Beyond DR – Maximizing the Value of Responsive Load

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ABSTRACT

With increasing penetration of renewable generation, the focus on resources needed to operate the future electric grid is transitioning from the *quantity* of generating capacity to its *quality*, or more specifically flexibility — frequency regulation, fast ramping, and load following. As implemented to date, demand response (DR) acts primarily as a capacity resource that reduces loads in times of short supply, but provides little in the way of flexibility. In order to act as the highly flexible resource that will be of the most value to grid operators in the future, the DR paradigm must shift to focus on using highly responsive load to integrate renewable and distributed generation. Highly responsive load is already in commercial operation, providing frequency regulation for PJM, ERCOT and MISO, but DR programs have yet to more fully tap its potential. Many flexible end-use loads (e.g., water pumps and industrial motors) are also primary targets for commercial and industrial energy efficiency measures, which can be made more effective with the technology that enables responsive load.

Background

The New Grid Demands More Flexibility

Historically, capacity planning for utilities and ISOs has focused on procuring a sufficient *quantity* of generating capacity to meet target reliability metrics.[1] Increasingly, capacity planning is focusing not just on the quantity but also on the *quality* of capacity procured. With higher levels of renewable and distributed generation, operators are concerned that generation and load will become more variable and difficult to forecast. The increased uncertainty is on time scales ranging from less than one minute for variations in wind and PV generation, to several hours for large and sustained increases or decreases in wind generation. To meet these challenges, operators and planners will require resources that can be dispatched on very short notice (e.g., frequency regulation) and rapidly increase or decrease generation in several minutes or several hours (e.g., ramp or load following).

DR Competes with CTs as a Flexible Capacity Resource

The combustion turbine (CT) serves as the proxy or benchmark of choice for a flexible capacity resource. CTs can be started on short notice (~10 minutes) and ramp quickly (~3 MW/minute). Both PJM and NYISO use the cost of new entry for a new CT in developing

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[1] Commonly used metrics include the planning reserve margin (PRM) to ensure that installed generation capacity exceeds forecasted peak loads by a given percentage (~ 15%), loss of load probability (LOLP) to ensure that the probability of load exceeding available generation in any given hour is below a given threshold (e.g. once in ten years) and contingency criteria (e.g. N-1) to ensure that the grid can continue reliable operations with the loss of a major generator or transmission line.

demand curves and price caps for their respective capacity procurement mechanisms. The California Public Utilities Commission (CPUC) uses a proxy CT to determine the capacity value of distributed energy resources.

Demand response (DR) is often cited as a cheaper and more environmentally friendly capacity resource than a CT. In the following sections, we explore how DR stacks up against a CT as a flexible capacity resource.

Limits of the Current DR Paradigm

The current framework for DR focuses on three pathways: (1) emergency DR, (2) economic DR, and (3) direct load participation in wholesale energy and ancillary service (AS) markets. In practice, none of these pathways provides the flexibility of a CT.

Emergency DR Programs are Restricted in Use and Limited in Reliability

Emergency DR gives utilities the right to curtail a customer's load during system emergencies or when other specific criteria or "triggers" are met. Emergency DR is largely event based, with a limited number of calls for curtailment each year (FERC 2010). As a capacity resource, emergency DR suffers from three primary constraints that limit its flexibility.

