Demand Response for Utilities in Restructured Markets: Getting More from Existing Assets

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ABSTRACT

As demand response capacity increases in wholesale electricity markets, electric utilities can benefit by leveraging this infrastructure to meet distribution-level needs in a cost-effective manner. This whitepaper describes the benefits of leveraging existing demand response investments in wholesale markets for these distribution-level needs. We provide examples of two models in use today: "incremental dispatch" or "layered" and "incremental capacity." We then discuss three ways that electric utilities have procured demand response resources in restructured markets – utilities can act as their own curtailment service provider, enter into a bilateral contract with one or more curtailment service providers, or create a standard offer program.

Introduction

Demand response (DR) is the reduction in electric consumption by end-use customers during periods of peak demand, high wholesale market prices, or system emergencies. DR can defer or eliminate the need to build new supply-side infrastructure, like peaking power plants and transmission and distribution assets. Utilities and grid operators can also rely on DR as an economic resource that reduces the overall cost of power.[1]

DR resources represent a substantial and increasing percentage of peak demand in the United States. A recent study by the Federal Energy Regulatory Commission (FERC) estimates the total potential for DR will be as high as 20 percent of peak demand in 2020,[2] with approximately 41 gigawatts (GW) built-out today.[3] A significant portion of this existing DR capacity is in restructured markets where regional transmission organizations (RTOs) and independent system operators (ISOs) include DR resources in their capacity procurement processes. As of July 2009, emergency programs administered by New York ISO (NYISO), ISO New England (ISO-NE), and the PJM Interconnection (PJM) represented over 11 GW of demand response capacity[4]. As DR achieves scale in these and other restructured markets, electric utilities have the opportunity to leverage this infrastructure for distribution-level challenges that are beyond the goals of an RTO-wide program.

In many cases, it is economically prudent for electric utilities to leverage existing DR assets for additional purposes. In general, the cost of acquiring new DR resources is higher than harnessing existing DR resources for more frequent use. It's important to note that utility DR programs that are built on top of existing ISO/RTO DR programs do *not* result in "douple-dipping." The same DR

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[1] The Brattle Group, "Quantifying Demand Response Benefits in PJM," January 2007.
[2] Federal Energy Regulatory Commission, "A National Assessment of Demand Response Potential," June 2009, p. xii.
[3] Federal Energy Regulatory Commission, "Assessment of Demand Response and Advanced Metering," December 2008, p. 23.
[4] PJM 2009/2010 Load Management Program Registration Data [as of 06/24/2009]; Special Case Resources Monthly Report July 2009; ISO-NE Load Response Statistics as of 07-01-2009.

resource is indeed paid two payment streams (one from the ISO/RTO and one from the utility), but those two payment streams are warranted because the ISO/RTO and utility programs serve different purposes.

For example, in 2009, PPL Electric Utilities (PPL) filed a plan with the Pennsylvania Public Utility Commission for a 50-hour commercial and industrial (C&I) DR program with capacity payments of approximately $40 per kilowatt (kW)-year,[5] a cost significantly below the level of alternative supply- and demand-side resources. Why does PPL believe $40 per kW-year will realistically attract participation? Because PPL's proposed program will leverage existing assets already enrolled in PJM's Emergency Load Response Program (ELRP) and pay only for the ability to call its own events when PJM resources are otherwise idle.

This whitepaper outlines the options available to electric utilities as they consider leveraging existing C&I DR assets in ISO/RTO DR programs. In Section 1, we discuss the benefits of DR programs. In Section 2, we outline two overarching models for leveraging DR assets in existing ISO/RTO programs, which we term "incremental dispatch" or "layered" and "incremental capacity." In Section 3, we discuss three general procurement options for electric utilities that we have observed to date.

Section 1. Demand Response Program Objectives

DR can be used to address a variety of system needs – and system operators design DR programs differently depending on these needs. It is helpful to categorize a DR resource by the role it plays in system operations. For example, DR can improve reliability during system emergencies, mitigate high wholesale market prices, and address distribution-level problems. These program drivers are best defined as "dispatch triggers," e.g., under what circumstances, or for what reason, will a DR resource be activated? The more frequently the defined system conditions are achieved, the more frequently the resource will be dispatched, and therefore the more significant the required commitment from C&I program participants.

