Incorporating Demand Response Into Community Solar Programs

A Module of the CSVP High-Value Community Solar Program Design Guide

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Community Solar Value Project

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Summary

Incorporating Demand Response Into Community Solar Programs is one volume of the *Community Solar Value Project (CSVP) High-Value Community Solar Program Design Guide*. Its primary objective is to assist utility solar program managers in including appropriate demand response (DR) measures for co-marketing to enhance the value of distributed solar—and particularly of utility-driven community solar. The Guide also may be useful to DR program managers, utility planners, and others who wish to understand how different applications of traditional DR are evolving to address new high-value opportunities in renewable-energy integration.

This Guide takes a practical approach, assuming an introductory understanding of issues related to rising distributed solar market penetration. It focuses on how adaptations of traditional DR can help to address these issues. The Guide reviews existing DR options found in utility programs throughout North America. Four categories are discussed, including curtailable load programs, automated DR (Auto-DR), direct load control, and pricing strategies. Specific examples are drawn primarily from CSVP's work with a Northern California utility, but options, including thermal storage, that are suitable in other regions are briefly discussed. The Guide presents a scoring method to quantify and classify the attributes of particular options to solve a variety of integration-related issues. Case studies from relevant utility programs are included. Information on costs for DR options is provided in an appendix.

This volume is the first to be published by CSVP in a set covering many aspects of high-value community solar program design, from strategic solar design and valuation, to business model selection and procurement, to additional DR and storage solar-plus options, to program micro-target marketing and pricing.

This work was funded in part by the Solar Market Pathways Program, powered by SunShot, in the Office of Energy Efficiency and Renewable Energy (EERE), U.S. Department of Energy, an agency of the United States Government, under Award Number DE-EE0006905.

Key words: distributed solar, community solar, demand response, solar-plus, program design.

About the Community Solar Value Project

The Community Solar Value Project (http://www.communitysolarvalueproject.com) aims to increase the scale, reach, and value of utility-based community solar programs by using strategic solar technologies, siting, and design, and by integrating suitable companion measures, such as demand-response (DR) and storage into broad program designs. Such measures can address grid impacts of rising solar penetration and increase solar net value. Market development for this model also is being addressed. The project is led by Extensible Energy, LLC, with support from Cliburn and Associates, Olivine, Inc., and Navigant Consulting. Utility participants include the Sacramento (California) Municipal Utility District (SMUD), Public Service of New Mexico, and other utilities nationwide. The project is powered by SunShot, under the Solar Market Pathways program of the U.S. Department of Energy.

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Disclaimer

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Introduction

The Community Solar Value Project (CSVP) aims to increase the scale, reach, and value of utility-based community solar programs, primarily in four ways: strategic solar siting and design, best-practice procurement, well-targeted offers and pricing, and suitable companion measures, such as demand-response (DR) and storage, integrated into program designs. The inclusion of DR and storage (also known as solar-plus or “triple play” strategies) in community solar programs is possibly the most innovative—and most important—aspect of the CSVP agenda. Community solar provides a unique market-based laboratory for utilities that need to know what distributed energy resource (DER) business models mean to them and their customers. Community solar provides the opportunity to attract customers who want to be part of a clean energy future. As a community solar program manager, you can engage in a dialog with customers about all the elements of DER, even as you demonstrate internally how DR and storage can ease the impacts of rising solar market penetration.

The timing for starting an enhanced community solar program could not be better. Most utilities do not face a need for full-scale renewables integration strategies today. Yet utility industry leaders concur that the future will include more renewables and DER, and that future is at hand. According to a recent report from the Smart Electric Power Alliance (SEPA), six states are actively engaged with integrated DER planning and market testing (Coleman, February 2016). And those six states include some of the largest in the nation. Their commitment to renewables integration has inescapable consequences for the industry.

The CSVP Utility Forum, a group of program managers from eight utilities that reviewed this document before publication, discussed the rise of DR, in particular, as a renewables-integration strategy that is emerging in integrated resource plans (IRPs) for significant build-out within five to eight years. Given that timeframe, the demonstration of DR as a companion measure for community solar is right on time.

There is a growing body of literature on the value of DR and storage for renewables integration. CSVP provides an updated sampling of those resources on its website. This DR module of the **CSVP High-Value Community Solar Program Design Guide** takes a more practical tack. We assume that the reader has some foundational understanding of renewables integration and of community solar. Thus, this Guide delves into the questions that utility solar program staff or their counterparts in DR and resource planning would ask during early-stage program design.

The overall integrated community solar program-design process is illustrated in Figure 1. It is discussed in each volume of the CSVP Guide. In relation to this volume, the selection of DR companion measures for community solar would take place in the highlighted box in Figure 1, referred to as “utility-driven elements.” At the same time, we note that the DR screening and selection process for community solar program design is scalable. It could be applied to community solar programs of any size or it could be applied utility-wide, as utilities get their virtual hands around what flexible grid operations mean on the local as well as regional level.

In Section 1, this document introduces the variability issues associated with solar photovoltaics (PV). In Sections 2 and 3 summarize how DR can help to address these issues. In Section 4, the discussion moves to a description of existing DR options, found in utility programs throughout

North America. Next, Section 5 discusses the scoring approach used to quantify and classify the attributes of these particular options to solve a variety of integration-related issues. We explain how DR for renewables integration differs from typical DR options and how many existing options may be adapted to capture integration-value opportunities.

Section 6 offers case studies of innovative integration strategies. Finally, this document concludes with a summary of the key points.

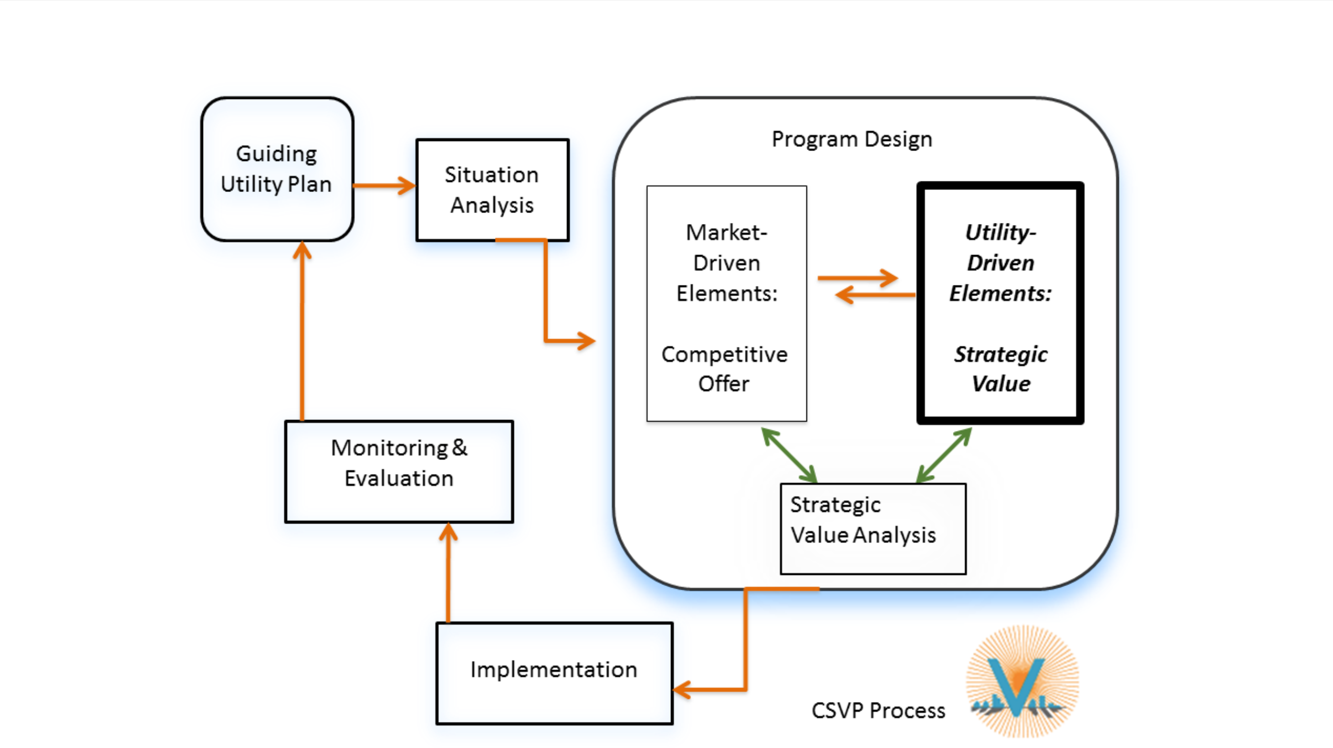

Figure 1: CSVP Process Map - The above figure highlights the location of the DR assessment and selection process within the overall process for community solar program design.

