that can be used by grid operators to inform DR program dispatch, by utilities and third-party aggregators to identify customers that may need event reminders, and by customers themselves to observe the impacts of their actions. For some ISOs and RTOs, the next level of DR coordination encompasses the development of a more in-depth understanding of the DR resources in their footprint and how they will perform under varying conditions, and an increased ability to observe DR resources in near-real time.

At the same time, some ISO representatives observed that while mandating extensive telemetry requirements tied to short-notice availability or

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operational criteria is desired, widespread adoption would outstrip their current ability to manage the enormous quantities of data that this would produce. Grid operators want the load impacts of DR to be ''observable,'' meaning not only that the resources are large enough to see, but also that they are incorporated into existing real-time system operations software. This would allow grid operators to easily see and integrate DR resources within the same scheduling and monitoring schemas that they use for generation resources.

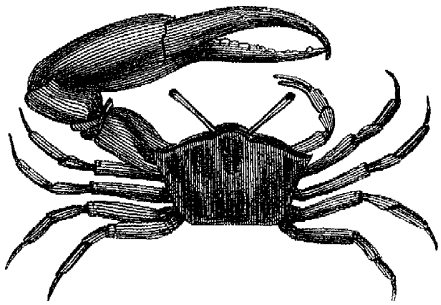
B. Clarifying environmental regulations

While replacing customer load with on-site generators presents great DR potential, their use for this purpose is often at odds with air quality regulations. Some regions are taking a hard stance on the issue in favor of strict environmental standards.[22] A few of our interviewees, however, felt that clarifying the rules for generator participation in certain types of DR programs (e.g., capacity markets) and dynamic pricing tariffs, while balancing environmental objectives, could open up untapped DR potential. One third-party-aggregator representative noted that customers could find it profitable to invest in pollution-control strategies for their generators, but without clear, long-term rules, these investments (often with a roughly three- to five-year payback) are considered too risky.

C. Valuing DR in planning processes

A number of issues were raised regarding how to integrate DR into electricity resource planning processes in the context of both organized wholesale markets and traditional utility regulation.

In regions with ISOs/RTOs that administer wholesale



markets, some parties expressed concerns about certain aspects of DR integration into new forward capacity markets. For example, some utilities were concerned about how their legacy programs, with proven DR resources, would be rolled in, and whether there would be detrimental impacts on customer retention. In some ISO regions, energy-only market structures presented a real challenge to reflect the full forward market value of DR, particularly in the context of caps on energy market prices.

In states with vertically integrated utilities, some utility representatives were finding it challenging to incorporate DR into their IRP processes because standard cost-effectiveness tests do not fully capture the time-varying value of DR.[23]

D. Improving DR recognition and support

Despite the development of broad stakeholder support for DR, and the performance of reliability programs across the country in 2006, a number of key stakeholders and decision-makers still need convincing. Some utility representatives noted a lack of high-level support for DR within their organizations. Others noted that regulators in their states were not providing sufficient guidance to support adequate development of DR resources. Within ISOs/RTOs and utilities, grid operators accustomed to dispatching supply resources still had trouble viewing DR as a dispatchable resource, although for some the experience of 2006 had improved their outlook. The performance of customers that participate as loads in the newly developed capacity and ancillary services markets—which could entail more frequent load curtailments than customers have previously been exposed to—will greatly impact whether and how quickly these perspectives change.

Over time, we expect that more state regulators and utilities will increase their focus on demand-side resources (including energy efficiency as well as DR) in response to tightening reserve margins, increasing cost projections for new baseload and

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peaking generation, concerns about mitigating potential risks associated with carbon policies or regulation, and perceived opportunities for demand resources to meet some portion of future resource needs at lower cost.

One individual that we interviewed noted that it has taken 30 years to develop a strong stakeholder consensus on energy efficiency, asking the question: ''How can we speed this up for DR?'' This is perhaps the greatest challenge for demand response in the next few years.■

FERC Estimates of DR Resource Potential

The most comprehensive picture of the existing contribution from DR resources is provided by a recent FERC Staff Report to Congress.[24] FERC staff combined information from a voluntary survey of about 3,000 entities with other data sources (i.e., Energy Information Administration Form 861 data, ISO reports) to estimate the existing DR resource contribution; the results were summarized for each of the eight reliability council regions established by the North American Electric Reliability Corporation (NERC) (**Figure 6**).

