Demand Response: Do Customers Have a Role in the ICAP Markets?

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ABSTRACT

This paper focuses on the role that demand-side resources and demand response programs can play in meeting future capacity and reserve needs in electricity markets. Of particular interest is how demand-side resources can be used as capacity resources in deregulated markets (the so-called installed capacity or ICAP markets). The paper also examines the economic, market, and regulatory issues affecting demand response, and how power markets, ISOs, and regulators are addressing these issues. Ultimately, the paper focuses on the critical interface between end-use customers and wholesale power markets, and the need to view and value demand response as insurance or as a call option to hedge against future price spikes or system emergencies.

Introduction

The California electricity crisis and the tightness of the capacity situation in other areas of the U.S. such as downstate New York has highlighted the importance of maintaining adequate reserves of capacity in restructured electricity markets. The lack of adequate reserves in California was a prime cause for the severity of the crisis and the creation of a "sellers market" in the state. Another causative factor was the lack of a price-sensitive demand, e.g., aggregate demand did not rise or fall as a function of market prices. Without demand elasticity, electric networks must maintain larger capacity margins in order to have sufficient supply to meet inelastic demand, whatever it is, and also ensure system reliability in the event of outages.

The development of a consistent policy on the level of capacity reserves needed (either supply or demand side) to forestall future capacity crises is one of the key issues being addressed by the Federal Energy Regulatory Commission (FERC) in the development of its policy on regional transmission organizations (RTO's). Options being explored include the use of installed capacity (ICAP) requirements, forward capacity contracts, and greater use of price-sensitive demand and load curtailment.

If designed and implemented properly, programs that allow the use of demand-side resources as capacity resources can play an important role in future markets. Ultimately, a mix of price-sensitive demand and load curtailment programs could be used within a broader portfolio of resource options available to customers and load serving entities. Price-sensitive demand should reduce the severity of price-spikes and capacity emergencies. If capacity reserves drop to low levels and/or prices increase significantly, load curtailment programs can be operated to further reduce customer demand to avert system emergencies or to mitigate high prices paid to generators.

The use of load management to meet capacity requirements and/or lower peak demand has been successful in the recent past.[1] In addition, the experience of the summer 2001 suggests that ISO-based demand response programs provide additional sources of capacity and demand elasticity.[2] The continued development of these programs, particularly in the areas of technology (e.g., metering, energy information systems) that will enable customers to participate and aggregation of multiple smaller customers will increase the value of demand response as a resource.

Need for Reserve Margins

The experience of the last several years has demonstrated the importance of maintaining adequate electric capacity to meet customer demand. Rapid customer growth, uncertainty associated with electric restructuring, and the lack of significant increases in capacity in the 1990s led to supply inadequacies and price spikes in the Midwest, California, and the Northeast. The fundamental policy issue is how to ensure capacity adequacy exists to meet customer needs, but at the same time allow competitive markets to exist.

Why Are Reserve Margins Needed?

Due to its unique characteristics (i.e., non-storability), electric power networks require access to sufficient generating capacity to respond to sudden and unpredictable changes in demand or unplanned outages of generating units. If this capacity is not available and cannot be brought on-line, then reliability can suffer. The availability of excess capacity can be viewed as reliability insurance.

Electricity is different than other commodities because aggregate electricity demand has historically been inelastic to short-term or real-time changes in wholesale prices due to fixed retail prices available to most electric customers.[3] Higher wholesale supply prices associated with higher demand are generally not directly passed-on to customers because of rate caps, fixed default service prices or fixed commodity offerings. The instantaneous characteristic of electricity delivery and use reduces the ability for demand to quickly respond. This lack of price sensitivity drives the need for adequate capacity reserves.