1 The Challenge of Solar Variability

The output of any photovoltaic (PV) system is inherently variable; power output varies by season, time of day, and over much shorter intervals due to intermittent clouds and shading. In each of these time domains, output variability can introduce grid planning, operation and stability issues that may require mitigation.

Very short-run variability is a relatively local issue, as geographic diversity across multiple solar sites greatly reduces the cumulative swings in production and their impacts on the utility system (Perez, 2009). However, diversity alone cannot compensate for all short-run effects. The type of variability that has garnered the most attention is the intra-day variation in solar output. Specifically, the fact that solar output naturally drops as load rises in the late afternoon and early evening has led utility planners to worry about the “duck curve,” explained further below. Even with best-practice strategic solar design, which may include southwest-facing installations, single-axis tracking, and advanced inverters, the issue of a rapid late-day ramp in customer demand affects utilities that have significant amounts of solar on the grid.

As more distributed energy resources are integrated into the grid, variability can be offset by a range of technologies and programs, including battery storage on either side of the customer meter, thermal storage, and DR. Combinations of these options are often most effective to mitigate variability and raise the utility value of distributed solar fleets.

2 Demand Response Applications

The use of DR to aid in renewables integration is still a relatively novel concept. Traditionally, DR programs have been designed to help distribution utilities meet peak load requirements, alleviate local distribution system constraints, or to mitigate grid emergencies. Each of these applications allow for a relatively generous response time, and each would be dispatched infrequently. Traditional DR relies upon notification by the system operator, so that customers or aggregators will reduce the load, providing relief for a variety of system problems. This has been referred to by some as "DR 1.0" (Martini, n.d.). These programs operate across varying time horizons, using different technologies and incentive structures (Federal Energy Regulatory Commission, 2010).

The incentive structure for these programs includes capacity payments for customers available to reduce load a specified number of times within a given time horizon. Often, such capacity payments stem from resource- or generation-adequacy credits that the operator may claim for DR programs. The signal to reduce load provided by the distribution company to the customer is known as an event or dispatch. Some programs provide additional energy payments based on how much load was actually reduced. Effectively, these programs are seen as replacements for generation since they can alleviate issues within the transmission and distribution system and/or avoid the need for additional peaking resources (Nolan, 2014).

2.1 Demand Response in Central Markets

Central markets (ISOs and RTOs) have run peak-shaving DR programs for more than a decade; at PJM alone, the portfolio of DR programs provides a resource of more than 10,000 MW (McAnany, 2016). Central-market programs can deliver peak load reductions in response to system emergencies, high wholesale prices, or both. One of the key benefits of DR is the potential for wholesale-market price reduction. Since electricity supply is fixed, the supply curve gets quite steep as it reaches system peak capacity.

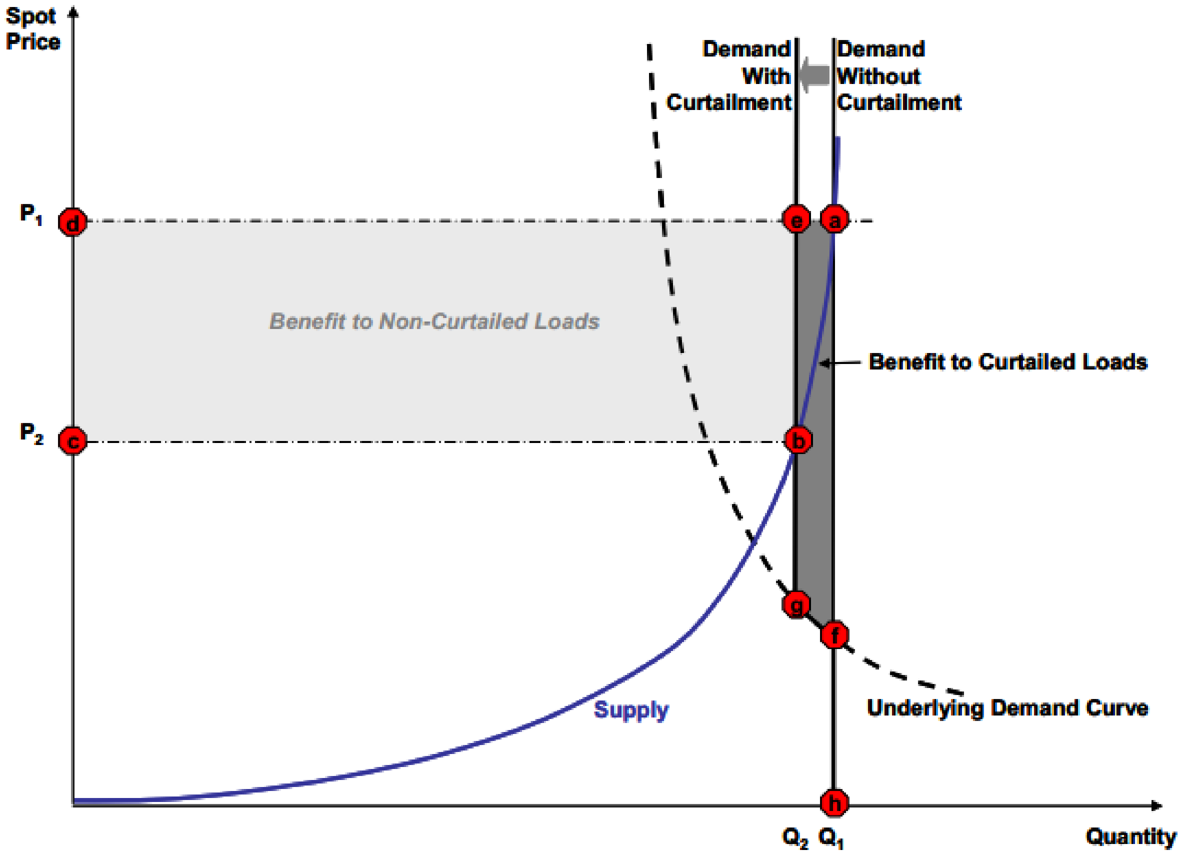

Figure 2: The above figure highlights the location of the potential surplus from DR participation in wholesale markets (Brattle Group, 2007).

In Figure 2, P represents the spot price of electricity in an organized market, while Q represents the quantity of electricity. In a scarcity or peak situation, the price and quantity rise to P_1 and Q_1, respectively. DR directly reduces load consumed and the quantity of electricity demanded from Q_1 to Q_2. As a result, the price decreases from P_1 to P_2. By virtue of the fact that the supply curve is so steep at it nears peak capacity, the difference between P_1 and P_2 is significant.

The obvious impact of movement along the supply curve is that everyone–the utility and all its customers—will benefit from the lower spot price. An important side effect of this dynamic is that the resulting price decrease from DR results in a net transfer of the surplus benefit from generators (or producers) to consumers (or "non-curtailed loads"). That is, producers who were selling peak power at much higher P1 * Q1 must now settle for P2 * Q2. If the difference between P1 and P2 is as significant in practice as the results of economic theory would indicate, the resulting transfer could be large.

There are many additional considerations that would help indicate whether this transfer or savings actually would occur in a real-world market scenario, and these are being documented. However, the above economic model has been compelling enough to policy makers, so that DR has become widely accepted. For most of the county, the potential benefits have been substantial enough to warrant further proof through implementation.

2.2 Renewables Integration at the Local Level

DR holds great potential for use in renewables integration. On the most basic level, it may be used to modify system loads at peak or during the steep afternoon ramp, to conform better to solar resource availability. However, to access their full potential, DR options must respond faster and more frequently than they have in the past. This evolution is often designated as DR 2.0. These advanced strategies also may work bi-directionally, providing not only load reductions but also load increases as needed.