Reliability-Based Demand Response

The most basic DR resources are intended to address system emergencies and are typically known as "emergency" or "reliability" DR programs. Many ISO/RTO DR programs are considered emergency programs, including the Electric Reliability Council of Texas' (ERCOT) Emergency Interruptible Load Service (EILS), NYISO's Special Case Resources (SCR), and PJM's ELRP. In exchange for capacity and energy payments, the curtailment service providers (CSPs) that represent C&I customers are obligated to provide a certain amount of capacity when dispatched, at the risk of financial or other penalties for non-performance. For emergency or reliability programs, dispatch triggers are usually defined by system conditions such as actual or forecasted reserve shortages.[6]

Distribution-Level Load Relief

Electric utilities can use DR resources to alleviate distribution-level issues or problems that ISO/RTO programs are not designed to address. Such programs usually apply only to targeted areas, and

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[5] Load Curtailment Program (Large Commercial and Industrial Sector) within "PPL Electric Utilities Corporation Energy Efficiency and Conservation Plan," July 1, 2009.

[6] PJM's ELRP program is specified for activation during a 'system emergency,' which occurs directly before rolling brownouts; ERCOT's EILS represents the last line of defense before rolling blackouts.

as a result can be built on top of emergency DR programs such that all participants in the distribution-level DR program are also enrolled in the emergency program (but not vice-versa). Because distribution-

level resources can also be dispatched in response to wider system emergencies, the trigger conditions associated with a distribution-level program are met more frequently than the conditions of emergency-only programs.

Peak Load Management

Peak load reduction programs are designed to shave peak demand, creating economic benefits for the utility. Utilities have greater flexibility when it comes to dispatch triggers for peak load shaving programs, and events are often called for economic reasons. For example, an event may be triggered when system demand exceeds a specified level. While the exact trigger will determine the frequency of dispatch for participants, it is safe to assume that a utility may dispatch peak load reduction resources to meet both emergency and distribution-level challenges, and as a result, participants in a peak load reduction program should expect more frequent dispatch than in either emergency or distribution-level programs.

Section 2. Demand Response Program Constructs in Restructured Markets

Currently, many ISO/RTO regions have existing reliability-based DR programs, but these resources don't necessarily solve the distribution-level or peak demand problems that the utilities within their footprints face. Increasingly, utilities are building upon existing ISO/RTO DR resources by creating supplemental programs to solve additional objectives. These utility DR programs in restructured markets typically take one of two forms: incremental capacity programs and incremental dispatch or layered programs. Put simply, the incremental capacity construct is intended to attract new participants into the ISO/RTO program in a particular geographic area by increasing total payment levels; the incremental dispatch construct gives existing participants the opportunity to earn more money in exchange for making themselves available to participate in events more frequently.

Incremental Capacity Programs

Incremental capacity programs focus on providing added incentives to increase the amount of DR capacity enrolled in ISO/RTO programs within a utility's service territory. Examples of incremental capacity programs include those in Connecticut, Maryland, and New Jersey.

Spotlight. In the late 1990s and early 2000s, Connecticut faced substantial load growth in the southwestern part of the state, with transmission and generation infrastructure unable to keep up. In the face of FERC-approved Reliability-Must-Run (RMR) contracts that drove retail electricity prices up, Connecticut's Legislature, the Department of Public Utility Control, and ISO-NE recognized a need for new resources, and the opportunity for bilateral DR contracts to play a role. In 2003, ISO-NE issued a "Gap" RFP to provide special payments for up to 300 megawatts (MW) of new supply- and demand-side capacity in southwest Connecticut (SWCT), with the intention of providing a stop-gap until new transmission and generation infrastructure came online. As a result, additional funding was made available to attract more resources to ISO-NE's 30-minute real-time DR program in SWCT. The annual supplemental payments associated with the SWCT Gap RFP translate to $14.04/kW-month in addition to the capacity payments that were already available through the installed capacity market.[7]

Incremental Dispatch Programs

Incremental dispatch programs provide the utility with dispatch capability above and beyond those specified by an existing ISO/RTO program. Typically, customers are enrolled in both the ISO/RTO program and the utility program. Incremental dispatch programs compensate customers who choose to participate with incentives incremental to the ISO/RTO payments in exchange for an incremental commitment. Because these programs essentially build a new DR resource on top of an existing one, they are often referred to as "layered" programs. Examples of layered DR include Con Edison (New York) and Burlington Electric Department (Vermont) programs, as well as those proposed by utilities in Pennsylvania to meet the state's Act 129[8] mandates.