Electric power networks historically responded to this need for sufficient reserves by requiring electric utilities to maintain reserve margins. States frequently required electric utilities to maintain 15 to 20 percent reserves. The tight pools in the Northeastern region of the U.S. (e.g., PJM, NYPOOL, and NEPOOL) all required pool members to maintain or contract for reserve margins in the range of 18 to 22 percent. Under cost-of-service regulation, the cost of maintaining these reserve margins and operating generating units that are rarely dispatched was recovered through rates.

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[1] Examples of successful electric utility load management and curtailment programs include the 1,325 MW of load curtailment capability at Xcel Energy in 2001 (Lawless 2002), and approximately 1,800 MW active load management within PJM utilities (PJM 2001).

[2] (Goldman 2002) reports that most ISO programs produced reductions in 2001. The largest reduction of 425 MW was associated with the Emergency Demand Response Program at the New York ISO. See Neenan Associates (2002) for a good review and analysis of the NYISO programs.

[3] (Hirst & Kirby 2001) provide a good discussion of this dynamic.

The development of deregulated and restructured markets has presented more of a challenge. The key issue is how to provide an incentive to these companies to maintain and invest in generating units that may not operate more than a few hours per year. Without an incentive or sufficient revenues from capacity or energy, independent generating companies find it hard to justify internally or in financial markets the investment and continued maintenance of these assets.

Options to Provide Adequacy of Electric Service

The current deregulated electric markets have used a variety of methods to maintain adequate reserves. The most common option in the currently operating ISO markets is the continuation of the same type of reserve margin obligation that existed in regulated markets. The only difference is that all Load Serving Entities (LSEs), not just utility distribution companies, must maintain sufficient capacity margins above the expected peak demand of their customers. These capacity obligations, also known as installed capacity requirements (or ICAP), are in place in PJM, NYISO, and ISONE. Other markets, most prominently California and ERCOT, along with several international markets such as Nordpool, do not require any capacity margins. In these markets, energy markets provide the only compensation and incentive for capacity.

The experience of the three Northeastern ISOs with ICAP obligations has been mixed. Each of these ISOs implemented markets in which LSEs could buy and sell capacity resources to meet their obligations. The ISO-NE chose to suspend the operation of their ICAP market in August 2001 because of concerns about market power (too few suppliers created market power). The PJM continues to operate its ICAP market, but has had to modify the structure of the market due to similar concerns about market power and incentives. The operation of the NYISO capacity market has been more successful. Due to its design, particularly its six-month capability period auction structure, the NYISO ICAP markets have not been subject to the same degree of market manipulation as in PJM, and prices have generally been in-line with underlying capacity prices.

In the U.S., the lack of capacity obligations was one of the key contributing factors to the crisis in California.[4] Without sufficient incentives to maintain and/or contract for reserve margins, California did not have sufficient reserves during 2000 and 2001 to meet load obligations. Consequently, wholesale electric prices soared to record heights, and charges of market power and market manipulation have been made.

Given the experience of California with no capacity obligations and problems with the operation of ICAP markets in the Northeastern ISOs, FERC has been examining options to provide capacity adequacy. This examination is part of its extensive review of electric markets during the development of standard market designs for RTOs. The options being considered by FERC were identified in a staff paper (FERC 2001):[5]

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[4] Other contributing factors included the requirement that the utility distribution companies must purchase most their generation in spot markets, and the disconnect between a variable, volatile wholesale market and frozen tariffs or rates in default service retail markets.

[5] Resource adequacy is also the subject of a working paper on standard market design released by FERC in April 2002 (FERC 2002).

- Employing current ICAP mechanism that impose capacity obligations on LSEs, and provides a revenue stream that helps to cover the carrying costs of units that receive little or no revenue from the energy market;
- Requiring either LSEs or the system operator to obtain generation that would provide reserve capacity at some time in the future (in other words, a call option on energy); and,
- Allowing LSEs to meet part of their ICAP capacity requirement (in MW available for pre defined time intervals) with contracts for curtailable loads or use of price-sensitive bids.