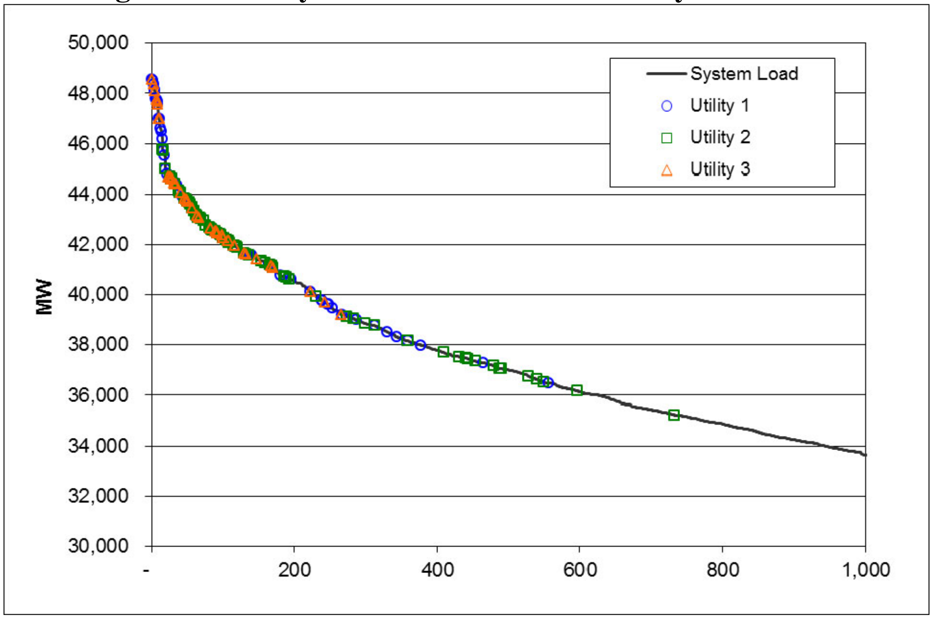
Advanced notification requirements limit precision. Requirements for advance notice of up to 24 hours prior to a DR curtailment call reduce the option value to the utility. Operators must incorporate a much greater degree of load and generation forecast error as compared to dispatch instructions that can be made closer to real-time. The utility is not able to respond to curtailment needs not anticipated the previous day and makes some curtailment calls that turn out not necessary in real-time. Operators will also tend to hold some calls in reserve through the end of the peak season, resulting in missed opportunities for curtailment if system peak loads occur early in the year.

DR programs limit the duration and frequency of curtailment. Because DR curtailment events are disruptive to customers, utilities are hesitant to use them to the full extent allowed. Despite the above-normal temperatures, each of the three California IOUs issued DR calls for only 70-80 hours in 2007,[2] less than one percent of the year. In comparison, the CAISO estimated that a new CT would have operated at a capacity factor of 8-9 percent, or approximately 750 hours (CAISO 2011).

The CAISO system load peaked at over 48,000 MW in 2007. Fifty percent of the curtailment hours occurred when system load was below 42,600 MW. For nearly 40 of the top 100 load hours, none of the three investor-owned utilities (IOUs) in California issued a DR call (Figure 1). Some of these missed opportunities or unneeded calls were due to local conditions or supply shortages not represented in the CAISO system load data. However, some were also certainly due to the program limits on DR call frequency, duration and advanced notification.

[2] Due to the economic slowdown, 2007 is the last year in which a high number of DR calls were made.

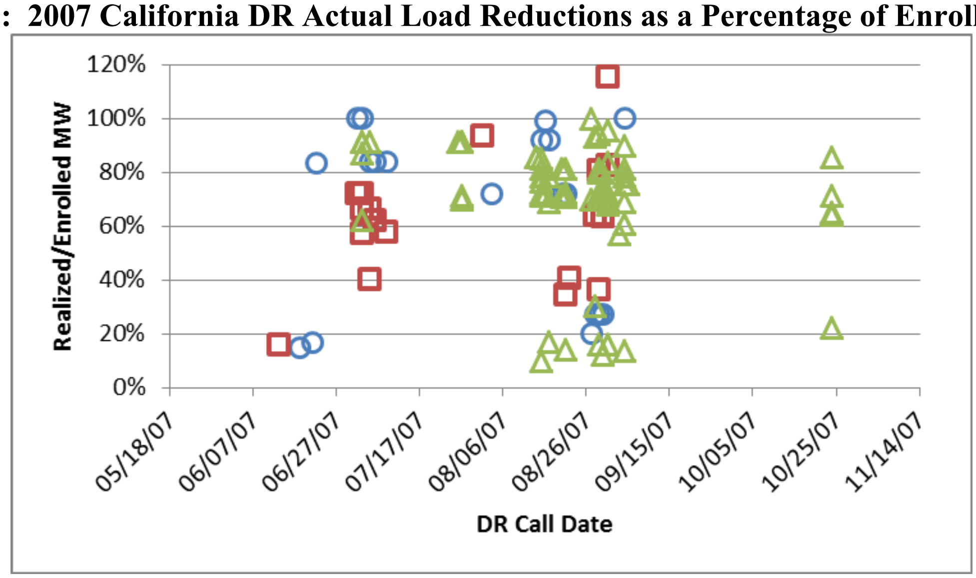
Figure 1: Utility DR calls Versus CAISO System Loads



