Is Direct Load Control a Program or a Resource? The Evolution of Demand Response and Why It Matters to Utilities Developing Load Control Capability

Stuart Schare, Summit Blue Consulting, Boulder, CO

Abstract

Several years ago, residential air conditioner (AC) cycling could unequivocally be characterized as a utility-run program where outside vendors did little more than sell the enabling technology. As the demand response field has matured, utilities have begun to view AC cycling and other forms of direct load control as system *resources* rather than just load curtailment *programs*. This is evidenced by the involvement of system operations staff in the development of load control capability and by the treatment of load control as a dispatchable resource and not just as an adjustment to demand growth projections.

In its extreme form, a load control "resource" is one that can be called by the utility as though it were nothing more than peaking generation providing megawatts and exhibiting a unique set of run-time and other operating constraints. These types of resources are now available from vendors who do all of the customer recruitment, equipment installation, and head-end software programming. Utilities acquire these resources in a manner similar to a power purchase agreement, with all the requisite performance guarantees, liquidated damages provisions, and other relevant terms.

This new paradigm of load control as a resource fits well with some utility demand response strategies. But other utilities prefer to develop and administer load control as a traditional program, foregoing the potential advantages of the load control "resource" but avoiding potential pitfalls as well. This paper discusses pros and cons of these two approaches in the context of how several utilities have begun significantly expanding their load control capability.

Introduction

Several years ago, residential air conditioner (AC) cycling could unequivocally be characterized as a utility-run program where outside vendors did little more than sell the enabling technology. As the demand response field has matured, utilities have begun to view AC cycling and other forms of direct load control as system *resources* rather than just a load curtailment *programs*. This is evidenced by the involvement of system operations staff in the development of load control capability and by the treatment of load control as a dispatchable resource and not just as an adjustment to demand growth projections.

In its extreme form, a load control "resource" is one that can be called by the utility (or independent system operator)[1] as though it were little more than peaking generation providing megawatts and exhibiting a unique set of run-time and other operating constraints. These types of resources are now available from vendors who do all of the customer recruitment, equipment installation, and head-end software programming. Utilities acquire these resources in a manner similar to a power purchase agreement, with all the requisite performance guarantees, liquidated damages provisions, and other relevant terms. Some of the more prominent characteristics of a program versus as a resource are presented in Table 1.

[1] Many of the concepts discussed in this paper apply to independent system operators as well as vertically integrated utilities. Any distinctions between the two are not addressed in this paper, and the term "utility" is used exclusively.

Table 1. Characteristics of a Program vs. a Resource

Characteristic	Program	Resource
Administration	By the utility	Acquired from vendor
Energy Savings (kWh)	Primary focus of the program	Secondary effect related to type of resource
Demand Impacts (MW)	Secondary objective	Primary objective
Resource Planning	Reduces load forecast	Increases capability to meet forecast load
Customer compliance	Assessed for each customer	Assessed at the aggregated level
Duration of DR	Indefinite duration	Finite contract term or equipment lifetime

This new paradigm of load control as a resource fits well with some utility demand response strategies. But other utilities prefer to develop and administer load control as a traditional program, foregoing the potential advantages of the load control "resource" but avoiding potential pitfalls as well. For some utilities, a middle ground may be most desirable, whereby the utility runs the "program" but 1) much of the marketing, recruitment, and equipment installation are outsourced to contractors and 2) the load control capability created through the program is overseen by system operators who dispatch it much like any other resource. Regardless of the exact course, utilities have a host of new considerations to address in planning their programs/resources and in soliciting assistance from contractors and vendors.

Program or Resource? Demand Response Defined

There are nearly as many definitions of demand response as there are papers written on the topic. The U.S. Department of Energy provides a reasonable starting point in defining demand (DR) as "Changes in electric usage by end-use customers… in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use…."[2] This approach to dividing DR into price-based concept versus an incentive-based concept is useful from a program design perspective, where utilities are choosing how to motivate customers to alter consumption. However, from an operational standpoint, a more useful definition may be one based on whether the change in consumption is *dispatchable* by the utility in discrete events or a *permanent characteristic* of customer demand.