The benefits of a DR 2.0 approach may be realized at the ISO level, but they also may be realized locally. Distribution utilities that integrate DR into community solar programs are driven to maximize many DER benefits that are not visible at the regional level. These range from less exposure to market risks, to lower distribution system costs, to emerging benefits, such as greater local resilience and clean electrification. Some communities believe managing solar plus DR strategies at the local level helps them to strike a better balance between self-reliance and interdependence. This document uses the terms DR 2.0 and simply DR, but intends consideration of DR 2.0 attributes whenever DR is used for renewables integration.

3 Demand Response Options

In order to develop a cohesive framework for evaluating DR 2.0 options, we must first classify them. Fortunately, a broad spectrum of literature has attempted to do just that (Rocky Mountain Institute, 2006). The following discussion provides an overview of five distinct classes of DR options: 1) Curtailable Load, 2) Automated Demand-Response, 3) Direct Load Control or Load Management, 4) Pricing Strategies, and 5) Residential Load Curtailment.

This is not intended to be a comprehensive review of existing DR options. Rather, this Guide takes a broad first cut at some of the most salient features common to each of the five categories selected, with emphasis on applications. That is because specific applications, in specific contexts, determine the right path for utility program implementation.

3.1 Curtailable Load

Curtailable load DR programs encourage customers to reduce load at specified times of the day by offering capacity payments and often, energy payments. Many of these utility-administered demand response programs are Day-Ahead (DA) and or Day-Of (DO) programs, in which the utility must notify each customer, either on the day before or on the same day as the required load reduction. These programs are typically designed for medium/large commercial and industrial (C&I) customers that have the potential to respond to dispatch signals before an event. Customers are paid monthly incentives based on the amount of capacity they commit to provide. These commitments—often called nominations—allow a customer or aggregator some flexibility to tailor responses, based on fluctuating operational characteristics.

The Pacific Gas & Electric (PG&E) Capacity Bidding Program (CBP) is an example of a curtailable load program. Several enrollment options provide curtailment events of one to six hours, which can be called between 11 a.m. and 7 p.m. For participants in the Day-Ahead option, notification is provided by 3 p.m. the day before; participants in the Day-Of option are notified on the morning of the same day as the event. As such, 20-26 hours advance notice would be required to dispatch the Day-Ahead program, while 3-5 hour advance notice is necessary to dispatch the Day-Of program. Capacity payments range substantially from $2.17/kW-month to $24.81/kW-month depending on the option selected by the customer, as well as by the time of year. Higher incentives are paid during the high demand summer months. Additionally, there are energy payments based on how much reduction was achieved by the participant during an event window. Energy measurement is calculated against a baseline.

3.2 Automated Demand Response

Automated demand response (Auto-DR) creates a direct loop between the operator and technologies that can reduce load on certain end-uses through automated notification and control. As the response time for Auto DR is much shorter than in the curtailable load programs mentioned above, there is well-documented potential to use these technologies to support flexibility on a variety of time scales (Watson, Kiliccote, Piette, & Corfee, 2012). In fact, some authors maintain that fast-response, demand-side resources that can provide ancillary services are an absolute necessity in meeting flexibility needs under a 33 percent renewable portfolio standard in California (Masiello, et al., 2010).

Given that Auto-DR represents a variety of automating technologies, the costs per customer are greater than those associated with traditional (often manual) demand response. As such, Auto-DR is often a more attractive option for larger C&I customers that can invest in sophisticated control technologies. Even with this expense, Auto-DR may make control of customer end-use equipment more cost effective than battery storage in certain applications.

3.3 Direct Load Control or Load Management

Direct load control (DLC), or load management programs install simple control technology on space-conditioning units or electric water heating systems that the program or system operator controls directly. This Guide characterizes four such options according to end-use (A/C switch control, smart thermostats, pool pumps, water heaters). In these examples, operators directly control the device, taking the customer out of the loop. One-way programs of this nature have been used by hundreds of utilities for the past 30 years, with millions of end use devices controlled. Approaches incorporating more sophisticated two-way communication (particularly in conjunction with communicating thermostats) have been tested in pilot programs by many utilities in the last few years. Much work has demonstrated that such automation increases load reduction potential significantly (Nolan, 2014). Moreover, many DLC programs such as the SmartAC in California allow for as many as 100 hours of operations per season. If configured appropriately, DLC programs among residential customers have tremendous potential to aid in renewable integration (Cappers, Mills, Goldman, Wiser, & Eto, 2011).

3.4 Pricing Strategies: Critical Peak Pricing and Time-of-Use Rates (TOU)

Price-responsive DR can trigger participants to modify load voluntarily, in response to higher-than-normal prices. The most straightforward example is a time-of-use (TOU) rate. TOU rates include tiered pricing schemes, which become more expensive during peak times or whenever the marginal cost of electricity generation or procurement to the utility is high. These rates are often have seasonal adjustments to match shifts in utility load.

Load reductions from these rates are voluntary; the prime incentive to the customer is saving on the monthly utility bill, not a direct payment. Compared with the programs described above, the yield is lower, on average (Faruqui & George, July 2002). Yet TOU rates can be helpful in addressing longer-term net load curve modifications; indeed, they can help match intra-day solar variability by encouraging users to shift typical daily electricity usage into off-peak periods. However, additional measures are often necessary to deal with specific days or hours with unforecasted changes in solar generation.

Critical peak pricing (CPP) adds an adjustable component to a flat or tiered rate structure. When triggered, the CPP event entails much higher than normal prices for a period on a specific day. CPP events can be triggered at the discretion of the utility, due to distribution needs or abnormally high wholesale market prices. Events are often limited to a certain number of times per season. The timing for notification of an event is individually driven by the utility, but tends to fall into the same Day-Ahead or Day-Of timeline as curtailable load programs (Rocky Mountain Institute, 2006).

3.5 Residential Load Curtailment Programs

Load curtailment programs that rely on customer behavior are particularly challenging to catalog because they are often designed and operated by third parties. However, the general feature is the reduction of any end-use loads by the customer upon receipt of a notification signal. Participants have flexibility around which appliances or end-uses they reduce. There is often an administrative split between the utility and third-party aggregator in this scenario. Since there is a less structured reduction strategy in a program like this, that the load reductions are more variable and less dependable, though this is ultimately driven by the particular end-use, the particular third party, and the program design (Federal Energy Regulatory Commission, 2009).

4 Scoring Analysis

4.1 Purpose

In order to help utility program planners quickly assess DR options and select those best suited for inclusion in a community solar program, this Guide offers a scoring system based on analysis of the various DR options. Using this methodology, a utility analyst would be able to pick out and identify a set of key measures to evaluate for a proposed program. To achieve this, the next section presents two tables of information about candidate DR options.

In Table 4-1, we build upon the previous descriptions of DR measures, defining each according to a set of key program attributes, such as enablement costs and average load impact per unit. These criteria, distilled from a broad research effort, contain important information for a utility program designer who wishes to quickly assess which DR options match their particular target audience.

Table 4-2 takes this analysis one step further, asking, "Considering the program criteria we have defined, what specific types of solar variability could a given DR option address?" Each program-type is then rated, according to its ability to address these characteristics.

4.2 Introduction to Table 4-1: *DR Opportunity Assessment*

Table 4-1 reviews a catalog of 11 DR options. As mentioned previously, some options require detailed program design, while others, such as Auto-DR, may be implemented with minimal program support. All of the options, although based on information garnered through looking at representative examples, are genericized to a certain extent. Each row provides a "median" value for each criterion presented and thus represents multiple similar programs of each type. In some cases, examples of specific programs are provided. The end goal of Table 4-1 is for a utility program planner to be able to assert a planning outcome, such as, "For a typical direct load control program employing A/C switch control, we can plan to spend $47/kW."

4.3 Definition of Terms in Table 4-1 and Appendix

Yearly Cost Planning Estimate ($/kW)	This figure is an estimate of the total yearly cost associated with running a program of this nature. It is composed of enablement and incentive costs: 1. Enablement costs are associated with purchasing and installing the end-use devices and control systems, which will be used for load management or reduction. Note that for options without any automated, pre-specified technology there would be no direct enablement costs. 2. Incentive costs are either one-time or ongoing payments (capacity/energy) made to the customer during the program cycle. *The calculus used to generate these figures and references for the input amounts are reviewed in detail in the Appendix.*
Average Load Impact per Unit	This metric provides a benchmark regarding the average load reduction per participant.
Seasonal Availability/Impact	This category is driven by the program window of availability, as well as the end-use in question. Most programs are operated during a single season (winter or summer) or year-round.
Events Feasible per Season	This column provides an estimate of how many times a dispatch may be called for a generic program of this type.

