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Consumer-Centric Energy and Demand Programs

The New Business Case Guidebook

NRECA
America's Electric Cooperatives

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The New Business Case Guidebook

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PREVIOUS VIEW

The National Rural Electric Cooperative Association

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA's members include consumer-owned local distribution systems—the vast majority—and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

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- Renewables and Distributed Generation
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- Transmission and Distribution

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Consumer-Centric Energy and Demand Programs: The New Business Case Guidebook

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1 Executive Summary

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Consumer-centric electric cooperatives are national leaders in energy programs (energy efficiency) and demand programs (demand response). Cooperatives represent members, not shareholders, and so can be more proactive and flexible when it comes to energy and demand programs for their members. Thus, in the contemporary demand-side management (DSM) landscape, cooperatives have opportunities to strengthen their DSM offerings and benefit their members.

In some respects, demand-side management programs haven't changed much over the years. The goal of demand response (DR) programs is to reduce demand during peak demand periods, and the goal of energy-efficiency (EE) programs is to reduce energy use across the board. These goals have stayed constant throughout the years. However, in other respects, the DSM landscape has changed dramatically in the last 10 years. New technologies, markets, and strategies are enabling types of DSM programs that were not feasible in the past.

For example, the number of U.S. homes with smart meters went from 7 million in 2007 to more than 50 million in 2014. Cooperatives have led the way in this transformation. These meters, along with other technologies, have greatly increased the number and scope of possible DSM programs. For example, smart meters enable peak-time rebate programs, which give rebates to cooperative members who reduce usage during "called" events. Another example is that a "remote-controlled house" is now a reality; using home energy management (HEM), residential members can now control their smart thermostats and even some appliances via their cell phones and computers.

In general, the recent advances in DSM can be grouped into the following categories:

1. **Cost-Benefit Categories That are More Detailed and Quantifiable.** For example, DSM reduces T&D expenses. If DR is used during peak hours, the avoided T&D costs can be substantial—delayed capacity upgrades, reduced stress on substation components, reduced general T&D expenses, reduced line losses, etc. The methods for quantifying these benefits are becoming more precise. See **Section 4** for more on this issue.
2. **New Cooperative Technologies, Information, and Capabilities.** As cooperatives get more AMI meters on their systems, and better data management systems, their DSM options increase. Hourly—or more granular interval—data enables Peak-Time Rebate (PTR) programs, time-of-use rates such as critical peak pricing, and advanced load control options. Improved data collection and management techniques also enhance these programs.

As cooperatives get more information about their systems, more DSM programs are enabled. For example, information about hourly load shapes, substation loads, and end uses can help cooperatives design DSM programs tailored to their needs.

3. **New Member Products and Technologies.** For example, home energy management (HEM) is a system (hardware, software, or both) that allows consumers to manage their household energy usage. At the current time, a "smart thermostat" (such as a Nest) that can be controlled via a remote phone or computer is the most common type of HEM. Other features that can be added are smart appliances, in-home displays, and various portals and software platforms. These are discussed in **Section 9** of this Guidebook. When paired with DR programs that have "called events," HEM programs can help cooperatives manage peak usage.

   Another member technology that is becoming widespread is the heat pump (for water heaters, heating, and cooling). Heat pump water heaters are now very competitive with natural gas water heaters in terms of fuel dollars per year, even at the current historically low natural gas prices. Ground- and air-source heaters can serve as the primary residential heating and/or cooling system in many regions of the country. These technologies can also help to add system load.

   One member technology that could be a game-changer is the plug-in electric vehicle (PEV). PEVs, when properly paired with a time-of-use rate, can serve as added load at off-peak times, which can enhance revenues and flatten load curves. Cooperatives should be doing all they can to encourage PEV purchases and infrastructure. See **Section 7** for more on PEVs.
4. **Renewable Energy and Distributed Generation.** These lead to both challenges and opportunities for cooperatives. Renewables can change the daily load shape for cooperatives. Distributed generation and renewables can affect transmission routes and strategies, so when these resources have high penetration on a system, cooperatives should adjust their DSM programs accordingly.
5. **Energy and Capacity Markets.** Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are developing energy and capacity markets. Energy markets are often day-ahead or 5-minute/real-time. Capacity markets typically look months or years down the road. Both EE and DR can usually be offered into capacity markets. Usually only DR is offered into energy markets. There are also ancillary service markets. Cooperatives in these markets should be aware that some DSM can serve as an extra revenue stream, even as it helps the cooperative system in other respects. The recent Supreme Court ruling on FERC Order 745 means that the price paid for DR will be the market price. See **Section 10** for more on energy and capacity markets.
6. **Regulation.** New regulations can affect the value and extent of DSM. For example, if a regulation results in stringent emissions targets, DSM programs may become more valuable for cooperatives as these programs would help cooperatives meet goals set by the states. Some sort of emissions regulation or carbon market is likely in the coming decade.

These six categories cover a large part of the new DSM landscape. However, as stated above, the cost-benefit tests themselves have remained fairly constant, although some refinements are evolving. The core portfolio of DSM programs has also remained fairly constant over the years (at a general level), but many new variables have been added: the ability to monitor load on an hourly or 15-minute basis, the emergence of new appliances and home energy management systems, energy and capacity markets, and so on.

Roadmap for Using the Guidebook

This section gives some big-picture guidance on how to use this demand-side management manual (the "Guidebook"), depending on your cooperative's circumstances. The challenge for a comprehensive Guidebook is to steer between two possible obstacles:

PREVIOUS VIEW

1. If the Guidebook is too detailed, and has too many technical cost/benefit analyses, it can become long and confusing, and readers may be reluctant to take the time to go through all the details to see if the analyses apply to their cooperative.
2. If the Guidebook is a general, high-level view of cost/benefit analyses, it may not contain all of the necessary technical information they need to perform their desired cost/benefit analyses.

This Guidebook will lean toward the "general" side, primarily because it would be impossible to collect every piece of technical information tailored to every possible cooperative circumstance. Where possible, we will recommend links to more technical resources, so that cooperatives will be able to find details that are not in the Guidebook. The goal is to inform cooperative management of some of the trends that are affecting demand-side management cost/benefit analyses and to identify big-picture resources and strategies to cope with the changing DSM landscape. In short, the focus will be more on big-picture DSM planning and less on the technical details of the analyses.

With that caveat, in **Section 6** is a somewhat detailed cost/benefit analysis that helps to illustrate some of the main themes. In other sections, cooperatives are directed to some external resources that contain more detailed methodologies.

The Guidebook is written so that cooperatives can read it cover-to-cover and get a solid overview of the new DSM landscape, and how to adjust their DSM cost/benefit analyses accordingly. However, we also realize that cooperatives are at different stages in the DSM process; some have extensive DSM programs in place, some have few or no DSM programs, and many are somewhere in between. **Section 2** may be a good reference for cooperatives which are somewhat new to DSM and would like a review of the basic DSM programs and terminology.

Guidebook Themes

This Guidebook has several themes that permeate the discussion of DSM cost/benefit analyses.

1. **DSM can be used to strengthen cooperatives' financial well-being and stability**, while at the same time serving and engaging their members. The cooperative model provides a unique opportunity to conduct programs that are in the best interest of members. Invester-owned utilities (IOUs) have shareholder and regulatory concerns; in contrast, cooperatives are well-suited to take advantage of DSM more aggressively, if the business case calls for it. For example, when we look at the unsubsidized, levelized cost of energy (LCOE) for generation technologies, we see that certain EE programs can be the most cost-effective "source" of energy.[1]
2. **DSM will become more and more prominent at utilities around the country.** This is partially a result of the first theme. Because DSM can be a cheap way to "produce" energy and capacity, utilities will be turning to it, especially as alternative energy sources have higher prices due to supply or regulation. Cooperatives need to understand how to value DSM, so they can find the lowest-cost solution for members. Increased regulation could put upward pressure on energy costs and have huge impacts on how states regulate cooperatives; this regulation could very well take the form of required EE targets.
3. **The new DSM landscape gives cooperatives a chance to utilize DSM to their great benefit**, above and beyond the immediate financial benefits related to energy and capacity. Specifically, DSM can serve to increase customer engagement and satisfaction, and allow cooperatives to solidify their status as trusted energy advisors.

   Cooperatives need to become conversant in the new technologies, such as plug-in electric vehicles, solar photovoltaic systems, and home energy management systems. The

[1] Adapted from *Lazard's Levelized Cost of Energy Analysis—Version 8.0*. September 2014. The levelized cost is an attempt to compare the cost of various sources of energy (coal, nuclear, gas, etc.) in dollars per megawatt-hour, over the life of the source.

prevalence of these technologies is on the rise. Cooperatives need to keep pace with their members' use of these and other technologies or run the risk of appearing to be behind the times or, worse, an active impediment to progress. With some carefully designed programs and projects, cooperatives can be seen as the "go-to" trusted energy advisors for their members.

There has also been some discussion in the industry about renewables leading to a "death spiral" for utilities. We will discuss this in **Section 7**, but the bottom line is that, even if the talk of a death spiral is overblown —and we think it is—cooperatives can nonetheless turn a possible threat (renewables and new technologies) into an opportunity. If cooperatives can get in front of new technologies—such as home-energy networks, renewables, and the increasing role of DSM in RTO markets—they can help direct change, instead of passively reacting to it. In addition, many of the new technologies lend themselves to beneficial electrification, especially the plug-in electric vehicle (PEV).

4. **Costs are often easier than benefits to put a dollar figure on.** For example, a cooperative will have a good idea what the costs of an EE rebate program will be, especially after running it for a year. Many of the benefits, however, are difficult to monetize precisely: avoided generation, deferred T&D expenses, reduced congestion and risk, avoided greenhouse gases, meeting regulatory targets, customer satisfaction and engagement, etc. Simply because a benefit is difficult to monetize does not mean it is not important.
5. **Business cases should look at the long run—the life of the DSM measure.** This can sometimes be overlooked when a DSM program has significant up-front expenses. If cooperatives closely examine the benefits over the long term, in many cases the upfront expenses are far outweighed by benefits in later years.

   Related to this theme is the fact that the value of some technologies is enhanced by their ability to enable future DSM programs. As an example, when cooperatives are considering the business case for advanced metering infrastructure (AMI) investment, it may be helpful to include the ability to run DSM programs in that calculation. As a practical matter, a cooperative deciding whether to invest in system-wide AMI will probably not also perform a DSM potential study at the same time. However, the fact is that AMI coverage can enable a wide variety of DSM programs, such as peak-time rebates or time-of-use pricing, or improve existing programs, such as direct load control.
6. **DSM cost/benefit calculations should ideally be done from a holistic portfolio perspective** rather than calculated individually for each program (i.e., direct load control, appliance rebates, peak-time rebates, etc.). Program interactions can influence overall portfolio results. For example, take a G&T that wants to lower its system peak demand due to a projected upcoming capacity deficit. If the G&T runs multiple DR programs, it cannot simply "add" the projected load reductions of each program to get the reduction of the portfolio as a whole. Each DR program will "flatten" the G&T's load curve, and so the first megawatt avoided is far easier to achieve than the twentieth megawatt avoided. The G&T should use the business case to determine the best portfolio of DSM programs, rather than assessing individual programs one by one.[2]

By keeping these themes in mind, the new DSM landscape will not be as intimidating. Although the technologies are changing, the basic question for cooperatives will stay the same: How can my cooperative utilize new DSM technologies to better serve our members and continue to provide cost-effective, reliable energy?

The next section covers the basics of the most common types of DSM programs. Sections 3 and 4 then get into the nuts and bolts of setting up a cost/benefit analysis.

[2] The principle in this example also applies to distribution cooperatives and to cooperatives which hope to use DSM to reduce T&D investments.

2 Introduction to DSM Programs

In This Section:

- **Common Demand Response Programs**
- **Types of Energy-Efficiency Programs**
- **DSM: The Next Generation**

Most cooperatives are familiar with the basic types of DSM programs, but a brief review of common DSM programs may be helpful. This section looks at DSM programs from a bird's eye view; it will be seen that many of the newer types of DSM programs are variations of these basic types. For example, a home energy network is, in part, a way to enable more "traditional" demand response programs, such as time-of-use rates.

Demand-side management programs are aimed at altering the end-use of electricity at the member's meter. The end goal is reducing costs—ideally for the consumer, the distribution cooperative, *and* the G&T. DSM programs are classified into two major categories: **demand response** (DR), and **energy response** (which includes energy efficiency). There are a number of subcategories beneath each of these two main categories. As a general rule, the goal of DR programs is to reduce demand at peak times and the goal of energy response programs is to reduce energy use at all times. However, we will see that energy response programs also reduce demand and that DR programs can also reduce energy use (although the effect of DR on energy can be small in some cases).

> The goal of demand response programs is to reduce demand at peak times. The goal of energy response programs is to reduce energy use at all times.

The goal of **demand response** programs is to reduce demand at peak times (or at times when electricity is most expensive).[3] This can be done either by shifting use to a nonpeak demand time or by simply curtailing usage at peak time with no corresponding shift in usage. Demand response programs can help G&Ts shift or avoid peak electricity use, so that major investments can be avoided, deferred, or reduced. Distribution cooperatives can reduce demand charges.

[3] The FERC definition of "demand response" is: "[A] reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." Source: FERC *National Action Plan on Demand Response*, June 17, 2010, p. 3. The FERC definition does not necessarily entail that the reduction occur at times of high demand, although, in practice, this is when demand response programs are enacted. It is also worth noting that an RTO or other authority could call for DR based on reliability concerns, not just price concerns.

Members can receive rebates or other incentives for reduced demand.

The investments avoided as a result of DR programs are typically one or more of the following:

1. new or upgraded peak capacity generation facilities,
2. energy or capacity purchases, and/or
3. new or upgraded T&D facilities which service peak capacity.

For distribution cooperatives with no generation facilities, DR programs can reduce demand charges from power suppliers, which are often calculated by the cooperative's coincident demand at the power supplier's monthly or annual peak. In many DR cost/benefit analyses, avoided capacity (for G&Ts) or reduced demand charges (for distribution cooperatives) are the biggest benefit to the cooperative.

Energy response programs do not focus on peak demand but rather on energy savings throughout all hours that the measure is used. In practice, EE programs reduce peak demand to the extent the energy reduction is coincident with peak demand. There are two main categories of energy response programs: **energy-efficiency (EE)** programs and **conservation** programs.

The goal of an EE program is to provide the same level of output for less electricity. Conservation, on the other hand, reduces overall usage by reducing the quality or amount of service. For example, consider a cooperative member who usually keeps her house at 70 degrees during the summer. An EE program might incentivize the purchase of a newer, more efficient AC unit, so that the customer can still keep her house at 70 degrees in the summer, but using less power. In contrast, a conservation program might encourage the customer to set her thermostat at 72 degrees in the summer, instead of 70. Thus, when conservation is being employed, the "performance" or comfort level changes; whereas, in an EE program, the comfort level stays the same.[4]

Energy-response programs can lessen the need for baseload generation. They will also reduce system demand to the extent that the appliance or process in question is in use during times of peak load. For example, an EE program that provides rebates for efficient air conditioners will, in addition to reducing energy usage throughout the day, help reduce peak summer demand, since AC units are usually on during these peak times. Thus, avoided capacity can also be a major benefit from EE programs.

Figure 2.1 illustrates the DSM hierarchy and provides examples of programs under the demand-response or energy-response categories. The examples are not meant to be exhaustive; for example, water heaters and air conditioners are not the only appliances that can be in a direct load control program.

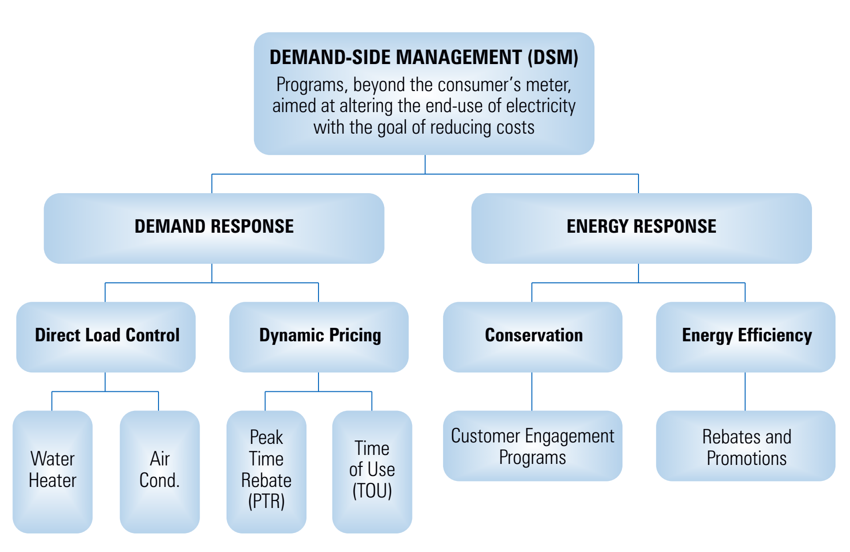

FIGURE 2.1: Types of DSM Programs

[4] Note: Some sources use the term "energy efficiency" to cover both energy-efficiency programs and conservation programs. This Guidebook mainly deals with energy-efficiency programs—for example, rebates for more efficient appliances. However, if a cooperative can implement conservation programs and track the results, these can usually also be counted toward "energy-efficiency" goals.

Common Demand Response Programs

There are a number of DR options available to cooperatives; which one is right for your cooperative will depend on a number of factors, including your load characteristics, end-uses, level of T&D congestion, generation capacity situation, technology, and rate structure. The following sections give high-level summaries of common DR programs. DR programs are generally divided into two main categories: **load control** and **dynamic pricing**.

In load control programs, the rate structure is typically unchanged and the main motivation for reducing load at peak times comes from bill credits or other incentive payments. In dynamic pricing programs, the motivation for reducing load at peak times comes from the rate itself.

Another way to think about DR programs is to consider whether, how, and why they are dispatched. Figure 2.2[5] shows how DR programs can be categorized on this metric. Some of the more common DR programs are described in the following sections.

Most DR programs, even those using emerging technologies, can fit into one of the categories shown in **Figure 2.1** and Figure 2.2, or are described in the sections following. For example, home energy management systems, wherein members use their cell phones and other advanced technologies to manage home energy use remotely, are hybrid DR programs that combine aspects of load control programs, EE conservation programs, and time-of-use rates with price signaling.

TIME-OF-USE PROGRAMS

Time-of-use (TOU) programs divide the day or month into blocks of time and charge different rates for each block. TOU programs can be either

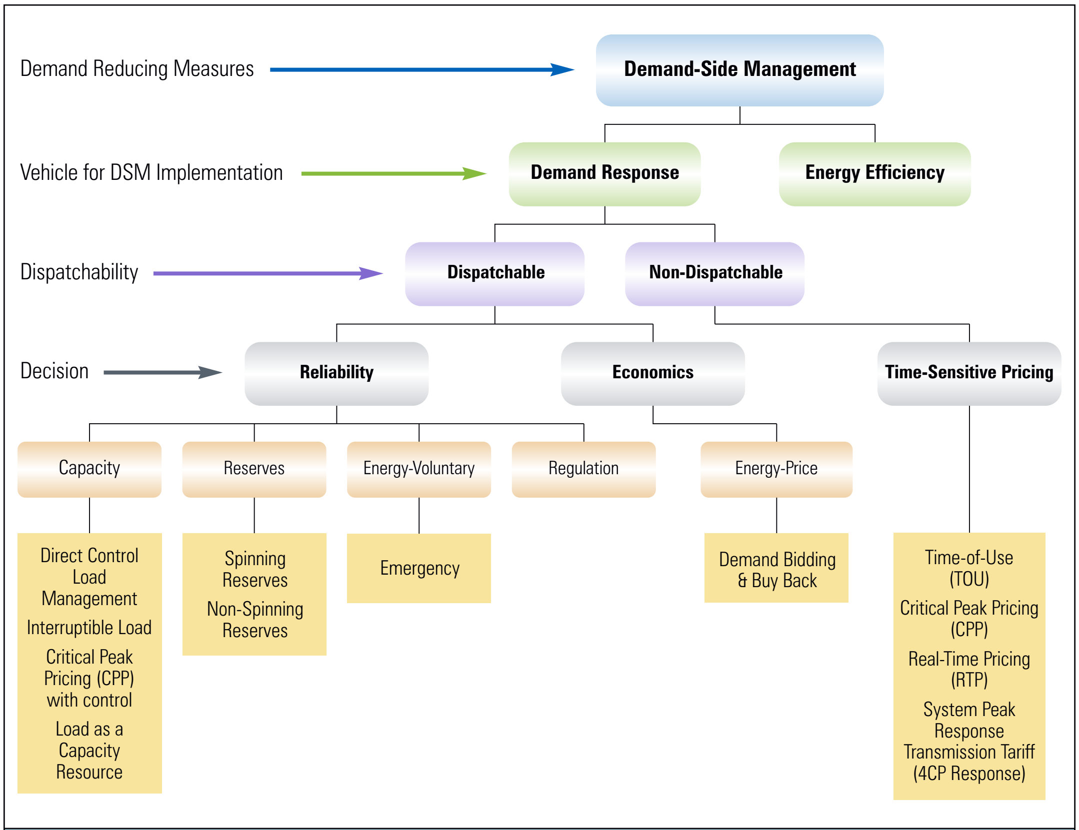

FIGURE 2.2: DR Categories by Dispatchability Characteristics

[5] *2011 Demand Response Availability Report*. North American Electric Reliability Corporation. March 2013.

voluntary or involuntary. Currently, most TOU programs are voluntary, especially at the residential level, since consumers are used to electricity costing the same at every hour of the day.

In the simplest time-of-use program, the energy rate is divided into "off-peak" hours and "on-peak" hours, with different rates. These hours and their rates are set ahead of time and do not change during the year. An example could be $0.15/kWh from 2 p.m. to 8 p.m. on weekdays, and $0.06/kWh the rest of the time; this is a TOU rate with only two "blocks" of time.

However, TOU programs can have more than two blocks of rates. Additional divisions in the time periods can be made, such as weekend rates, holiday rates, or multiple levels of pricing (e.g., low cost during low load times, mid-cost in times of medium load, and high costs in peak times). Rates can also change by month or season, although, under a "regular" TOU program, these blocks would be designated in advance and would not change in response to weather or market fluctuations.

TOU rates have several advantages:

- TOU rates, since they follow a well-defined and predictable schedule, can result in permanent load shifting away from the high-cost times as residential accounts and businesses learn to adjust their usage.
- TOU rates (especially the simpler ones) are fairly easy to explain to members: "At *this* time, your rate will be X. At *that* time, your rate will be Y."
- Members can lower bills if they can shift usage.
- TOU rates can help facilitate the transition to newer technologies, such as plug-in electric vehicles or energy storage systems (these can be charged during the low rate period).
- These rates also help the education process for members, with an introduction to the notion that electricity costs vary depending on the time of day.

Disadvantages include:

- Some members may have higher bills if they won't or can't change usage (this applies more when the rate is involuntary).
- If voluntary, participation rates can be low. Consumers, especially residential consumers, can be reluctant to change. Commercial and Industrial (C&I) consumers tend to be more willing to do the math and see if a new rate will save them money.
- Response (in kilowatt-per-member reduction over the old flat rate) is typically not as high as some other DR programs.
- Reduction is not dispatchable (in the sense that load control is).
- There can be member confusion and dissatisfaction when the new rates kick in.
- If a cooperative's wholesale energy charges are set according to its demand on a monthly or annual peak coincident with its power supplier's peak, then TOU rates can be a very blunt instrument: they vary the rate for a whole block of time throughout the year or month, just in an attempt to "hit" the peak of a particular hour. Thus a TOU rate can waste some member effort if the goal is simply to reduce usage on certain peak days.

It is worth noting that "smart" appliances can be designed to take advantage of TOU rates. For example, a smart refrigerator could be programmed to only run the defrost cycle during low-rate periods.

TIME-OF-USE: REAL-TIME PRICING

A real-time-pricing (RTP) program is technically a TOU program, but it differs in that rates are not set ahead of time, except on a very short-term basis. In an RTP program, the consumer pays a rate that is based on the current market price of electricity, based on the day or even the hour. Thus, these prices are not locked in for a season or year, but fluctuate daily or hourly according to the market.