Dispatchable demand response implies that the DR event is short-term in nature and called by the utility. Common forms of dispatchable DR include direct load control (DLC) such as residential air conditioning cycling, callable commercial/industrial load curtailments, and event-based pricing such as critical peak pricing. Non-dispatchable demand response provides permanent load reductions during specific seasons and/or times of day and includes schedule load shifting (*e.g.,* irrigation pumping), thermal energy storage, and time-based pricing such as time-of-use rates and real-time pricing.

The distinction between dispatchable and permanent load reductions becomes important when considering how utility resource planners and system operations staff plan for and utilize demand response; in other words, whether DR is a *program* like energy efficiency rebates or a dispatchable *resource* like a power plant.

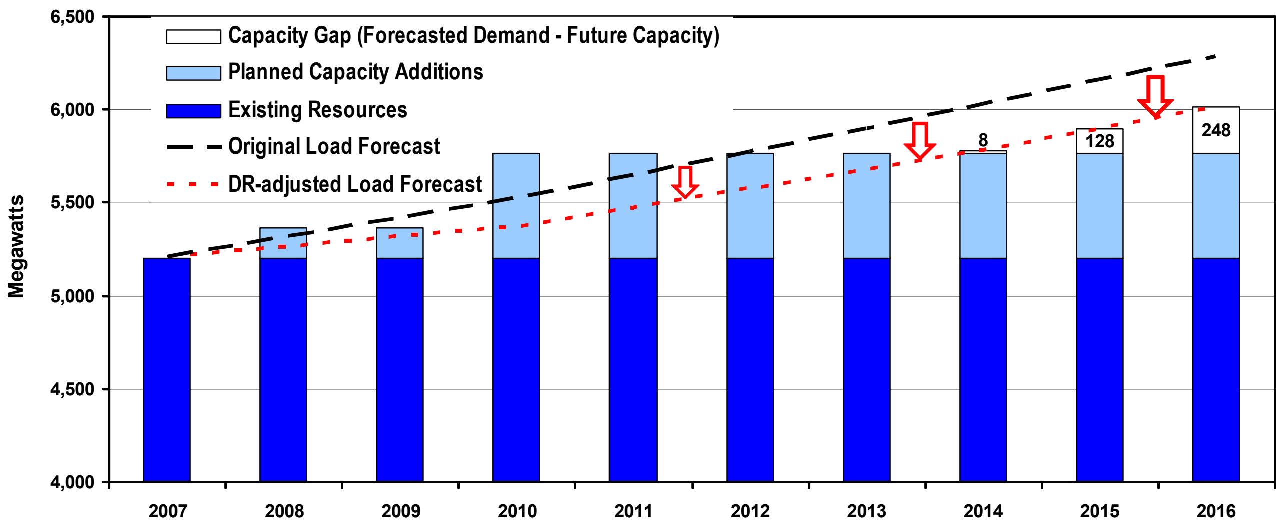
---

[2] U.S. Department of Energy. 2006. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United State Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.*

Demand Response as a "Program"

One way to view a "program"—whether energy efficiency or demand response—is as a utility function that produces a continuous, if not permanent, reduction in the system-wide load forecast. Figure 1 presents a demand and supply forecast used by one U.S. utility to account for the impacts of demand-side management (DSM) programs, including demand response.[3] Utility planners tend to concern themselves little with the details of programs because, to a planner, a program is merely an input to the load forecast against which the planner must secure generation resources. At most, planners may view a program as an explicit load forecast scenario in much the same way that high or low economic projections affect estimates of future loads. For the systems operations department (*i.e.,* generation dispatchers), non-dispatchable DR programs are even less relevant. The programs are already underlying contributors to current levels of demand, and they cannot be called upon in real time to meet specific load balancing needs.