Source: Freeman, Sullivan & Co. and Energy and Environmental Economics 2009

Uncertain customer response reduces reliability. DR programs vary widely in the quantity of customer load enrolled versus the load reductions actually achieved. Some DR programs achieve near universal response while others experience high rates of non-performance (Cappers, Goldman & Kathan 2010). The load reductions realized from California IOU DR calls in 2007 are shown in Figure 2. Two-thirds of the calls realized load reductions less than 80 percent of the enrolled MWs and one-fifth achieved results of 50 percent or less.

Figure 2: 2007 California DR Actual Load Reductions as a Percentage of Enrolled MWs



Source: Authors' analysis of California DR Program Impact Evaluations

More recent load impact studies performed for California show similar variations in response (Christensen 2011; FSC 2011). Uncertain availability is not limited to California. In

2006 PJM had 1475 MW registered under the economic DR programs, but only 325 MW cleared in the market on the system peak day (Walawalker et al., 2010). Realized load reductions for the NYISO Emergency Demand Response Program ranged from 35 to 71 percent of enrolled MW between 2001 and 2007 (Cappers et al., 2010).

AutoDR does not fundamentally address the limits of emergency DR. Automated demand response (AutoDR) addresses some of the limits to emergency DR, but is not a complete fix. AutoDR can enable more rapid response, and the enabling technology supporting AutoDR can more readily connect to specific loads and equipment. This reduces the customer's burden of responding to a DR call and increases the reliability of their response. However, AutoDR still operates in an event-based DR paradigm. Programs in which AutoDR has been implemented to date still suffer from the limited number of permitted calls per year and utility reluctance to disrupt customers too frequently. Also, advanced notification requirements may be reduced, but are not eliminated.

Economic DR does not lead to Cost-reflective Prices or Reliable Price Response

Economic DR employs some form of dynamic pricing to induce a load reduction by the customer.[3] Dynamic pricing has evolved to encompass a wide range of time-varying pricing schemes, including time-of-use (TOU) rates, critical peak pricing (CPP), peak-time rebate (PTR) and real-time pricing (RTP). However, dynamic pricing is limited in its ability to reflect capacity costs, and the available evidence suggests that hourly price response is uncertain.

Correlation between energy prices and capacity resource needs is weak. With most jurisdictions in the U.S. using hybrid energy and capacity markets, the correlation between energy prices and system loads is much weaker than what would be expected in a pure energy market.[4] Table shows Pearson and Spearman correlation coefficients for the CAISO, MISO, and PJM markets in 2011. As the table shows, the correlation between real-time energy prices and system loads (0.24-0.65) is much weaker than it is for day-ahead prices and system loads (0.66-0.85). The correlation coefficients for the top 250 load hours are lower than they are for the full year. The day-ahead market correlation coefficients range from 0.43-0.66 for the top 250 while the real-time market coefficients are all below 0.50.

The relationship between day-ahead and real-time prices is also not consistently strong and varies significantly across the ISOs. For the top 250 load hours, the correlation between day-ahead and real-time prices is reasonably strong for PJM, quite low for MISO and virtually non-existent for CAISO. Clearly different resource portfolios, market rules and scheduling practices across ISO's affect the relationship between day-ahead and real-time prices. Energy price alone is a poor predictor of the need or value of load reductions in real-time.