In most RTP programs, consumers are notified the day or hour beforehand what the price will be. RTP programs typically require AMI and a more sophisticated billing system.

Currently, residential RTP programs are offered by a few utilities in Illinois, including Ameren and Commonwealth Edison (ComEd); Adams Electric Cooperative also has a pilot RTP program.[6]

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[6] See Adams Electric Cooperative's Rate WATTcher program.

It is more common to have RTP pricing for large industrial customers, as these customers are more sophisticated and diligent about tracking electricity usage to maximize their benefit. In contrast, in the past, not many residential consumers have wished to bother with unpredictable time-varying rates. It is asking a lot of residential customers to monitor energy prices and adjust use on an hourly basis, although smart grid technologies—such as a home-energy network—might make this process easier.

However, with third-party products like smart thermostats and home energy management systems, more residential consumers may be willing to try RTP programs. For example, if a consumer had a Nest or Honeywell smart thermostat that was linked to the RTP rates, the consumer could set the thermostat to automatically shut down certain appliances when the RTP rate reached a certain threshold. Thus, when hourly prices spiked, the high-usage appliances like AC units and refrigerators could be turned off or cycled.

For an example of a current RTP program, ComEd (an IOU serving the Chicago area) sends an email, text, or automated phone call when day-ahead hourly prices are expected to reach or exceed $0.14/kWh during any hour of the following day. These alerts also come on any day the actual RTP exceeds $0.14/kWh (even if it was not predicted the day ahead).[7] Most residential RTP programs are voluntary.

The 2014 average monthly residential RTP rate for ComEd is shown in Figure 2.3.[8] The higher prices in the first three months of the year may have been from the "polar vortex" of early 2014.

The hourly prices on a higher-load day are shown in Table 2.1.[9] This illustrates the potential spread in prices within a single day.

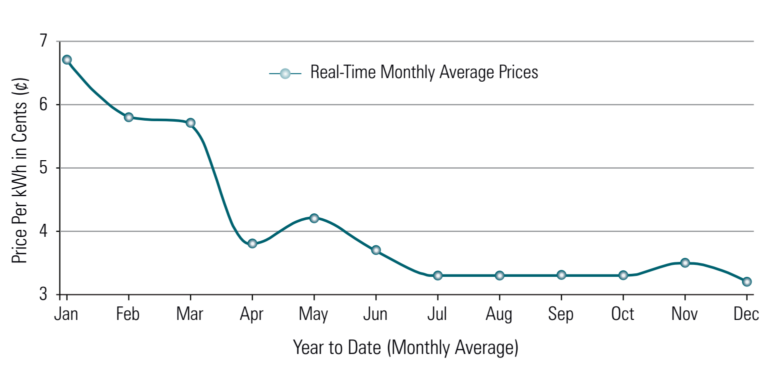

FIGURE 2.3: 2014 ComEd RTP Average Monthly Price

TABLE 2.1: 2014 ComEd RTP Hourly Price on a Hot Summer Day

Time (Hour Ending)	Day-Ahead Hourly Price	Real-Time Houly Price
12:00 AM	2.6¢	3.5¢
1:00 AM	2.2¢	2.8¢
2:00 AM	2.1¢	3.1¢
3:00 AM	2.0¢	3.0¢
4:00 AM	2.0¢	2.4¢
5:00 AM	2.2¢	3.4¢
6:00 AM	2.6¢	3.5¢
7:00 AM	3.1¢	3.1¢
8:00 AM	4.2¢	4.3¢
9:00 AM	5.2¢	4.1¢
10:00 AM	6.3¢	4.5¢
11:00 AM	6.3¢	3.5¢
12:00 PM	6.0¢	5.9¢
1:00 PM	6.2¢	8.3¢
2:00 PM	7.2¢	7.4¢
3:00 PM	8.2¢	6.4¢
4:00 PM	9.4¢	15.2¢
5:00 PM	7.8¢	8.2¢
6:00 PM	6.4¢	5.3¢
7:00 PM	5.0¢	6.1¢
8:00 PM	5.7¢	7.6¢
9:00 PM	5.7¢	8.1¢
10:00 PM	4.8¢	8.0¢
11:00 PM	3.4¢	4.4¢

[7] See the ComEd RTP FAQ.

[8] ComEd Real-Time Monthly Average Prices for 2014.

[9] The day is June 17, 2014. See ComEd Live Prices and click "Pricing Table," then enter date.

Advantages of RTP rates include:

- Out of the various TOU programs, the RTP programs do the best job at conveying the "true" price of electricity to the consumer, thus allowing the market to operate efficiently.
- The rate conveys the information to the member that energy costs are higher during certain hours.
- A well-designed RTP program should reduce peak demand by a substantial amount.
- Members who are sophisticated can save substantial amounts on their bills.
- If the consumer is sophisticated, RTP rates can result in a large drop in usage during times of peak demand, thus acting like a DR program.

Disadvantages of RTP rates include:

- Consumers can be harmed (relative to old rates) if they fail to adjust their usage based on hourly prices.
- Such a rate requires AMI and other automated technologies.
- Residential consumers tend to not be able to adjust usage as much in response to prices, for reasons of comfort and convenience.
- Real time pricing requires rate tariff adjustment.
- The program can be a "hard sell" to residential consumers.

CRITICAL PEAK PRICING

Critical peak pricing (CPP) programs can be also considered a form of time-of-use pricing: energy is priced differently at different times. However, whereas the time-of-use rate schedule applies for the whole year or season, CPP rates apply only during certain "called" peak periods, or "events."[10] This differs from RTP pricing in that there are only certain specific rates that are charged, and these rates are set ahead of time. The *times* and *dates* of the peak event periods are not set ahead of time; they are "called" the day or hour before a high-use period.

The CPP program is typically voluntary; members who sign up are placed on a new rate structure. The CPP rate usually offers lower electricity rates year-round in return for a rate higher than the regular rate on "critical peak" hours, which occur on a limited number of hours. The idea is that, in light of the higher rate during critical peak periods, members will cut their usage during the called event hours.

In CPP programs, the cooperative keeps an eye on its hourly demand forecast. The cooperative is typically trying to "hit" either its own peak or its power supplier's peak. When the next day's load is predicted to reach a predetermined threshold, the cooperative designates the high-load day to be a "critical peak" day; typically, notice is given a day ahead of time.

The critical period can be determined by the cooperative. For example, for summer-peaking cooperatives, the critical period might be in the afternoon to evening of a high load day, e.g., from 2 p.m. to 8 p.m. A cooperative might call multiple critical event days throughout a month, attempting to ensure that one of the "called" days coincides with the peak day.

During the critical peak time, the price per kilowatt-hour is higher than the off-peak price. Typically, the price at the critical peak time might be 5 to 10 times higher than at off-peak. There can also be different categories of peak time, such as "peak" and "critical peak."

The rate structure for people on the program might look something like Table 2.2, which compares a sample flat rate to a sample CPP rate. The "critical peak rate" might only apply for 1% of the hours of the year and, for 85% of the hours, the rate would be lower than the old flat rate.

TABLE 2.2: Sample Three-Tiered CPP Rate

Rate Period	Old Flat Rate (per kWh)	New CPP Rate (per kWh)	% of Annual Time on Each New Rate (average)
Off Peak	$ 0.09	$ 0.065	85%
Peak		$ 0.11	14%
Critcal Peak		$ 0.45	1%

[10] In this guidebook, "event" or "called event" refers to a time period announced by the cooperative a day or an hour ahead of time during which prices are higher (or rebates are given). The defining characteristic of an event is that it is called by the cooperative without much warning. If a time period is "set" at the beginning of the year, it is not a called event (e.g., in January a cooperative says rates will be higher on "weekdays from 3 p.m. to 6 p.m. during July and August").

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CPP programs are designed to be revenue-neutral and assume a specific number of event days during the rate design stage of the program. If the actual number of events exceeds the expected number of events, the participant can be hurt by the program, and if the actual event count per year is lower than expected, the cooperative can receive less revenue.

Currently, most residential CPP programs around the country are voluntary: members can stay on the old flat rate or sign up for the new CPP rate structure. However, the CPP could certainly be designed to be involuntary; a cooperative could require its members to be on the CPP rate structure.[11]

Advantages include:

- There is a high incentive to change behavior (the "pain" of a higher rate).
- The participants that do sign up for a CPP program are typically the consumers with the greatest flexibility in usage who can give a high kilowatt reduction per event.
- The rate conveys the information to the member that energy costs are higher during certain hours.

Disadvantages of CPP programs include:

- Members who are on a CPP may be negatively impacted (i.e., their bill may end up being higher than before they were on the CPP rate).
- The design of the CPP program can be confusing at first to the participant, and it may be unclear to them if they are better off with or without the program.
- Because members can be negatively impacted, voluntary participation rates are usually much lower than for a peak-time rebate program (see more on PTR at right).
- The cooperative must be able to "hit" the peak day with one of its called days or the program will not work as designed.
- A new rate design is required.
- The program may not be entirely revenue neutral.
- CPP programs require hourly AMI data.

VARIABLE PEAK PRICING

Variable peak pricing (VPP) is a hybrid of TOU and CPP rates. In VPP programs, the peak hours are defined in advance (e.g., "every weekday from 2 p.m. to 6 p.m. will be a peak period"), but the price paid at those peaks will vary, announced a day ahead of the peak (or a few hours ahead). The difference between CPP, TOU, and VPP is shown in **Figure 2.4**.[12] Real-time pricing in not shown on the figure, but RTP would essentially follow the actual marginal electricity cost (the top line) as closely as possible.

PEAK-TIME REBATE PROGRAMS

The peak-time rebate program (PTR) is another kind of "event-driven" program. In a PTR program, the cooperative pays the consumer directly for a reduction during "called events." The reduction is determined by comparing the members' usage on peak days to their "baseline" usage, which represents what the member would have used in the absence of a called event. A PTR program can be run without a change in the rate structure; in fact, the program can be run with a traditional "flat rate" that applies at all times.

The called events in a PTR program are on days where the cooperative predicts a peak event, such as hot summer days. Since the program requires a change in behavior to be effective, a notice of the event day needs to be provided to the participant. Usually this notice occurs one day in advance, but it could also be a few hours prior. A sample incentive could be $1 per kilowatt-hour reduced during the event hours.[13]

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[11] Fenrick, Steve, Lullit Getachew, Chris Ivanov, and Jeff Smith. "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes, and Other Customer Characteristics," *The Energy Journal* 35 (3): 1-24. 2014

[12] *American Recovery and Reinvestment Act of 2009: Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*. Smart Grid Investment Grant Program, U.S. Department of Energy. June 2015.

[13] For more information on PTR programs, see "Peak-Time Rebate Programs: A Success Story," by Dave Williams, Chris Ivanov, and Steve Fenrick (*TechSurveillance*, NRECA CRN, July 2014). Although the goal of the program is kilowatt reduction at peak time, rebates are typically paid on kilowatt-hour reduction.

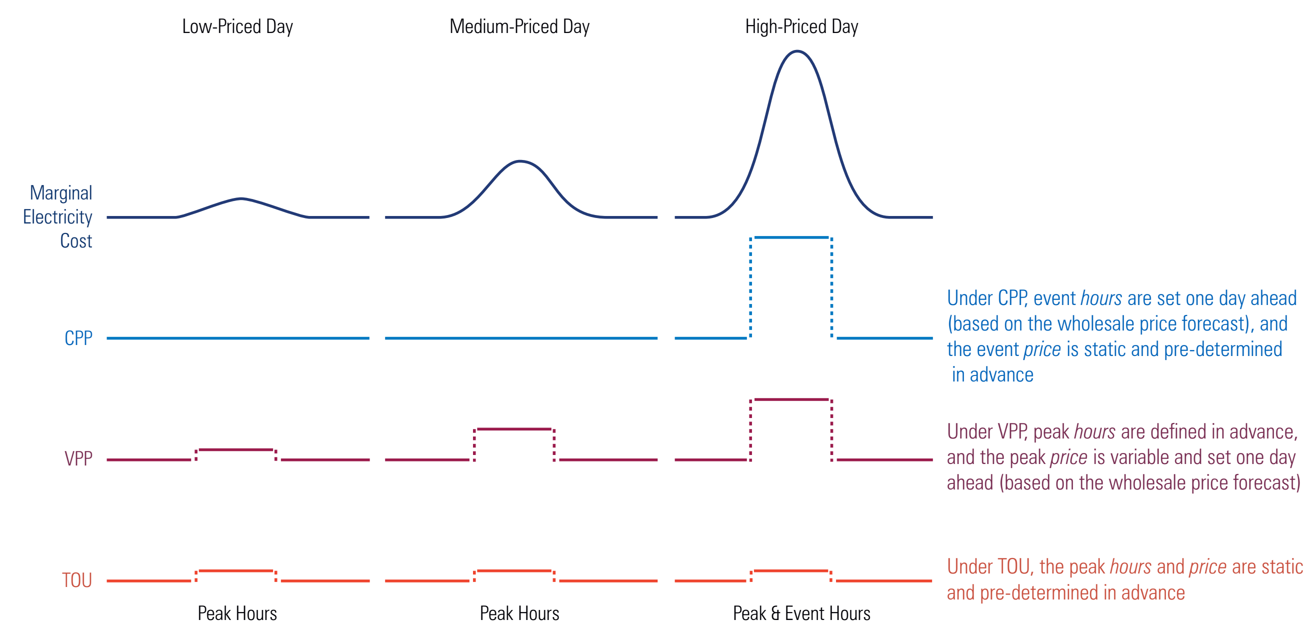

FIGURE 2.4: U.S. Department of Energy Comparison of Time-Based Rate Designs

There are several advantages to a PTR program:

- Members cannot be negatively impacted by the program. If they reduce energy during a called event, they get a rebate. If they use energy normally during a called event, or if they don't sign up for the program at all, they pay the same as they did before the program was started.
- Since members cannot be negatively impacted and sign-up is voluntary, PTR programs are usually popular with members.
- No rate change is needed.
- The program is flexible, with low upfront costs. In a summer with only a few hot days, few events need be called and so little cost will be incurred by the cooperative.
- Most of the costs of the program end up as rebates sent to the participating members (instead of going to third parties).
- Conveys the information to the member that energy costs are higher during certain hours.

Disadvantages include:

- The PTR program impacts can vary from event to event, creating difficulties at the dispatch decision stage.
- If a cooperative calls a large number of events that "miss" the peak days, this can result in higher costs; the cooperative must still give rebates for called events that miss the peak.
- The cooperative must calculate a "baseline" usage for each customer in order to estimate what each customer would have used in the absence of the PTR program. This is a crucial piece to get right and may require econometric modeling conducted by an external consultant.
- Hourly AMI data is required for a PTR program.

Technically, the rate does not change on a PTR program. However, due to the rebate, the *effective* rate changes for some members. PTR programs are typically considered a subset of TOU programs, even though the nominal rate charged remains the same.

LOAD CONTROL

In direct load control programs, cooperatives compensate members for the ability to remotely disconnect certain appliances or other loads. In most cases, the cooperative installs a device to

PREVIOUS VIEW

an appliance or machine that enables the cooperative to shut the load off (or cycle it). This shut-off can be done via cellular or other wireless means, or through power line carrier (PLC) technology. The compensation can be in the form of lower off-peak rates, bill credits, or other incentive payments.

These direct load control (DLC) programs can reliably achieve consistent reductions for each event due to the control of each appliance by the utility. DLC programs also have the added flexibility of being dispatched without the prenotification necessary with a PTR or CPP program, as long as this is made clear to members when they sign up. Air conditioning (AC) and water heaters are two of the most commonly controlled types of residential appliances, but other devices may be directly controlled, such as irrigation units or swimming pool pumps.

For many of the residential AC DLC programs, the reduction per participant is between 0.8 and 1.5 kW, but this depends on the specific climate, control time, cycling strategy, and other factors. DLC programs for air conditioners are sometimes tied to smart thermostat programs; these will have additional startup costs due to onsite device installations.

Smart thermostat programs are very similar to an AC DLC program. Instead of a control switch on the air conditioner, the utility installs a smart thermostat at the consumer location. In return, the utility maintains the ability to raise or lower the thermostat a few degrees during event days. A smart thermostat program will tend to have immediate impacts in the first hour of control, but with diminishing impacts as the event persists. This is because, once the house heats up to the new thermostat set point, the AC comes on again. AC DLC programs tend to have more consistent impacts during each hour of the event as the AC continually cycles on and off. Similar programs can be used for electric heat.[14]

Programs that control an AC unit, such as an AC DLC program or a smart thermostat program, might be limited to a maximum monthly or annual number of control hours by the cooperative. Furthermore, these programs are often energy-neutral or almost so, because many members have a very strong usage rebound immediately following the event. Although the reliable reduction impacts and lack of prenotification can greatly benefit the dispatch plan by helping to correctly identify when to call an event, the limited event hours, member inconvenience, and large rebound effect can make optimal dispatch challenging.

Water heater (WH) direct load control programs have average reduction typically around 0.3 kW to 0.8 kW. This depends on climate, time of control, and varies with the season. However, the number of maximum controllable hours for a WH control program is often much higher. WH DLC programs have a greater consumer willingness to participate, because the "reduced comfort" experienced is less noticeable than in an AC DLC program. Both traditional resistance electric water heaters and electric heat pump water heaters are good candidates for a load control program. WH DLC programs will also have a rebound effect after the event is concluded, making them energy neutral or close to it.

Advantages of load control programs include:

- When operating correctly, the response is very predictable, since cooperatives have control of the turn-off switch.
- Programs can be designed to respond with or without notification to members. In programs without notification requirements, with the right technology, cooperatives can have close to real-time control over the load, which is useful for emergency situations.
- When used for large commercial, irrigation, or industrial machines or processes, direct load control can have a large impact per member.
- DLC programs can be integrated with smart appliances and home energy networks.

Disadvantages include:

- The sign-up rate for residential programs can be low, since members lose control of their appliances and may experience reduced comfort (e.g., a warmer house in summer).

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[14] Fenrick, Steven A., Lullit Getachew, Christopher G. Ivanov, David C. Williams. "MVEC Smart Thermostat Program." *TechSurveillance*, NRECA CRN. May 2014.

- Load control switches and communication systems can entail significant upfront costs, for both equipment and installation.
- Installation of load control switches usually requires a home visit.
- Rebound energy usage can create new peaks.
- Depending on the technology used, it may be difficult to verify control of an individual appliance. Some DLC programs could be circumvented (e.g., a member could switch to an AC window unit when their central AC unit is controlled).

LOAD SHIFTING AND OTHER TYPES OF DEMAND RESPONSE

Load shifting is an agreement between a cooperative and a member whereby certain processes or appliances will only be run at designated times. In many cases, load shifting operates similarly to direct load control. For example, a cooperative could install a device on a swimming pool pump, so that the pump only operates during nonpeak hours.

On the C&I side, load shifting can occur when a business agrees to run certain high-energy processes or equipment during off-peak hours (e.g., overnight). This load shifting is often accompanied by incentive payments in the form of rebates or lower off-peak rates. The effect of a load-shifting program is to flatten the load curve, by shaving peaks and filling valleys.

One emerging example of load-shifting involves plug-in electric vehicles (PEVs). PEV loads can be very beneficial for cooperatives because they are a source of added load and revenue that is flexible. Many PEV owners charge their cars overnight, which is a great way for cooperatives to fill valleys. PEVs are, therefore, good candidates for load-shifting rates, load control, and TOU programs. See **Section 7** for more on PEVs.

Another related variation of load control is the "interruptible rate" program. This is a hybrid between a load control program and a rate-induced program. In a typical interruptible rate program, a member (often a large commercial or industrial member) pays a lower rate year-round in return for the cooperative's ability to shut off part or all of the facility on short notice in emergencies.

Types of Energy-Efficiency Programs

Energy-efficiency programs tend to be a bit more straightforward than design response: rate redesigns are typically not necessary and less *ongoing* action is usually required by the consumer, although an initial action is often mandatory, such as the purchase of a new appliance. This section briefly covers some of the main types of EE programs.

There are many ways to categorize EE programs. Usually, they are divided up by rate class or sector (e.g., residential, commercial, industrial, agricultural) because cooperatives are likely to roll out EE programs by member type. There are numerous specific appliances, machines, or processes that can be the subject of an EE program. Any time an appliance or process can be made more efficient, or exchanged for a more efficient version, an EE program is possible.

EE programs often involve rebates or incentives that encourage end-users to make physical modifications to their homes or businesses. For example, assume a residential member is in the market for a new clothes dryer because his old one stopped working. The cooperative can offer him a rebate if he buys an energy-efficient dryer (for example, one that meets the EPA's Energy Star standard). Thus, the member may buy a more-efficient dryer than he would have bought in the absence of a rebate.[15]

Another type of EE program offers an incentive for residential members to have a home energy audit. The audit can uncover efficiency issues in the member's house: leaky windows where air escapes, places that could use more insulation, etc. Again, the idea is that the program induces the customer to make energy-efficiency improvements that he or she would not have made in the absence of the program.

Following are some of the most common EE programs by sector. This is just a partial list; in most cases, the EE program will consist of a rebate

[15] There is the possibility the member was going to purchase the energy-efficient dryer without the rebate. This is known as the "free rider" problem; he is getting the rebate for something he was going to do anyway.

or incentive to buy the product or service that is listed. Almost any appliance or machine can be the object of an EE program. For example, if a cooperative has a lot of swimming pools on its system, rebates for efficient swimming pool pumps could be considered. If irrigation is prominent, rebates could be offered for efficient irrigation pumps. Most industrial machinery and processes can be the subject of EE programs; however, the technical specialization involved in some processes can make the evaluation of options tricky.

Residential EE Programs

- Lighting
- Appliances
- HVAC Systems and Ductwork
- Weatherization
- Whole-Home Audits
- Whole-Home Retrofit Programs
- Residential New Construction Standards
- Low-Income Programs
- Enhanced Billing and Information

Commercial EE Programs

- Lighting
- HVAC Systems and Ductwork
- Building Envelope (Weatherization)
- Commercial New Construction Standards
- Power Strips
- Computer Equipment
- Equipment Retrofits/Rebates (e.g., Commercial Refrigerators, Freezers)

Industrial

- Lighting
- Specialized Equipment Efficiency (Presses, Motors, Dryers, Boilers, etc.)
- Pipes
- HVAC Systems and Ductwork
- Building Envelope

Agricultural

- Lighting (e.g., Barn Lighting)
- Other Agricultural Processes (e.g., Milk Cooling, Ventilation, Pumping, Water Heating)
- Specialized Equipment Efficiency (e.g., Irrigation Pumps)
- Variable Speed Drives

CONSUMER BEHAVIOR PROGRAMS

One subcategory of EE program that is worth emphasizing is the "consumer behavior program." EE programs often involve rebates and energy-efficient equipment, but it is important to remember behavior programs, which can sometimes have low up-front costs but good results. Examples of EE consumer behavior programs include:

- **Prepaid Metering Programs.** Consumers prepay their utility bills for the month, and have a meter that tells them how their bill is progressing relative to the prepay amount. Studies have shown that prepay programs can have substantial conservation impacts. For example, one study of cooperatives showed a 10%+ reduction in energy use from prepay programs.[16]
- **Consumer Feedback Programs.** There are many versions of this program; the basic idea is that consumers receive ongoing information regarding how much energy they are using. The information could be accessed online, through an in-home display, or through a mobile device. In some cases, electric usage can be monitored on a real-time basis.
- **Peer Group Feedback Programs.** For these programs, consumers receive feedback on their bills regarding where they stand with regard to a peer group. An example might be an insert with the monthly bill that says "You used 15% less electricity last month than the average household in your neighborhood."
- **Informational Campaigns.** Consumers are educated on certain aspects of energy usage. For example, consumers can be informed about how energy costs are higher during peak times, or about energy efficiency strategies in general. General conservation campaigns, which encourage lower electricity use across the board, fall into this category.

[16] Martin, William M. *Pay-As-You-Go Electricity: The Impact of Prepay Programs on Electricity Consumption.* Master of Science Thesis. Theses and Dissertations—Agricultural Economics, Paper 29, University of Kentucky. 2014.

- **Competition Programs.** Consumers make a "game" of how much energy they can reduce.