Signal-to-response Time	This is the time between sending a signal to begin a change in load and the onset of that load change by the customer or equipment.
Duration of Impact	This is an average measurement of the length of the load reduction period for the program
Target Customer Class	This column characterizes the general class targeted by such a program classification: Commercial/Industrial (C&I), or Residential (Res)

Table 4-1: DR Opportunity Assessment (Options 1-7)

DR Option		*Yearly Cost Planning Estimate ($/kW)*	*Avg. Load Impact per Unit*	*Seasonal Availability/ Impact*	*Events Feasible per season*	*Signal-to-response time*	*Duration of Impact*	*Target Customer Class*
1	Curtailable Load (Day-ahead)	$198	Depends on end-use	Most effective during peak season	Frequently limited to less than 50	20-26 Hours	2-6 Hours	C&I
2	Curtailable Load (Day-of)	$228	Depends on end-use	Most effective during peak season	Frequently limited to less than 50	3-5 Hours	2-6 Hours	C&I
3	Auto-DR	$265	Depends on end-use	14% of peak load winter; 16% for summer	Depends on program	5-15 Min	5 min–1 Hour	C&I
4	Direct Load Control (A/C switch control)	$47	0.37 kW -2.06 kW	Warm months only	~100	2-10 min	2-4 Hours	Res
5	Load Management (Smart Thermostat)	$85	.67 – 0.86 kW	0 .61-1.079 kW-	~30	2-10 min	1-4 Hours	Res
6	Direct Load Control (Pool pumps)	$38	N/A	Year-round	~Often	2-10 min	30 min–4 Hours	Res
7	Direct Load Control (Electric water heaters)	$38	0.65-0.69 kW	Year-round	~100	2-10 min	30 min–4 Hours	Res

Table 4-1 (continued): DR Opportunity Assessment
(Options 8-11)

DR Option		*Yearly Cost Planning Estimate ($/kW)*	*Avg. Load Impact per Unit*	*Seasonal Availability*	*Events Feasible per season*	*Response time to signal*	*Duration of Impact*	*Target Customer Class*
8	Critical Peak Pricing	Costs typically borne by utility	5-17% load reduction (manual); 20-60% (automated)	Year-round	~100	2-10 min (RMI)	30 min–4 Hours (RMI)	Any
9	TOU Rates	Costs typically borne by utility	4–17% load reduction	Year-round	N/A	N/A	N/A	Res
10	TOU w/ CPP	Costs typically borne by utility	N/A	Year-round	~8-30	~20-26 Hours	Often 4 Hours	C&I
11	Residential Load Curtailment (Behavioral)	Costs typically borne by utility	N/A	Year-round	Depends on third-party design			Res

Sources: Killiccote, Piette, Wikler, & Chiu, 2008; Rocky Mountain Institute, 2006; Haeri & Gage, 2006; Fenrick, Getachew, Ivanov, & William, 2014; Portland General Electric Company, 2004; Lopes & Agnew, 2010.

4.4 Introduction to Table 4-2: *Ability of DR Options to Address Integration*

Table 4-2 describes key attributes of a variety of DR options. To select options directly applicable to a particular community solar program, an additional step is required. Table 4-2 takes the characteristics from Table 4-1 as a starting point to ask, "How well could a particular option address a specific variability concern?" Assertions of this nature depend crucially on the specifics of the program, as well as the particular nuances of the variability concern. With that in mind, the scoring methodology is simple, assigning a value from zero to four (presented as ○ ◔ ◑ ◕ ●) to characterize the ability of each option to meet a particular variability concern. This approach can be extended by applying weights to each variability concern (or column) in Table 4-2, according to each concern's importance at any utility.

The specific terms of these variability criteria are defined below.

4.5 Definition of Terms in Table 4-2

"Duck Curve"	This measure determines whether the DR option can help mitigate steep evening hour ramps from 4-8pm in Spring and Fall when mid-day net loads are low. This dynamic is further explained in the context of Curtailable Load Programs.
Intra Hour Fast Ramps	This category examines whether the DR option can assist with un-forecasted steep ramps that occur anytime throughout the day because of cloud cover within a 30-minute to two-hour time frame.
X>2 Hour Forecast Error	If the DR measure generally has the ability to be dispatchable within 2 hours to meet forecast error, this category will be labeled High.
X>24 Forecast Error	If the DR measure generally has the ability to be dispatchable within 24 hours to meet forecast error, this category will be labeled High.
Peak Load Reduction	For this column, we assess the potential of the DR option to contribute to system peak load reduction, especially as net system load shape changes due to the mismatch between gross system load shape and solar output.

Table 4-2: Ability of DR Options to Address Integration

	Integration Issue	*"Duck Curve" Issues*	*Intra Hour Fast Ramps*	*X>2-Hour Forecast Error*	*X>24-Hour Forecast Error*	*Peak Load Reduction*
1	Curtailable Load (Day-ahead)	◑*	○	○	◑	●
2	Curtailable Load (Day-of)	◑*	○	◑	◑	●
3	Auto-DR	●	●	●	●	◕
4	Direct Load Control (A/C switch control)	○	◕	◕	◕	●
5	Load Management (Smart Thermostat)	○	◕	◕	◕	●
6	Direct Load Control (Pool pumps)	◕	◑	◑	◑	◑
7	Direct Load Control (Electric water heaters)	●	●	◑	●	◑
8	Critical Peak Pricing	◑	○	◑	◑	◑
9	TOU Rates	◑	○	○	○	◕
10	TOU w/ CPP	◑	◔	◑	◕	◑
11	Residential Load Curtailment (Behavioral)	◔	◔	◑	◑	◑

● = High ◕ = Med. / High ◑ = Medium ◔ = Low ○ = None

*Assuming ability to operate during shoulder seasons

5 Discussion of Scoring Analysis

Note that for each of the categories of DR Programs discussed below, program cost estimates will be an additional consideration. This Guide does not focus on costs, as they differ greatly based on program size, technical requirements, and other factors. A brief review of DR program cost estimates is included in the Appendix of this Guide.

5.1 Curtailable Load Programs

Before considering any DR program, it is important to recognize the role of forecasting. Regional and system load forecasts are now routine and generally are accurate for traditional-DR time domains (seasonal or day-ahead and sometime finer). The need to forecast variable generation resources when using DR for renewables integration presents a different, but generally achievable challenge. In particular, solar generation forecasting has been shown to reduce integration costs significantly (Perez, 2013), thanks to readily available advanced solar forecasting tools. This is especially true for geographically diverse distributed solar fleets, which naturally mitigate "passing cloud" variability. The CSVP recommends taking a fleet perspective and balancing against the system load (or at minimum, a circuit load), rather than against a specific project site, to engage diversity benefits on both the generation side and the load side. Yet, some forecasting errors occur, especially in shorter time domains, and these can be costly. For example, if actual solar resources are greater than predicted, DR could be dispatched unnecessarily to deal with renewable integration. In general, this dynamic renders Day-Ahead and Day-Of DR programs to be somewhat blunt instruments for renewables integration on time scales finer than the hourly level.

Nevertheless, curtailable load programs have quite a bit of potential to address a variety of integration issues. Below, we summarize impacts of operating curtailable load programs on two specific integration concerns: 1) Summertime peak load reduction, and 2) duck curve issues.

Consider the following stylized example of the impact of DR on net load during a hot summer. Solar production comes online around 10 am. In effect, the net load is thus lower than system demand. However, as solar production begins to wane due to decreased sunlight (Hours 19, 20 in the graph below), the net load, in effect bounces back up and hovers closer to demand. Demand, during the hot season will not diminish until far later in the evening when temperature has cooled significantly. DR programs of this nature, can play a vital role at coming in right as solar production begins to drop off, thereby driving down net load. This dynamic is illustrated in the figure below.