As was discussed above, ICAP markets are already in place in several deregulated markets. Key remaining issues associated with their use are how to obviate or reduce market manipulation of capacity prices and who contracts for or installs the capacity. The remaining two options being considered by FERC are new and represent innovative ideas. Capacity obligations in the second option can be obtained through either long-term forward contracts with generation owners or call options on energy. In the last option, demand-side resources serve as the primary source of capacity during periods of reserve deficiencies.

Necessary features of any resource that can provide capacity reserves or meet capacity obligations are longevity and firmness. Longevity refers to assets that will be in existence for the longer-term, i.e., generally greater than one or two years, and can be counted on to meet future load growth or plant outages. Firmness refers to the likelihood that the asset will be available and operating during periods of high demand or during reserve emergencies. Since most generating capacity assets are by their nature long-lived, they meet the requirement for longevity. Depending on the way that generating units are dispatched, generating assets can also be firm.

Contracts for demand-side resources can also be long-lived and firm if they are designed correctly and if sufficient incentives exist for their operation. Indeed, demand-side resources could provide capacity resources under all three of the FERC options. The remainder of this paper focuses on how demand-side resources have and can provide capacity resources in electric markets.

Demand Response

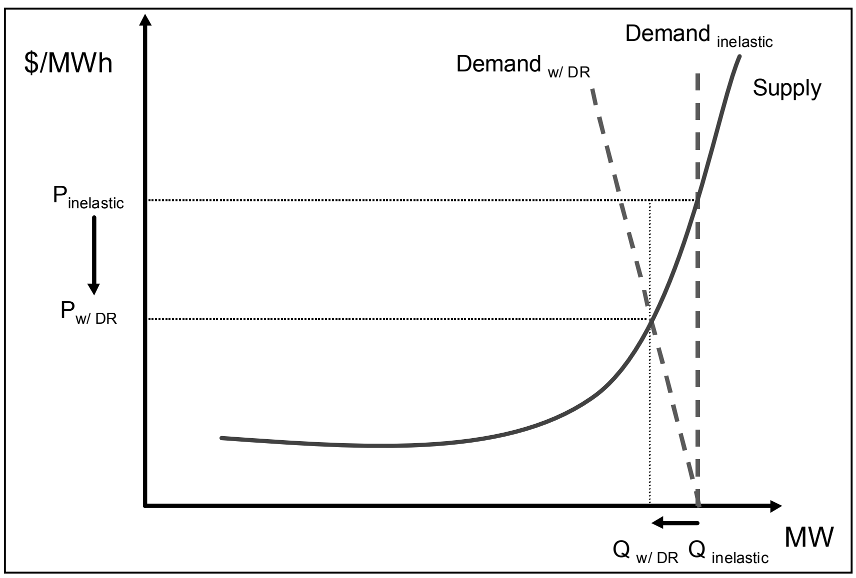
The use of the term "demand response" to refer to the participation of demand-side resources in wholesale markets is relatively new. Historically, the term "load management" was used to describe utility programs designed to stimulate customer load curtailments or load shifting. The term "price responsive load" has also been used to describe programs that either passed-through wholesale prices to retail customers or to describe tariffs that incorporated time-varying prices based on underlying costs in the wholesale market. The term "demand response" is used in this paper as the generic term for all customer changes in actions or behaviors that introduce price elasticity into the wholesale market or can be used to increase system reliability. Hence, demand response includes both load reduction in response to reliability problems and price responsive load.

Benefits Associated with Demand Response

The incorporation of demand response into electric markets can produce important and significant benefits. These benefits include:[6]

- *System Reliability*. Customer demand management can enhance reliability of the electric system by providing system operators another potentially cost-competitive option to address local reliability, transmission congestion, and system reserve shortages.
- *Cost Reduction*. A key driver for demand management is cost reduction for all parties. Customers can benefit through reduced electric rates and bills. System operators, LSEs and utility distribution companies (UDCs) benefit through direct cost savings from avoided generation as well as avoided transmission and distribution costs including capacity costs, line losses, and congestion charges. All market participants benefit through direct or indirect reductions in wholesale market prices.