Sometimes a consumer behavior program might act more as a demand response program than an EE program. For example, if a cooperative informed its members that energy at peak times is more expensive, members might respond by voluntarily using less energy at peak times.

What all these consumer behavior programs have in common is that they aim to change members' habits. Typically, these programs involve neither punitive measures (for using more electricity) nor rewards (for using less energy), other than the price of electricity itself. Consumers are motivated to change for social or psychological reasons. Cooperatives should keep these programs in mind as low-cost additions to the traditional appliance/rebate EE programs.

NRECA has published a three-part series in *TechSurveillance* that gives a good overview of consumer behavior programs.[17]

SETTING THE INCENTIVE LEVEL

Incentive levels for EE programs should be based on a cost/benefit evaluation. The goal of setting the incentive level should be to have overall benefits exceed costs at that incentive level (for example, using the total resource cost/benefit test, or "TRC," as described in **Section 3**).

EE participants should be offered incentive levels that induce behavior change and make the purchase of the EE appliance an economically sound decision, based on a participant cost/benefit evaluation (using the Participant Cost Test, also described in **Section 3**).

ENERGY EFFICIENCY PROGRAMS AND COOPERATIVE REVENUES

How DSM programs can be integrated with rate design is briefly discussed in **Section 12**. Here are a few points about the concern that DSM programs can lead to revenue losses:

1. Although revenues will be reduced by some DSM programs, this is not as big of an issue for cooperatives as it is for IOUs. Cooperatives do not have shareholders; the owners are the members. Therefore, a reduction in total load as a result of DSM programs is reflected in a corresponding reduction in members' bills.
2. DR programs typically do not result in much, if any, revenue erosion. DR programs are often called only at peak periods for short times and, in many cases, there is "rebound" usage (after a called event), or pre-event usage (e.g., pre-cooling the house in anticipation of a called event). DR programs, and to a lesser extent EE programs, will also tend to lead to lower wholesale costs.
3. EE programs can induce movement toward beneficial electrification programs. This actually increases revenues. A good example of this is offering a rebate for heat pump water heaters or heat-pump HVAC units.
4. Some EE programs can lead to revenue losses. However, in cases where revenue is lost and cannot be recovered by means of rate design, for a well-structured program, the benefits can still outweigh the costs. For example, if a cooperative implements an energy-efficient air conditioner rebate program, it will likely lose revenue relative to what it would have received in the absence of the program. However, it could also have benefits that far outweigh the costs—avoided capacity, avoided T&D expenses, meeting of GHG targets, etc.

TYING AN EE REBATE TO A DR PROGRAM

Cooperatives should be aware of "combination" programs—EE and DR programs working together. In combination, these programs can sometimes have big returns for cooperatives. For example, a cooperative could offer a large rebate on high-efficiency air conditioners (EE), under the condition that such AC units be

[17] The first part is titled "Behavior-Based Energy Efficiency Program: Volume 1—An Overview" by Christine Grant and Patrick Keegan of Collaborative Efficiency, *TechSurveillance*, July 2014. Subsequent parts appear in August 2014 and September 2014.

enrolled in a load control program (DR). Therefore, even if some revenue is lost due to the AC rebate (considered as a stand-alone program), the reduced peak from the load control program can more than make up for it.

These types of combination programs can also promote revenue growth—from natural gas or propane water heaters to electric water heaters. Natural gas companies can, of course, offer their own rebates, but they do not have the ability to reduce demand charges with “natural gas DR”; there is no such DR, because natural gas does not have the peak-time usage issue that electricity does. Electric water heaters, thus, have an advantage because they can help avoid capacity costs for the utility, while increasing load factors.[18]

DSM: The Next Generation

The previous sections have discussed some of the more “traditional” DSM programs. As technology and the smart grid improve, the DSM landscape will change. Many of these “next generation” DSM programs are already operational, but market penetration is small. These newer DSM programs will be discussed at various places in the Guidebook. Some of the newer DSM-related programs include:

- Energy Storage (Batteries, Thermal Storage, etc.)
- Distributed Generation
- Plug-In Electric Vehicles
- Home Energy Management Systems
- Smart Appliances

The reason these are not included in this section is that the new DSM “programs” are often not programs in themselves, but enablers of the more traditional programs. For example, a home energy network (see **Section 9** discussion) does nothing to reduce demand or energy on its own; rather it allows the member to more fully participate in other programs, such as peak-time rebate or critical peak pricing programs.

Another example is the “smart appliance,” a refrigerator that knows not to run the defrost cycle at peak times, for example. This refrigerator would lower demand by acting as its own load control switch in response to price signals from the cooperative.

Plug-in electric vehicles, improved batteries, and distributed generation are potential “game changers” and are discussed in **Section 7**.

[18] Fenrick, Steve, Chris Ivanov, and David Williams. “The Value of Improving Load Factors Through Demand-Side Management Programs.” NRECA CRN. March 2013.

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3 Cost-Benefit Tests

In This Section:

- **Introduction to Cost/Benefit Tests**
- **Understanding the Tests**
- **Which Test Should My Cooperative Use?**
- **Summary of Recommendations—DSM Cost/Benefit Tests**

Cooperatives naturally want their demand-side management programs to be cost-effective. Unfortunately, the methods for determining cost-effectiveness are not always simple. Questions include:

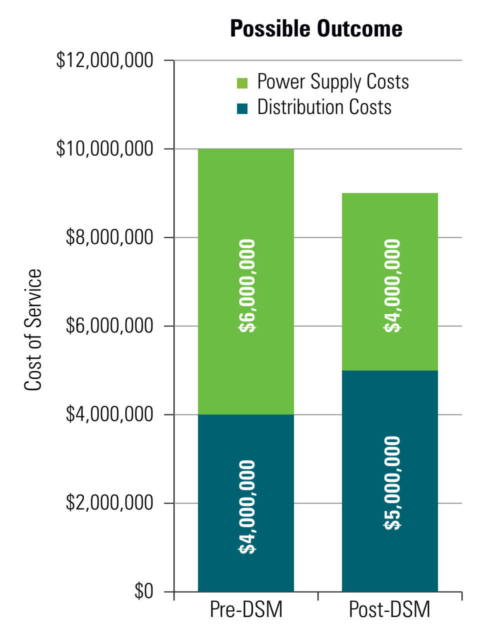

FIGURE 3.1: Illustrative Pre- and Post-DSM Costs

How do we put a dollar amount on avoided capacity? How long will the DSM measure in question have the desired effects? Should we take greenhouse gas emissions into account? Furthermore, there is the question of perspective—when we measure cost-effectiveness, are we measuring it from the perspective of the distribution cooperative? The G&T? The members? Society as a whole (i.e., "all of the above")?

To help answer these questions, several "standard" cost/benefit tests have been developed. Before discussing these standard tests, it is worth repeating the fact that, when considering the cost-effectiveness of DSM, it is often being evaluated in light of the alternative, which is getting the energy or capacity somewhere else—from an RTO/ISO market, from a bilateral contract, or from new power plants.

One common driver behind implementing DSM is avoiding power supply costs. When DSM programs are designed correctly, a no-DSM (or pre-DSM) scenario will have power supply costs higher than the post-DSM scenario. After DSM is implemented, distribution costs may increase because of the DSM programs, but the power supply costs will decrease by a larger amount *if the benefit-cost ratio is greater than 1.0.* A hypothetical situation is illustrated in Figure 3.1.

Introduction to Cost/Benefit Tests

The “standard” tests were discussed in the 2009 CRN DSM Guide, *The Guide to the Essentials of Energy Efficiency and Demand Response*. The basic types of cost/benefit tests have not changed since the 2009 Guide; the reader should refer to that Guide’s detailed discussion of the purpose of each test for more information. This Guidebook will give a brief overview. There are five main tests; the bird’s-eye view of each test is shown in Table 3.1.[19]

These tests are commonly used for both EE and DR programs. They originated with the California Public Utilities Commission (CPUC) and have remained mostly constant, with some minor changes, over the last couple of decades.

TABLE 3.1: The Five Main Cost/Benefit Tests

Test	Key Question Answered	Summary Approach	Implications
Societal Cost Test (SCT)	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society	Most comprehensive comparison but also hardest to quantify
Total Resource Cost (TRC)	Will the sum of utility costs and program participants’ costs decrease?	Includes the costs and benefits experienced by all utility customers, including program participants and nonparticipants	Includes the full incremental cost of the demand-side measure, including participant cost and utility cost
Program Administrator Cost Test (PACT, sometimes called the “Utility Test”)	Will utility costs decrease?	Includes the costs and benefits that are experienced by the utility or the program administrator	• Identifies impacts on utility revenue requirements • Provides information on program delivery effectiveness, i.e., benefits per amount spent by the program administrator
Participant Cost Test (PCT)	Will program participants’ costs decrease?	Includes the costs and benefits that are experienced by the program participants	• Provides distributional information • Useful in program design to improve participation • Of limited use for cost-effectiveness screening
Ratepayer Impact Measure (also known as the “Ratepayer Test”) (RIM)	Will utility rates decrease?	Includes the costs and benefits that affect utility rates, including program administrator costs and benefits and lost revenues	• Provides distributional information • Useful in program design to find opportunities for broadening programs • Of limited use for cost-effectiveness screening

Understanding the Tests

The basic theory behind a cost/benefits analysis is fairly simple: pick a DSM program or portfolio of programs, decide how many years it will be in operation, and, for each year, add up all the costs and benefits from the program for each year, then convert the total costs and total benefits to a net present value. The benefit/cost ratio of the program is the present value (PV) of the benefits, divided by the present value of the costs (where t is the program lifetime in years):

[19] Taken from Woolf, Tim, Erin Malone, Lisa Schwartz, and John Shenot. *A Framework for Evaluating the Cost-Effectiveness of Demand Response*, pp. iv-v, with some modifications. Implementation Proposal for the National Action Plan on Demand Response. Lawrence Berkeley National Laboratory. February 2013.

$$\text{Benefit Cost Ratio} = \frac{\sum_0^t \; PV\ Benefits}{\sum_0^t \; PV\ Costs}$$

While the basic theory is pretty easy to understand, the details can get complicated: **From whose perspective are the costs and benefits measured? What categories of costs and benefits should be included? How do we know how long the program will last? How do we predict future values of certain benefits and costs (e.g., the value of avoided capacity)?** These and other questions will be addressed in the following sections.

COSTS AND BENEFITS FROM WHOSE PERSPECTIVE?

The costs and benefits of a DSM program will vary, depending on which perspective is being considered. For example, lower energy sales will result in reduced wholesale revenue at the G&T level, which is a cost to the G&T, but will also result in reduced wholesale costs at the distribution cooperative level (a benefit). Likewise, incentives or rebates paid to participants are a cost to the distribution cooperative, but a benefit to the participants. There may be some costs and benefits, such as emissions from power plants, which are not considered at all from some perspectives. The five tests in **Table 3.1** each represent a different perspective.

The **total resource cost** (TRC) test measures the ultimate costs and benefits to the entire cooperative system—G&T, distribution cooperatives, and members. Transfer payments between stakeholders, like a rebate paid from cooperative to member, are typically netted out and not included in the TRC test. Absent other constraints, a TRC benefit-cost ratio above 1.0 means that the overall benefits exceed costs for the system being studied. From the TRC perspective, even if one stakeholder initially has higher costs than benefits, stakeholders can "share" these net benefits to other stakeholders via transfer payments, thus assuring that each stakeholder benefits from the program.

The **participant cost test** (PCT) measures a program from the perspective of a program participant. For example, if a residential cooperative member signs up for an Energy Star-rated clothes dryer rebate program, will she come out ahead financially? From her financial perspective, the things that matter are: (1) the cost to her to buy the efficient washer vs. the normal washer, (2) the rebate, and (3) the potential bill savings. (Even if she cares about GHG emissions, these are not counted under the PCT, because there is not any immediate financial impact on her from GHGs.)

Other tests evaluate programs from a different perspective. The **ratepayer impact measure** (RIM) test measures a program from the perspective of nonparticipating ratepayers: will their electric rates go up or down as a result of the program?

The **program administrator cost test** (PACT) evaluates a program from the perspective of the utility (or other party that administrates the program). This test can be thought of as measuring all costs and benefits that would eventually be passed on to consumers.

The TRC test takes both the utility and the participants into account; therefore, the TRC test is basically the PACT test with participant costs and benefits added in. The TRC test does not take externalities such as GHG emissions into account.

The societal cost test (SCT) is the most comprehensive test. In its most complete form, it takes all possible costs and benefits into account, whether these accrue to program participants, the utility, or society as a whole. For example, the SCT includes the benefits of GHG emission reduction, which could, in turn, improve health (by reducing smog, etc.) or strengthen national security (by reducing our dependence on foreign oil). When creating their analyses, cooperatives may not always wish to include some of the more esoteric costs and benefits that can appear in the SCT; however, depending on federal regulations, GHG emission benefits may soon become part of many cooperatives' cost-benefit analyses (see **Section 11**).

THE TESTS EVALUATE DIFFERENT CATEGORIES OF COSTS AND BENEFITS

There are a few things to note about the categories of costs and benefits. **First, as seen in the previous section, what counts as a benefit under one test may count as a cost under another.** For example, under the participant cost test (PCT), incentive payments—such as appliance rebates—are a benefit. Under the ratepayer test (RIM), those same rebates would be a cost, because the rebates are a cost to the utility, which could potentially adversely affect the rates that nonparticipants pay.

Second, the results of an analysis will vary depending on whether the test is being applied at the distribution cooperative level or the G&T cooperative level. The costs and benefits might change depending on which perspective is used; for example, a demand charge could be a cost for a distribution cooperative, but a benefit for a G&T.

In a case where a G&T is administering a system-wide program, it is recommended that separate tests be performed, including tests from the G&T perspective and the distribution cooperative perspective. This enables programs to be designed equitably, avoiding possible cross-subsidization between the G&T and member systems. (Note: If the TRC benefit/cost ratio is above 1.0 for the G&T system as a whole, then, even if one distribution cooperative is under 1.0, each distribution cooperative could still benefit by the program through transfer payments.)

Third, the societal cost test (SCT) is the only major test that addresses GHG emission benefits. The SCT may become more prevalent as GHG emissions become more important for cooperatives. States may set GHG targets for cooperatives, in which case, the societal cost test may become more common.

Fourth, the categories of costs and benefits are not set in stone. There are no widely accepted, detailed descriptions of which costs and benefits go into which categories, and parties can disagree about what goes where. Furthermore, the categories are somewhat fluid and costs/benefits could migrate from one category to another. For example, if GHG emissions are somehow built into the revenue requirements of utilities as a result of the Clean Power Plan, then “avoided GHG emissions” might be subsumed more under a utility cost/revenue umbrella (the PACT test).

The major cost/benefit categories are described in the following sections.

THE MAJOR COST/BENEFIT CATEGORIES

There are many specific costs and benefits of any DSM program; most can be placed in the following major categories:

- Energy and Capacity
  - Energy- and Capacity-Related Avoided Costs (Includes T&D)
  - Additional Resource Savings
  - Market Suppression Effects
- Non-Energy Benefits
  - Miscellaneous Non-Energy Benefits
  - Greenhouse Gas Benefits
  - Reduced Risk, Avoided Cost of Environmental Compliance
- Administrator and Participant
  - Participant Benefit (Incentives and Bill Savings)
  - Administrator (Cooperative) Equipment and Installation Costs
  - Administrator Program Overhead Costs
  - Participant Contributions
  - Incentive Payments/Lost Revenue

Avoided capacity/energy and associated **avoided T&D costs** are fairly self-explanatory; these are the benefits that a cooperative gets from not having to buy or produce energy, build or buy capacity, and upgrade and maintain T&D assets. However, as we will see, assigning an exact dollar value to these benefits can be tricky.

“**Additional resource savings**” just means savings of resources other than electricity. For example, when weatherization helps reduce air conditioning use (electricity), it may also reduce furnace use in the winter (natural gas).

“**Market suppression effects**” occur when DSM reduces energy and capacity demand in an organized market, thus leading (at least temporarily) to reduced clearing prices. Most cooperatives will probably not estimate market suppression effects for their analyses; for smaller utilities, these effects will be miniscule and difficult to calculate.

Participant and utility/administrator costs and benefits are also fairly self-explanatory; these are the costs and benefits seen by program participants and by utilities as DSM programs are implemented. These include installation costs, administration costs, the cost of personnel dedicated to DSM programs, rebates, and participant benefits.

Incentive payments include rebates, program incentives, and any equipment and installation costs paid by the program administrator.

These cost and benefit categories are covered in more detail in **Costs and Benefits of Demand Response** and **Costs and Benefits of EE Programs**, where the specific costs and benefits for DR and EE programs are discussed. The energy and capacity benefits are typically the focus of a basic cost-benefit analysis, along with participant and administrator costs and benefits. Non-energy benefits are difficult to quantify; they are discussed briefly in the next section.

NON-ENERGY BENEFITS

Some benefits, such as avoided capacity, are directly related to the production and consumption of electricity, but not all benefits are; these are "non-energy benefits." These are costs and benefits that are not directly related to electric use. Non-energy benefits are often external to the utility and its consumers, and can be difficult to quantify in dollar terms—e.g., avoided greenhouse gas emissions, improved health from cleaner air, reduced consumer comfort, etc.

> The terminology around non-energy benefits is confusing. Sometimes the term "non-monetized benefits" is used; this represents things like "increased national security due to less dependence on foreign oil," which is very hard to put a dollar figure on. The problem is that some benefits which were previously not monetizable become monetizable—for example, a market for GHG reduction. Another commonly used term is "other program impacts" (OPIs), which refer to costs and benefits outside the production of electricity. OPIs typically include: (1) non-energy benefits, and (2) "additional fuel savings," which result from savings of natural gas, water, propane, etc., as a result of electric DSM programs. An additional confusion is that, although many sources only use the phrase "non-energy benefits," there can be "non-energy costs" as well; for example, if a consumer turns off her AC to get a peak-time rebate, she sacrifices comfort, which is a cost.

An important non-energy benefit to G&Ts, one that is sometimes not discussed, is the possibility of **reduced risk**. Consider a G&T that needs to procure additional capacity because of a projected load increase due to, for example, growth in oil production or the expansion of a very large C&I member. The G&T could invest in a new power plant with the expectation that the plant will be needed for the next 50 years. However, note that there are quite a few ways the projected load could be different than expected: (1) the load could be a "boom" load, i.e., it could be present for a few years and then decline rapidly; (2) other electric usage could decline (due to a separate lost load or general declines in usage); or (3) the oil load could fail to materialize in the first place (due to political or economic factors). Any of these scenarios could result in a stranded asset if a new plant is built.

Alternatively, an aggressive DSM program, perhaps including a DR program for oil wells, could be utilized to eliminate the need for the new plant. The DSM program has the flexibility to be discontinued if circumstances change; this would result in far fewer stranded assets.

Other non-energy benefits are more commonly mentioned in the literature. Sample non-energy benefits and costs include:[20]

- Reduced Risk
- Avoided GHG Emissions
- Operation and Maintenance Cost Savings (to participants)
- Participant Health Impacts
- Increased Employee Productivity
- Effect on Property Values
- Improved Comfort
- Decreased Comfort (e.g., when thermostats are set higher in the summer)
- Public Health and Welfare Benefits
- Air Quality Impacts
- Water Quality and Quantity Impacts
- Decrease in Coal Ash Ponds and Coal Combustion Residuals
- Improved Economic Development and Employment Effects
- Decreased Societal Risk

[20] List partially adapted from Lazar, Jim, Ken Colburn, et al. *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Regulatory Assistance Project (RAP).

- Increased Energy Security
- Increased National Security
- Benefits for Low-Income Customers

At the present time, most cooperatives probably do not account for these benefits in their analyses; they are too hard to quantify. However, in the future, these benefits are likely to play a bigger role. For example, avoided GHG emissions could become an important benefit if federal or state governments set GHG emission targets that apply to cooperatives. If cooperatives are assigned targets, they will wish to get "credit" for every DSM benefit, and these non-energy benefits will certainly be a part of that process. If state or federal emissions or EE targets are assigned, cooperatives should first look to regulators for guidance on how to value non-energy benefits. If avoided GHG emission and other non-energy benefits become monetizable or tradable, the markets should also provide some guidance on how to value them. We cover avoided GHG emissions in more detail in **Section 4**.

Which Test Should My Cooperative Use?

Of the five tests mentioned above, the total resource cost test (TRC), the societal costs test (SCT), and the program administrator cost test (PACT) are the most commonly used at the state level. A study done by the American Council for an Energy-Efficient Economy (ACEEE) in 2012 counted 29 states that use the TRC as the primary test, five that used the PACT, and six used the societal cost test.[21] It is common practice to use at least two tests, so that different perspectives can be seen. However, it often helps to have a primary test, and that primary test is typically the TRC.

A positive TRC test indicates that the anticipated benefits exceed the costs for the entire cooperative system. It is a summation of the costs and benefits of all the stakeholders. The other cost-benefit tests can then be used to determine how each stakeholder (G&T, distribution cooperative, participants) fares due to the program. Absent other constraints, a positive TRC test implies that all stakeholders can be made better off if the program is designed accordingly (using transfer payments if needed). In other words, where the TRC test indicates a benefit-cost ratio over 1.0, a "win-win" across all stakeholders should be possible and can be reflected in the more specific stakeholder tests.

It should be noted that the TRC test typically does not count environmental externalities. If compliance with greenhouse gas emissions standards becomes an issue, the societal costs test will become more prevalent. Thus, cooperatives should become proficient in two tests: (1) the PACT, and (2) either the SCT or the TRC test.

Many cooperatives will also be interested in the RIM test. The RIM test measures the impact of a program on the rates of program participants and nonparticipants. It measures the presence of possible cross-subsidization from ratepayers to DSM program participants.[22]

The participant cost test (PCT) is the measure of the quantifiable benefits and costs to the member who participates in a DSM program. It does not include avoided capacity and energy costs and is, therefore, of limited use for utility planning purposes. However, it is useful to do a PCT analysis to make sure that, from the prospective participants' perspective, the program is "worth" joining.

COST AND BENEFIT CATEGORIES (DETAILED)

For both EE and DR, the first step when formulating a cost/benefit calculation is to determine which *categories* of costs and benefits will be used.

On the benefit side, cooperatives should realize that most DSM programs have a number of benefits categories. DR programs do reduce peak capacity, which, in turn, lowers demand charges (for distribution cooperatives) and reduces capacity needs (for G&Ts), but DR

[21] Kushler, Martin, Seth Nowak, and Patti Witte. *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs*. Report Number U122, p.13. American Council for an Energy-Efficient Economy. February 2012. One state did use the RIM as its primary test, but has since discontinued that practice. (See Martin Kushler's *A Brief Review of Benefit-Cost Testing for Energy Efficiency Programs: Current Status and Some Key Issues*, June 3, 2014.) Note: Sometimes the PACT is called the utility cost test, or UCT.

[22] This same cross-subsidization concern is currently being discussed in regards to solar installations.

programs also have many other benefits—reduced line losses, T&D savings, lower risk, and many more. On the costs side, cooperatives need to be aware of all the various cost categories as well. For example, energy-efficiency programs may have rebates as the primary cost category, but there are also administrative costs, M&V costs, and others.

The cost and benefit categories for EE and DR are typically similar, although there are some minor differences. For illustration, look at the major categories for costs and benefits for DR programs, and how they fit in to the five major tests, as shown in Table 3.2.[23]

TABLE 3.2: DR Costs and Benefits

	Participant	RIM	PACT	TRC	Societal
Benefit					
Avoided Capacity Costs	—	Yes	Yes	Yes	Yes
Avoided Energy Costs	—	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	—	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	—	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	—	Yes	Yes	Yes	—
Market Price Suppression Effects	—	Yes	Yes	Yes	—
Avoided Environmental Compliance Costs	—	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	—	—	—	—	Yes
Participant Bill Savings	Yes	—	—	—	—
Financial Incentive to Participant	Yes	—	—	—	—
Tax Credits	Yes	—	—	Yes	—
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	Depends	Depends	Depends	Depends	Depends
Cost					
Program Administrator Expenses	—	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	—	Yes	Yes	Yes	Yes
Financial Incentive to Participant	—	Yes	Yes	—	—
DR Measure Cost: Program Administrator Contribution	—	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	—	—	Yes	Yes
Participant Transaction Costs	Yes	—	—	Yes	Yes
Participant Value of Lost Service	Yes	—	—	Yes	Yes
Increased Energy Consumption	—	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	—	Yes	—	—	—
Environmental Compliance Costs	—	Yes	Yes	Yes	Yes
Environmental Externalities	—	—	—	—	Yes

[23] Woolf, Tim, Erin Malone, et al., *Op. cit.* Lawrence Berkeley National Laboratory.