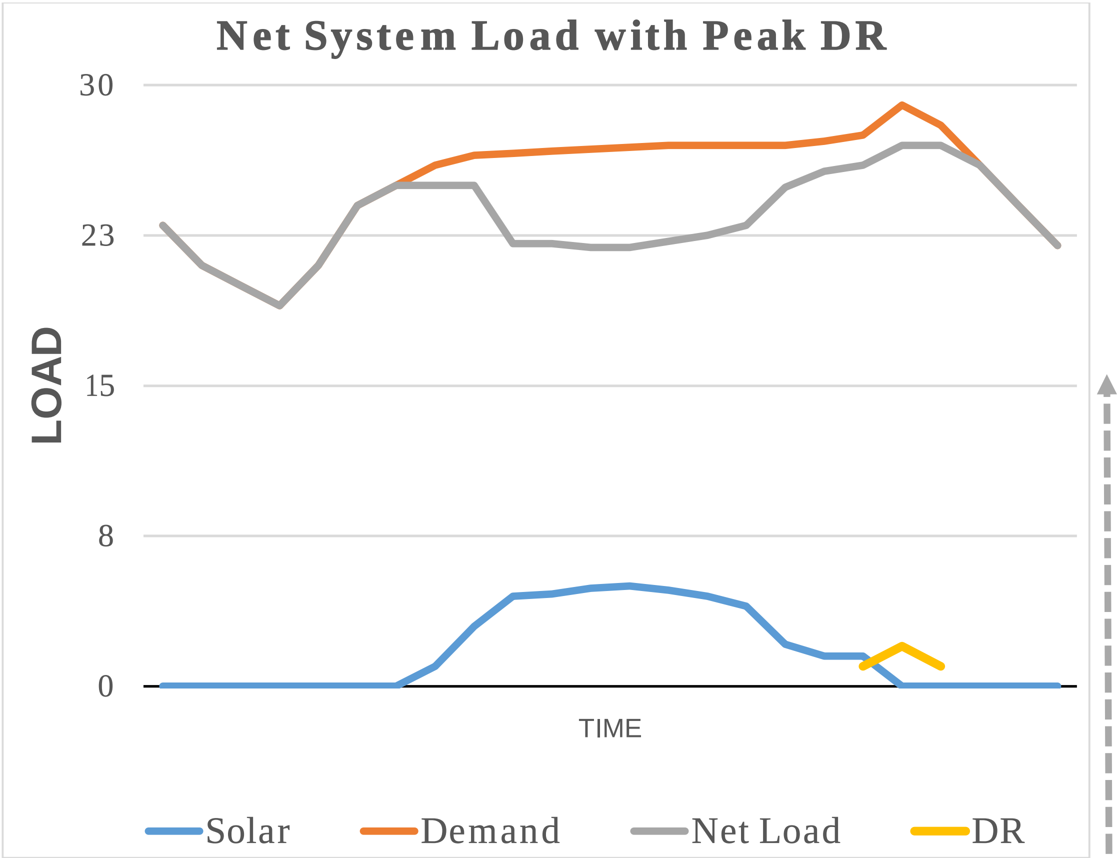

Figure 3: Example Net System Load w. Curtailable Load DR: The above load curves demonstrates the effect of utilizing DR on demand & net system load during hot season.

In addition, certain programs of this design can play a role in addressing a related but distinct issue: the duck curve. During shoulder months (spring and fall), solar generation peaks earlier than system loads and falls off when system loads peak, causing a steep increase in net demand. Curtailable programs can be operated during this window to help with overall system needs of this nature, provided they are available on a year-round basis. The load curves shown below demonstrate the general effect of this on net system load (California Independent System Operator, 2013).

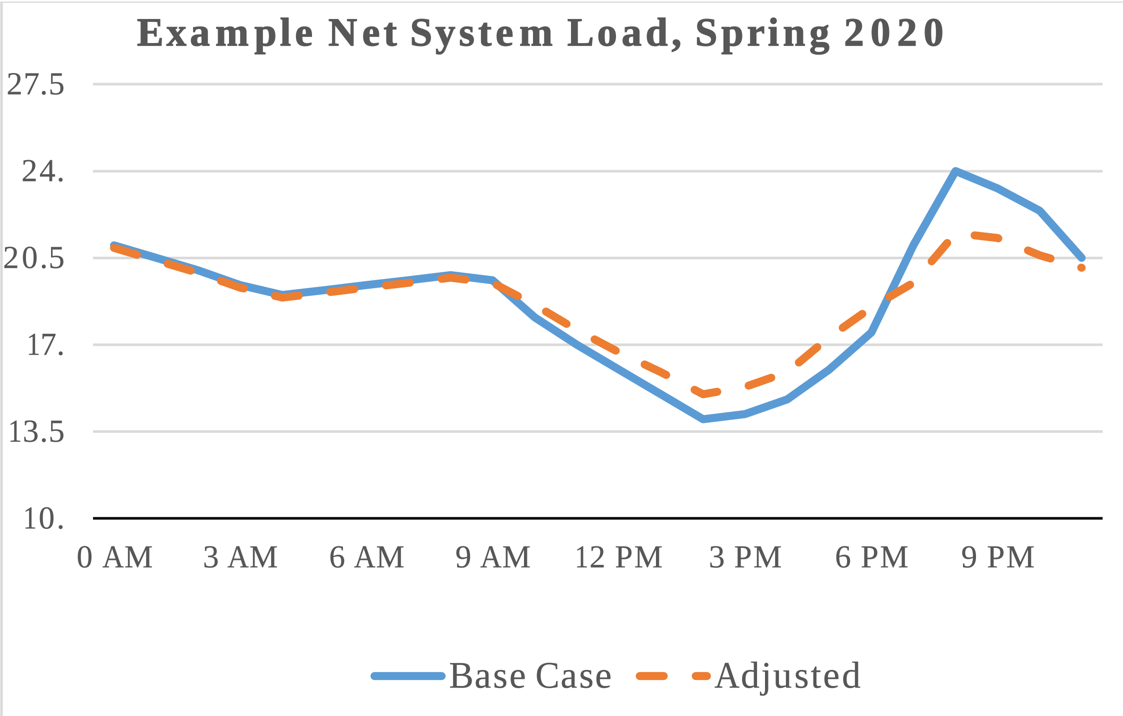

Figure 4: Example Net System Load 2020.

Depending on when program event windows are set up, these types of programs could help mitigate some of the variability driving the evening ramp, leading from the base case (blue), to an adjusted case (orange). For this to occur, programs would be triggered during evening hours (e.g., 4pm-8pm). Aside from the fact that some programs might not be dispatchable over this time period, an additional constraint is the number of times each program can be dispatched per season. Since distribution utilities and customers have come to expect using these programs on an infrequent basis, they may need significant changes to address the duck curve issue. More suitable companion measures might involve a permanent load-shift, through a time-of-use rate, or technology enabled measures, such as battery or thermal storage.

5.2 Automated Demand Response (Auto-DR)

With short notification timelines and the ability to accommodate frequent dispatch, it is clear that the technical potential of Auto-DR to address all variability concerns listed in Table 4-2 is high. The following diagram indicates the interplay between automation, notification timelines and frequency of dispatch for the main categories of DR options. Not surprisingly, Auto-DR leads the group.