Spotlight. Con Edison's Distribution Load Relief Program (DLRP) is a distribution-level DR program that can be categorized as "layered." Con Edison is a part of NYISO, and NYISO administers SCR, a reliability-based DR program. However, NYISO can only dispatch SCR by zone (there are 11 across the state) and not at the distribution-level. Thus, in order to meet localized distribution challenges, Con Edison developed the DLRP program as a means of recruiting participants already enrolled in SCR to commit to more frequent events in exchange for additional incentives. Participants in DLRP earn the payments available from SCR, in addition to supplemental payments that range from $3/kW-month to $7.50/kW-month for May through October, depending on the number of events to which the participant commits.[9]

Section 3. Capacity Delivery Models for Demand Response in Restructured Markets

A utility in a restructured market can procure incremental capacity and layered DR resources in three general ways. A utility has the option to (1) act as a CSP and build and manage its own program; (2) sign a bilateral contract with a third-party CSP to provide guaranteed DR; or (3) create and administer a standard offer program open to all approved CSPs in its service territory.

Utility as CSP

In many ISO/RTO regions, utilities and CSPs alike enroll participants. Often, utility involvement is motivated by customer service considerations, and utility account managers may provide their most important customers with an opportunity to earn payments in exchange for making a DR commitment. It is important to note that in these cases, the utility is serving as a CSP as part of another entity's DR program--and not procuring the resource for its own use.

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[7] ISO New England, 2005 Annual Markets Report, p. 113, footnote 165, available at: http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/2005_annual_markets_report.pdf.

[8] Signed into law in October 2008, Act 129 mandates that (among other things) Pennsylvania Electric Distribution Companies (EDCs) reduce their system peak demand by 4.5%, on average, across their top 100 demand hours during summer 2012 (http://www.puc.state.pa.us/electric/Act_129_info.aspx)

[9] http://www.coned.com/energyefficiency/dist_load_relief.asp

In the case where a utility wants to foster more DR participants in its service territory (incremental capacity) or harness existing resources for more frequent events (incremental dispatch), the utility might choose to manage its own DR program.

Spotlight. Exelon's Commonwealth Edison (ComEd) is an electric utility in northern Illinois in the PJM footprint. ComEd administers its own DR program to defer distribution expenses. It enrolls customers that are located at or near a substation that is nearing capacity, but where demand is growing slowly.[10] Nothing precludes these resources from enrolling in PJM's ELRP and other PJM DR programs. Under this construct, ComEd shoulders a majority of the performance risk and planning risk.

While a utility may act as a CSP in an ISO/RTO DR program, it may be, but is not necessarily, positioned to manage its own DR program. If a utility needs firm DR capacity for planning purposes, it will need to make a substantial investment in DR infrastructure, training, and processes. For example, for a utility to manage a successful C&I DR program internally, it may be required to focus on C&I customers beyond those that meet the 'managed account' threshold and develop in-depth internal expertise on end-user consumption behind the meter. In addition, utility-managed programs will require either the utility or participating customers to bear the risk of non-performance. These responsibilities are sometimes considered to be outside the utility's core competency. For example, utility account management personnel are not specialists in identifying and maximizing unique energy reduction plans across a wide variety of C&I facilities, and as such, curtailment levels at facilities enrolled through a utility might be lower than those delivered by a third-party CSP. In contrast, CSPs are uniquely positioned to guarantee the delivery of DR capacity to utilities (through financial assurance and nonperformance penalties, thus reducing utility risk) while also insulating participating customers from all financial penalties.

Bilateral Contract

When a utility decides that the most prudent course is to outsource DR activities to CSPs, it can use either a bilateral contract or a standard offer. Both models are used for layered and incremental capacity programs. In most cases, a key difference between a bilateral contract and a standard offer construct is the notion of certainty. Through a bilateral contract, the CSP makes capacity commitments, typically backed by financial guarantees. Examples of both incremental capacity and layered programs delivered via bilateral contract are discussed in more detail below.