WHICH COST/BENEFIT CATEGORIES SHOULD MY COOPERATIVE USE?

If a cooperative is using the cost/benefit analysis to satisfy a regulator, it should by all means include every cost and benefit category for which it has a reasonable estimate. Therefore, if a state sets a target based on dollars, absolute kWh/kW, or kWh/kW as a percentage of load, cooperatives should utilize all available benefits to reach the target. The regulator, in that case, may provide some assistance with estimations of non-energy benefits. Thus, when a regulator is involved, the cooperative should look at **Table 3.2** and related tables, and use as many benefit categories as possible, so as to cost-effectively meet the regulator's assigned goals.

If the cooperative is not trying to meet an external target, but is trying to: (1) avoid capacity, energy, and T&D costs, and (2) provide the most cost-effective programs to its members and/or respond to member preferences, then the cooperative may not be as concerned with non-energy benefits. Cooperatives may also not be concerned with additional resource savings or market suppression effects. It is worth keeping in mind, however, that these benefits exist and, even if they are not easily priced at the moment, they may be more important in the future.

TABLE 3.3: Hypothetical PTR Program Parameters

2016 Charges	
Winter Avoided Production Demand Charges (per kW)	$14.16
Summer Avoided Production Demand Charges (per kW)	$20.26
Avoided Transmission Demand Charges (per kW)	$3.50
Avoided Substation Demand Charges (per kW)	$0.95
On-Peak kWh Charge (Jan., Feb., Jun., Jul., Aug., Dec. only)	$0.075
Off-Peak kWh Charge	$0.04

TABLE 3.4: Hypothetical Residential PTR Program Costs and Assumptions

One-Time Variable Costs Per Participant	Postage, mailing costs, program description, billing, and data changes	$18
One-Time Project Costs	Personnel Training Marketing Materials Website Development	$20,000 $20,000 $10,000
Annual Operational Project Costs (marketing, impact evaluation, administration, peak event messaging)	2016 2017 2018 Steady State (2019-2038)	$85,075 $103,000 $106,090 $109,273
Rebate Payment per kWh Saved During Peak Events		$1.00
Other Assumptions	Discount Rate Inflation Rate	5.0% 3.0%
Impact Assumptions at Meter (kW monthly peak impact per participant)	0.30 kW	

BASIC COST/BENEFIT: PEAK-TIME REBATE PROGRAM

To illustrate a basic cost/benefit analysis, consider a residential PTR program at a hypothetical distribution cooperative starting in 2016.[24] The cooperative has separate summer and winter demand charges. There is also an associated transmission charge per kilowatt. There is an added "on-peak" energy charge in the summer and winter months. The charges for 2016 are shown in Table 3.3, along with other assumptions about the program.

This example is for a distribution cooperative which buys wholesale power with a seasonal demand charge and an on-peak/off-peak energy rate. For simplicity's sake, we assume the demand and energy charges accurately capture the marginal costs of demand and energy to the G&T. However, the G&T perspective cost-benefit calculation should also be conducted based on the value of avoided capacity and energy costs to the G&T.

The assumed wholesale charges are given in Table 3.3.

The costs of the program and other assumptions are provided in Table 3.4.

In 2016, it will be a pilot program, and so the number of participants is low. Starting in 2017, the program is expected to be available to all who want it, estimated that year at 10,000 participants.

[24] All numbers used in this example are hypothetical, but are close in magnitude to actual numbers from cost/benefit analyses Power System Engineering, Inc., has performed for cooperatives.

TABLE 3.5: Sample PTR Cost/Benefit Analysis

	Total Resource Cost Test (TRC)	Distribution Utility Test (PACT)	Participant Cost Test (PCT)
Present Value of Benefits (2016)	$6,483,216	$6,483,216	$3,845,651
Present Value of Costs (2016)	$1,170,297	$5,015,947	$0
Net Present Value	**$5,312,919**	**$1,467,269**	**$3,845,651**
Benefit-Cost Ratio	**5.54**	**1.29**	**N/A**
Sum of Nominal Benefits	$13,688,155	$13,688,155	$7,972,268
Sum of Nominal Costs	$2,329,194	$10,301,462	$0

To perform a cost/benefit over a 20-year period, the avoided demand charges and rebates are added up for each year. The annual operational costs are added to the rebates, and then a net present value (NPV) calculation is done, which takes the discount rate into effect. The benefit/cost ratio of the entire program is calculated by dividing the PV of the benefits by the PV of the costs. If this ratio is over 1.0 under any particular test, the program is cost-effective under that test. Table 3.5 shows a sample of what this analysis might look like using the benefit/cost ratio under the TRC test, the distribution utility test (the PACT), and the participant test (PCT). Again, numbers are not supposed to reflect any actual cooperative.

The difference between the TRC and the PACT is that, for the PACT, the present value of costs includes the rebates paid to the participants and the TRC does not (or, more precisely, in the TRC, the rebates are cancelled out by the cost to the cooperative and the benefit to the participants). The benefit/cost ratio under the TRC is quite high. The ratio is "infinity" under the participant cost test, since there is essentially no cost paid by the participants in a PTR program. The participant may bear the "cost" of a warmer house, but that is not typically included in the participant cost test.[25]

There are a few points to note about the above analysis:

1. It is fairly simplified. Several assumptions were made which may need modification. For example, the program assumed that 10,000 members would participate in year 2017 and in each year following. In reality, this number would start off a little lower in 2017 and rise at a certain percentage per year. This analysis was done from the distribution cooperative perspective. The avoided costs for a distribution cooperative are easy to set; they depend on the energy and demand charges from the G&T. It is much harder to calculate the avoided energy and demand charges for the G&T, as will be seen in **Section 4**. An annual increase has been estimated for all demand charges.
2. PTR programs have fairly low upfront costs as no equipment is needed (assuming AMI is already in place). Annual operational costs include the calculation of participant baselines, and the formulation of a dispatch strategy. The dispatch strategy is more important for a DR program that has either: (1) an added marginal cost for each dispatch (as in a PTR program), (2) a limited number of event hours (interruptible C&I program), or (3) the possibility of a high level of member inconvenience (e.g., air conditioner load control). For a program with essentially "free" called events, such as a water heater direct load control program with no "per event" payments, a precise dispatch strategy is not as important.
3. Changing the rebate amount may change the impact at the meter. For example, the cooperative might save a lot in rebates by reducing the rebate to $0.75 per kilowatt reduced. However, this could cause the participant reduction per event hour to decrease as well. The pilot program should be designed to test some of this sensitivity. For example, half the pilot participants could get one rebate amount, half could get another.

[25] For a real-world example of a PTR cost/benefit, please see Power System Engineering's expert witness testimony this this subject at: Kansas Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.

DISCOUNT RATES, NET-TO-GROSS RATIOS, TIME FRAMES, AND OTHER CONSIDERATIONS

Discount Rates

The calculation of the net present value of costs and benefits requires the use of a discount rate. The discount rate to use depends on which test is being used. For example, if the participant cost test is used, the appropriate discount rate is the consumer lending rate, because this is the rate members would pay if they financed the program. From the cooperative's perspective (program administrator cost test, or PACT), the discount rate to use is the cooperative's weighted average cost of capital (WACC), or the interest rate paid if supply-side investments need to be financed.

In a recent survey of EE programs across the country, ACEEE found that, from 2009 to 2012, the typical WACC rates used in utility cost/benefit analyses ranged from 7% to 8% (in nominal terms). The same survey showed that societal discount rates ranged from 1.2% to 6.0% in real terms.[26]

Net-to-Gross Ratios

Another parameter that can affect the cost/benefit analysis is the net-to-gross ratio (NTG). The NTG adjusts the cost/benefit analysis so that it only counts efficiency gains that are a direct result of the program being considered. Some efficiency gains might have come about even if no program had been in place.

One thing the NTG attempts to address is the problem of "free riders"—people who receive a rebate, but who would have adopted the measure even in the absence of the program. For example, if a cooperative offers a rebate on an Energy Star rated air conditioner, there are some members who receive a rebate, but would have bought Energy Star air conditioners even without the rebate. Other factors that the NTG might correct for include:

- Cases where the consumer receives the equipment in question, but does not install it (e.g., a consumer gets a CFL light bulb but continues to use incandescents);
- Equipment failures/bypasses (e.g., load control switches cease to function or consumers find a way to bypass direct load control); and
- Spillover effect (e.g., consumers who do not sign up for a rebate but are nonetheless influenced to adopt an efficient resource by the existence of the program).

NTG ratios can be difficult to calculate; it is difficult to measure how many free riders there are, for example. Cooperatives should take one of two routes with respect to the NTG ratio: (1) assume that the gross benefits and costs are identical to net (in other words, a ratio of 1.0), or (2) use an NTG ratio of 0.9.[27] If a regulator is involved, the easiest solution is to ask their staff what ratio they would prefer.

It is appropriate to assume that the NTG ratio is 1.0 for some programs, especially DR programs where the effect is measured or calculated. For example, in PTR programs, you can estimate participants' load reduction by comparing the expected usage to actual usage; there is no equipment to fail and you can measure what consumers use in the absence of the program. For EE programs, an NTG lower than 1.0 might be appropriate if the cooperative wishes to be conservative in its estimation of program effects.

Measure Life

For EE programs, the cost/benefit analysis should cover the expected useful life of the measure in question. For example, if a cooperative gives rebates on purchases of energy-efficient clothes washers, it should calculate the cost-benefit for those washers based on the expected useful life of the washers. A CRN paper containing sources of useful life estimations[28] states:

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[26] Molina, Maggie. *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs*. American Council for an Energy-Efficient Economy. Research Report U1402, p. 15. March 2014. Nominal discount rates take inflation into account, whereas real discount rates do not include inflation. If inflation is 2%, a nominal discount rate of 7% would be 5% in real terms.

[27] See, for example, Molina, Maggie, *Ibid.* The ACEEE estimates a NTG of 0.9 as being consistent with most states that consider the issue.

[28] Fenrick, Steven A., and David C. Williams. *Estimated Useful Life of Energy-Efficiency Improvements.* NRECA CRN 2013.

In most cases, it will not be necessary for cooperatives to perform their own [studies] and … using the EUL estimates from a national database will be [their] simplest and most effective choice.… The database recommended … is the Database for Energy-Efficient Resources (DEER), provided by the California Public Utilities Commission (CPUC).

For many DR programs, the measure life can be whatever the load forecast window is, typically 15 or 20 years. Programs like PTR don't have any equipment that can fail, and so these programs can go on indefinitely. Time-of-use rates can also be extended indefinitely into the future; the smart meter and the associated systems are the main equipment, and those are not typically budgeted to DR programs in the cost/benefit analysis.

Load control programs may have switches or other equipment that have projected lifespans; these programs can be analyzed for the expected life of the equipment. Switches that fail before their lifetime is up can be covered by using the appropriate NTG ratio or by having switch replacement costs included in the "cost" category in the cost/benefit analysis.

Summary of Recommendations—DSM Cost/Benefit Tests

Using the PACT (utility test) is recommended, plus either the SCT (societal cost test) or the TRC (total resource cost) test. The PACT will allow accountants to see how a program will affect cooperative finances. The TRC test allows the cooperative to see how all cooperative stakeholders, including program participants and nonparticipants, will benefit. The SCT is similar to the TRC test, but the SCT adds non-energy benefits, such as avoided greenhouse gas emissions.

Which cost/benefit categories should a cooperative use in its analysis? The reason that an analysis is being performed should dictate which cost/benefit categories a cooperative should utilize. If a cooperative is performing a DSM analysis to meet a regulator's target, it should use every possible benefit allowed by the regulator in order to meet the target. For example, it should assign a benefit to avoided GHG emissions, as seen in **Section 4**.

On the other hand, if a cooperative is using DSM to defer or eliminate the need for added capacity (built or purchased), it may wish to focus more on the capacity/energy/T&D benefits of DSM. The consequences of failing to defer capacity could be costly. Therefore, omitting the non-energy benefits can serve as a kind of "safety valve." The cooperative will know that the non-energy benefits are still present; it can even calculate these benefits. But cooperatives can design DSM programs such that capacity/energy/T&D benefits alone give a benefit/cost ratio of over 1.0, even without considering non-energy benefits.

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4 Methods for Determining Specific Costs and Benefits

In This Section:

- **Costs and Benefits of Demand Response**
- **Costs and Benefits of EE Programs**
- **Potential Studies**

In this section, we present big-picture strategies for how to monetize the various categories of costs and benefits for DSM programs. The costs of DSM are usually tangible and easier to calculate: rebates, incentives, equipment installed on appliances and machines, administrative costs, marketing, etc. These costs, while not always easy to predict exactly, are at least "known" in the sense that we have an idea of how much cost to put on a given level of effort. For example, we might not know how much mailing and marketing would be required for a DSM program, but once we nail down the amount required, we would be able to calculate the costs.

Benefits are different. They are harder to estimate and quantify. Even after a DSM program is deployed, estimating the exact energy or capacity saved is difficult, because we cannot meter energy that is not consumed.

Furthermore, even if we know how much energy or demand is avoided, determining an exact $/kW or $/kWh value is tricky; there are many different methods. Avoided capacity is particularly difficult to put an exact dollar figure on. Other non-energy benefits, such as avoided risks, are also problematic.

Therefore, in this section, much of the focus will be on valuing benefits, especially avoided energy and capacity. This is because long-term avoided energy and capacity are key components of a cost/benefit analysis. Cooperatives must make two main decisions in this area: (1) how to value capacity and energy in general, and (2) how to project those values into the future.

In the PTR cost/benefit analysis discussed in Section 3, it was fairly simple to determine the current values for energy and capacity; they were based on the wholesale charges from the G&T. If a distribution cooperative goes it alone on a DSM program,[29] the G&T's energy and demand charges should form the basis for those values in the first year of the program. G&Ts may also give estimates for these values into the future, and these projected values can be inputted into the analysis.

For G&Ts, the current and projected costs of energy and demand can be less transparent. One possible source is the market—either the RTO, if the G&T is in one, or the bilateral market if not. Some RTOs give projected capacity costs that go out a couple of years. Another source could be the G&T's expected production cost of

[29] Again, it is not recommended that distribution cooperatives coordinate their own DSM programs if they are members of a G&T; this should be done at the G&T level where possible.

TABLE 4.1: General Approaches for Valuing Avoided Energy and Capacity Costs

Utility Type	Near-Term Analysis (i.e., Market Data Available)	Long-Term Analysis (i.e., No Market Data Available)
Distribution Cooperative	Current forward prices of energy and capacity	Long-term forecast of market prices of energy and capacity
G&T	(1) Current forward market prices of energy and capacity, or (2) Expected production cost of electricity and value of deferring generation projects	(1) Long-term forecast of market of energy and capacity, or (2) Expected production cost of electricity and value of deferring generation projects

electricity and the value of deferring generation construction projects. The different general approaches are summarized in Table 4.1.[30]

In Table 4.1, for G&Ts there are two main strategies for valuing avoided energy and capacity: (1) markets, or (2) expected production costs. "Markets" can refer to either an RTO footprint or a developed bilateral market. In either case, determining the costs for avoided energy and capacity for a few years out can be done by looking at forecasts for that particular market. These forecasts could come from a number of sources, including:

- The RTO itself
- A third-party forecast, such as Platt's *Megawatt Daily*
- The cooperative's own internal market forecast
- Federal forecasts (e.g., the *EIA Annual Energy Outlook*, which has projected electricity prices to 2040 nationwide and by geographical region of the country)
- State forecasts (e.g., CPUC in California)

The second major strategy in Table 4.1 for G&Ts is "expected production cost of electricity and value of deferring generation projects." This method is appropriate when there are no market forecasts available. This can be done in a couple of different ways. One method is production simulation models, which are software tools that run dispatch scenarios based on different resource mixes. The National Action Plan for Energy Efficiency (NAPEE) describes the process as follows:

> *For self-resourced electric utilities that do not have wholesale market access or actively trade electricity, a "production simulation" forecast may be the best approach to forecast energy costs. A production simulation model is a software tool that performs system dispatch decisions to serve load at least cost, subject to constraints of transmission system, air permitting, and other operational parameters. The operating cost of the "marginal unit" in each hour or time period is used to establish the avoided cost of energy.*[31]

This can be a good choice for G&Ts without market exposure. Another option for G&Ts which do not rely on the market much is setting marginal costs based on a "proxy plant," in which a specific type of plant, usually a combined cycle or combustion turbine, provides the parameters for analysis, as described by the NAPEE:

> *Developing a "proxy plant" is an alternative to production simulation approaches and may be used when market data is not available or appropriate. Under this approach, a fixed hypothetical plant is used as a proxy for the resources that will be built to meet incremental load. Selecting the proxy-plant, the construction costs, financial assumptions, and operating characteristics are all assessed from its characteristics. As an example, the variable costs of a combined-cycle natural gas plant may be used as a proxy for energy costs. The annual fixed cost of a combustion turbine may be used as a proxy for capacity costs.*[32]

These are the typical sources for current and future costs of avoided energy and capacity. The next few subsections will discuss how these values fit into DR and EE cost-benefit analyses.

[30] Adapted from the National Action Plan for Energy Efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*, p. 4-4. Energy and Environmental Economics, Inc., and Regulatory Assistance Project, U.S. Environmental Protection Agency. November 2008.

[31] *Ibid.*, p. 4–5.

[32] *Ibid.*, p. 4–5.

Costs and Benefits of Demand Response

For DR programs, avoided capacity is typically the largest benefit. Figure 4.1 is taken from an LBNL report[33] and shows the benefits and costs of a DR portfolio run by a California utility.[34] Avoided capacity is by far the largest benefit. DR programs are usually designed to keep the peak down for a short period of time and, therefore, do not accumulate significant energy savings or GHG benefits in the way that EE programs do.

Therefore, when determining DR program benefits, the most important question is usually this: **How should my cooperative calculate the avoided capacity of the DR program?** That valuation will most likely be the key driver in the accuracy of the analysis. It does not pay to spend as much time on the other benefits of DR.

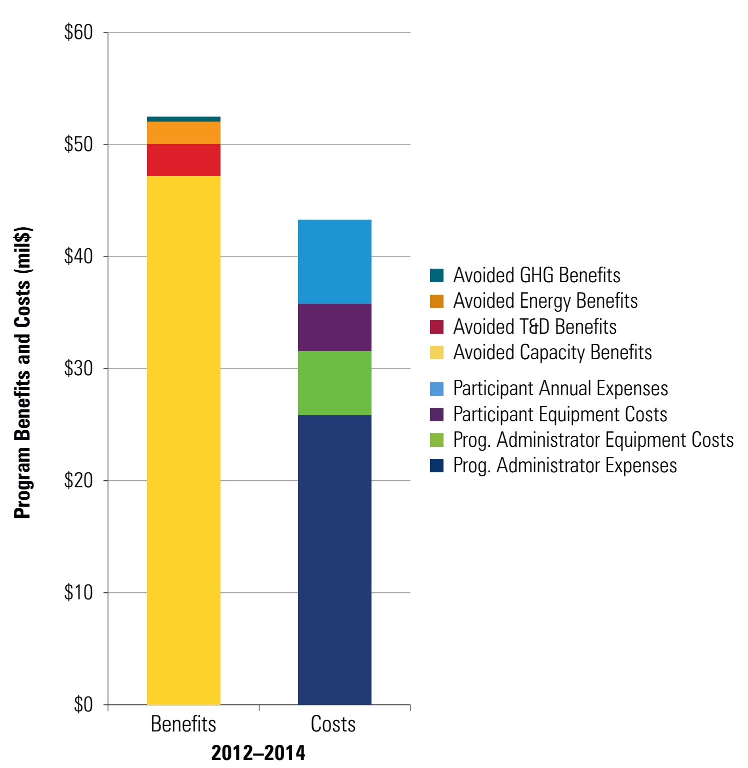

FIGURE 4.1: Illustrative DR Cost/Benefit Components

VALUING AVOIDED CAPACITY: DEMAND RESPONSE

Avoided capacity is typically the biggest benefit for DR programs; unfortunately, it is also not always straightforward to quantify.[35] The general considerations were covered in the section above. There are also some considerations specific to DR, such as:

- **How dispatchable is the resource?** Dispatchable resources, such as direct load control by the cooperative, tend to have a higher value. Programs where the result is controlled by the consumer, such as time-of-use rates, may not be as "firm" at providing capacity.
- **Is there a capacity market in the region?** Does it treat DR similarly to other capacity? If there is a wholesale capacity market where the DR is being implemented, the value of avoided capacity could simply track the market price for capacity.
- **If the alternative to a DR program is building a power plant**, which type and what would the fixed and variable costs be?
- **Are there limits or constraints on the DR program?** Are limits on the number of times an event can be called or on the duration of each event? How much notification is required?
- **Will the DR resource be used as a reserve**, or be actively used to reduce system peak demands?

Luckily, the convoluted process of valuing capacity can be shortened in many cases. If a distribution cooperative is planning a DR program on its own, it can simply value power supply capacity at the G&T demand charge, as seen in previous sections. Similarly, if a G&T buys or sells capacity from/to a third party, a DR program implemented at the G&T level means avoided capacity can be valued at the contracted rate.

If your cooperative is in the footprint of an RTO with a wholesale capacity market, you can simply look to the RTO forward capacity price.

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[33] Woolf, Tim, Erin Malone, et al., *Op. cit.* Lawrence Berkeley National Laboratory.

[34] Note: This figure is for illustrative purposes only; different DR programs may have very disparate results.

[35] Some points in this section are adapted from Woolf, Tim, Erin Malone, et al., *Op. cit.*, Chapter 5. Lawrence Berkeley National Laboratory.

Thus, in regions with wholesale capacity markets, "the basic approach should be to forecast the market price for capacity for each year in which the demand response program will be operational."[36] These prices can be forecast by the local RTO or other balancing authority.

As a general rule, in the long term, the forecasted prices for capacity should tend to converge toward the cost of a new natural gas combustion turbine, which is the most commonly built peaking (or "peaker") plant type. Thus, one strategy for future prices would be to simply have the avoided cost of capacity converge to projected costs of a natural gas plant (whichever type of plant would be built if not for the DSM).

TABLE 4.2: ISO-NE Historical Forward Capacity Auction Prices

Auction Commitment Period	Total Capacity Acquired (MW)	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/kW-Month)
FCA #1 2010/2011	34,077	1,188	626	$4.50 (Floor Price)
FCA #2 2011/2012	37,283	448	1,157	$3.60 (Floor Price)
FCA #3 2012/2013	36,996	309	1,670	$2.95 (Floor Price)
FCA #4 2013/2014	37,501	515	144	$2.95 (Floor Price)
FCA #5 2014/2015	36,918	263	42	$3.21 (Floor Price)
FCA #6 2015/2016	36,309	313	79	$3.43 (Floor Price)
FCA #7 2016/2017	36,220	245	800	$3.15 (Floor Price) NEMA/Boston: $14.99
FCA #8 2017/2018	33,712	394	30	$15.00/new $7.025/existing
FCA #9 2018/2019	34,695	367	1,060	System wide: $9.55 SEMA/RI: $17.73/new $11.08/existing
FCA #10 2019/2020	35,567	371	1,459	$7.03

HISTORICAL RTO CAPACITY PRICES

Some RTOs/ISOs currently have "mandatory" forward capacity markets, meaning that certain resources must bid their capacity into the markets. PJM, NYISO, and NE-ISO all have mandatory capacity markets. MISO's capacity market is not yet mandatory and its shareholders are resisting making it so. Capacity prices tend to be higher in markets where the auction is mandatory.[37]

Table 4.2 shows the results of the ISO-NE Forward Capacity Auction results for the past few years.[38] It should be noted that, in most RTOs, forward capacity prices can vary from region to region. When an RTO reports its overall capacity price, it is typically a weighted average of some sort.