[3] The distinction between emergency DR and economic DR is blurred when the trigger is based on energy prices or when the utility initiates a curtailment event by sending an administratively determined price signal.
[4] Because utility loss of load probability (LOLP) study results are not widely available, we use system loads as an imperfect but reasonable proxy indicator of when capacity resources are needed, as there is usually a fair degree of overlap between hours of peak system load and high LOLP

Table 1: Pearson/Spearman Correlation Coefficients for Day-Ahead and Real-Time Markets, CAISO, MISO, and PJM, 2011

	CAISO	MISO	PJM
2011 Year Round			
Day-Ahead	0.80/0.85	0.79/0.80	0.66/0.70
Real-Time	0.24/0.51	0.44/0.63	0.52/0.65
DA Price – RT Price	0.28/0.58	0.50/0.72	0.71/0.89
2011 Top 250 Hours			
Day-Ahead	0.47/0.43	0.55/0.57	0.66/0.64
Real-Time	0.05 /0.30	0.17/0.40	0.50/0.47
DA Price – RT Price	-0.04/0.18	0.22/0.29	0.73/0.58

Source: Authors' analysis of 2011 CAISO, MISO and PJM market prices.
Notes: The Pearson correlation coefficient, shown first in Table 1, measures the linear correlation between system load and energy prices. The Spearman correlation coefficient, shown second, measures the correlation of the rank order between system load and energy prices.

PJM has the highest correlation between real-time prices and system loads of the three ISO's presented here. However, more than half of both the day-ahead and real-time energy prices in the top 250 load hours are below $100/MWh. This is more than double the annual average prices of approximately $42/MWh for both the day-ahead and real-time markets, but hardly the level of price spike that inspires a high degree of confidence in a consistently strong response.

Efficient pricing is limited by political and regulatory reality. The lack of retail customer response during periods of high energy prices has been frequently noted as a failure in the prevailing design of energy markets (King, King & Rosenzweig 2007). However, far from being merely a market imperfection, barriers to real-time pricing at the retail level are grounded in political and regulatory reality, limiting the potential for price spikes relative to an unfettered energy market. Economic efficiency must compete with the requirement that rates be just, reasonable and equitable and the requirement for stable utility revenues that recover embedded costs and facilitate long-term investments in a reliable electric system (Woo 2004). Outside of a few notable successes (e.g. Niagara Mohawk, Georgia Power), customer participation and response in RTP programs remains limited (Zarnikau & Hallett 2008; Hopper et al. 2006).

Price response is inconsistent and unpredictable. Inconsistent customer response further reduces confidence in price response as a reliable, flexible capacity resource. While, customers have been shown to be responsive to prices in general (Faruqui et al. 2010; Faruqui, Hledik & Sergici 2010), the magnitude of response for a specific hour is highly uncertain (shown above). Furthermore, demand for electricity can be highly inelastic at precisely those periods that are of greatest concern, such as on the third day of a heat storm (Coughlin et al. 2008).

Direct Load Participation in Wholesale Markets is Limited, does not Provide Flexibility, and is too Complicated

In response to FERC and state utility commission directives, ISOs and utilities across the US have worked to incorporate demand response programs into ISO energy, capacity, and AS markets in recent years. Commonly referred to as 'load participation,' ISOs and utilities have modified tariffs and market rules to allow loads to participate on equal terms with generators in AS markets. A summary of load participation in ISO markets is presented in Table .

Table 3: Summary of Demand Response and Direct Load Participation

	CAISO	ERCOT	MISO	SPP	PJM	NYISO	ISONE
System Size							
Load (GWh)	224,922	319,239	590,424	223,030	691,330	163,800	134,160
Peak Load (MW)	47,350	65,776	108,995	45,373	136,465	33,500	27,677
Utility/ISO DR Programs							
Emergency DR	3,934	491	4,528	400	11,825	2,498	1,243
Emergency DG			3,524				663
Energy/Economic/ Non-dispatchable	2,009	>1,000	930	1,500	2,178	8.3	877
Direct Load Participation in AS markets							
Regulation	-	35	10	n/a	0.2	-	-
10 Min/Sync	-	1,150	98		155	-	47
30 min/Non-Sync	-	-	15		-	-	-

Source: Authors' analysis of 2010 annual market performance reports and 2011 DR and load participation reports and presentations downloaded from the website of each ISO.