Figure 1. Impact of Small Changes in Demand Elasticity on Market Clearing Prices



- *Market Efficiency*. When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result is more efficient use of the electric system. In addition, the introduction of demand elasticity allows the market to equilibrate. Figure 1 demonstrates the benefits to both participants and non-participant from introducing demand elasticity into tight supply situations. When customer demand reaches the steep section of the supply curve, small changes in demand can produce significant reductions in market clearing prices. A recent cost-benefit analysis of the implementation of RTO policy nationwide for FERC by ICF

[6] This list of benefits is partially based on the (PMLA 2002)

Consulting (ICF Consulting 2002) suggests that the introduction of price-sensitive demand could reduce total national wholesale system costs by $4 billion per year.

- *Risk Management*. Demand response allows customers and retailers to hedge their risk exposure to system emergencies and price volatility. Customers can use demand response technologies to control their peak demand levels if they are subject to demand charges in their tariffs, and can use these same technologies (including distributed generation) in the event of system emergencies.[7] Retailers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating appropriate price offers for those customers who are willing to face varying prices.
- *Environmental*. Demand response has the potential of reducing environmental burdens placed on the air, land, and water by lowering demand during peak periods, especially if only customer load reductions are used. Demand response can also reduce or defer new plant development, and transmission and distribution capacity enhancements resulting in land use benefits.
- *Market Power Mitigation.* The use of demand response programs to introduce demand elasticity to the wholesale market has important market power mitigation benefits.

Types of Demand Response Programs

Demand response programs can be categorized into reliability-based programs and market-based programs. Reliability-based programs operate in response to system contingencies or emergencies. These programs have the capability to serve as capacity resources. Market-based programs are triggered by changes in wholesale market prices, particularly high prices.

Reliability-based programs. Reliability-based programs include both contractual (also known as call options) and voluntary programs. In the contractual program, customers are paid a guaranteed payment per month or per kW in exchange for curtailing their consumption during system emergencies. Customers can be penalized if they do not reduce their consumption within the time frame in their contract when directed. Interruptible rate tariffs and direct load control programs are examples of existing load management programs that meet this definition. Contractual programs will likely be the source of firm load curtailments that can be used to defer capacity additions or act as capacity reserves. Voluntary programs do not include a guaranteed payment for timely performance – participating customers are asked to reduce their consumption when directed, however they are not obligated to perform the curtailment. Participating customers are typically paid only the market clearing energy price or alternative floor price an incentive to participate. Voluntary programs can also assist utilities or LSE's balance demand and supply during periods of reserve shortages, but they are not well suited for replacing generation capacity on a long-term basis.

Market-based programs. Market-based programs can also be subcategorized into bid-based programs and programs where the customer is a price-taker. In the bid-based programs, the

[7] The Optional Mandatory Binding Control program in California allows customers who can reduce their peak demand by 15% to avoid rolling blackouts.

customer submits a bid identifying their minimum price required to curtail and the curtailment amount. This bid is chosen when it is economic for the system operator to dispatch the demand reduction instead of an alternative demand bid or a generator bid. In the price-taker programs, the customer only indicates a particular amount of load available to be curtailed, and doesn't specify a specific price. In these price-taker programs, the ISO specifies the minimum price or the customer receives the market-clearing price. Due their market-based nature, the use of these programs to meet capacity obligations or serve as capacity reserves is limited.

Demand Response Programs in Existence

Demand response programs have been in existence at electric utilities for years. Many electric utilities invested in load management programs in the late 1980s and early 1990s. Table 1 lists electric distribution utilities that are currently implemented these types of programs.