For most of the past few years, ISO-NE capacity was around $3 to $4/kW-month; however, for 2017/2018, this shot up to around $15/kW-month for new capacity and $7/kW-month for existing capacity. 2019/2020 was back down to $7.03/kW-month. The 2017/2018 prices in Table 4.2 are probably more reflective of peaker construction costs.

Table 4.3 shows the RPM Base Residual Auction Resource Clearing Price Results in PJM for the past years.[39] The clearing price has been

[36] *Ibid*., p. 37.

[37] See, e.g., Heidorn, Jr., Rich, "MISO Stakeholders Call for Seasonal Resource Construct; Cool to Mandatory Capacity Market," *RTO Insider*, March 2, 2015. There was almost as much consensus among stakeholders in opposition to a move to a mandatory capacity market such as PJM's. "MISO is not PJM," said Justin Joiner of Vectren. "The concerns there do not exist in MISO." Alcoa and other members of the End-Use Customers sector also rejected the idea, also noting the differences between MISO, PJM, NYISO, and ISO-NE: "There has been a vibrant bilateral capacity market in place within the MISO footprint that has allowed end-use customers in MISO that do have retail choice (as well as municipal and cooperative electric utilities) the ability to contract for capacity at fixed prices at least three years into the future at reasonable prices significantly lower than in these other ISOs and RTOs."

[38] See ISO-NE's Results of the Annual Forward Capacity Auctions.

[39] PJM 2018–2019 RPM Base Residual Auction Results.

more variable than that of NE-ISO, with the price bouncing around between $0.49/kW-month and $5.23/kW-month over the last 11 auctions, with 2017/2018 coming in at $3.60/kW-month. Note again that these prices would vary from region to region.

These two examples show how capacity could be valued in an RTO/ISO footprint with an established market. As other RTOs (such as MISO and SPP) expand—and possibly add capacity markets—the historical prices will form a backdrop against which to value avoided capacity from DSM.

TABLE 4.3: PJM RPM Base Residual Auction Resource Clearing Price Results

Auction Year	RTO Resource Clearing Price ($/MW-Day)	$/kW-Month
DY 07/08	$40.80	$1.22
DY 08/09	$111.92	$3.36
DY 09/10	$102.04	$3.06
DY 10/11	$174.29	$5.23
DY 11/12	$110.00	$3.30
DY 12/13	$16.46	$0.49
DY 13/14	$27.73	$0.83
DY 14/15	$125.99	$3.78
DY 15/16	$136.00	$4.08
DY 16/17	$59.37	$1.78
DY 17/18	$120.00	$3.60
DY 18/19	$164.77	$4.94

More detail about the PJM forward capacity market appears in **Section 10**.

AVOIDED ENERGY

Table 4.1 showed the possible sources for avoided energy costs. In that section, we saw that the wholesale market is a good place to look when estimating capacity values. The same is true for energy. However, the source of the wholesale price may be different for the distribution cooperative and the G&T.

In most cases, a distribution cooperative can simply use the G&T's kilowatt-hour energy wholesale prices to determine the value of avoided energy. If this is a flat rate, all saved energy can be valued based on the total energy saved multiplied by the wholesale energy rate. However, if there is a time-of-use component to the wholesale rate, then a further evaluation of the timing of the energy savings (and possible rebound energy for DR) should be accounted for.

On the G&T level, locational marginal prices (LMPs) of the energy market can serve as the basis for cooperatives which take part in a market. Figure 4.4 shows the average MISO locational marginal prices for both day-ahead and real-time for the summers of 2012, 2013, and 2014.[40]

The anticipated hourly impacts of the DSM program, along with the anticipated market prices, can form the basis for the avoided energy estimation. If the G&T is not part of the market, bilateral contract prices or the marginal cost of producing power should be used in place of the LMPs. Just as with capacity, there are also third-party entities that project energy prices into the future.

TABLE 4.4: MISO Summer Hourly Average LMPs 2012, 2013, and 2014

	2012		2013		2014	
LMP ($MWh)	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time
June	$29.03	$27.25	$31.27	$28.89	$39.22	$36.95
July	$40.76	$38.48	$33.09	$32.97	$33.27	$32.15
August	$27.86	$27.21	$30.86	$31.65	$33.37	$32.12
3-Month Average	$32.59	$31.02	$31.75	$31.19	$35.24	$33.70

[40] *MISO 2014 Summer Assessment Report*. Information Delivery and Market Analysis, November 2014.

AVOIDED T&D EXPENSES

Avoided T&D expenses can be a large part of DR benefits in certain situations. There are two main methods for evaluating avoided T&D costs—the targeted approach and the system-wide approach—and there are no widely accepted guidelines for when one approach should be used over the other. This is because DSM programs can have both local benefits (e.g., avoided upgrades to a substation) and system-wide benefits (e.g., reduce overall loading on transmission lines). This makes valuing avoided T&D expenses difficult.

Another difficulty is that avoided T&D benefits can vary greatly from system to system. As stated in an LBNL Report:

> *The extent to which demand response programs actually avoid or defer T&D investments is somewhat uncertain and is subject to debate. Avoided T&D costs for demand response programs may depend on: (1) the characteristics of the individual utility system; (2) the specific T&D investment proposed; (3) the characteristics of the customer load to be served by the proposed T&D investment; (4) the attributes of the proposed demand response program; and (5) the level of uncertainty associated with the projected load impacts of the demand response program.*[41]

In following sections, these two main methods for valuing avoided T&D expenses are discussed, along with a brief survey of how utilities around the country are using these methods.

The Two Main Approaches to Valuing Avoided T&D

Despite the variation in ways to value avoided T&D, there are some emerging methodologies. As mentioned above, the two main categories of approaches to valuing avoided T&D are the targeted approach and the system-wide approach.[42]

The **targeted approach** looks at specific feeders and substations where investments are required or soon will be. This is sometimes called “active deferral,” since the utility is actively trying to defer a specific T&D upgrade. Using this approach, avoided T&D upgrades can be priced according to upcoming investments, the cost of which is known. The avoided T&D benefit will be tied to the time value of money, calculated by how long the DSM will postpone the investment. In some cases, the DSM could eliminate the need for the investment altogether. The avoided T&D value under this approach would include the following factors:[43]

- The magnitude of demand reduction
- The location of the demand reductions
- When the demand reduction capability is available or on-call
- How well demand reductions coincide with the local need (which may differ at transmission and distribution levels)
- How soon the investments are needed
- How long the investments are deferred
- The value of the deferred or avoided investment

The second approach is the **system-wide approach**, which attempts to measure avoided T&D costs across the whole system. On the system-wide approach, it is recognized that DSM benefits will result in lower load across the system (and with DR, the load factor should increase) and the lower load should result in avoided T&D upgrades.[44] Trying to avoid system-wide T&D costs is sometimes called “passive deferral,” described in more detail as follows:

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[41] Woolf, Tim, Erin Malone, et al., *Op. cit*., p. 44. Lawrence Berkeley National Laboratory.

[42] Bode, Josh, Stephen George, and Aimee Savage. *Cost-Effectiveness of CECONY Demand Response Programs.* Prepared by Freeman, Sullivan & Co. for Consolidated Edison Company of New York. November 2013. Much of this discussion is taken from Appendix A3.

[43] *Ibid.*

[44] PSE has created econometric cost models on the factors that influence T&D costs; these models show that lower peak demand results in lower T&D costs.

PREVIOUS VIEW

> *…Passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs.*[45]

The benefit of this approach is not associated with any particular avoided upgrade, but instead looks to what "average" T&D upgrades cost over time. ConEd, in its 2013 study, described system-wide costs as follows:

> *The value is estimated by modeling the transmission and/or distribution system with and without demand response. The net benefit of demand response is then distributed across the entire system or calculated for specific zones. …These load growth related investments are divided by the actual or projected load growth over the same time period in order to estimate the transmission and/or distribution investment required per kW of load growth.*[46]

In cases of active deferral where the utility is certain that DSM programs delayed specific T&D upgrades, calculating the avoided costs is fairly straightforward: the avoided costs are simply the costs of the upgrades that were planned, but were postponed or obviated completely. In cases of system-wide avoided T&D (passive deferral), avoided costs can be far more difficult to calculate (as shown in the ConEd approach quoted above).

Using DSM to Defer T&D Upgrades

How often do U.S. utilities use DSM to avoid T&D upgrades? The short answer is: targeted deferrals are not very common, although they are starting to become more common. System-wide deferrals are fairly common, in the sense that, theoretically, any utility that has DSM reduces stress on its system and possibly defers the need for T&D upgrades.

Studies have estimated that, from 2010–2030, U.S. utilities (including municipals and cooperatives) will spend much more on distribution and transmission capital investments than they will on generation capital investments—in total, $537 billion for generation and $936 billion for transmission and distribution combined.[47]

Despite all these T&D expenses, utilities have limited experience with using DSM to defer T&D upgrades. There are several reasons for this, including:[48]

- **Incentives.** Many utilities earn rates of return on capital investments, but not on EE. This will not be as much of an obstacle for cooperatives.
- **Difficulty in Assessing Benefits.** EE and DR have multiple benefits, including avoided energy and capacity, avoided GHG, increased reliability, reduced lines losses, and T&D-related benefits. It is difficult to properly account for these benefits in a holistic manner and properly assign the benefits in a rigorous business case.
- **System Planning is Engineering-Oriented.** Utilities tend to think in terms of building capacity and upgrading T&D infrastructure, rather than in terms of reducing demand. As the cited Neme/Sedano RAP report puts it: "System engineers trust assets that they can control, like 'poles and wires,' and tend to be more skeptical or distrustful of investments on the customer side of the meter to reduce demand."[49]
- **Transmission Costs are Often Diffuse** and socialized across the entire regional grid, whereas DSM costs are borne by the specific

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[45] Woolf, Tim, et al. *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs.* Regulatory Assistance Project (RAP). November 2012. Note that, although this particular quote refers to EE only, the same principle can also be applied to DR programs.

[46] Bode, Josh, *Op. cit.*, p. 92.

[47] Neme, Chris, and Rich Sedano. *U.S. Experience with Efficiency as a Transmission and Distribution System Resource*, p. 2. Regulatory Assistance Project (RAP). February 2012. The scenario described is the "base case," which includes realistic estimates of EE and DR.

[48] *Ibid.*, pp. 4–5.

[49] *Ibid.*, p. 4.

utilities implementing them. Transmission solutions are also technically complex and need longer lead times. Transmission planning is often done at a higher level than distribution planning; state regulators, RTOs, FERC, and utilities are all involved in transmission planning, so decisions in this area are difficult, as there is no one single entity in charge.

Despite these difficulties, there is a large untapped potential for cooperatives in the area of using DSM to defer T&D costs. The two main barriers are: (1) Difficulty in putting a value on avoided T&D costs (this is discussed throughout this section), and (2) Engineering and planning concerns. The next section shows the general idea behind how DSM might be used to defer T&D investments. **T&D Avoided Costs—The System-Wide Approach** (this page) gives some examples of how utilities have valued avoided T&D costs. **Sample Targeted T&D Projects** shows a hypothetical business case that uses DSM to postpone T&D investments.

T&D Avoided Costs—The Theory Behind the Targeted Approach

The general idea behind the targeted approach is that specific investments that are needed due to anticipated load growth can be deferred by implementing DSM programs. For example, suppose that a substation has a peak load of 100 MW in 2015 and a capacity of 110 MW. With 3% load growth, the load will pass 110 MW in 2019, so a substation upgrade is needed by 2019 (see Table 4.5). With a DSM program that reduces load by 1% per year, the substation doesn't reach 110 MW until 2020, so the upgrade is deferred one year. Thus, in that case, the savings would basically be the time value of money with respect to the project cost for one year.

A 2% reduction per year from DSM postpones the project until 2024, a deferral of six years. A 2.5% reduction per year postpones the project until 2035 (not shown in the table). A 2.5% savings of peak load is aggressive but feasible, so there are times when a DSM program could postpone a T&D upgrade until the asset needs to be upgraded or replaced for reasons other than capacity.

Thus, if we want to look for substations that are good candidates for targeted DSM, to avoid T&D upgrade costs, we would look for a substation or other asset with the following characteristics:

- The asset needs an upgrade due to load growth or lack of capacity (not due to age or failure).
- The asset is projected to be upgraded at least two years in the future. This gives the cooperative time to ramp up the DSM program in that specific area.
- The reduction needed to postpone the upgrade is manageable. The availability of possible peak reductions will be dependent on the types of loads in that specific location.

T&D Avoided Costs—The System-Wide Approach

As mentioned above, the methods for avoided T&D cost calculations have not yet been standardized, and regions vary, so the range of estimates is quite large. When examining how other utilities have estimated avoided T&D costs, be

TABLE 4.5: Hypothetical Impact of DSM on Substation Upgrade

DSM Program Savings	Projected Growth Rate	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
None	3.0%	100	103.0	106.1	109.3	112.6	115.9	119.4	123.0	126.7	130.5	134.4
0.5% Savings per year	2.5%	100	102.5	105.1	107.7	110.4	113.1	116.0	118.9	121.8	124.9	128.0
1.0% Savings per year	2.0%	100	102.0	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	121.9
1.5% Savings per year	1.5%	100	101.5	103.0	104.6	106.1	107.7	109.3	111.0	112.6	114.3	116.1
2.0% Savings per year	1.0%	100	101.0	102.0	103.0	104.1	105.1	106.2	107.2	108.3	109.4	110.5
2.5% Savings per year	0.5%	100	100.5	101.0	101.5	102.0	102.5	103.0	103.6	104.1	104.6	105.1

careful to note whether they are discussing a targeted project or a system-wide project.

A couple of recent reports contain estimates of ranges for system-wide avoided T&D costs: (1) the cited Neme/Sedano RAP report, and (2) a study conducted by the Mendota Group for the Public Service Company of Colorado (Xcel Energy). These studies survey attempts to quantify the benefits of avoided T&D costs.[50]

In the Neme/Sedano RAP paper, the authors give some estimates for passive deferral avoided costs.[51] The authors note that passive deferral costs are usually used for assessing whether EE programs will be cost-effective; this is usually a regulatory or funding issue.

These avoided T&D cost estimates are typically calculated by dividing forecast T&D capital investments due to load growth by the forecast growth in system load. In other words, capital investments due to aging/failing infrastructure, etc., are not included.

The Neme/Sedano study addresses New England, where recent estimates of avoided T&D costs for passive deferral typically range from around $55/kW-year to $120/kW-year. On the high end of this range is Vermont, which has around $120/kW-year for avoided summer load and $80/kW-year for avoided winter load. For New England, avoided distribution costs typically make up 70–80% of the avoided T&D costs. [52]

The paper also studied some utilities in California and the Pacific Northwest, noting ranges of $30 to $105/kW-year, with an average of around $50/kW-year. Costs avoided by active deferral of T&D costs are much more site-specific.

The cited Neme/Sedano paper summarizes some recent active deferral projects, but the discussed projects do not have much in the way of hard numbers to measure cost-effectiveness.

The authors of the Xcel Energy report collected data from around 30 U.S. utilities that have recently calculated their avoided T&D costs. Average avoided distribution costs for the studied utilities are around $48/kW-year, with a range of $0 to $171/kW-year. Average avoided transmission costs for the studied utilities are around $20/kW-year, with a range of $0 to $88/kW-year.

With transmission and distribution added together, T&D avoided costs average around $66/kW-year, with a range of $0 to $200/kW-year. These T&D costs are most heavily grouped around the $40 to $60/kW-year range. Thus, if a cooperative wished to perform a back-of-the-envelope calculation for passive deferral of T&D costs, this range could be a starting point. PSE does caution that, ultimately, costs are avoided for specific projects. The estimates discussed here may not be applicable to your system.

Consolidated Edison and Other Targeted Deferrals

There are currently a number of targeted T&D deferral projects around the country. One of the biggest is the attempt by Consolidated Edison Company (ConEd) in New York to use DSM to defer a billion-dollar substation: [53]

> *Facing growth in the area and staring down the need for a $1.1 billion substation to handle that demand, the utility will spend up to $150 million on energy-efficiency initiatives and distributed resources. Ultimately, the goal is to find about 20 MW of energy savings or capacity by early next year. If successful, the utility will delay having to build the substation until 2024 and customers could see as much as $500 million in savings on their electricity bills.*

ConEd has a wide range of DSM programs, including payments to commercial buildings (or aggregators) of up to $500,000 over a three-year period for every MW of reduction provided.

[50] Mendota Group, LLC. *Benchmarking Transmission and Distribution Costs Avoided by Energy-Efficiency Investments.* Prepared for the Public Service Company of Colorado (Xcel Energy, Inc.). October 23, 2014.

[51] Neme, Chris, and Rich Sedano, *Op. cit.*

[52] Neme, Chris, and Rich Sedano, *Op. cit.*, p. 3. These estimates are based from on a top-down approach, not a bottom-up engineering analysis.

[53] Details taken from Walton, Robert, “How ConEd is Boosting Demand Management to Save on Grid Upgrades.” *Utility Dive*, February 18, 2015.

Other programs focused in the Brooklyn-Queens target area (the area with the need for the $1.1 billion upgrade) include:

- Small business direct-install EE measures (ConEd directly installs the measures and pays up to 70% of the costs)
- Multifamily building EE programs
- Combined heat and power installations
- Distributed generation fuel cells
- DR resources obtained by a competitive market process (similar to how an RTO clears DR as capacity)
- Utility-side distributed energy storage systems[54]

The ConEd DSM program is probably the biggest such T&D deferral project currently being conducted, but there are others. Some other past and current projects are described in a Northeast Energy Efficiency Partnerships (NEEP) report by Chris Neme and Jim Grevatt,[55] starting on page 27.

The next section describes a smaller project, one more plausible for cooperatives.

Sample Targeted T&D Projects

Here's a hypothetical case where DSM is used to postpone a substation upgrade. Although this case describes a much smaller project than the one ConEd is attempting, it is perhaps a more realistic scale for cooperatives. This case is based on some details of a real case, although this example should still be considered hypothetical.

A cooperative has a substation (Substation A) in a corner of its system that serves a significant number of subdivision loads on the outskirts of a major city. Load growth, particularly in the summer, has been substantially higher than the remainder of the system. New subdivisions continue to be added and filled with large, new homes that have high energy usage.

Peak demand during the summer has stressed local distribution facilities, in part due to the high AC demand. Ties to adjacent substations are limited to only one distribution tie. The distribution feeder tie from the adjacent Substation B is also heavily loaded and, due to the topography of the distribution, facilities served by Substation A can do little to divert some of the load to Substation B.

Cooperative planning has identified that a new substation (Substation C) is needed in the area to unload the existing stressed distribution facilities, provide contingency capability, and allow for continued high levels of load growth in the area. The estimated cost of the new substation, transmission facilities to feed the substation, and integration into the existing distribution system is $3.5 million.

Installation of this new substation, however, is hindered by difficulties in finding a suitable location available for purchase where Substation C can be built (and to which transmission facilities can be extended). These difficulties stem largely from: (1) concerns from residents in the area about the new transmission and substation facilities being constructed near their homes, and (2) requirements by local authorities relating to aesthetics and location of facilities.

The cooperative needs to identify measures to defer investment in Substation C and transmission facilities until a suitable location can be purchased and all of the requirements and concerns of the local residents and authorities satisfied. Traditional actions alone—such as load balancing, installation of capacitors, and voltage regulators—are not sufficient to defer the new substation until such time that the substation can be constructed, particularly in terms of distribution conductor capacity.

Transfer of load to Substation B feeders is not an option (as described above). Installation of new distribution lines and/or upgrades to existing lines may require a lot of time and would not come online any faster than Substation C, nor do they result in the most economical long-term solution.

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[54] This is just a partial list of DSM programs. More description can be found in ConEd's *BQDM Quarterly Expenditures & Program Report*, 1st Quarter 2015, filed 6/1/205 in case #14-E-0302, New York State Department of Public Service.

[55] Neme, Chris, and Jim Grevatt. *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*. Northeast Energy Efficiency Partnerships. January 9, 2015.

Substation C could, theoretically, be deferred by installation of distributed generation resources in the area connected to the existing distribution facilities to offset load. Diesel gen-sets, however, do not offer a good option in terms of economics and environmental considerations. Renewable resources will take too long to develop and bring online and may not be economical.

Another alternative to deferring the need for Substation C is reducing the projected peak by demand response. For example, the system is a good candidate for air conditioner load control. The cooperative has in place a two-way AMI system that allows for the installation of load management controls on end-use equipment at consumer locations.

The cooperative has determined that it would like to be able to defer the new substation for three years to give ample time to obtain the property and easements and to construct all facilities. To accomplish this, the cooperative estimates it will need to reduce load during peak summer demand times by 1.5 MW. Approximately 3,000 residential consumers are served in the area where the load reduction needs to occur and it is estimated that nearly all of these consumers have air conditioning installed.

The costs and benefits categories of a DSM program used to defer Substation C are fairly straightforward (at least with respect to targeted T&D). The benefits (looking just at the targeted benefits, and not the avoided capacity or energy benefits, GHG emissions, etc.) consist of the time value of money of $3.5 million over three years: around $310,000.[56] Each AMI load management device will have a cost to purchase and install.

The cooperative will most likely offer rebates or other incentive so that members will participate. Additional costs to implement the DSM program to control AC load during peak summer demand times include developing the internal systems to determine when load control is needed, how much is needed, and for how long.

On the system we are considering, the average diversified kilowatt demand per consumer during peak is 5.5 kW. A reduction of 1 kW per participant is reasonable to expect with a cycled AC load control program, and residential participation rates of 30–50% could be achieved with a concerted marketing effort and healthy incentives.

Even assuming 25% of the residential members sign up, the feeder could have 750 participants and a demand reduction of 750 kW during peak times. This is halfway to the goal of a 1.5-MW reduction, so the residential AC load control program could be supplemented by other DSM programs, such as commercial AC load control, water heater load control, peak-time rebates, critical peak pricing, LED lighting incentives, interruptible rates, etc.[57]

In theory, DSM could also be used to reduce the required size of Substation C. It should be noted, however, that there is a large step function when it comes to transformer sizing and a DSM demand reduction program would have to be quite large in order to result in a smaller needed transformer.

For example, the cooperative described above was planning a 12/16/20 MVA transformer for Substation C. The next smaller standard size is typically a 10/14 MVA transformer, so 2–6 MW of DSM peak reduction would be needed—depending on whether the base rating or the max rating is considered—to avoid the larger transformer size. This is not impossible, but it would require a large DSM program. The difference in price between these two substation sizes is substantial. The exact difference will depend on what else is being upgraded, but may be more than $400,000.

There are a few things to note about this hypothetical situation:

1. This hypothetical case does not take avoided capacity, energy benefits, or avoided transmission into account; the benefits considered are based on deferred distribution alone. Thus, once these other benefits are added in, the overall benefits may be much higher.
2. The case for DSM in this hypothetical example could be improved greatly if Substation C

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[56] This figure is based on a weighted average cost of capital of 6%, compounded annually over three years.

[57] Achieving 1.5 MW in reduction may require subscribing more than 1.5 MW to the program, due to rebound energy and secondary peaks.

could be not just delayed, but avoided altogether. To accomplish this, aggressive DSM programs would need to be instituted before Substation A neared its limit. However, if load growth is high, and contingency requirements are large, the avoidance of Substation C may not be possible. Proximity and line losses should also be taken into account.