Load participation in energy, capacity and reserve markets is limited. The ISO capacity markets are most similar in nature to demand response. The generator or load is paid to stand ready to be called upon to increase generation/reduce load when needed to meet peak system loads. Most ISOs have, or are moving toward, allowing emergency DR programs to participate in capacity markets with recognition of its contribution towards meeting planning reserve margins. Load participation in the PJM capacity market has increased from under 2,000 MW in 2007/08 to over 9,000 MW in 2010/11 (Monitoring Analytics 2010). In both ISONE and PJM, Emergency DR participating in the capacity market totals approximately 10 percent of their respective peak system loads.

Contingency reserves are also similar in concept to DR, but require response times of 10-30 minutes, much shorter than the minimum notification time of most DR programs. The only market where load is providing significant quantities of contingency reserves is ERCOT where Load acting as Reserves (LaaRs) is providing the maximum allowed (1,150 MW (50%) of the responsive reserve requirement) (Zarnikau 2010).[5] Outside of this one example, load participation in reserve markets remains small. Load provision of regulation remains quite limited, despite several years of concerted effort to remove barriers to load participation.

Load participation in centralized markets does not provide flexibility. Load participation in centralized energy and reserve markets does not provide flexibility to the system operator in the form of dispatchable control that can readily respond to unexpected changes in load or generation. Much of the system operator management of variability occurs sub-hourly in the 15 to 5 minute security constrained/real-time economic dispatch processes. In this time scale, 5 minute imbalance energy and frequency regulation markets provide the flexible resources that operators rely upon. Unfortunately, load participation in these markets that provide the highest degree of flexibility and dispatchability to the grid operator remains small.

[5] In 2011 ERCOT proposed removing the 50% limit. The proposal is undergoing stakeholder review.

Barriers to load participation remain — the devil is in the details. Facilitating load participation in wholesale markets is a far from straightforward process. Many barriers to load participation remain (Kim and Shcherbakova 2011).

The fundamental question — what price to pay load? — is extremely controversial. Unlike generators, load participating in wholesale markets see dual benefits to load reductions, energy payments in the wholesale market and retail bill savings from their utility or LSE from reduced consumption. This causes a potential distortion in that loads can offer lower bid prices in the wholesale energy markets and still kept whole (Dashti & Afsharnia 2011, Borlick 2012; Falk & Rosenzweig 2012; Gonatas 2012). Determining the proper price is not even half the battle. Billing and settlement between the ISO, utility, aggregator and customer has proven extremely complex and time consuming. In nodal markets, there is invariably "missing money" resulting from the multiple pricing points involved. LSE's or CSP's schedule loads in the day-ahead markets at one price and realize curtailments in real-time energy markets at a different price.

Establishing a baseline methodology against which the customer's response is measured is also eternally controversial. The baseline approach is subject to competing concerns regarding its simplicity, accuracy and potential for gaming or abuse (KEMA 2011a; KEMA 2011b). Separate methodologies may be established for forecasting, impact estimation and billing where multiple regulatory agencies are involved. There are frequent disagreements between Curtailment Service Providers, ISOs and FERC regarding the proposed baseline methodologies or changes thereto (see FERC Docket No. ER11-3322-00).

The economic theory of using a consistent product definition for all resources to participate in wholesale energy, capacity and AS markets is compelling. It supports large, liquid markets with active trading to promote competition. However, fostering participation of non-generation resources in wholesale markets is more than a matter of changing market rules and tariffs. In practice, the challenges that must be overcome for load to play on the same field as generation are substantial. The greatest potential for load acting as a resource to the electric grid lies elsewhere.

A New DR Paradigm: Highly Responsive Load

Defining Highly Responsive Load

To be of value to the future grid, load will need to serve as a much more flexible grid resource and overcome many of the barriers described above. This responsive load will combine four key characteristics to maximize its value to the grid operator.