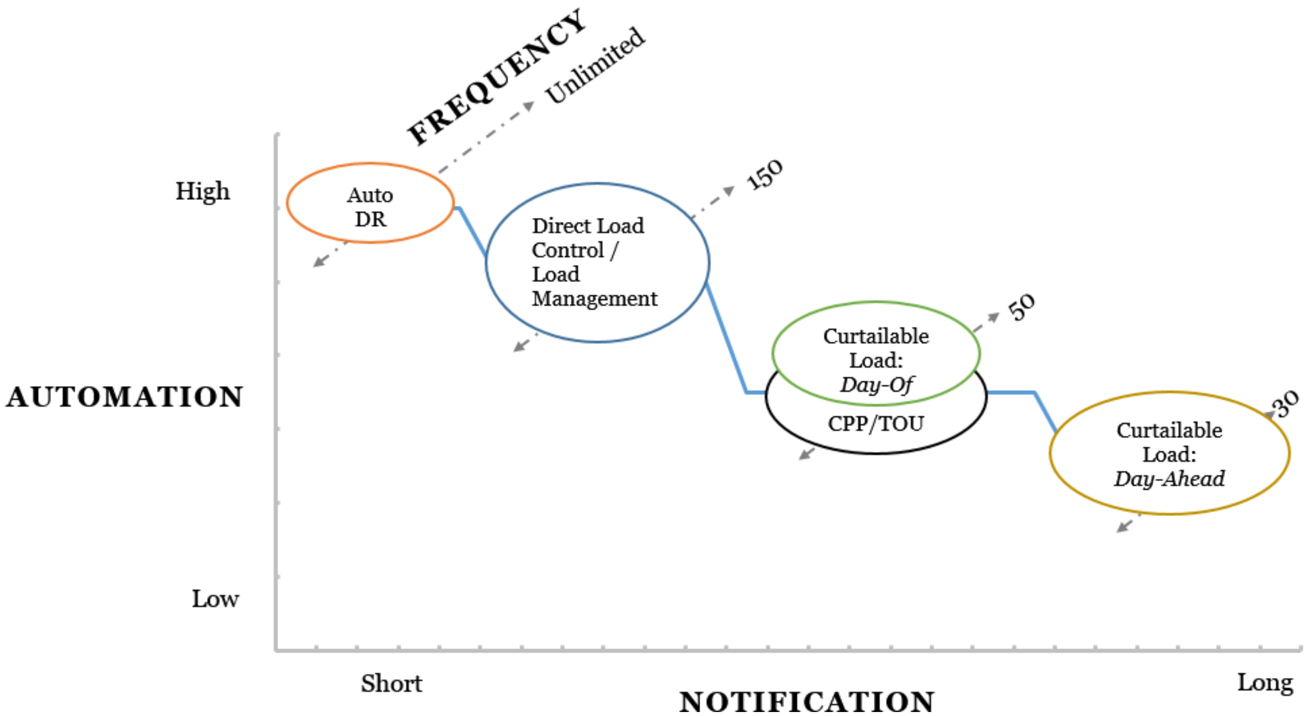

Figure 5: Notification and Automation: The above diagram illustrates that increased automation will impact notification timelines as well as the potential frequency with which the resource may be called.

Although ripe with potential, the underlying ability of Auto-DR to fulfill variability needs may varies across geographical regions due to other factors, beyond technical capability. Even in California, often assumed to be one of the more developed markets, there is likely not enough capacity in Auto-DR to meet the overall system needs that will result from the 2020 Renewable Portfolio Standard (Watson, Kiliccote, Piette, & Corfee, 2012). In the PJM market, fast-responding DR resources play a significant role in the wholesale market, comprising roughly 36 percent of all Tier 2 synchronized (spinning) reserves provided in 2012. However, a policy of infrequent, contingency-only dispatch, by definition limits the value of this option.

One potential bright spot in using Auto-DR for integration is in the Midcontinent Independent System Operator (MISO) region. Automated load response has been providing ancillary services to MISO for a number of years. An aluminum smelter plant in Warrick County, IN, operated by Alcoa, has been consistently providing between 10-15 MW of various ancillary services into MISO after significant investment starting 2009, meeting a large portion of overall regulation needs. Since then, the Warrick plant has moved into providing spin, energy and spinning reserve services through interruptible load. (Todd, et al., 2009).

The high potential of Auto-DR should be weighed against availability and other practical constraints. Still, it may be a cost-effective opportunity for integration, especially when smart-grid technology is already in place.

5.3 Direct Load Control

In line with much of the research reviewed, the scoring analysis indicates that direct load control (DLC) programs offer tremendous potential for renewables integration. The main channel by which this flexibility can be delivered is through extremely short signal-to-response times. The diagram below illustrates the correlation between signal-to-response and the suite of integration issues. In sum, although peak load reduction can be addressed using all of the measures listed here, the faster the ability to respond, the more applicable the DR measure is to solving ramping and short duration (2-hour) forecasting issues.

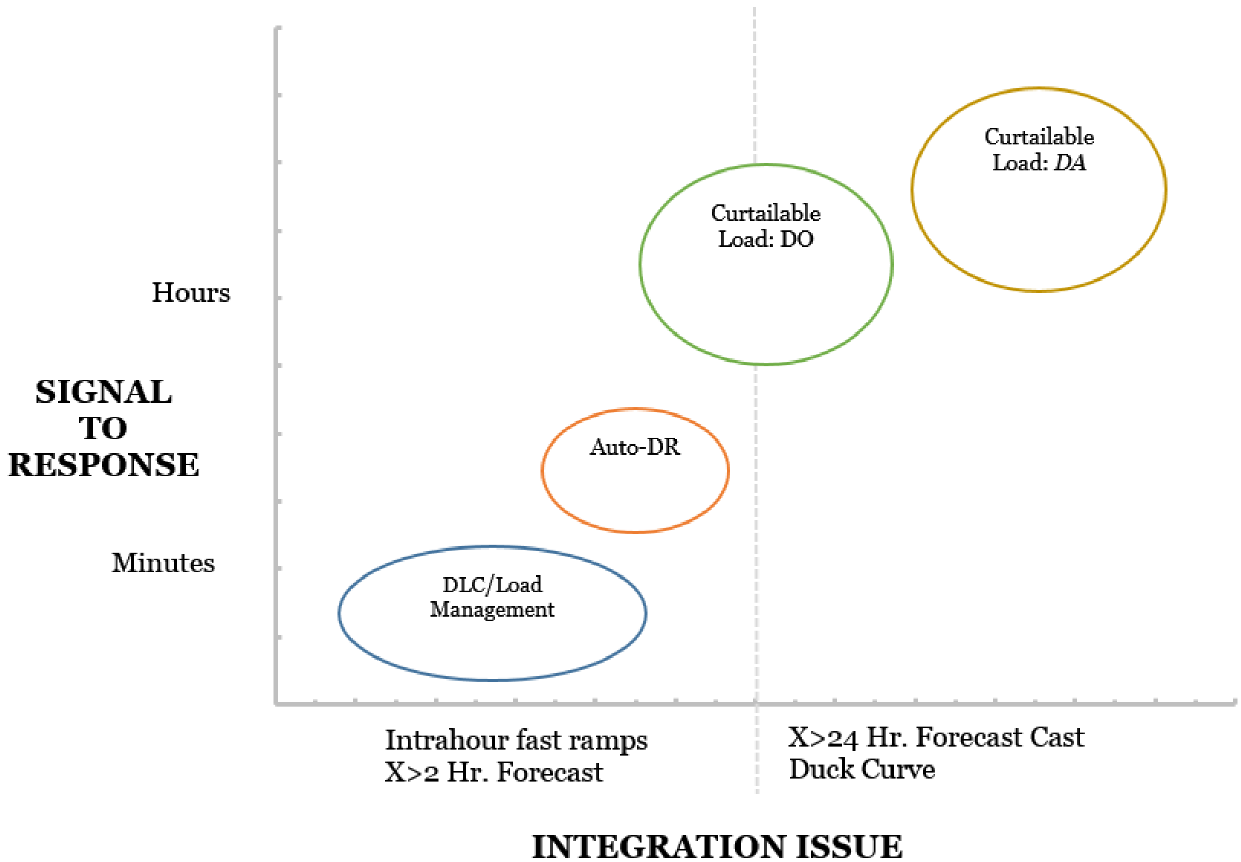

Figure 6: Signal-to-response / Integration Issues: The above diagram illustrates that lower signal-to-response times allow for the ability to address a different set of integration issues.

Resource magnitudes for DLC/Load Management programs generally tend to be the smallest of the DR options surveyed here. This is not necessarily be a drawback. For the distribution utility, there may be great value in commanding a fleet of smaller locations, insofar as it translates into the ability to geographically target grid areas of need with greater precision.

As factors such as these illustrate, the applicability of the potential for DLC programs depends on some key on-the-ground factors. For example, PG&E's SmartAC-Residential program which had 125,057 service accounts in April 2015 currently has no near-term plan for partial (granular) dispatch. Clearly, dispatching the entire portfolio of customers across various geographic regions comes with certain inherent costs and complexities. This may limit the potential application of this program to a smaller subset of integration issues.

The granular dispatch issue has been addressed by many other utilities. For example, with 710,000 participants delivering 1,000 MW during normal operation, Florida Power & Light has operated one of the largest and most popular residential DLC programs in the country, "On-Call," since July of 1986. The On-Call program cycles air conditioning and heating loads, turning them off for 15 minutes out of every 30 minutes for 3 hours. It also offers participants bill credits on a yearly basis. As Florida is not part of an ISO and the program can be dispatched on a highly localized basis, this program plays a critical role in addressing both local and system-wide needs (Malemezian, 2003). The considerable differences between the On-Call and SmartAC programs underscores the fact that while DLC holds tremendous potential, programs must be carefully structured—and, in some cases, restructured—in order to fully unlock the potential that best complements variability needs.