3. The need for more capacity is only one reason that a substation may need to be upgraded. Upgrades could also be needed for voltage issues, reliability/congestion issues, contingency concerns, or equipment aging/deterioration. In can be difficult to separate capacity out from these other concerns when conducting a cost/benefit analysis.
4. Building on the last point, DSM only defers upgrades in cases where the substation or other T&D asset would soon have to be upgraded for capacity reasons but otherwise would have been functional for years. If a substation must be replaced soon because it has reached the end of its useful life, the DSM programs will not defer the upgrade. (DSM may still have a role in this scenario, if it can make the upgrade less costly than it would have been without DSM.)
5. The consequences for a failed demand reduction program could be severe, including damage to large industrial equipment or to cooperative facilities due to low voltage. Thus, it is important to have a sound plan implemented for how DR signals (e.g., to load controlled devices) will operate and assurance it will deliver when needed.
6. Following on the last point, if a DR program is intended to serve as assurance that load will never exceed a specified level (e.g., "we will use DR to assure that the load on this substation will never exceed X MW"), then the DR program may need to be constructed under "n minus 1" planning guidelines. In other words, if failure of the DR program would cause blackouts/brownouts, the appropriate safeguards would need to be taken to meet "n minus 1" planning standards. If the DR reduction is to come from several separately run programs (e.g., a combination of PTR, direct load control, interruptible rates, etc.), then this may provide the contingency assurance.
7. A cooperative would want to have a PTR program and an EE program already piloted before it started targeting these programs to specific substations.
8. Targeted DSM could be appropriate in areas with rising renewable penetration. As solar, wind, and batteries become more prevalent, distributed generation will crop up, which could, in turn, reduce the size required for substations. If cooperatives can use DSM to postpone distribution upgrades, it may postpone or even eliminate the need for costly upgrades that may become stranded in the event of high renewable/distributed generation penetration. Where feasible, DSM is a much more flexible solution than investing in infrastructures that could be oversized in the near future.
9. The previous point also applies to areas that may experience a boom/bust cycle: for example, areas with oil or gas growth. This growth goes in cycles and cooperatives do not want to invest in costly substation upgrades based on a current boom, only to have the station be oversized after the boom subsides. This again shows the flexibility of DSM: instead of upgrading distribution infrastructure based on a peak that will subside, the cooperative can reduce the peak using DSM.

Avoided Line Losses

One aspect of T&D savings that is sometimes overlooked is avoided line losses. In addition to the average line loss on a system, cooperatives should be aware of the concept of "marginal line losses," the loss associated with the next kilowatt of added load at a given load level. Marginal losses increase as the system load rises. A kilowatt added at times of low load may only have a 5% loss associated with that kilowatt, but a kilowatt added at peak demand may have a 20%+ loss.

DSM programs can help reduce marginal lines losses at peak. Any program that reduces peak demand, such as direct load control of air conditioners or peak-time rebates, avoids more losses than previously thought. And, as shown in this Guidebook, reducing losses and energy purchased at peak demand time can have avoided energy and demand benefits.

For example, consider a system where average losses are 7% and losses at peak load are 20%. One kilowatt saved at the meter at peak time doesn't just save the cooperative 1 kW at the point of generation or purchase. Losses must be taken into account. One method is to use the average annual loss figure, which at 7% means that 1.075 kW is actually saved for each kilowatt saved at the meter:

$$\begin{gathered}1.075 \text{ kW at generation (or purchase)}\\ -(0.07 \times 1.075 \text{ kW})\\ \approx 1.0 \text{ kW saved at meter}\end{gathered}$$

However, in reality, a kilowatt saved at peak saves more than just 1.075 kW if losses at peak are 20%. The kilowatt saved at the meter saves **1.25 kW** at purchase:

$$\begin{gathered}1.25 \text{ kW at generation}\\ -(0.20 \times 1.25 \text{ kW})\\ = 1.0 \text{ kW at meter}\end{gathered}$$

This is a significant source of savings that should be considered by cooperatives if possible. More detail on avoided line losses can be found in the CRN paper *Marginal Line Losses*.[58]

Recommendations

Our recommendations regarding how to value avoided T&D expenses are as follows:

1. If a cooperative is using DSM to avoid specific T&D upgrades, the avoided T&D costs should be calculated based on the targeted approach—specific upgrades and the time value of money—as shown in the example in **Sample Targeted T&D Projects**.
2. If a cooperative is using DSM to avoid capacity and energy, and avoided capacity is simply a system-wide side benefit, then avoided T&D costs should probably be calculated based on the industry standards referenced in **T&D Avoided Costs—The System-Wide Approach** and its referenced reports.
3. If cooperatives are using DSM to meet a standard set by a regulatory body, it should look to the regulator for guidance. Absent any guidance, cooperatives should feel free to use industry estimates and standards described in **T&D Avoided Costs—The System-Wide Approach**.

DR COSTS

The costs of DR programs vary quite a bit from program to program. For example, a direct load control program may require substantial upfront costs, as the communication infrastructure needs to be put in place and load control switches need to be purchased, installed, and monitored. Once a load control program is set up, however, costs in future years are not as great. In contrast, some DR programs (e.g., interruptible C&I rates) have little or no upfront equipment costs, but require more costs on an ongoing basis due to reduced kilowatt-hour rates or other incentives.

Certain DR programs have fixed costs that are higher, but with relatively low variable costs. Perhaps the best example of this is water heater direct load control. Other programs have fixed costs that are lower, but the variable costs are high (a peak-time rebate program, for example). Understanding the costs and whether they are fixed or variable will help determine the optimal DR portfolio or dispatch strategy.

Some of the main costs of DR programs include:

- Incentives and rebates
- Equipment costs (e.g., technology specific to a participant's home or business, such as smart thermostats or other in-home displays, load control switches, two-way communications devices at the consumer)
- Utility technology costs (e.g., information technology equipment housed at the utility)
- Equipment installation costs and other home visits (includes drive time)
- EM&V
- Rate design
- Regulatory requirements
- Accounting and record-keeping
- Database management
- Staff and overhead for these items
- Marketing (mailing inserts, website design, flyers, letters, and other media designed to inform members about DSM programs, or to induce members to enroll in the programs).

[58] Ivanov, Chris, and David Williams. *Marginal Line Losses.* NRECA CRN. August 2012.

These costs are often put into the categories shown in Table 4.6 for purposes of determining which costs are included in the various cost-benefit tests.

It should be noted that only costs incremental to the program should be imputed to the DR program. This is fairly straightforward in some cases, but other cases can be difficult. For example, if a new billing system is installed for a DR program, it can be difficult to determine what portion of the new system to assign to the DR program itself. Cooperatives should estimate what percentages of new software, billing systems, etc., are directly related to the DR program and what percentages are used for non-DSM programs.

The categories in Table 4.6 are explained below.[60] The commonly used term "**program administrator expenses**" (also known as "administrative costs") includes operations and maintenance costs, program costs, information technology expenses, DR operation and communication costs (e.g., text charges for "event" signals), marketing costs, and EM&V costs.

"**Program administrator capital costs**" are often kept separate from administrative costs for accounting purposes. These costs cover information technology equipment and demand control technologies. These costs are the utility-wide "big-picture" technologies, *not* "demand response measure costs," which are the costs associated with a particular program participant.

Incentives include payments or rebates to customers. Examples include a monthly bill credit for participants in a load control program or rebate payments made to PTR participants who reduce their usage during peak events. This does *not* include the cooperative's contribution to the measure cost (such as load control switches). These two categories should be kept separate because incentives and rebates are not included in the TRC test or the SCT—because the rebate *from* the utility is cancelled out by the rebate *to* the participant.

Measure costs are divided into two categories: (1) the administrator (cooperative) contribution, and (2) the participant contribution (if any). Load control switches and other installed equipment would go in this category.

Participant transaction costs are costs borne by DR program participants—for example, if C&I employees had to be trained on DR compliance paperwork or on procedures for shutting down equipment during load control events. For most residential programs, these costs can be left out of the analysis; most residential DR participants don't have to do much in order to participate. Large commercial or industrial programs could have substantial costs in this area.

Participant value of lost service costs are member costs that are created by the program. An example of this may be a C&I interruptible program where the C&I member can quantify the dollar amount of lost production or revenues resulting from an event. Obviously, the incentives offered to the C&I participant should outweigh this value of lost service (if quantifiable), but the value should be included in participant, TRC, and societal cost/benefit tests.

TABLE 4.6: Demand Response Cost Categories[59]

Cost	Participant	RIM	PAC	TRC	Societal
Program Administrator Expenses	—	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	—	Yes	Yes	Yes	Yes
Financial Incentive to Participant	—	Yes	Yes	—	—
DR Measure Cost: PA Contribution	—	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	—	—	Yes	Yes
Participant Transaction Costs	Yes	—	—	Yes	Yes
Participant Value of Lost Service	Yes	—	—	Yes	Yes
Increased Energy Consumption	—	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	—	Yes	—	—	—
Environment Compliance Costs	—	Yes	Yes	Yes	Yes
Environmental Externalities	—	—	—	—	Yes

[59] Table 4.6 from Woolf, Tim, Erin Malone, et al., *Op. cit.* Lawrence Berkeley National Laboratory.

[60] *Ibid.* The following discussion is adapted.

Increased energy consumption and **lost revenues to the utility** are related costs due to the energy impact of the program. If an EE or DR program reduces revenues due to lowering kilowatt-hour sales, this will be a cost borne by the utility and ratepayers (while it is a benefit to the participants in the form of lower electric bills).

Environmental compliance costs are costs borne by the utility to comply with environmental standards. For these costs to be accounted to the DSM program, they need to be directly incurred by the utility and attributable to the DSM program.

Environmental externalities are costs *not* borne by the utility but pushed onto other people external to the utility or members. This can take the form of creating pollutants that may harm the environment. These costs have no impact on utility rates, costs, or revenues, so they are not included in any of the cost-benefit tests except the societal test.

Costs and Benefits of EE Programs

In general, the categories of costs and benefits for EE programs are similar to those of DR, although there are some costs and benefits that are more prominent in EE programs.

Cost/benefit tests for energy-efficiency programs follow the same general structure as those for DR.[61] The categories of costs and benefits are somewhat different for EE programs, but the overall approach is much the same (see Table 4.7).

As was the case with DR cost/benefit analyses, the tests that we recommend using for EE analyses are (1) the PACT and (2) either the TRC or the SCT.

TABLE 4.7: Costs and Benefits for EE, by CPUC Test

Test	Benefits	Costs
PCT—Benefits and costs from the perspective of the customer installing the measure	• Incentive payments • Bill savings • Applicable tax credits or incentives	• Incremental equipment costs • Incremental installation costs
PACT—Perspective of utility, government agency, or third party implementing the program	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program adminstrator incentive costs • Utility/program administrator installation costs
RIM—Impact of efficiency measure on nonparticipating ratepayers overall	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program adminstrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills
TRC—Benefits and costs from the perspective of all utiliy customers (participants and nonparticipants) in the utility service territory	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Monetized environmental and non-energy benefits • Applicable tax credits	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)
SCT—Benefits and costs to all in the utility service territory, state, or nation as a whole	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Non-monetized benefits (and costs) such as cleaner air or health impacts	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)

[61] Table 4.7 and much of the ensuing discussion is from National Action Plan for Energy Efficiency, *Op. cit.*

GENERAL EE BENEFITS

DR programs typically result in immediate benefits—reduced demand in the year that they are enacted. However, DR programs employed in one year don't typically carry benefits forward into the following years; most DR programs must be "re-employed" every year.

EE programs are somewhat different in that benefits accumulate. A program that results in the member purchase of 100 efficient refrigerators in 2015 will have benefits in 2015, 2016, and so on, for the useful life of the appliance. Thus, annually adding new EE programs, and adding participants to existing programs, will help to meet regulatory goals by accumulating benefits. Therefore, for many EE programs, some of the cost is spent upfront and the costs in subsequent years is a bit lower.

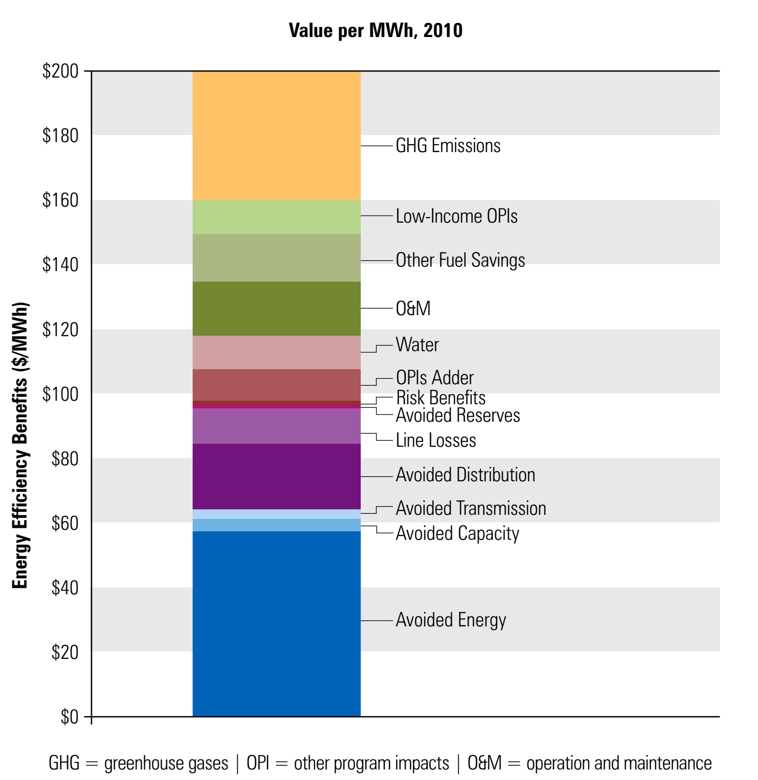

FIGURE 4.2: Sample EE Benefits

EE benefits come in many different categories, including:

- Avoided energy
- Avoided capacity
- Avoided T&D expenses
- Avoided line losses
- Reduced emissions; fulfillment of regulatory/government standards and goals
- Other fuel savings
- Non-energy benefits (sometimes called "other program impacts" or "OPIs")
- Benefits to low-income households

Whereas DR benefits come primarily from avoided capacity, EE benefits are more spread out over several categories. One of the largest benefits for EE is typically avoided energy costs (which, depending on the categorization used, may also include avoided transmission, distribution, line losses, and reserves).

Avoided capacity costs are another benefit, although these may not be as high in $/MW terms as those from DR programs. If federal GHG or carbon regulations go into effect, avoided GHG emissions will also become a major source of benefits.

To see an example of EE benefits, consider Figure 4.2, showing an estimate of EE savings in Vermont.[62]

BENEFITS—REDUCED KW AND KWH

In general, there are two sources for determining the reduced kW/kWh of EE measures: (1) deemed savings values, or (2) project-specific measurements and estimates.[63] Deemed savings values are often used for common measures that are somewhat uniform. For example, when a 60-watt incandescent bulb is replaced by a CFL or an LED, there are databases that tell cooperatives what the "standard" or deemed savings will be, on average.

The actual savings of any particular replacement will depend on the exact wattage of the replacement bulb, the number of hours the light is used per year, and other factors. However, this information would be impossible to collect

[62] Watson, Elizabeth, and Kenneth Colburn. "Looking Beyond Transmission," *Public Utilities Fortnightly*, April 2013, p. 39. The article uses data from Woolf, Tim, et al. RAP, *Op. cit.*

[63] A third, less common method for measuring the benefits is the "comparison group method," which is discussed in Section 13, which covers the EM&V of EE programs.

for every single light bulb, so deemed savings values give an estimate for how much energy the average CFL/LED will save.

Deemed savings values can also be used for appliances like energy-efficient air conditioners. If an old air conditioner is replaced by a new one with a certain SEER rating, a deemed savings database can give an average savings value.

The deemed savings method does not work for large, unique EE projects, such as certain large industrial process or large-building retrofits. For example, if a university were to implement a campus-wide EE retrofit, there would be no database that could give an estimate of the energy savings. Certain measures within the retrofit could use deemed savings (lighting programs), but certain measures could not (HVAC system for a basketball arena).

In the latter case, the basketball arena would have a unique usage profile and building envelope, so an improved HVAC system would need to be measured individually to calculate energy savings. This could be done using engineering estimates (nameplate ratings of equipment, hours of usage, etc.), but the true savings might only be known after a before-and-after measurement (via metering) of the arena.

When it comes to the deemed savings approach, similar methods are used for both pre-program analyses and post-program EM&V. When an EE program is being planned, cooperatives can use deemed savings estimates in their cost/benefit analyses—along with estimates of program enrollees—to determine how much energy and demand will be saved. After the program is installed, the cooperative will know more precisely how many enrollees there are, but will again use deemed savings databases to calculate the total amount of energy savings.

BENEFITS—AVOIDED GHG EMISSIONS

As **Figure 4.2** shows, a major benefit of EE programs is avoided GHG emissions. In fact, in that figure, avoided GHG emissions are the second largest benefit, after avoided energy. For cooperatives that do not have state-mandated DSM targets, it is understandable if GHG emissions are not considered a priority in the cost/benefit analysis. After all, from the utility perspective (PACT test), GHG emissions are an externality and so do not affect the cooperative's bottom line.

However, there are reasons why cooperatives should start considering avoided GHG emissions:

1. **State EE Targets.** Some states have EE targets that may apply to cooperatives. In these cases, cooperatives may be required to include avoided GHG in their analyses. Even if not required, adding avoided GHG benefits may make it easier for cooperatives to reach their designated target.
2. **Emissions Markets.** In some cases, cooperatives may be able to monetize their avoided GHG emissions by selling them to other utilities that need them. If the U.S. develops a carbon cap-and-trade system, avoided GHG emissions from EE programs could be sold in that market. These markets may be similar to the current markets for SO_X and NO_X emissions.[64] Even with no carbon market, there has been groundwork laid in some states to develop "energy efficiency certificates" (EECs)—which would be similar to renewable energy certificates (RECs)—which could be bought and sold in order to meet targets. These EECs have not yet gained much traction. If they do, however, cooperatives may be able to sell their avoided GHG in that market.

The next sections present some high-level discussion on how to value avoided GHG emissions if your cooperative uses that metric in its cost/benefit analyses. The specifics of how to value avoided GHG will depend on your cooperative's geographical location and RTO participation (if any). As always, a good "first stop" for guidance would be the state regulator, if applicable.

[64] See, for example, the EPA's discussion of SO_X and NO_X allowance markets under the Clean Air Act at www.epa.gov/airmarket/participants/allowance/index.html.

Embedded vs. Non-Embedded Avoided Emissions

One thing to keep in mind when valuing avoided emissions is that, in some cases, the cost of some emissions—especially SO_X, NO_X, and CO_2—are already built into the cost of capacity; they are "embedded." For example, an Avoided Energy Supply Component (AESC) 2015 study provides "estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy-efficiency program cost-effectiveness analyses."[65]

The AESC 2015 study employs a market simulation model (the model is the "pCA") that projects future avoided energy and capacity. The model includes avoided costs associated with "expected and existing" regulations:

> *The unit costs associated with each of these emissions when calculating the generator offer prices used to make commitment and dispatch decisions. In this way, [AESC 2015] projects market prices that reflect, or "embed," the compliance costs for each type of emission….*[66]

Thus, when using projected energy and capacity costs, a cooperative should determine what environmental costs, if any, are already embedded. Most estimated future energy and capacity costs will include embedded emissions costs because most projections are based on market costs—or what a utility would pay to build/buy capacity—and *these* costs include embedded emissions costs (under the assumption that "whatever regulations are now in effect will continue to be in effect").

One way cooperatives can use embedded emissions costs is to project future energy and capacity costs with a "base case" and one or more alternate cases, in which the embedded environmental costs differ from their current level (for example, a "high-carbon-cost" case can be added to the base case). For example, if CO_2 regulation becomes much more stringent, embedded environmental costs will rise, increasing the benefits of DSM when compared to building or purchasing energy.

Estimates of Future Environmental Costs

For an example of the magnitude of GHG costs, see the costs for SO_X, NO_X, and CO_2 in **Table 4.8**.[67]

Non-embedded emissions costs are impacts from the production of electricity that are not reflected in the price of electricity. These are typically not considered by cooperatives when considering DSM programs. They are only brought up here because it is possible that, in the future, the government will attempt to embed these costs in the price of electricity—that is, turn these non-embedded costs into embedded costs.

Carbon costs will most likely make up the majority of emissions costs in the future. In fact, the U.S. government has attempted to value the "social cost of carbon," which is an "estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year."[68] Their estimates for future social costs of carbon are shown in **Table 4.9**. The "95th" column represents a scenario where CO_2 results in "higher-than-expected impacts from temperature change" from CO_2. Again, the point is not to get into a discussion about possible climate change, but to note that the government could, in the future, embed these "social costs of carbon" into electricity prices.

To put **Table 4.9** in perspective, the amount of CO_2 produced by coal plants in 2013 is around 2.10 lb./kWh.[69] A baseload 1,000 MW

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[65] Hornby, Rick, et al. *Avoided Energy Supply Costs in New England: 2015 Report*, p. 1-1. March 27, 2015; Revised April 3, 2015. Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group.

[66] *Ibid.*, p. 4-2.

[67] *Ibid.*, p. 4-3.

[68] Interagency Working Group on the Social Cost of Carbon, U.S. Government. Technical Support Document: *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*. Under Executive Order 12866, p. 2. May 2013.

[69] See www.eia.gov/tools/faqs. ("How much carbon dioxide is produced per kilowatt-hour when generating electricity with fossil fuels?")

Table 4.8: Emission Allowance Prices per Short Ton (Constant 2015$ and Nominal Dollars)

	NO_x		SO_2		CO_2	
Year	**2015$**	**Nominal**	**2015$**	**Nominal**	**2015$**	**Nominal**
2015	10.00	10.00	1.11	1.11	6.28	6.28
2016	10.00	10.17	1.11	1.13	7.26	7.38
2017	10.00	10.16	1.11	1.15	7.87	8.15
2018	10.00	10.57	1.11	1.17	8.47	8.95
2019	10.00	10.78	1.11	1.19	9.32	10.05
2020	10.00	11.00	1.11	1.22	10.16	11.18
2021	10.00	11.22	1.11	1.24	12.54	14.07
2022	10.00	11.44	1.11	1.27	14.92	17.07
2023	10.00	11.67	1.11	1.29	17.30	20.18
2024	10.00	11.90	1.11	1.32	19.67	23.42
2025	10.00	12.13	1.11	1.34	22.05	26.74
2026	10.00	12.36	1.11	1.37	24.43	30.18
2027	10.00	12.59	1.11	1.39	26.80	33.74
2028	10.00	12.82	1.11	1.42	29.18	37.42
2029	10.00	13.07	1.11	1.45	31.56	41.23
2030	10.00	13.31	1.11	1.47	33.94	45.17

TABLE 4.9: EPA Revised Social Cost of CO_2, 2010–2050 (2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Average	3.0% Average	2.5% Average	3.0% 95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

coal plant at 60% capacity factor might produce 432,000 MWh in a month.[70] This works out to around 5.184×10^9 kWh in a year. This much generation would result in around 4,938,000 metric tons of CO_2 in a year.[71] If the $37/metric ton in Table 4.9 (3.0% discount rate, 2015) were applied to this coal plant, it would result in around $158 million in 2015 alone, which would add around 3.5¢/kWh if spread over all kilowatt-hours. If the 95th percentile scenario occurred, the carbon cost would add around 10.4¢/kWh in 2015.

Clearly, the government is not going to assign this entire societal cost to the price of electricity any time soon. Carbon costs may become monetized in the future, however, and cooperatives should keep this in mind when planning for long-range capacity and energy.

DSM can help minimize the risk of scenarios like the one discussed above. There is no mandated embedded societal cost of carbon at the present time, but DSM programs will be a good way to hedge against the risk if it happens in the future.

The CO_2 costs estimated by the EPA in Table 4.9 are not outliers. Other experts and utilities that have studied the issue have made estimates of future CO_2 prices and the ranges of the estimates, while not identical, all point to the expectation that carbon costs will rise over the next 30 to 40 years.

For example, the consulting firm Synapse recently released a report that made projections of CO_2 prices.[72] Synapse's basic assumption is this:

[70] 1,000 MW × 30 days × 24 hours/day × 60% = 432,000 MWh

[71] (5.184×10^9 kWh/year) × (2.1 lb./kWh) × (1 metric ton/2,204.62 lb.) = 4,937,993 metric tons CO_2/year

[72] Luckow, Patrick, et al. *2015 Carbon Dioxide Price Forecast.* Synapse Energy Economics, Inc. March 3, 2015.

Near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector.[73]

This pressure will most likely eventually result in a federally established method for setting a carbon price. Synpase's projected CO_2 prices for 2020 to 2050 are shown in Figure 4.3. The "Low" case represents a scenario wherein the regulation would be "relatively lenient as easily achieved." The "Mid" case is a scenario in which "federal policies are implemented with significant but reasonably achievable goals."[74] The forecast assumes that no federal price is established until 2020.