1. **Dispatchable**: The load will be directly dispatched <u>up or down</u> by the ISO, utility or aggregator, within limits established by the customer.
2. **Flexible**: dispatch requires <u>little or no advance notice</u> with only limited restrictions as to frequency, duration or timing.
3. **Fast Response**: for selected and potentially the most valuable applications, load will be required to <u>respond very quickly</u>, on the order of 10 seconds or less.
4. **Visible**: the response will be <u>immediately visible to the operator</u>, verified with real-time sub-metering or robust statistical sampling.

Fast responding load-based resources with all four of these characteristics have moved beyond the pilot and demonstration stage and are already in commercial operation. In November 2011, PJM received the first frequency regulation service from small-scale demand resources live in the wholesale regulation market.[6] ENBALA Power Networks manages a portfolio of water pumps and other loads to response to PJM's frequency regulation signal every 4 seconds. Another participant, Viridity Energy, uses building loads and a battery installed at the customer's site. Alcoa Power Generation Inc. provides up to 25 MWs of regulation in the MISO AS market through control of smelter loads. Two customers in ERCOT provide 35 MW of load responding to automated signals and grid frequency.

The revenue potential from load participation in ISO markets such as frequency regulation has spurred a great deal of innovation in technology and DR program design. Participating in ISO energy and ancillary service markets, however, does not capture the full potential of highly responsive load. **We propose that it makes little sense to focus primarily on shoehorning a portfolio of extremely *diverse and distributed* energy resources into acting as a generator in a limited number of *homogenous centralized* markets**.

Highly Responsive Load Turns DR into a Truly Flexible Resource

Responsive load as described here offers several improvements over emergency or economic DR, as implemented to date. Paying loads to act as a flexible resource via short-term operator dispatch vastly simplifies both billing and baseline calculations. Retaining the option to dispatch responsive loads with capacity payments decreases the relative importance of energy payments and the associated billing and settlement complexities described above. Short-term dispatch for flexibility also avoids the baseline issues that have proved so controversial for DR; forecasting loads 5 minutes to 1 hour ahead entails far less uncertainty than morning-of or day-ahead calculations.

Providing direct and verifiable dispatch provides a much higher degree of confidence in the timing and magnitude of response. This reduces the discounting or double procurement that occurs when DR resources are not trusted by utility operators. Drastically reducing or eliminating the notification requirements and curtailment limitations increases the option value to the utility. Operators can make decisions close to real-time with less forecast error and fewer missed opportunities or unnecessary curtailment calls. Utility dispatch can also provide a more refined, measured response, rather than the "give us all you can" curtailment calls for DR programs. A networked approach has the additional advantage of making the operation virtually invisible to the individual customer while providing an aggregated response to the utility dispatch instruction. Without fear of customer disruption and complaints, utilities can be much less restrained in their use of load as a resource.

Responsive load can provide a number of additional services not provided by the existing DR paradigm. Several ISO's are evaluating ramp or load following products that fall in between 5 minute imbalance energy markets and hourly real-time markets, and which are not adequately provided by current energy and AS products. Responsive loads that can respond in the 5-30 minute time frame can both reduce the forecast error for load and serve as a resource providing a ramp or load following service.

[6] See http://pjm.com/~/media/about-pjm/newsroom/2011-releases/20111122-news-release-dr-firms-participate-regulation-service.ashx and http://pjm.com/~/media/about-pjm/newsroom/2011-releases/20111122-news-release-dr-firms-participate-regulation-service.ashx

Highly Responsive Load Provides Distributed Benefits not Captured by Load Participation

We propose that the highest and best use of loads is to take advantage of their distributed nature. With advanced metering and increasingly affordable and sophisticated communications and IT, aggregated loads with automated dispatch can meet a number of distribution system operational needs. On the distribution system, decreasing loads can reduce voltage drop, help to maintain voltage within tolerance levels and defer system upgrades (Dashti & Afsharnia 2011; Venkatesan, Solanki & Solanki 2012).