Table 1. Utility Distribution Company Demand Response Program Experience

Reliability-Based Programs		Market-Based Programs	
Direct Load Control	**Emergency Response**	**Variable Pricing**	**Demand Bidding**
BG&E	Allegheny Energy	Cinergy	Ameren
Black Hills Power	BG&E	Dominion Virginia Power	Cinergy
Exelon (ComEd)	Cinergy	FirstEnergy	Con Edison
Con Edison	ComEd	Georgia Power	Duquesne
Florida P&L	Con Edison	Gulf Power	Entergy
Florida Power	Dominion Virginia Power	Illinois Power	Georgia Power
Georgia Power	GPU	KCP&L	GPU
GPU	Idaho Power	Penn P&L	Idaho Power
LIPA	KCP&L	Puget Sound Energy	Otter Tail Power
LG&E	Nevada Power	Tuscon Electric	PG&E
MidAmerican	PG&E	Wisconsin Public Service	Pacificorp
PEPCo	Pacificorp	Xcel Energy	Portland General Electric
PSE&G	PEPCo		Wisconsin Electric
Reliant	Portland General Electric		Xcel Energy
SCE	Penn P&L		
Wisconsin Public Service	PSNH		
Xcel Energy	PSE&G		
	Puget Sound Energy		
	San Diego G&E		
	Sierra Pacific Power		
	SCE		
	Tampa Electric		
	Texas New Mexico Power		
	Tuscon Electric		
	Utilicorp		
	Xcel Energy		

Source: Partially based on EEI (2002)

In Table 1, direct load control refers to the use of remotely controlled-switches on customer appliances (e.g., air conditioners, water heaters, and pool pumps) by LSEs and utility distribution companies. Customers typically receive a monthly bill credit in return for curtailments. Emergency response programs pay customers for load curtailment. These programs can either be contractual or voluntary. Variable pricing programs refer to tariffs that vary by time of day (time of use) or by hour (real-time pricing). Demand bidding programs implemented by utility distribution companies typically let customers bid the price at which they are willing to curtail. Distribution companies exercise these bids when they are economic.

Each of the four ISOs also implemented demand response programs in the last several years. Table 2 places each of the existing ISO programs that were designed before the summer of 2001 into the four demand response categories defined above. The only reliability-based contractual program that currently provides capacity resources is NYISO's ICAP Special Case Resources program. The ISO-NE is working towards including guaranteed payments from ICAP markets in its Demand Response Program. The current payments are based on operating reserve prices.

Table 2. Classification of 2001 ISO Demand Response Programs

ISO	Reliability-Based		Market-Based	
	Contractual	**Voluntary**	**Bid-Based**	**Price-Taker**
ISO NE	Demand Response Program			Price Response Program
NYISO	ICAP Special Case Resources	Emergency Demand Response Program	Day-Ahead Demand Response Program	
PJM		Emergency Option		Economic Option
CA ISO	Participating Load Program Demand Relief Program			Discretionary Load Curtailment Program

Customer Involvement in ICAP Markets

Although the involvement of demand response in electric markets is growing, the participation of demand-side resources in ICAP markets has been limited. This section explores the recent experience with demand-side resources participation in these competitive markets, issues associated with demand-side participation, and barriers to participation.

Existing ICAP Markets Where Customers Have Access

As of winter 2002, only one ISO (NYISO) allows demand-side resources to actively participate in installed capacity markets. During the summer of 2001, approximately 360 MW of ICAP was procured as NYISO ICAP Special Case Resources. Load curtailments comprised 312 MW of this total, the remaining 48 MW was from customer generators. An even higher amount, 446 MW, was selected for the 2001-2002 winter capability period. The ISO-NE has plans to allow demand-side resources to participate in ICAP markets once they reinstate this market. At the present time, the ability of demand-side resources to participate in the PJM capacity markets is limited to utility distribution company active load management (ALM) of its customers.