Although the units in Figure 4.3 are slightly different than those in the EPA's projected prices in **Table 4.9** (2014$/short ton, vs. 2007 dollars per metric ton), the magnitudes of the projections are reasonably similar. Synapse also surveyed some recent IRPs conducted by large U.S. utilities, and many of these IRPs, especially recent ones, include a CO_2 price in their reference scenario projections. For example, 19 of the 24 reviewed IRPs that were released in 2014–2015 included a CO_2 price in the reference scenario. Most of the reviewed IRPs had forecasted CO_2 prices in 2030 in the range of $10 to $30 per short ton.[75]

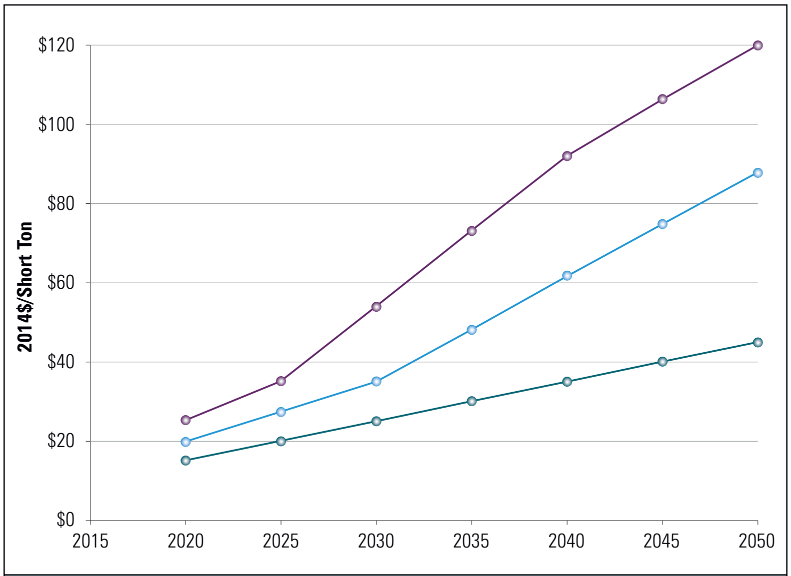

FIGURE 4.3: Synapse 2020-2050 CO_2 Price Projections (High, Medium, and Low)

Avoided Environmental Costs: Key Takeaways for Cooperatives

Price forecasts for CO_2 and other emissions are like any economic forecasts: it is very difficult to predict with much accuracy what the values will be in 5 or 10 years. At the present time, the political climate is such that carbon taxes or cap-and-trades are not likely in the next few years. However, most experts and most of the utilities (if IRPs are any indication) agree that, over the next 20 years, some sort of carbon cost will increase the price of fossil-fuel generation. The fact is that most experts agree an increased carbon price is coming over the next decade and this is what cooperatives should plan for.

DSM is a good hedge against these possible future carbon costs. Cooperatives should consider a carbon cost estimate to be part of best practices in any long-range planning, including DSM planning. A simple way to do this would be to use projected energy and capacity values that include some embedded carbon costs. If cooperatives do not include avoided carbon costs in their DSM cost/benefit planning, they should know that their resultant analysis will most likely be on the conservative side and that DSM programs may result in avoided carbon costs in the future and will, therefore, provide a risk-reduction strategy against future carbon cost spikes.

EE COSTS

The costs of EE programs vary quite a bit from program to program. Some of the main cost categories include:

- Incentives and rebates
- Equipment costs (smart thermostats, light bulbs, etc.)

[73] *Ibid.*, p. 1–2.

[74] *Ibid.*, p. 3.

[75] *Ibid.*, pp. 25–28.

- Equipment installation costs and other home visits (includes drive-time)
- Home and business energy audits (if performed by the cooperative)
- EM&V
- Regulatory requirements
- Accounting and record-keeping
- Database management
- Staff and overhead for these items
- Marketing (mailing inserts, website design, flyers, letters, and other media designed to inform members about—or to induce members to enroll in—EE programs)

Although keeping track of these costs can be tedious, the costs themselves are relatively straightforward.

Potential Studies

Sometimes state utility commissions require investor-owned utilities to complete DSM potential studies. Although cooperatives have, so far, been mainly exempt from these requirements, new federal regulations may change this situation. Furthermore, some cooperatives may wish to perform potential studies on their own, especially if they are considering using DSM to supplant “steel in the ground” generation or contracted energy. Thus, the potential study can serve a crucial role in the new DSM landscape.

The problem is that detailed potential studies can be expensive. There are some ways of keeping costs down.[76] Here are some tips for conducting potential studies:

- There are different types of DSM potential studies, depending on what cooperatives will use them for. These studies vary in size and scope.
- Costs for DSM studies vary widely and depend on a number of factors, including the type and purpose of the study and whether it will be scrutinized by a regulator.
- A detailed potential study is not always needed. In general, if a study is required by a regulator, or is being conducted to show that DSM can supplant steel in the ground generation, the study must be more detailed.
- Cooperatives can sometimes use data from previously published studies, instead of re-inventing the wheel.
- When member surveys are needed, there are strategies to use that will help reduce survey costs. For example, it is not always necessary to survey every distribution cooperative in a large G&T. Some cooperatives will have similar demographics and load profiles.
- Mailed surveys with an electronic option can save costs (when compared to phone surveys, which require extra personnel). Mail/internet combination surveys also tend to be more representative than phone surveys as the number of land lines decreases and cell phone numbers can be difficult to obtain.
- If a cooperative is performing a potential study because of state or federal regulations, it could turn to its state utilities commission for guidance on how to evaluate avoided capacity and energy, how to approach deemed savings, etc. This may save time and effort down the road.
- In most cases, a “bottom-up” approach to estimating potential is preferred.

In many cases, potential studies and cost/benefit analyses cover much of the same territory. For example, if a cooperative wishes to perform a cost/benefit analysis of a direct load program, it needs to know what level of participation is reasonably achievable and what kind of demand reduction it can expect on average; these are questions that are addressed in a potential study. Thus, many metrics and data sources used in a potential study are also used in cost/benefit analyses—deemed savings databases, expected useful life calculations, energy and demand impacts from previous studies, etc.

In many cases, it is appropriate to use program impacts from other cooperatives or IOUs in these analyses. If your cooperative is starting

[76] See Williams, David. “Cost-Effective DSM Potential Studies.” *TechSurveillance*, Business and Technology Strategies (BTS), NRECA. November 2015.

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a PTR program and performing preliminary impact estimates, you can look to results from other utilities, and use those impacts at first. After pilot programs are conducted, you will have some impacts specific to your cooperative, but, before that, using figures from another source is appropriate.

Possible sources for impacts from various sources include:

- *TechSurveillance* and other NRECA papers.
- The NRECA/DOE Smart Grid Demonstration Project. The results of these programs can be found in a series of *TechSurveillance* articles over the past few years. Many of the results are also collected at **www.nreca.coop/what-we-do/bts/smart-grid-demonstration-project**. That website has project results listed by topic.
- Other U.S. government sites, such as reports from the Smart Grid Investment Grant Program: **www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.html**. This website gives numerous reports on a variety of pilot programs. For example, at the bottom of the webpage there is a link for Consumer Behavior Studies.

5 General Considerations for the DSM Business Case Study

In This Section:

This section presents a big-picture strategy for designing a Demand-Side Management portfolio that is right for your cooperative. The emphasis is on high-level decisions and inputs that drive the cost/benefit analysis and how these decisions and inputs vary from cooperative to cooperative. The following sections present more details on some specific cost/benefit analyses and technologies.

What is a Business Case?

Business cases are more than simply the description of the costs and benefits that will accrue from a proposed program. At its heart, a business case is a plan. President Dwight D. Eisenhower once said, "Plans are worthless, but planning is everything." A similar statement might apply to business cases. For DSM programs, any given business case may not predict exactly how the costs and expenses play out in "real life," but the business case is still essential, because it presents at least one possible outcome (with some alternate scenarios considered).

So the business case is a planning tool. It allows cooperatives to project costs, expenses, and revenues that result from a proposed program. The business case projects when those costs and benefits will flow and to whom. Thus, the business plan should influence the eventual design of the DSM programs.

Cooperatives have a unique take on business cases, as the bottom line for cooperatives is usually: "How will this affect our members?" This makes cooperative business cases a little different than those of investor-owned utilities, where the bottom line sometimes involves shareholder value. For this reason, the cooperative business case will focus more on the impact on members. One operating assumption of this Guidebook is that benefits or expenses accrued at the generation and transmission level—or at the distribution cooperative level—will often accrue at the member level.

The Guidebook will also focus on some benefits that are not easily quantifiable in dollar terms.

For example, it is very difficult to put a dollar amount on the avoided risk that can sometimes result from DSM programs (the risk of spikes in energy prices, etc.). Another example is customer satisfaction. This is not measurable in dollar terms, but is a high priority for cooperatives.

Some benefits are not easily quantifiable at the present time (e.g., avoided greenhouse gases), but may become so in the near future (e.g., if a cap-and-trade system is implemented). Programs that accrue these unquantifiable benefits are included throughout the Guidebook.

Another focus is on establishing and maintaining cooperatives as "trusted energy advisors." This can sometimes involve taking the long view, rather than simply next year's costs and revenues.

The Major Steps in a Business Case

The following steps give a bird's-eye view of recommended use of the Guidebook for G&Ts and distribution cooperatives in various stages of DSM implementation. These are just general high-level steps cooperatives should consider; the specific circumstances of your cooperative may dictate other steps.

Figure 5.1 depicts the process of developing a DSM program as a cycle; this is appropriate, as results from a pilot program and from full deployment should be incorporated into the DSM plan on an ongoing basis. The steps are explained in the following sections.

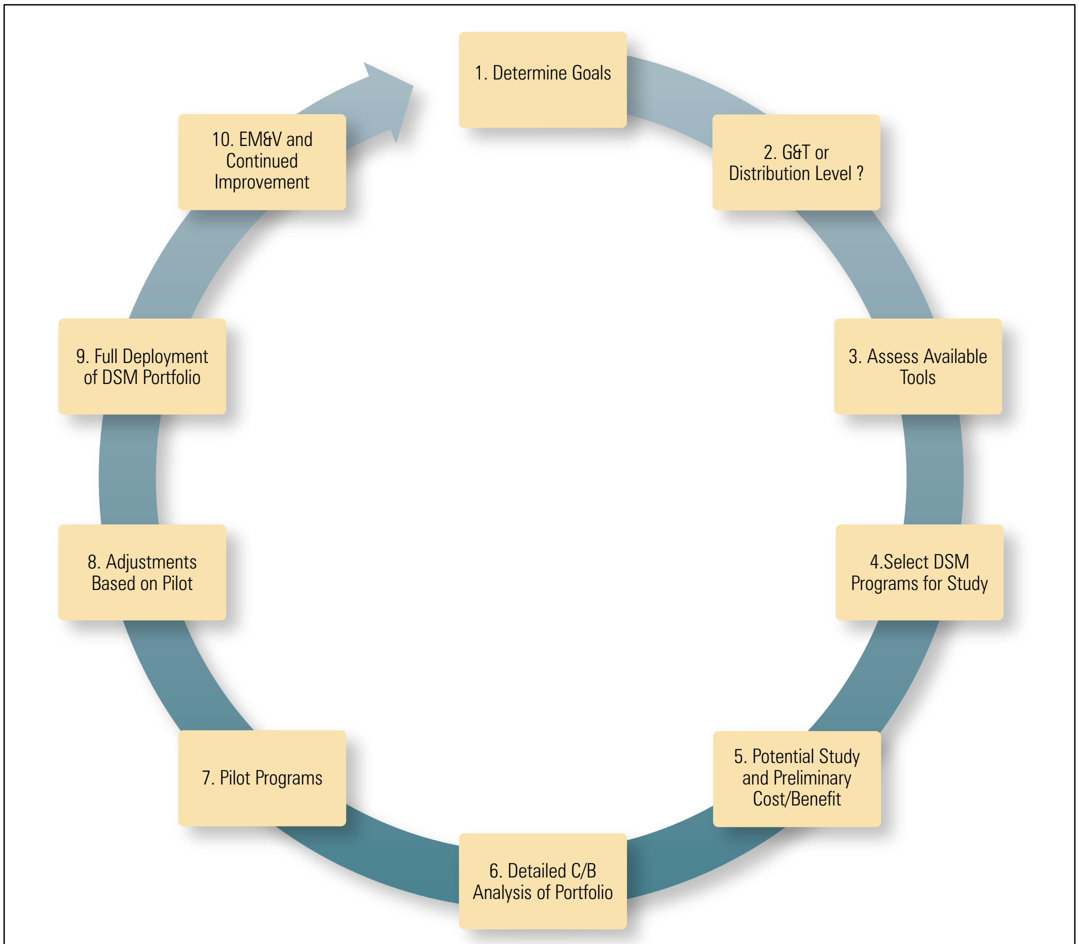

FIGURE 5.1: DSM Program Process

STEP ONE: WHAT ARE THE GOALS OF OUR DSM PROGRAMS?

Before DSM programs are planned, cooperatives should have a clear idea of *why* they are creating these programs. Possible goals include:

- Serve members with reliable, reasonably priced electricity
- Reduce wholesale charges
- Provide peaking or baseload capacity
- Reduce member/system energy usage
- Reduce costs to members
- Increase member satisfaction and engagement
- Meet state or local regulatory requirements
- Reduce greenhouse gas (GHG) emissions
- Solidify revenue through beneficial electrification
- Delay or eliminate the need for T&D upgrades
- Sell DSM in an organized market (e.g., ISO/RTO)
- Offer solutions and choices that allow members to maximize their value

Of course, many of these benefits and goals overlap and, in most cases, DSM programs have more than one goal. However, some cooperatives can have circumstances which dictate specific programs.

For example, if a cooperative will soon be facing some costly T&D upgrades in certain geographical areas, programs that are aimed at reducing peak demand could be targeted to the congested areas (i.e., demand response). On the other hand, if a cooperative's state has just instituted aggressive GHG targets, then a wide-scale energy-efficiency program may be called for. Thus, cooperatives should consider the goals of the prospective programs before embarking on a cost-benefit study.

During this step, it also helps to start to consider *how much* EE and DR is desired, although that can also be considered in later steps. For example, if the main goal is to defer T&D investments at a certain substation/feeder, then that could mean a different scale of DSM than if meeting a state requirement. The answer to questions in other steps can also influence how much DSM is planned.

STEP TWO: IS THE G&T COORDINATING THE DSM?

For G&T cooperatives, an early consideration in any large-scale DSM inquiry should be: "Should we coordinate our distribution cooperatives' DSM programs?" For distribution cooperatives, the inquiry is much the same: "Should my G&T coordinate any DSM programs that we run?"

As explained further in **When DSM Programs Should Be Coordinated by the G&T**, it is recommended that, in most cases, G&Ts should coordinate these programs. Some of the reasons for this are as follows.

- **Economies of Scale.** The process of performing cost/benefit studies, pilot programs, branding, evaluation, measurement and verification (EM&V), etc., can be somewhat time-consuming and it makes financial sense for these activities to be coordinated at the G&T level, rather than having each distribution cooperative perform them individually.
- **Peak-Shifting and Other DR Minefields.** If distribution cooperatives attempt to reduce demand charges by predicting when the G&T's peak will occur, and lowering demand during that time, they can negate each other's efforts. New secondary peaks may be created, thus nullifying the peak reductions of some of the DR programs and pitting distribution cooperatives against each other. Considerable financial opportunities are wasted with the "every cooperative for itself" mentality.

  This is explained in detail in **When DSM Programs Should Be Coordinated by the G&T**. Since one of the main benefits of DR is often to postpone or avoid new capacity, the G&T will be the entity best suited to predict peak demand, choose optimal portfolios, layer programs, and optimize program call times, all of which will help reduce the capacity required for the system as a whole.
- **Energy and Capacity Markets.** G&Ts are more suited than distribution cooperatives to serve as the conduit for DSM capacity and energy into the energy and capacity markets (PJM, MISO, etc.). Again, there are economies of scale involved; it makes more financial sense for a G&T to deploy DR for the capacity market, rather than having multiple distribution cooperatives deploying, sometimes in competition with each other.

STEP THREE: ASSESS COOPERATIVE TOOLS

Cooperatives need a good idea of what data and tools they have at their disposal before selecting a DSM program. Although it varies from program to program, in general, DR programs require more advanced tools than EE programs do.

Most cooperatives can run a wide range of EE programs; most traditional EE programs do not require specialized "smart grid" equipment or software programs. For example, a residential AC rebate program does not typically require AMI or any installed equipment (other than the AC unit, of course). However, as EE programs become more integrated with DR programs, they may require AMI metering or a basic meter data management system (MDMS) to analyze the data and perform EM&V functions.

The tools required for DR programs vary, but, in general, more tools are required than for EE. For example, direct load control requires equipment installation on the appliance or machine being controlled. Many DR programs require AMI and at least a basic MDMS to process the data. For example, PTR programs require AMI so that peak-time reductions can be measured and compensated. **Section 4** and **What Tools and Data Does My Cooperative Need** give more detail regarding what tools are required for various programs.

STEP FOUR: SURVEY THE RANGE OF DSM PROGRAMS

Consider the various types of DSM programs, taking note of what tools and resources are required for each, and determine which programs might be good candidates for your cooperative. Cooperatives familiar with the full range of DSM options may want to skim or skip this step. However, even cooperatives with extensive DSM portfolios could benefit from a review of the various DSM programs; there may be a new or overlooked program that would be appropriate. Cooperatives with very limited DSM experience may wish to spend a bit more time on this step, so that they can become familiar with the DSM landscape.

Section 2 of this Guidebook gives an introduction to the various categories of DSM programs, with pros and cons of some of the more popular options, and references to more detailed descriptions of specific programs.

STEP FIVE: POTENTIAL STUDY AND PRELIMINARY COST/BENEFIT ANALYSIS

In conducting a potential study and preliminary cost/benefit analysis in Step Five, cooperatives should again think about how much EE and DR is desired. For example, if the goal is to defer a peaker plant (or avoid one entirely), a cooperative may only need a specified level of DSM.

It should also be noted that some DSM programs can have diminishing returns; once the cost-effective "low-hanging fruit" is picked, the more expensive DSM can get (on a $/kW or kWh basis). Furthermore, as the amount of peak reductions grows and program rebounds get larger, the load curve will get flatter, making forecasting progressively more difficult. This may result in the need for "layering" of call times, or for new DSM programs.

For these reasons, if a specific level of DSM reduction is desired, the cooperative may wish to perform a DSM Potential Study at this step. A Potential Study can let cooperatives know what level of DSM reduction is technically possible, economical, and achievable on their system. For more on how to perform a cost-effective potential study, see *Cost-Effective DSM Potential Studies*.[77]

This step also involves doing some preliminary screening cost/benefit analyses to see what programs make sense for your cooperative. In this step, cooperatives may not yet know the specifics of some of the cost/benefit inputs, such as third-party costs (e.g., what specific load control devices will be used, what will be the size of the informational mailings, etc.). For these inputs at this step, estimates can be used if needed. The goal is to input some plausible costs and benefits so that programs can be approved for a more detailed analysis.

STEP SIX: DETAILED COST/BENEFIT ANALYSIS OF THE POSSIBLE PORTFOLIOS

After DSM programs are selected, in most cases, cooperatives should do a more detailed cost/benefit analysis of the candidate DSM programs for planning purposes. This analysis is similar to the one done in Step Five, but may be more detailed with respect to cooperative employee time, specific vendors, and equipment used, etc. This

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[77] Williams, David. *Cost-Effective DSM Potential Studies. Op. cit.*

analysis should be done using the full deployment scenario.

It is usually not necessary to perform a cost/benefit analysis isolated on the pilot program, which is described in the next step. Pilot programs need not have a positive cost/benefit ratio and, in fact, normally do not. This is partially due to unfavorable economies of scale and partially because the purpose of pilots is to test out marketing, load impacts, call strategies, rebate levels, and/or other details.

In many cases, if multiple programs are selected for analysis, the cost/benefit analysis at this step should be performed on a portfolio of programs as a whole, rather than simply doing a cost/benefit analysis of each program separately. The reason for the portfolio approach is that many programs, especially DR programs, can affect other DSM programs. Cooperatives need to ensure that they do not create rebound peaks, or cause other coordination issues. This step is the focus of the section on **DSM Portfolios**. Furthermore, DR and EE programs can often complement each other; for example, rebates for an appliance could be coupled with the requirement that the appliance be load controlled.

For EE programs, this step is where cooperatives should determine the exact amount of the rebate or incentive to be offered. For example, take a rebate program that is meant to induce members to buy an energy-efficient clothes dryer (e.g., the program gives a rebate if a member opts for a dryer that has an Energy Star designation). If the rebate is too low, not enough members will buy the preferred appliance. If the rebate is too high, the cooperative may pay out more in rebates than is required to meet their EE goals.

STEP SEVEN: PILOT PROGRAMS

Some DSM programs benefit greatly from pilot programs. In particular, for DR programs, a pilot is often necessary to tweak the marketing, dispatch methods/strategies, incentive levels, and other program aspects. For example, a pilot is a good idea for peak-time rebate programs; cooperatives can test the method by which they notify members of an event (text, email, phone calls).

Cooperatives can also test the member responsiveness to the size of the rebate. For example, is a rebate of $1/kWh of reduction[78] enough to get members to reduce usage during a “called” event, or is more (or less) required?

Some EE programs, such as appliance rebates, can be implemented on a cooperative-wide level without a pilot program. Even with EE programs, however, a pilot can be used to test marketing channels, responsiveness to certain rebate levels, vendor methods, etc. A whole-house program could benefit from a pilot, to see how long the process takes and whether there are any kinks. Pilots are discussed in **Piloting Selected DSM Programs**.

One issue that needs to be ironed out in the pilot stage is the dispatch strategy. This applies mainly to DR peak-reducing programs, such as direct load control, C&I interruptible, peak-time rebate, and critical peak pricing programs. These programs typically try to “hit” the peak of the power supplier; often the actual peak is not known until the end of the month or the end of the summer.

For these programs, there is a trade-off; the more a program is dispatched, the more likely it is that the peak will be hit, but each deployment costs the cooperative money. Members may get frustrated if too many events are called, thus reducing the program impact, especially with DR programs such as AC load control and other curtailment programs.

STEP EIGHT: LESSONS FROM THE PILOT PROGRAMS

After the pilots have been completed, the cooperative should assess the original cost/benefit analysis performed in Step Six. Did the assumptions hold? Did the expected reductions occur? Would the rebound energy directly after the event cause a new peak in a full deployment scenario? If needed, the cooperative may have to refresh the analysis with updated numbers to ensure that

[78] For reasons described in *Peak-Time Rebate Programs: A Success Story* (Dave Williams, et al., *Op. cit.*), we recommend that many rebates that target kilowatt reduction should be compensated on a kilowatt-hour basis. Although the goal of the program is kilowatt reduction at peak time, rebates are typically paid on kilowatt-hour reduction, which is easier to meter.

the adjusted numbers still support the business case. If the analysis still holds up, the program can be fully deployed.

This step should also give cooperatives some feedback about marketing strategies. We recommend a short survey at the end of the pilot program, so that participants can give feedback. The pilot could test response rates to bill inserts vs. stand-alone mailings, for example. Participants can also give feedback on whether they prefer contact by email, phone call, or text. These preferences can be enacted for the system-wide roll-out.

STEP NINE: FULL DEPLOYMENT OF SELECTED PROGRAMS

Once DSM programs have been selected and piloted, the programs are deployed on a cooperative-wide level or targeted to site-specific areas (if T&D deferral is the goal). With DR programs, full deployment often occurs the year after the pilot program, especially when summer or winter peak days are being targeted. With EE programs, full deployment can often begin sooner.

STEP TEN: ASSESSMENT OF PROGRAMS—EM&V AND CONTINUED IMPROVEMENT

Once DSM programs have been in full deployment, cooperatives may wish to perform evaluation, measurement, and verification (EM&V) to ensure that the programs are resulting in the expected energy or demand reduction. For most DSM programs, the effects cannot be measured directly, but must be estimated, based on what the energy or demand would have been in the programs' absence.