5.4 Pricing Strategies: Critical Peak Pricing and Time of Use

The pricing strategies represented in rows 8-10 of Table 4-2 pose an interesting scenario. Within a Day-Ahead or Day-Of time domains (dependent on the notification period), pricing can be used to target specific integration issues. In fact, there may be more flexibility in this time threshold to address certain integration issues than would be present in a typical curtailable load program. While a DR event may be called for a four-hour block of time, it suffers from discrete dispatch so that if a customer needed to return to normal load levels at some point during the event they would have no economic signal to aid in the decision of which hour to choose. Rates and tariffs can be created and implemented address that need. Each individual hour of the event period could be priced according to specific system need. In this way, the utility can set up a rate structure that incentivizes load reduction behavior within the Day-Ahead or Day-Of time frame, which is more flexible than what a typical curtailable program could achieve.

However, the distinction between programs designed for bill savings rather than direct payments add complexity to this comparison. Research on past DR programs showed that on average, customers on dynamic rates do not reduce load as much as those on automated or DLC programs (Faruqui & George, July 2002). There also could be significant regulatory hurdles to instituting a new rate to target solar integration over the simple retooling of an existing DR program. One final concern is that these rates are limited primarily to the subset of integration issues that can be addressed within the Day-Ahead or Day-Of time frames. Given the fact that large numbers of customers are often placed on TOU or CPP, most of these customers cannot be expected to have access to advanced load-management technologies.

These considerations produce relatively low scores in this analysis of rates and tariffs for renewables integration. However, broader adoption of these rates with new design elements in coming years, could offer new, highly-ranked solutions.

6 Case Studies of DR Integration with Renewable Resources

Distribution utilities that have worked to maximize smart grid capabilities have begun to see DR in combination with distributed generation, including wind and solar. The following case studies relay different approaches to addressing renewable variability concerns. These studies portray the cutting edge of what utilities might do to merge the two worlds of demand-side management and renewables integration.

6.1 Oklahoma Gas & Electric–SmartHours Dynamic Pricing (2013-Present)

Oklahoma Gas & Electric's SmartHours dynamic pricing program utilizes peak-hour pricing from 2-7 pm. This program has been developed to help aid in the integration of the wind resources, which are now at 7 percent of the utility's total resource mix (Oklahoma Gas & Electric, 2014). The program is projected to grow with new transmission in Western Oklahoma, connecting the utility with additional wind resources (Walton, 2014). Like the Steele Waseca program described in detail below, this program has the utility interfacing directly with customers. The objective is to help manage the utility's peak load and to maximize the benefit of renewables on the system. This is sometimes characterized as a "smart distribution utility" approach to renewables integration, since pricing and devices used together to help manage system load, independent of the ISO/RTO.

6.2 Arizona Public Service–Solar Pilot Project (2010-Present)

Driven by a state mandate for 15 percent renewables by 2020, Arizona Public Service (APS) filed for a pilot project in 2010 to install utility-owned solar arrays on roughly 200 homes, including solar water heaters in 50 homes and small-scale stand-alone wind turbines, in Flagstaff. With funding from the US Department of Energy, the project is highly localized in one electric distribution area. It delivers 1.5 MW of distributed solar. The key distinguishing feature of this project is the goal to balance demand and supply within a small geographic footprint. As discussed below, this approach has been avoided in some other case studies for reasons that are further detailed in the PowerShift case study below. Nevertheless, it is a precursor to some micro-grid oriented solar-plus projects.

6.3 Bonneville Power Administration"Non-Wires Solutions" (2002-Present)

The Bonneville Power Administration has taken a pre-emptive approach to addressing ongoing transmission and distribution concerns. It launched an initiative in 2002 that sets up a "Non-Wires Solutions" assessment, looking at viable energy efficiency and demand response options before launching any T&D upgrades. This creates a formal process by which alternatives to new wired projects are evaluated, with an initial screening to be considered. Any construction project goes through this analysis if it will cost at least $5 million and will be undertaken at least eight years in the future (Neme & Sedano, 2012).

6.4 Steele-Waseca Cooperative Electric Sunna Project (2015–Present)

Steele-Waseca Cooperative Electric (SWCE) is based in Owatonna, MN, and serves nine districts in a territory of roughly 900 square miles. The co-op serves about 60-MW of peak load. As a member of the Great River Energy G&T, SWCE gets 15 percent of its energy from wind resources. With water heating representing between 13 percent and 17 percent of residential energy consumption, the shifting of this load has tremendous potential to aid in renewables integration and to raise the effective net value of wind (and eventually, of solar) generation (Troutfetter, 2009).

The Sunna Project community solar program operates on a familiar co-op community solar model. The solar project serves the distribution grid, overseen locally by SWCE. Members of the co-op may subscribe to one 410-Watt solar panel for one-time fee of $170, so long as they agree to join a water heater load control program as well. (For those who opt out of the water heater program, the cost of the solar panel increases to $1,225.) An equivalent amount of kWh production is deducted from the participant's electric bill each month, in a form of virtual net metering. SWCE's 16-Hour Water Heater Program provides willing members with a new 105-gallon electric storage water heater at no additional cost. These water heaters are outfitted with mixing valves, which allow the unit to store water at a higher temperature than needed for domestic use. The hotter water is mixed with cooler water as it exits the tank, so there is no noticeable difference from standard water heating. The main control strategy employed by the utility is to shift the water heating load from on-peak to off-peak hours (Walton, Why one electric co-op is offering their solar customers free water heaters, 2015).

The solar project is just one source of variability on the co-op system, so the water heaters balance against the system load instead of the community solar project alone. The program utilizes the significant flexibility for charging the water heaters to work at night time, when net system loads are low (typically due to high availability of wind power). This approach takes advantage of lower electricity prices, and can help the utility avoid over-generation. As such, there is no direct coordination between the charging of the water heaters and the availability of renewables, except via the intermediary of the grid itself. The configuring of the DR measures to grid conditions, rather than directly to the production profile of the renewables themselves is a recurring theme across best-practice case studies for renewables integration.

6.5 New Brunswick Power PowerShift Atlantic (2010 – 2014)

PowerShift Atlantic was an innovative research and demonstration project led by New Brunswick (NB) Power, which spanned Canada's three Maritime Provinces–New Brunswick, Nova Scotia and Prince Edward Island. This demonstration project was the basis for program development work, which is ongoing. Together, these provinces controlled a hefty 675 MW of on- and off-shore wind power, which is about 13 percent of peak system load (Natural Resources Canada, New Brunswick Power, 2014). The PowerShift strategy relied upon year-round, bi-directional load response. It stands in contrast to many traditional DR programs, as well as to the Sunna Project model, which trigger peak load reductions over pre-specified times of day. The demonstration was highly successful and led to ongoing efforts.

As designed, the program had a tiered structure, with NB Power acting as program administrator. At the top of the operational hierarchy, a Virtual Power Plant (VPP) system created by Leidos,[1] received forecasts of net system load from the system operator. The VPP also interacted with five DR aggregators, each controlling their own aggregations of customers. Aggregators provided the VPP with forecasts based upon the operating parameters of their individual customers. The VPP operator calculated energy targets that were sent back to the aggregators every fifteen minutes. In turn, the aggregators were expected to send control signals out immediately to end-use loads and devices in a continuous feedback loop of responsive load.

[1] Leidos (formerly the Science Applications International Corporation) is a Fortune 500 American defense company headquartered in Reston, Virginia, that provides scientific, engineering, systems integration, and technical services.

It is noteworthy that even though the overarching program goal was renewable integration, program administrators learned that it was better not to have the VPP optimize the load response against the wind forecast alone. This lesson was learned by examining what could happen on a peak day. Depending on when large wind resources came online during the evening and how they coincided with overall system peak, the VPP could signal for loads to shift directly into peak hours. This could result in aggregators increasing the load beyond grid capacity. Instead, the VPP set out a load trajectory on a 24-hour basis, to best smooth the forecasted net load shape (load minus wind) that was received from the system operator. This way the VPP reduced the strain on conventional generation, shifting loads to reduce the effects of the variability of the wind generation, not the generation itself.