Nationally, 2005 DR potential was estimated at about 37,500 MW, with roughly 9,000 MW contributed by ISO/RTO programs. **Figure 7** shows both the total estimates of DR resource potential in each NERC region (based on combined data sources) and the breakdown by several types of DR program (based only on the FERC survey data, so the totals are smaller than the more comprehensive estimates). In the ERCOT, NPCC, and RFC regions, a significant portion of DR resources is attributable to programs offered by ISOs and RTOs: demand-bidding (i.e., economic), emergency, capacity, and ancillary services programs. Elsewhere in the U.S., the majority of DR potential comes from more traditional DR programs: direct load control and interruptible/curtailable rates.[25]■

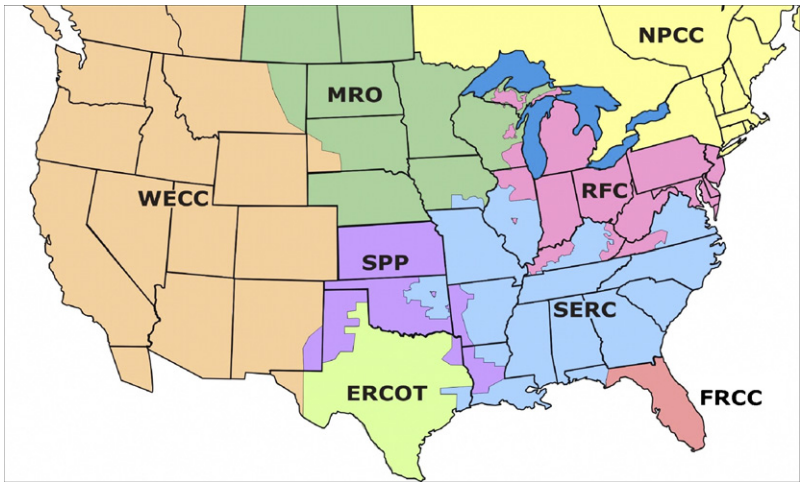

Figure 6: NERC Regions

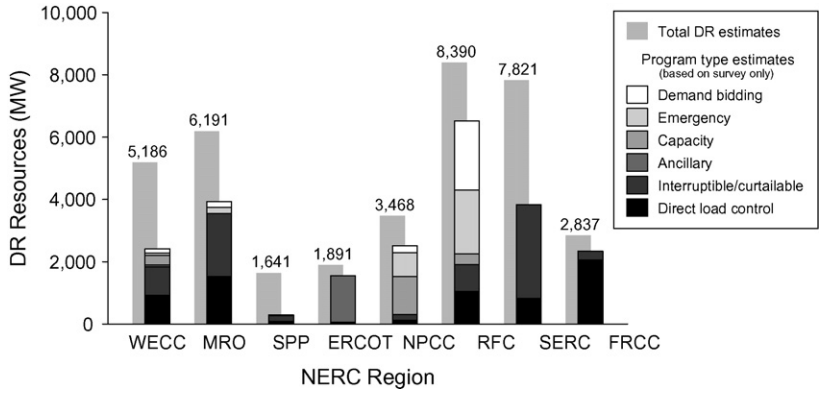

Figure 7: U.S. Demand Response Resources in 2005 (**Source:** Goldman (2007))

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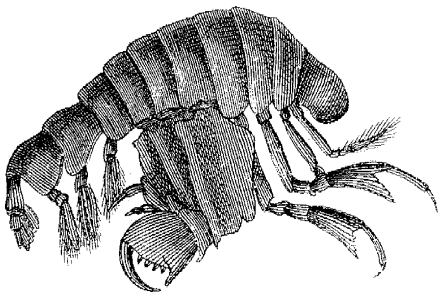

Endnotes:

1. DR is defined in U.S. DOE (2006) 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.''

2. FERC (2006a).

3. See NOAA National Climactic Data Center, Asheville, NC (http://www.noaanews.noaa.gov/stories2006/s2700.htm). For the Jan.–Aug. period, 2006 was the warmest on record.

4. An E-Source report by Komor (2007), EDRP-F-10, had similar findings.

5. For simplicity, we consider capacity, reserves and emergency programs, along with DLC and I/C rates, to be ''reliability-based'' DR programs. We distinguish them from ''economic'' DR programs (e.g., demand bidding and energy-market programs) and dynamic pricing (e.g., real-time pricing and critical-peak pricing). However, in some cases, programs are triggered by both reliability and economic criteria (e.g., certain DLC programs and critical-peak pricing tariffs).

6. One possible reason for the lower realization rate in the CPP program is that July 24 fell on a Monday and the day-ahead notice was given on a weekend.

7. Sue Covino and John Reynolds, PJM Interconnection, personal communication, Feb. 2007.

8. MISO (2007). Approximately half of the load reductions are attributed to loads on interruptible/curtailable rates, and almost 20 percent each to behind-the-meter generation and public appeals.