Figure 1. Demand Response as a Reduction to a Utility Load Forecast



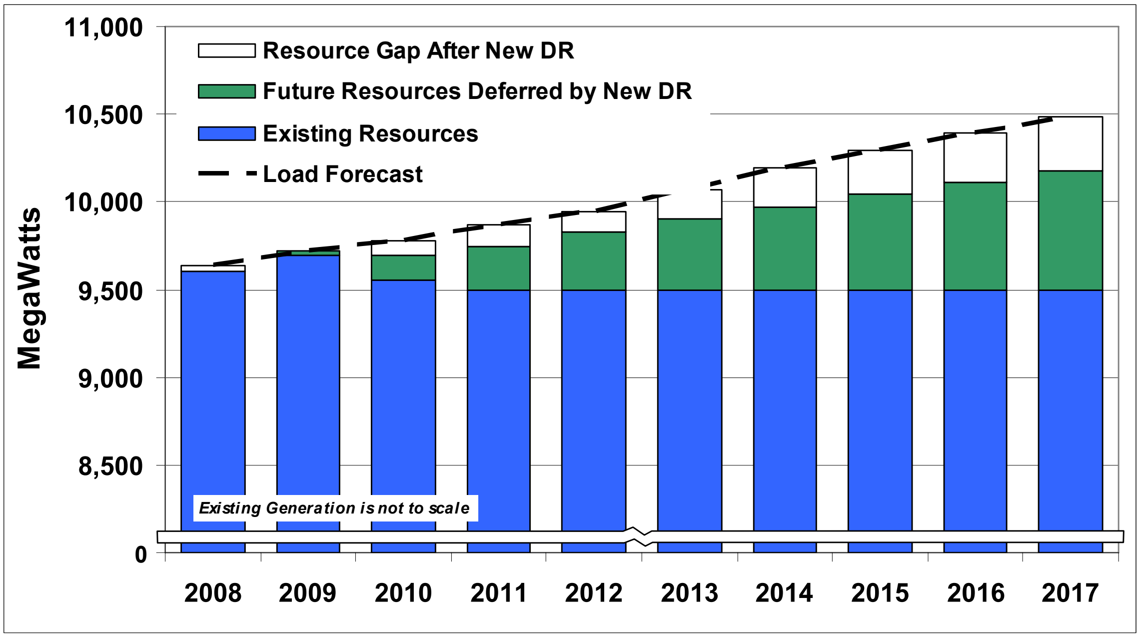
Source: Summit Blue and utility resource planning initiatives

Demand Response as a "Resource"

Unlike a demand response program that lowers system loads over time, a DR "resource" increases the available resources that can be used to meet demand. Figure 2 illustrates how one utility explicitly considers demand response to defer generation resources.

[3] This figure and other figures and anecdotes presented in this paper are based on actual resource planning work performed or currently being conducted by Arizona Public Service Co., Hawaiian Electric Co., JEA (formerly Jacksonville Electric Authority), Progress Energy Carolinas, and the Sacramento Municipal Utility District (SMUD). The scale of the data and the precise figures have been modified here for illustrative purposes and because much of the planning work has not yet been released to the public.

Figure 2. Demand Response as a Resource to Defer New Generation



Source: Summit Blue and utility resource planning initiatives

For planners, this implies that megawatts from demand response are added to those from generation resources and power purchase contracts. For operations staff, it suggests that demand response can be dispatched like a combustion turbine, including consideration of variable costs,[4] resource limitations, and distribution system benefits (Table 2). These considerations affect where demand response appears in the dispatch order. Since the megawatts available from DR often change by season and hour in rough proportion to customer loads, demand response is most likely to be utilized during peak periods.

[4] Variable costs include energy payments and the hard-to-quantify cost of inconveniencing customers, which may result in migration from the program and consequently cost the utility in terms of reduced future benefits and/or additional marketing/recruitment costs. Resource limitations of a DR resource are analogous to emission limitation or minimum ramp times for a combustion turbine. These limitations include advanced notification requirements, maximum number of events or hours per year, and maximum duration of a curtailment event. Distribution system benefits often take the form of deferral of substation upgrades by strategically deploying and calling on localized DR resources.

Table 2. Comparison of Demand Response Resources to Peaking Generation

Attribute	DR Resource	Combustion Turbine
Resource Size	Number and size of customers; scope of curtailable loads	MW unit size
Temperature Dependency	Temperature-dependent loads; Season and time of day	Temperature-dependent heat rates and capacity
Responsiveness	Advanced notification requirements	Start-up/ramp-up times
Limitations	Constraints on number and duration of events	Emissions limits
Reliability	Communications reliability & interaction of DR resources	Available fuel supply & transmission capacity
Resource Diversification	Diversity of self-generation and end-uses	Fuel diversity

Why Calling DR a "Program" or a "Resource" is More than Semantics

The way that demand response is viewed by the utility has important implications for system planning and for implementation—if implementation is even appropriate terminology for a DR resource that is not considered to be a "program."