Spotlight: Incremental Capacity. In 2008, Maryland identified challenges similar to those Connecticut faced in the early 2000s, with PJM forecasts showing capacity shortfalls in the state by 2011 and 2012, particularly in central and eastern Maryland. As a result, the Maryland Public Service Commission (PSC) initiated a proceeding in August 2008 to investigate how best to address this capacity need. The proceeding resulted in the PSC requiring Maryland investor-owned utilities (IOU) to file Gap RFPs for the delivery of incremental DR capacity into the PJM emergency program. This Gap RFP resulted in the four Maryland IOUs signing individual bilateral contracts with four CSPs and one large institutional customer for a total of 400 MW of contracted capacity. In exchange for supplemental payments, the

[10] Violette, Daniel, Ernesto Orlando Lawrence Berkeley National Laboratory, "Development of a Comprehensive/Integrated DR Value Framework," March 2006, p. 21, footnote 25, available at http://drrc.lbl.gov/pubs/60130.pdf.

contracts require that CSPs guarantee their capacity commitments for the 2012-2013 delivery year and beyond, to ensure sufficient reliability resources within Maryland.

Spotlight: Incremental or Layered Dispatch. Burlington Electric Department (BED) in Vermont is an electric utility within ISO-NE. BED signed a bilateral contract with a CSP[11] for capacity delivery beginning in June 2008. Through this contract, BED reduces the demand charges and energy charges it pays to ISO-NE and mitigates distribution-level congestion by leveraging existing ISO-NE DR participants in its service territory. Customers enrolled in the BED program receive additional compensation in exchange for being able to reduce consumption more frequently than required by ISO-NE's program.

Standard Offer

In contrast to the bilateral contracts described above, resources procured through a standard offer can deliver little certainty when it comes to minimum guaranteed capacity levels or timing, with a cap on maximum allowable capacity or payment levels acting as the utility's only controllable lever. Under the typical standard offer construct, stakeholders determine compensation up front and provide the incentive to any parties interested in and qualified to participate, up to the maximum level of specified capacity. Examples of the standard offer approach for both incremental capacity and incremental dispatch are discussed below.

Spotlight: Incremental Capacity. The New Jersey Board of Public Utilities (BPU) created a standard offer program for incremental capacity. The BPU initiated a proceeding in 2007 to increase the level of DR in PJM's ELRP. Based on input from a range of stakeholders—utilities, CSPs, and ratepayers—the BPU's effort resulted in a standard offer program, where electric utilities were required to make available an additional incentive of $22.50 per MW-day (or about $8.20/kW-year) for all incremental capacity added to the PJM ELRP in the state in advance of the 2009-2010 PJM year.[12] The BPU capped the program at a maximum of 600 MW, with the total capacity allocated on a pro rata basis across the state's electric utilities.

Spotlight: Incremental Dispatch. Like the NJ example, ConEd's DLRP program is open to all qualified providers and CSPs, up to a specified cap. Unlike the NJ program, DLRP requires participants to commit to more frequent events to address distribution-level congestion.

Table 1. DR Program Matrix: Construct and Delivery Model

	Utility as a CSP	Standard Offer	Bilateral Contract
Incremental Capacity	N/A	New Jersey BPU Program	Maryland Gap RFP (Allegheny Power, Baltimore Gas & Electric, Delmarva Power & Light,

[11] EnerNOC Press Release, "EnerNOC Signs Contract with Burlington Electric Department," 1 July 2008, available at http://www.enernoc.com/press/releases/pr_080701.htm.
[12] Assets enrolled in previous years were not qualified; only new resources were eligible for funding.

			PEPCO) Connecticut GAP RFP
Incremental Dispatch	Commonwealth Edison’s Distribution-level DR	Consolidated Edison’s Distributed Load Relief Program (DLRP)	Burlington Electric Department

Conclusion

The investment has already been made—a large and growing DR resource base exists today throughout ISO/RTO regions. In these areas, electric utilities are increasingly taking advantage of this existing infrastructure to meet local needs. Importantly, by leveraging existing ISO/RTO infrastructure, these programs can be built for considerably less cost than would be required if designing a DR program from scratch. Given the range of options facing electric utilities, from incremental capacity to incremental dispatch and bilateral contracts to standard offer programs, understanding program goals will be critical to the development of these cost-effective demand response programs. Regardless of program goals or construct, all stakeholders will benefit as existing demand-side investments are leveraged to provide further benefit to the electric grid.