9. Dynamic pricing rates such as RTP and CPP provide time-varying electricity price signals to customers. Customers are not explicitly compensated for load curtailments, other than through the price signal provided by the retail tariff. As a

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result, most utilities do not collect data on potential or actual load reductions associated with dynamic pricing tariffs. In its DR survey, FERC found that for dynamic pricing tariffs, utilities typically reported only the number of customers enrolled on the tariff. Only 25 percent of the 187 entities that offered TOU tariffs provided data on existing DR resource potential, while 35 percent of the 47 entities that offered RTP tariffs provided data on DR resource potential (see FERC, 2006a).

10. In recent years, IRP has seen a resurgence among utilities in several regions (e.g., West, parts of Mid-west) as policymakers have placed increased emphasis on resource adequacy, resource assessment and ensuring diversified resource portfolios.

11. For example, in the Northwest, both PacifiCorp and the Northwest Power and Conservation Council have included DR explicitly in their recent resource planning processes (NPCC, 2005; PacifiCorp, 2005).

12. For example, the Connecticut utilities provide supplemental capacity payments to bring the incentives for ISO-NE's emergency programs up to $80/kW. Initially, this was done on a regional basis, but in early 2006 this practice became statewide.

13. California is a notable exception: its investor-owned utilities are required to count price-responsive demand among their resources.

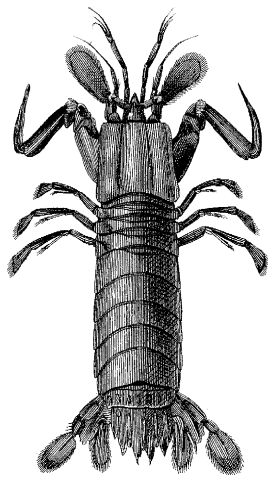
14. Barbose *et al.* (2005) also found that competitive retailers were interested in more aggressively pursuing DR.

15. A few individuals did see a connection between the hot weather of summer 2006 and global climate change, but noted that this was not necessarily formally acknowledged within their organizations.

16. CPUC (2007).

17. For example, in September 2006, Gov. Romney of Massachusetts proposed a Nex-Gen Energy Plan that would significantly expand the state's investments in energy efficiency, distributed generation, combined heat and power, and renewable energy sources (see http://www.boston.com/news/local/massachusetts/articles/2006/08/11/romney_outlines_energy_plan_mixing_conservation_alternate_supply/). Similarly, in June 2006, Rhode Island adopted legislation requiring utilities to develop a least-cost plan that includes procuring all cost-effective energy efficiency—among other clean energy resources—when it costs less than traditional fossil-fuel power supplies (see http://www.rilin.state.ri.us/news/pr1.asp?prid=3451).

18. FERC (2006b).



19. An automated DR pilot in California with a sample of ~30 medium and large commercial, institutional, and high-tech buildings demonstrated this potential, achieving consistent average load curtailments of ~10 percent with high customer satisfaction (Piette *et al.*, 2005). California's investor-owned utilities will be ramping up automated demand response in 2007–08 to several hundred facilities (CPUC, 2006).

20. Some utilities expressed concern about degrading resources (i.e., failure and disconnection rates of DLC switches) in their legacy DLC programs, without concurrent reductions in operational costs.

21. Pilot studies have shown that residential and small commercial response to CPP events is significantly enhanced by programmable, communicating thermostats. See, for example, Charles River Associates (2005) and Voytas (2006).

22. The New York State Department of Environmental Conservation has proposed rules to regulate and limit the usage of on-site generation sources that are expected to go into effect in 2007 (NY DEC, 2006). Designed to achieve compliance with ozone requirements in severe non-attainment areas throughout New York State, the rules incorporate several approaches: tightening allowable air emissions for existing emergency generators by 2009; setting limits on annual hours of operation during system emergencies, and setting capacity caps on existing emergency generators in the New York City area and the rest of the state. The capacity caps would be ratcheted down over time: in New York City, for example, the proposal reduces the cap from 280 MW in 2007 to 50 MW by 2014.

23. Recent work attempted to account for the time-varying nature of electric resource value in a recent California Public Utilities Commission (CPUC) proceeding on avoided costs for energy efficiency programs; see Energy and Environmental Economics (2004). The CPUC has initiated a new proceeding to refine and update benefit cost tests for DR (see http://www.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/63999.htm). In valuing DR resources, it is important to explicitly account for avoided or delayed capacity additions and avoided energy, any avoided transmission and distribution upgrades and re-builds (or T&D capacity line losses); and avoided reserve margin requirements.

24. FERC (2006a).

25. DLC programs are typically offered to residential and small commercial customers. In return for a bill credit, customers allow the utility or grid operator to remotely shut off or cycle down specific equipment (e.g., air conditioners or water heaters) for reliability purposes. I/C rates are typically offered to large commercial and industrial customers, who receive a bill credit in return for agreeing to reduce a pre-specified amount of load when called for reliability purposes.

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