Issues Associated with Demand-Side Participation

Although demand response programs are gaining favor, the ability of demand-side resources to actively participate in capacity markets has been limited. One of the key hurdles to demand-side resource participation is that system operators are familiar with the use and dispatch of generating assets, not aggregated customer load curtailments. Reserve "capacity" that doesn't have traditional dispatchability characteristics, and cannot be monitored in real time usually is not treated in the same manner as generation by system administrators.

Firmness of load curtailments. One of the key concerns raised about demand-side resources and demand response in general is that the reductions in load cannot be relied upon if customers are not obligated by contract to perform. System planners are reluctant to base transmission decisions and reliability assessments on programs that ultimately depend upon customer behavior and participation. The experience with customers not fulfilling their obligations within the interruptible programs in California serves as a cautionary tale.

Longevity of load curtailments. A related concern is the longevity of load curtailments. Can system plans and generation planning rely on the continued existence of customers willing to provide load reductions on call over several years? This concern has two dimensions. First, generation assets are by their very nature long-lived. In order to be comparable, demand-side resources must be at least sustainable and perceived as profitable to the owner of the demand side resource (the customer) for a similar period. Second, in order to replace or defer capacity needs, demand-side resources must exist for at least the period of time required to build new capacity, typically two years or more.

Lack of supporting technology. The last major issue is the current lack of enabling technology needed to participate in demand response programs. Interval meters are necessary for participation in capacity markets, because they provide they provide verifiable measurement of curtailment. However, not all customers have interval meters. In addition, except for the installed base of direct load control, hardware and software that automate load curtailments when dispatched or when customers receive notification are still in development and are not installed at many customer locations.

Drivers and Barriers to Customer Participation

As was indicated above, many of the issues associated with demand-side participation are associated with customer behavior. In particular, will customer load curtail at time of system peak, and will loads be available to curtail in the future?

Barriers to broad-based customer participation. Even though customers have an interest in participating in demand response programs, barriers to customer participation exist. Kathan & Mihlmester (2001) and Xenergy (2002) found the following barriers to customer participation:

- Perception that participation creates risk for customers;
- Customer disinterest in programs that contain credible penalties;
- Time required to monitor prices and system conditions;
- Disinterest in losing control of their operations and systems;
- Lack of technology, particularly interval meters, limits participation by many customers;
- Environmental rules associated with distributed generation; and
- The use of load profiling, which limits the ability of the customer and/or its aggregator to extract value from customer curtailments.

These barriers have important implications for demand-side participation as a capacity resources. Given the firm commitment required to receive capacity payments, general customer disinterest in programs that require sizable commitment, and have the potential for penalties, customer interest in participating in ICAP programs may be limited.

Means to reduce to barriers. The ideal program to address these customer drivers and barriers would combine limited customer impact, limited reliance on customer behavior, and high and predictable payments for participation. While this ideal may be hard to achieve, there are at least two means to overcome these barriers. The first is to assist customers in the deployment of enabling technologies, especially equipment that automates load curtailment. The second is aggregation of customer curtailments. Through aggregation, LSEs or third-party curtailment providers can use the diversity of customers to provide firm reductions.

Role for Demand-Side Resources

As has been mentioned earlier, demand-side resources may have a role in providing capacity in electric markets. More importantly, the use of demand-side resources as options to hedge against price risks and system emergencies should be exploited. Demand-side resources should be developed as call options that can be called during periods of high demand or low capacity reserves, or can be used to support forward contracts for capacity. Alternatively, demand-side resources could be used as part of a LSE's portfolio. Demand-side resource's role in the portfolio would either be to reduce capacity obligations when requested by system operators or as a means to reduce customer peak demand.

Can Demand-Side Resources Provide Reliable Capacity in ICAP Markets?