Demand Response and Resource Planning

It is more than a matter of semantics whether utility management considers demand response to be a program that reduces demand or resource used to meet demand. This is because a utility's paradigm affects how resource planners value DR. By treating DR as a reduction to the load forecast, the value is implicitly comprised of 1) the avoided cost of the new capacity that would otherwise have been required to provide sufficient reserve margin for the projected demand, and 2) any other related benefits such as deferral of distribution system upgrades. When viewed as a resource, however, the value of DR is more akin to a generation resource. This implies that the value depends on when it can be used, for how long, and at what level of capacity (curtailment). Estimating this value requires modeling the resource within a utility's resource planning framework and, at the least, entails explicit consideration of the following:

- The months and hours that the DR resource would be dispatched and the corresponding value of avoided generation during these times
- The resource's "fit" with alternative future resource portfolios and demand growth scenarios
- Changes in the operational and economic value of the resource under alternate assumptions about natural gas prices, turbine costs, and carbon emissions regulations.

In many ways, treating DR as a program is easier. Many utilities have been doing it for years, and there are standardized and widely accepted tests for evaluating cost effectiveness.[5] However, proper

[5] The most often cited cost-effectiveness tests include the Total Resource Cost (TRC) test, Ratepayer Impact Measure (RIM), Program Administrator (or Utility Cost) test, and the Participant test. See State of California, Governor's Office of Planning and Research. 2002. *California Standard Practices Manual*: *Economic Analysis of Demand-Side Programs and Projects.*

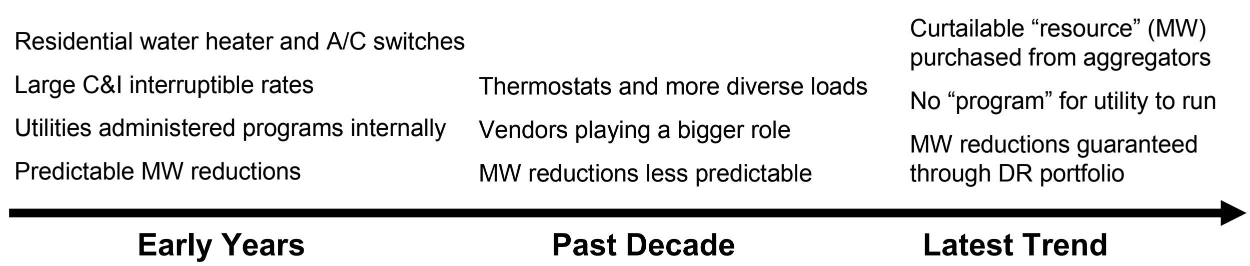
valuation of demand response may require treating it as a resource, particularly for dispatchable DR capability in which the timing of the resource availability is a critical determinant of the megawatts that it can deliver. At present there is a great deal of uncertainty surrounding proper and commonly accepted valuation techniques, but the growing consensus is that traditional methods for assessing DSM program cost-effectiveness are not sufficient for effective resource planning.[6]

Implementing Demand Response Initiatives

The way that a utility regards demand response also affects how DR initiatives are administered—and ultimately what the benefits and risks are to the utility. Historically, DR has consisted of narrowly defined programs run by the utility. These programs were often in the form of residential direct load control of water heaters or air conditioners; or, for commercial and industrial customers, interruptible rates under which participating customers could be called on to curtail load or use available self-generation to reduce demand on the system.

Figure 3 presents a rough timeline describing how vendors assumed a larger role as technological advances began to influence program designs and marketing strategies (*e.g.,* web-programmable thermostats that enable load control have largely replaced compressor-mounted load switches and become a customer incentive in themselves). In recent years, DR "aggregators" have begun to offer utilities guaranteed load curtailments in fixed megawatt amounts, essentially packaging a DR resource that takes the place of a utility-run program. Effectively, these aggregators play a similar role to that of independent power producers who offer utilities power purchase agreement and call options of various durations and contract terms.