Downstream from the VPP optimization, aggregators relied primarily on end-uses with some kind of storage component. One aggregator utilized pre-cooling, controlled electric water heating, and manipulation of pump timing, while another focused on optimization of pumping system loads from industrial processes.

NB Power had a unique benefit to aid in the success of PowerShift: a high degree of trust from its customers. This was due in part because the project was promoted as a Canadian national demonstration, invoking public support. Successful marketing also played a key role. The program was able to recruit a high number of participants, and most of the control equipment belonged to customers, who did not receive incentives to participate. Reportedly, public support for the region's wind resource has been a major driver.

NB Power has leveraged some of the infrastructure and networks developed through this project in the Reduce and Shift Demand (RASD) program, which aims to create an innovative smart grid framework through smart communicating thermostats, energy smart appliances, self-serve options for energy shifting, energy usage dashboards; and thermal energy storage.

6.6 Pacific Gas & Electric Intermittent Renewables Management Phase 2 (IRM2) Pilot (2013 – 2014)

As in many other locations, the influx of renewables is rapidly changing the shape of California's load curve (Lazar, 2014). The Intermittent Renewable Management Phase 2 Pilot (IRM2), a PG&E project administered by Olivine, was conceived as an integrative model for how distributed energy resources (DER) could be dispatched economically to address short term system needs related to variability. The program ran from February 2013 through December 2014 and was open to commercial and industrial customers of PG&E.

IRM2 brought demand-side resources, including DR, directly into the wholesale market as a supply resource, similar to a generator, becoming part of the economic bid stack and affecting wholesale spot prices. Through the daily optimization of market offers, these resources met needs that are directly driven by the generating characteristics of renewables.

Critical to IRM2 are the must-offer obligations (MOOs). Load Serving Entities (LSEs) are required to contract for capacity above their load requirements in order to meet reliability requirements and ensure adequate capacity is available if needed. Contracted generators bid MOOs into the wholesale market, to be available for dispatch if needed. Although there is little DR currently integrated into the wholesale market, policies and procedures are now being implemented to use DR to meet resource adequacy requirements and compete for these contracts.

One of the lessons of IRM2 was that participants who were able to meet pilot participation requirements demonstrated an increased level of operational sophistication and the ability handle dispatch events often. Many of the parties who inquired or enrolled relied on innovative demand-side technologies, and few had previous experience with traditional utility-program DR. Applicable resources included storage batteries and even modulated Electric Vehicles.

Through the daily optimization of market offers, these resources were able to effectively demonstrate their benefits, such as reliability and flexible ramping, for replacing the need to use gas peaker plants to address intermittency.

An integral component of the IRM2 was the fact that these DERs were part of the small group of resources that have participated in the wholesale market outside of distribution utilities' minimal program integration. Utility and CAISO market systems to support DER were still in the early stages of development during the program. IRM2 shed light on real-world challenges, as this market grows and expands to address renewable-resource intermittency. Since completion of the IRM2 the CAISO's Flexible Resource Adequacy Must Offer Obligations guidelines have been modified and approved by FERC to include DR resources. California regulators now have launched a statewide Demand Response Auction Mechanism (DRAM) Pilot to test the viability of procuring DR for resource adequacy purposes, which would carry the MOO, through an auction mechanism with a standard contract.

Conclusion

In addition to the practical comparisons of DR measures for use in renewables integration, this Guide offers at least two key takeaways. First, if DR is to aid in the integration of renewable resources, accurate forecasting (particularly of net system load) is critical to setting DR-for-integration targets. In the PowerShift and Steele Waseca projects, it was demonstrated that forecasting overall grid needs, as opposed to the output of any single renewable facility, can be effective and helps avoid unintended consequences. Second, there is a need for a variety of fast-responding, flexible DR options to aid in renewable integration. As all the above case studies suggest, new end-uses must be recruited, which ideally offer bi-directional load shifting, i.e., load reductions and load increases.

Although traditional DR lessons apply, distribution utilities may find it better to create new DR programs for renewables integration, or to create specific new messaging about modified program offerings, to ensure that all the criteria for flexibility are met. Advanced DR programs for renewables integration, sometimes called DR 2.0, are best-suited to newer, smart grid technologies. In the context of community solar marketing, DR companion programs also might leverage new third-party provider capabilities. Ultimately, the creation of multiple options for customers with innovative DERs (on both sides of the meter) would help to assure not only the viability of significant community solar fleets, but ultimately the path towards a lower-carbon future.

The development of DR programs to address renewable resource variability need not compete with traditional DR programs, nor erode their value in addressing seasonal peak load. Nascent experience shows that customers who are eager to adopt and embrace solar PV in particular represent a new target market, willing to consider other options as well, to address the impacts of variability. They are likely to speed the use of new technologies, such as DR 2.0, thermal storage, storage batteries, and EV charging. While not necessarily suitable for longer DR events, many of these work frequently but quickly, and with little or no customer inconvenience. Innovative DR program design and targeted customer recruitment can extract value that complements the challenge of increased solar market penetration.

Community solar program design is a new area; most utilities do not have robust community solar programs yet. Incorporating DR options into such programs adds a layer of complexity to be sure. However, customer enthusiasm for solar and solar-plus strategies and the pace of change in the solar industry should not be underestimated. As the community solar market rapidly grows, it is appropriate for utilities to incorporate measures needed to support growing solar penetration. The grid will look very different in just a few years than it does today. As the percentage of variable generation increases, responsive load will become increasingly valuable.

The CSVP sees opportunities for utilities to combine utility-driven community-solar business models with DR options–and ultimately with DR plus storage as bi-directional sink and source options–to address variability in net load. Today, such value would be difficult to capture with other solar projects (e.g. customer rooftop, or remote utility-scale power plants). Solar program designers need to embrace such opportunities to ensure that customers have access to the power choices they want, while utilities can maintain grid stability as renewable penetrations increase.

Appendix: Planning Cost Estimates

The following table was used to calculate values for the Planning Estimate Yearly Costs introduced in Table 4-1. For all rows the values in Enablement and Incentive costs were taken from literature review. “All-in Monthly Cost” was calculated by taking the Enablement Cost divided by the program period, then adding the monthly $/kW incentive cost. We assume a 5-year program period. The “All-in Monthly Cost” was multiplied by 12 to calculate with the “All-in Yearly Cost.”

		Input Costs						**Totals**						
	DR Option	*Enablement Cost ($/kW)*			*Incentive Costs ($/kW)*			*All-in Monthly Cost ($/kW)*		*All-in Yearly Cost ($/kW)*		*All-in 5 year Cost ($/kW)*		*Avg Yearly Cost ($/kW)*
		Low	*High*	*Term*	*Low*	*High*	*Term*	*low*	*high*	*low*	*high*	*low*	*high*	
1	Curtailable Load - Day- Ahead (Navigant Consulting, Inc., 2015)			One-time	$2	$30	Month	$3.00	$6.25	$36	$75	$180	$375	$56
2	Curtailable Load- Day-of (Navigant Consulting, Inc., 2015)			One-time	$2	$35	Month	$3.00	$6.25	$36	$75	$180	$375	$56
3	Auto-DR (Ghatikar, Riess, & Piette, 2014)	$125	$300	One-time	$2	$35	Month	$4.08	$40	$49	$480	$245	$2,400	$265
4	Direct Load Control - A/C switch control (Haeri & Gage, 2006) (Rocky Mountain Institute, 2006)	$70	$150	One-time	$100	$150	One-time	$2.83	$5.00	$34	$60	$170	$300	$47
5	Load Management - Smart Thermostat (Haeri & Gage, 2006) (Rocky Mountain Institute, 2006)	$200	$400	One-time	$100	$150	One-time	$5.00	$9.17	$60	$110	$300	$550	$85
6	Direct Load Control - Pool pumps (Haeri & Gage, 2006)	$55	$75	One-time	$100	$150	One-time	$2.58	$3.75	$31	$45	$155	$225	$38
7	Direct Load Control – Electric water heaters (Haeru & Gage, 2006)	$55	$75	One-time	$100	$150	One-time	$2.58	$3.75	$31	$45	$155	$225	$38

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