If demand-side resources can be shown through design or experience to be firm and long-lived, the answer is yes. In order to meet these two criteria, we believe that the following characteristics of the resources and the demand response programs will be required: (a) measurable load reductions must be verified and transparent to market participants, (b) customers or LSE's must provide evidence of longer-term commitment, and (c) credible penalties must exist and be used if customers break contracts. History has shown that demand-side resources can provide capacity resource – see the use of Active Load Management to reduce LSE capacity obligations in PJM.

Based on the criteria above, several observations about current demand response programs and technologies can be made. First, remotely-operated curtailment programs such as direct load control or other hardware-based load curtailment programs which can be initiated remotely without customer participation are the best candidates for capacity programs. While system operators would like to control the switches, LSEs and/or customers can also control the switches and sell the firm reductions into the capacity market, or serve as the basis for a call option. Hardware-based curtailments are also likely to have greater longevity.

Second, non-hardware programs can also provide capacity resources if they can be aggregated into larger programs. This is the approach being taken by aggregators in New York. For example, ConsumerPowerline.org aggregates a large quantity of customers into a curtailment group, and then bids an expected level of curtailment. This expected level is less than the maximum in order to take account for non-participation. Alternatively, large companies with multiple facilities can aggregate their loads as part of their portfolio.

Nevertheless, it is difficult to predict whether these efforts will be long-lived. Evidence of a contractual agreement would bolster the use of aggregation as an ICAP resource.

Third, penalty provisions need to be real and monetary. NYISO's ICAP program in 2001 penalized non-participation with removal from the program in upcoming capability periods. Non-monetary penalties create significant opportunities for gaming. NYISO has changed this policy and now sets credible market-based penalties.

Demand-Side Resources as Options to Reduce Risks

Fundamentally, demand-side resources and demand response programs are options, particularly with regards to volumetric risk. As was discussed above, demand response provides the capability to reduce demand in the face of high prices or system emergencies. Hence, the use of demand response is optional and will only be used when prices are sufficiently high or reserves are low. The ability to respond when required is the source of the option value for demand response. Recognition of these characteristics provides support for the use of demand-side resources in ICAP programs and as a firm resource.

Demand response programs which pay (or reduce rates for) customers or aggregators a guaranteed payment to be available when called, such as the NYISO ICAP Special Case Resources, electric utility curtailment programs, and direct load control, are the best examples of their use as an option. The guaranteed payment (typically expressed in $/kW-month) is the option premium. In exchange for the option premium, the customer or aggregator agrees to exercise their program when the "option" is exercised by the utility or ISO. Customer acceptance of direct load control over the last two decades along with recent experience with the NYISO ICAP programs suggests that customers are interested in participating in these programs.

Demand-side resources can also be used to hedge volumetric risk in customer, retailer, and utility portfolios. Volumetric risk is created when load changes from the expected, in both absolute value and shape (timing). Demand response programs such as load curtailment can be effective physical hedges to the volumetric risk faced by a supplier, comparable to swing options in its portfolio.

Viewing demand-side resources as options has an additional advantage. A key problem in the design and implementation of demand response programs is determining the level of incentive/payment to be paid for load curtailment. The use of option valuation techniques can both demonstrate the value of demand-side resources to these critics and as a source of bidding values in capacity auctions or in forward contract negotiations.

Summary

When properly designed and implemented, demand-side resources and programs can serve as capacity reserves. Demand resources that are not overly reliant on customer behavior to trigger load reductions and can be dispatched by system operators or aggregators such as LSEs are the best candidates. Programs or contracts that do not share these desired characteristics can still be aggregated such that the total firm reduction can be relied upon as a capacity resource. However, full participation of customers willing to serve as demand-side resources in future capacity markets will depend on greater market penetration of interval meters and curtailment software and hardware.

While the most logical near-term capacity market for load curtailment programs are the ICAP markets, the best use of demand-side resources as an alternative to generation capacity is as either a tradable call option on peak capacity or as the underlying support for forward contracts for capacity. In either contract, the unique insurance aspects of load curtailment can be exploited.

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