Figure 3. Evolution of Utility Demand Response



There are good reasons why a utility might choose to administer its own DR programs. For many companies, maintaining close customer relationship is paramount, and the possibility of using a DR aggregator is scarcely considered. The utilities may also want to develop internal staff expertise and take advantage of synergies with other DSM programs that may be offered to DR program participants—synergies that may be difficult to realize if an outside aggregator is responsible for recruiting and assisting load curtailment customers. However, the DR aggregator model has important advantages that are attractive to many utilities.

---

[6] The issue of valuation of demand response resources is a significant and timely one, as evidenced by the 2007 California Public Utilities Commission (CPUC) rulemaking proceeding dedicated to the subject (CPUC R.07-01-041). In its Order Instituting Rulemaking, the Commission cited a previous Decision recognizing "the need for additional work to integrate DR programs into the resource planning process, and evaluate and measure the effect of DR programs" (D. 05-11-009). Consequently, R.07-01-041 includes among its explicit goals 1) establishing a comprehensive set of protocols for estimating the load impacts of DR programs and 2) establishing methodologies to determine their cost-effectiveness.

These advantages may include fewer utility staffing requirements, quicker ramp-up for load curtailment capability, guaranteed costs, and reduced non-performance risk for utilities. Although aggregators may charge a risk premium, their expertise in recruiting and enabling customers for load curtailment may offset the higher cost by creating a greater DR capability than could the utility on its own. A significant advantage that aggregators have over utilities is their ability, as unregulated entities, to offer customized incentives to customers such that greater participation can be achieved without raising incentives to those customers who do not require additional compensation to participate.

Furthermore, since the aggregator is responsible for individual customer contracts, the utility can view demand response from the perspective of the entire portfolio of customers, rather than on an individual customer basis. In practice, this means that resource planners can treat DR more like the resources that they are accustomed to dealing with. Depending on the utility, an aggregator contract may be easier or more difficult to pass through the regulatory process to ensure cost recovery. Self-administered DR programs may qualify more readily for existing DSM cost recovery mechanisms, but some utilities may have more success treating a DR aggregator contract as a power purchase agreement that fits under the umbrella of a previously approved resource acquisition plan.

There is no clear winner between utility-administered programs and guaranteed DR resources acquired through contract from aggregators. Some of the more prominent advantages of each are presented in Table 3. However, the greatest advantages to any given utility will depend on the utility's circumstances and management preferences.

Table 3. Advantages to Treating Demand Response as a Program vs. a Resource

Program	Resource
▪ Closer contact with customers	▪ Fewer staffing needs
▪ Develop internal expertise	▪ Quicker ramp-up time
▪ Easier synergies with other DSM programs	▪ Reliable MW / Less risk
▪ Leverage existing Account Rep relationships	▪ Lock in price
▪ Use existing DSM cost recovery mechanisms	▪ Customized incentives
	▪ Compliance at portfolio level

Conclusion

Many utilities still regard demand response as a form of DSM program to be administered by the utility and treated in much the same way as energy efficiency initiatives. However, the demand response field has evolved to the point where direct load control and other initiatives to enable load curtailment are no longer the clear responsibility of the DSM staff. Utilities are beginning to view load control as a resource that is handled differently internally and that may receive special regulatory treatment as compared to traditional DSM programs. Recent bi-lateral demand response solicitations in California are testament to this evolution.[7]

It is imperative that utilities and the consultants serving them understand the new issues being raised with regard to demand response and the options available for acquiring new load curtailment capability. There are important differences between demand response and efficiency that warrant special consideration

[7] See the California Public Utilities Commission approval of bi-lateral DR agreements for Pacific Gas & Electric Co. and Southern California Edison: CPUC Decision 07-05-029, May 3, 2007.

and, at the least, demand response needs to be integrated more closely with traditional utility resource planning and system operations functions.

The way that demand response is viewed within the utility can affect how it is valued in the planning process, which DR programs (or are they resources?) are selected, what benefits the utility realizes, and what risks it accepts. There is no single correct way to approach demand response. The appropriate paradigm depends on an individual utility's unique situation, including the resource mix, the nature of its customer relationships, the regulatory environment, and the utility's risk profile and tolerance. Demand response has matured over the past several decades and has gained in prominence and acceptance, suggesting that it will be an integral part of utility resource planning for the foreseeable future. As such, each utility needs to develop an approach toward developing these programs/resources that complements the company's business strategy and resource planning methods.