Using responsive loads to promote higher penetration and lower cost interconnection of distributed renewable generation deserves particular attention. Using loads to selectively manage even just 1 percent of a PV system's output to prevent backflow has the potential to more than double PV interconnection potential relative to simple limits based on a percentage of feeder load (Energy and Environmental Economics 2012). The same type of operation that provides frequency regulation for the ISO can also be used to supply voltage measurement, voltage control and renewable generation firming that are not provided under current interconnection requirements. Firming intermittent PV generation also increases its value to the utility as a local capacity resource in constrained areas.

The Technical Potential for Highly Responsive Load is Significant

Load has the potential to provide a significant portion of the anticipated need for regulation, load following and ramp services needed to integrate renewable resources. As one example, load based regulation pilots have relied primarily on large, variable frequency drive (VFD) motors in process and water pumping applications. Large electric motors comprise just 0.03 percent of the total stock by number, but account for 23 percent of all motor power consumption and 10 percent of total electricity demand (Wade & Conrad 2011). Turning more specifically to California, the CAISO has estimated a need of 1,700 MW's of flexible resources for the 2011 Long Term Procurement Proceeding (CAISO 2011). California college campus loads total over 500 MW and have a diverse portfolio of potentially flexible cogeneration, electric and steam chillers, thermal storage tanks. Potentially flexible industrial end-use loads, including pumps, fans, motors and compressors and total over 2,000 MWs of load (Itron 2007).

Moving beyond event based load reductions has the potential to increase participation, if the necessary cost reductions and technology improvements are achieved. A much wider variety of major end-use commercial and industrial loads can accommodate frequent, but small adjustments as compared to disruptive event based DR curtailments.

Implementation Challenges Remain

Enabling responsive load is not without its challenges. Most critically, given the diverse nature of customers, installations enabling highly responsive load must currently be custom engineered at each site. Standardization of communication and control protocols will help to simplify implementation, but is not without its own challenges. Continuing improvements and cost reductions in communications and control technology must be realized to expand potential beyond large commercial and industrial customers. As with DR programs, customer acquisition and retention can be difficult and time consuming. Rules and procedures for aggregating loads to participate in utility and ISO scheduling and operations will need to be far simpler to implement.

These issues can and are being addressed in demonstration programs and continuing development of smart grid and communication technologies.

Responsive Load Increases Realized Energy Efficiency Savings

Water pumping and water or wastewater treatment is just one example of where responsive load and energy efficiency overlap, with mutual benefit. Water systems often, though certainly not always, have a significant degree of flexibility in when and how individual pumps and motors are operated. These very same pumps and motors are also primary targets for variable frequency drive (VFD) efficiency programs. However EM&V studies in California have found mixed results for VFD measures. For example, the three of seven water pumping VFD implementations studied had measured savings that were less than 50 percent of those predicted (Itron 2010a; Itron 2010b). Without real-time monitoring, lower operating efficiencies can go unnoticed. For these reasons, the EM&V reports for both SCE and PG&E industrial efficiency programs recommend more real-time measurement and verification.

Payments for providing responsive load greatly enhance the business case for installing such equipment. The same real-time measurement and verification used to provide renewable integration and grid support services can also be used to operate the system closer to its maximum efficiency and determine when equipment should be replaced or refurbished.

Conclusion

The economic theory of load actively responding to price signals in competitive wholesale markets is appealing. In practice, DR fails to fully realize its potential capacity value, electricity prices induce a limited and uncertain response and load participation in wholesale energy and AS markets remains complex, challenging and limited. Focusing so much effort on forcing an extremely diverse portfolio of distributed load based resources into a few homogenous, centralized markets is ultimately unproductive. Enabling distributed load-based resources to provide dispatchable, flexible, highly responsive and visible control to utility operators can provide significant value in integrating renewable and high penetration distributed resources. There is significant overlap between the end-use commercial and industrial loads that are potentially flexible and also primary targets of energy efficiency programs. Pursuing both enhances cost-effectiveness as well as the load reductions achieved through efficiency measures.

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