The rigor of EM&V can vary, depending on how the DSM programs are being used. For example, if DR programs are being used to delay or avoid the need for new capacity, the EM&V will need to be fairly detailed and precise to ensure that the expected demand reductions are occurring. If the DR programs do not deliver the expected reductions, capacity issues could arise.

After EM&V is performed, adjustments and improvements can be made to existing programs to help keep costs low and impacts high. EM&V is discussed in **Section 13**.

The 'Lost Revenue' Barrier to DSM

Before getting to the some big-picture strategy considerations, it may be helpful to go over some of the common barriers that can prevent cooperatives from implementing DSM programs. The 2009 CRN DSM Guide addressed some of these barriers, so we will refer the reader to it for more details.[79] However, it is worth discussing one of these barriers: the notion that DSM reduces sales and makes rates go up.

We have heard staff at some cooperatives say things like, "It doesn't make sense to spend money on DSM just to reduce sales," and "DSM programs will make rates go up." These concerns are related because, in some cases, reduced sales could lead to higher rates.

The other side to this is that reduced sales lead to lower electric bills for the DSM participant members. To the extent cooperatives are assisting members in making prudent purchasing decisions, the utility is providing value to members and fulfilling its service mission.

These are real concerns for cooperatives. It is true that some DSM programs will reduce sales, thus causing upward rate pressure and higher bills to non-DSM participant members. However, there are measures to take that can mitigate the issue and impact for the nonparticipating members.

First of all, this concern, for the most part, doesn't apply equally to many DR programs. Many DR programs have rebound or "pre-bound" effects; for example, people pre-cool their houses before a "called" peak-time rebate event and turn on the AC full blast after an event. This can make the program sales-neutral. Furthermore, even if there are some lost sales, they should be modest, because most DR programs are run for a very limited number of hours.

In a well-designed DR program, the saved capacity costs should make up for any lost sales, so that, although sales are reduced, costs are, too. Most DR programs that are implemented are done so because they have a positive benefit/cost ratio under both the PACT (utility test)

[79] *The Guide to the Essentials of Energy Efficiency and Demand Response*, Section 2. NRECA CRN. 2009.

and the RIM (ratepayer test). In other words, the benefits of DR typically outweigh the loss in sales, which are usually modest or close to zero.

Second, the concern about increased rates doesn't apply to all EE programs, for similar reasons. For example, an air conditioner rebate program may result in substantial capacity savings for a summer-peaking system since the units are usually on during peak times. Thus, although there are reduced sales, there are also reduced capacity costs to the utility that can help compensate for the lost sales revenues, so rates may not need to increase.

Third, EE programs that do reduce sales can be paired with DR programs that reduce capacity. For example, rebates on efficient irrigation pumps can be conditioned on enrolling those pumps into a direct load control program.[80] Here again, lost sales would be counterbalanced by avoided capacity.

Fourth, rates can be designed to be more DSM-friendly. This is discussed in **Section 12**. Two ways to make rates more DSM-friendly are to make the fixed charge/variable charge more reflective of cost-causation principles, and to offer time-of-use rates so that "true" hourly costs are reflected in rates.

For other barriers to DSM, we refer the reader back to the 2009 CRN DSM Guide.

What Tools and Data Does My Cooperative Need?

Before looking for candidate DSM programs, cooperatives need to have a good idea of what kind of data it has on hand and what tools it has to analyze that data. Specific DSM programs, especially DR programs, may require specialized equipment, such as load control switches or telemetry devices. However, here we are discussing "tools" in the more general sense: what information and smart grid devices are required in general to facilitate DSM programs?

AMI AND MDMS

In general, Advanced Metering Infrastructure (AMI) meters are not required for most EE programs, although they can be used for EM&V of EE programs. For example, rebates for energy-efficient central air conditioners require no AMI or Meter Data Management Systems (MDMS): members simply purchase an AC unit that meets the required standard and install it. However, AMI would be useful for measuring the hour-by-hour impacts of this program (EM&V).

With no AMI, the impact can be roughly estimated by using deemed savings databases or by statistical measurements using the monthly load data. Similarly, home weatherization projects (storm windows, attic insulation, weather-stripping, etc.) and other EE programs can be performed without AMI.

On the other hand, some DR programs require AMI interval data (and the ability to process this data) in order to be implemented. For example, any time-of-use rate program will require AMI and an MDMS to record and analyze hourly usage data. Peak-time rebate and CPP programs require AMI data (hourly or 15-minute) in order to determine usage during called events. Many load control programs can be implemented without AMI, but verification of the demand reduction, and whether the technology is working properly, is difficult without AMI.

This Guidebook will not go into the business case of implementing AMI system-wide, but cooperatives should note that AMI/MDMS do enable some DSM programs that are not otherwise feasible.

If cooperatives or their larger members wish to participate in some of the real-time RTO market products, such as ancillary service regulation, telemetry will likely be required to support the AMI system and associated data.

More discussion of DSM-related technologies appears in **Section 7**, **Section 8**, and **Section 9**.

[80] PSE conducted a cost-benefit examination for a cooperative's air conditioner EE rebate program. The Ratepayer Impact Measure (RIM) test was right around 1.0, due to the estimated impact on peak demands and the subsequent capacity savings. Thus, the program provided benefits to the participating members without creating upward pressure on rates. Note that every program is different and that this result may or may not be similar on your cooperative's system.

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THE COOPERATIVE LOAD CURVE

Another tool that is very valuable in DSM programs is the hourly load curve, a curve in which the average load for each hour of the year is depicted, from highest to lowest. This data is crucial for certain DR programs. For example, if a cooperative wants to perform a cost/benefit analysis on a DSM program, it needs to examine its own load curve and the anticipated impact load curve of the DSM program to be able to calculate the capacity benefits.

Consider a hypothetical cooperative, which has a DR program that can reduce peak demand on the 40 highest demand hours of the year (from 100 MW to 90 MW, from 99 MW to 89 MW, etc.). If hour 41, which is not controlled, has a peak of 92 MW, then the new peak demand is not 90 MW, but 92 MW[81] (see Figure 5.2). In other words, the peak demand impact of DR on the system is not the demand reduced in one peak hour, but rather the difference between the original peak demand and the new peak demand. Furthermore, rebound energy from programs can create new (and possibly higher) peaks if not properly dispatched.

This analysis also assumes no rebound energy added to hours after the program is shut off. In most cases, there will be a rebound and/or a secondary peak. Thus, in many cases, this cooperative can only achieve a maximum demand reduction of even less than 8 MW from the program. Therefore, depending on program implementation, it may be incorrect to say this program has a load reduction impact of 10 MW. The exact reduction will depend on many different factors and assumptions.

The expected impact of a program will depend mainly on the DSM impacts by hour and the system load curve, based on the actual weather and other factors experienced. Both of these factors will be dependent on the actual weather experienced, along with random variation in

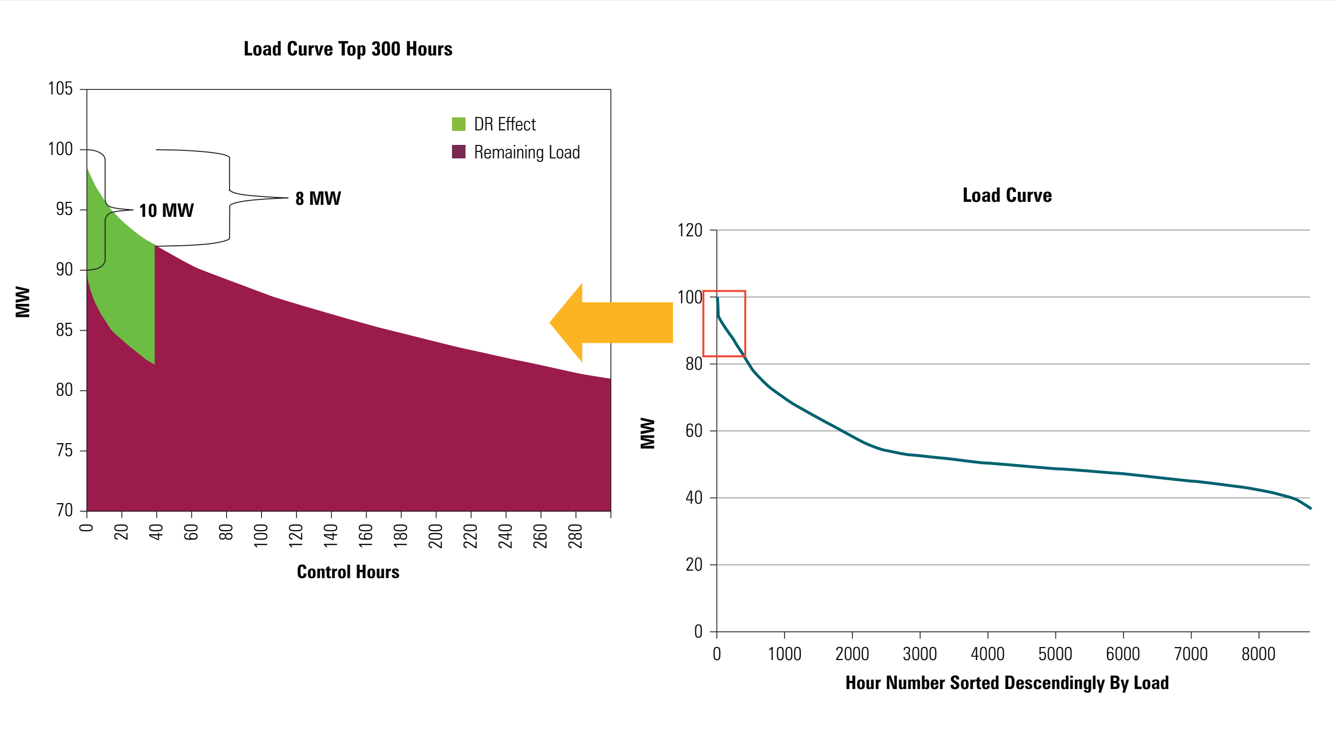

FIGURE 5.2: DR's Effect on the Load Curve

[81] This is true even with the (unrealistic) assumption that the top 40 demand hours are predicted perfectly, so that all events are called on the top 40 demand hours.

impacts and loads. For this reason, running simulations of the possible different weather scenarios that the cooperative may experience is recommended to get a distribution of the likely impacts. For further reading on this subject, see PSE's paper on this topic.[82]

THE VALUE OF SURVEYS

Surveys can be a valuable tool for getting the most out of your EE and DR programs. A detailed understanding of the member base can provide information regarding equipment saturations, current trends, motivating factors for special rate program participation, and preferred marketing messages and channels. There are many uses of survey information, including:

- Member information can be used to identify "low-hanging fruit," the programs or initiatives that can quickly and effectively reduce energy and capacity costs. These "low-hanging fruit" programs are important, because early program successes can help improve member satisfaction, thus creating positive buzz for the cooperative and cementing its status as a trusted energy advisor. Early successes also have positive effects for later programs, as members become accustomed to EE and DR programs that save them money.
- Surveys form the backbone of any system-wide potential study by identifying residential and commercial appliance saturations, housing and business characteristics, and other information.
- Many existing programs and analyses can be improved with the use of survey data, including load forecasts, IRPs, DSM and EE studies and pilots, and engineering surveys.
- Surveys can reveal members' attitudes towards participating in certain DSM programs. For example, agricultural members can be surveyed to determine whether they are able to participate in an irrigation DR program (and for how long and during what hours). This information is invaluable is designing DSM pilots and full programs.
- Marketing strategies for DSM programs can be tailored to fit in with your members' attitudes and characteristics. Studies have found that individual members react differently to utility initiatives based on socioeconomic conditions, education, housing footprint, and household characteristics (e.g., family size and composition). For example, if a majority of the members list environmental reasons as the top reason to reduce energy usage, this would lead to a different marketing campaign than if "saving money on my bill" was the top reason to reduce energy usage.
- Survey information could be used for DSM programs that are targeted toward certain substations or other areas of the cooperative. For example, if a certain geographical area has a high saturation of electric water heaters, it could be a good candidate for a water heater load control program.

Length and Scope of Surveys

Surveys can range in length and scope, from a simple one-page survey that asks a few questions about the household or business and its appliances, to an extended survey that drills down in detail about multiple topics, including: household size and age, member demographics, appliance type and age, member attitudes towards DSM programs, and more. For commercial members, detailed surveys can gather information about building footprint, HVAC sizing, equipment, employees, lighting, shift structure, and other nformation that can help cooperatives to design DSM programs.

Surveys, like DSM programs, are often best done at the G&T level. There are economies of scale in survey design, printing and mailing cost and effort, and consultant cost (if any). In some cases, it will be appropriate to send a survey to a sample group in each distribution cooperative, but, in other cases, the G&T can save costs by only surveying selected distribution cooperatives and extrapolating that information to the unsurveyed distribution cooperatives. For example, this would be appropriate when past surveys have shown two distribution cooperatives to have similar demographics and loads.

[82] Fenrick, Steve, Chris Ivanov, and Matt Sekeres. *Demand Response: How Much Value is Really There? (And How to Actually Achieve It)*. Power System Engineering, Inc. 2014.

END-USE AND LOAD SHAPE DATA

End-use and load shape data is helpful in (1) designing some DSM programs and (2) running program-specific business cases. G&Ts will already have hourly system load data. However, for certain DSM programs, it will also be helpful to have end-use and load shape data, including:

1. Class load shapes (e.g., the hourly load shape of the residential class as a whole)
2. Load shapes for an "average" member of each class (e.g., hourly load shape for an average residential member on a hot summer day)
3. Load shapes broken down by end use for certain classes (e.g., hourly load shape for an average residential member on a peak day, broken down by end-use or appliance)
4. Hourly load shapes of large customers (e.g., load shapes for large industrial customers with high demand peaks)

For example, hourly load shape data for the irrigator class will give the cooperative an idea of how "peaky" irrigation pump usage is, how often irrigation pumps are typically "on" during peak hours, and so on, so that DR impacts can be estimated more accurately. Similarly, end-use data for residential appliances such as water heaters and air conditioning allows the cooperative to design load control/PTR programs that minimize the chances of a "rebound" peak or a "pre-cool" peak.

For EE programs, some of the same considerations apply. Knowing how often and when water heaters and air conditioners are "on" will help cooperatives estimate the avoided energy and demand from (for example) rebate programs.

End-use data is also valuable for performing EM&V calculations, for the same reasons mentioned above.

Developing DSM Program Candidates

At this point, cooperatives may be thinking, "We have a good idea on how to structure a cost/benefit study for some selected DSM programs. But how do we know what programs to select in the first place?" In other words, how are DSM program candidates screened and selected? The answer to this question is almost always: "It depends on the demographics and load characteristics of the cooperative." However, there are certain principles that can be used to guide the selection process.

NATIONAL AND REGIONAL ELECTRICITY USAGE BY END-USE

Ideally, when determining which DSM programs to consider, a cooperative would have a recent, detailed end-use study of its entire system, which shows how each class uses electricity by end-use. However, many cooperatives will not have these studies. Luckily, there is other data that can be considered. One such alternate source is national residential electricity end-use, shown in **Table 5.1**.[83]

Looking at this national breakdown, it would seem that air conditioning, lighting, water heating, and refrigeration would be good areas in which to consider DSM programs. Obviously, things like air conditioning saturation and electric heat saturation change dramatically from climate zone to climate zone, and from urban to rural areas. Thus, national end-use data and appliance saturations should be used only if no other data is available.

There are also some regional U.S. Energy Information Administration (EIA) data sources on residential electric end-use, although this data is not as detailed. This regional data can be found in EIA's Residential Energy Consumption Survey (RECS).[84]

COOPERATIVE SURVEY AND CLASS DATA

Even if cooperatives do not have end-use data, they often have at least some survey data. This data can be used to perform an initial screening for candidate DSM programs. Are houses on the

[83] EIA *Annual Energy Outlook 2015*. Table: "Residential Sector Key Indicators and Consumption."

[84] See www.eia.gov/consumption/residential/data/2009.

TABLE 5.1: 2012 National Residential Electric End-Use

Residential Electrical Use	Quadrillion Btus	Percentage
Space Cooling	0.83	18%
Lighting	0.64	14%
Water Heating	0.44	9%
Refrigeration	0.37	8%
Televisions and Related Equipment[a]	0.33	7%
Space Heating	0.29	6%
Clothes Dryers	0.20	4%
Computers and Related Equipment[b]	0.12	3%
Cooking	0.11	2%
Dishwashers[c]	0.10	2%
Furnace Fans and Boiler Circulation Pumps	0.09	2%
Freezers	0.08	2%
Clothes Washers[c]	0.03	1%
Other Uses[d]	1.06	23%

[a] Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[b] Includes desktop and laptop computers, monitors, and networking equipment.
[c] Does not include water heating portion of load.
[d] Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.

system old? Consider weatherization programs. Is the saturation of electric heaters high? Consider a heating load control program. Do many members have old refrigerators in their garages? Consider a fridge recycling program.

Even if no survey data is available, cooperatives often have different rates for different end-users, so they have a count of users by class. If there are large numbers of irrigators, then cooperatives can look into energy-efficient pumps and irrigation DR programs. If there are large industrial customers, customized DR programs or time-of-use rates can be considered. Agricultural members that use large amounts of lighting or heat lamps can be offered efficient lighting rebate programs. Every cooperative system has particular end-uses that can be tailored to specific DSM programs.

Although class data can give a rough idea of what programs might be appropriate, there is no substitute for good survey data. If surveys have not been conducted in your system for a few years, surveys can be considered. (See **The Value of Surveys** for a discussion of surveys.)

Surveys should be sent not just to residential members, but also to small-to-medium commercial members. Large C&I members may merit their own customized interview; this can add costs to the survey process, but can also result in large energy and demand savings from a small number of members.

Piloting Selected DSM Programs

It is difficult to describe in a few pages the ins and outs of designing DSM pilot programs; each individual DSM program will have specific challenges when it comes to pilots. However, the basic idea is simple. Pilots are small-scale versions of the larger program, designed to identify and iron out any bugs in the process, set the incentives at proper levels, and verify the business case prior to making a larger investment in the program. The following sections identify some issues that can be addressed through pilot programs.

EVENT COORDINATION AND DESIGN

Pilot programs are a good way to iron out communication strategies. Members who participate in event-driven DR pilots such as PTR or CPP can choose to be informed of events by email or text, and sending "batch" messages via these media presents some logistical challenges. It is best to work out any kinks during the pilot stage.

Furthermore, different event notification strategies can be tested. For example, typically for called events there will be a notification 24 hours in advance, then a reminder the day of the event. Does a reminder in the morning result in a bigger reduction than a reminder 20 minutes before the event starts? After the pilot is over, members can be surveyed to determine which method of communication they preferred.

Pilots can also be used to determine the optimal duration of events and when in the day they should be called. For example, for residential members, do three-hour events have similar peak reductions as five-hour events, or do members get "burned out" during longer events? Is rebound usage similar for a 3 p.m.

to 6 p.m. event and a 4 p.m. to 7 p.m. event? Members' work schedules and other factors may affect how much reduction occurs at different hours of the day. Similarly, C&I members may not have a lot of reduction after 5 p.m. if most employees work an 8 a.m. to 5 p.m. shift. Pilots can help test all these factors.

Cooperatives can also test their load-prediction skills in a pilot program. It can be difficult to determine whether an upcoming day should be an event day. This is often done by looking at temperature and humidity forecasts, but G&Ts with large service territories may have areas with forecasts that vary quite a bit. Predicting which days of the week will have a peak load can be a tricky business, and the pilot helps to work out some details. Which weather forecast is used—NOAA, Accuweather, etc.? How many weather stations will be used? How do hourly forecasts fit in? Are there other factors besides weather that help to predict a peak load day?

Many cooperatives still "eyeball" weather forecasts to decide whether to call a DR event. Cooperatives would do better to develop short-term load forecast models that use a variety of inputs (e.g., historical data, temperature, humidity, day of the week). These models can give a specific kilowatt prediction for upcoming days, which will enable more accurate event-calling.

INCENTIVE LEVELS

Pilots can also be used to test out rebate levels. For example, a G&T could pilot a peak-time rebate program and have two groups—one that gets paid $0.75/kWh reduced, and one that gets paid $1.50/kWh reduced. The demand impact and survey responses of the two groups could be compared, thus giving an idea of the sensitivity of the rebate levels.

Similar sensitivity could be tested for EE rebates. For example, how many members will go for the energy-efficient air conditioner when offered a $100 rebate, as opposed to a $150 rebate? In practice, however, it may not be good PR for one member to get a higher appliance rebate than another. One strategy could be to offer a system-wide rebate one year, then a different system-wide rebate in the following year, to determine if the response rate differs significantly.

PILOTS FOR EE PROGRAMS

EE rebate programs are typically not piloted. The mechanics of a rebate for an energy-efficient appliance are fairly straightforward. However, there are some EE programs where pilot programs may be appropriate. Any program that requires extensive installation may be piloted to test out member reaction. For example, whole-house weatherization programs could be piloted to gauge member interest and participation and to test out various third-party contractors.

Another EE program that could be piloted is a program that involves substantial HVAC changes, such as a switch to ground-source heat pump HVAC systems. A ground-source heat pump would involve extensive construction and a pilot would be able to work out the kinks in this area. The pilot would also allow EM&V of the new system to ensure that the anticipated benefits were being achieved.

DSM Portfolios

To get the clearest cost/benefit picture possible, cooperatives need to evaluate DSM programs in terms of concrete portfolios rather than evaluating programs one-by-one.

Overestimation of DR benefits is commonplace throughout the industry because of the misconception that programs can be analyzed in isolation rather than as part of a portfolio. Many industry studies evaluate programs based on how much demand they reduce in one given hour. However, reducing demand in the highest demand hour may create a new peak in the second highest demand hour.

Furthermore, as seen in **The Cooperative Load Curve**, a DR program that has 10 MW of reduction might not reduce the overall demand by 10 MW. As other DR programs are added on the system, they will tend to flatten and change the load curve. Assuming the same original load curve for many different DR programs can result in an incorrect assessment of benefits. This is why examining DR "portfolios" and finding the best portfolio fit based on a comprehensive analysis is recommended.

EE programs can also influence the results of DR programs. To take a simple example, if an air conditioner rebate program is instituted, it will affect how much reduction can be expected from an AC load control or PTR program.

WHEN DSM PROGRAMS SHOULD BE COORDINATED BY THE G&T

In the case of a cooperative G&T that has several distribution cooperatives as members, DSM programs should be coordinated at the G&T level when possible, not the distribution cooperative level. There are several reasons for this recommendation.

1. **Without coordination at the G&T level, the actions of one distribution cooperative can harm other distribution cooperatives.** Many DSM programs, especially DR programs, can work against each other if performed at the level of the distribution cooperatives (without G&T coordination).

   A lack of coordination between distribution cooperatives could hurt all distribution cooperatives in two ways. First, in many cases, wholesale rates are set based on average embedded costs. In this case, rates are designed to recover revenue requirements and are not necessarily reflective of the marginal costs of serving peak demand or energy. Furthermore, when demand charges for distribution cooperatives are based on monthly peak charges, rather than based on the G&T annual peak, the mismatch in cost causation and rate design can create cross-subsidization issues between the G&T and its distribution members.

   If only one cooperative aggressively pursues a DR peak reduction program, and wholesale demand charges are set higher than the G&T's marginal demand costs, this will put upward pressure on future wholesale rates at the G&T (thus harming nonparticipating cooperatives). Likewise, if the marginal costs of demand are higher at the G&T than the demand rate, the nonparticipating members will be "free-riding" off of the one cooperative providing the added value.

   There are wholesale rate strategies around this issue, such as decoupling wholesale rates from the DSM incentive. This is discussed further in **Section 12**.
2. **Even if many distribution cooperatives enact programs, their efforts can be negated by peak shifting.** Assume a G&T with 10 distribution cooperative members: even if all 10 cooperatives enact DR programs, their uncoordinated efforts can be negated if a new peak is created as a result of the program. For example, if all 10 cooperatives call air conditioning load control events from 3 p.m. to 6 p.m. on a hot summer day, which is the projected high peak period, a new peak could be created at 7 p.m., as members all blast their AC units to make up for the load-control period.

   This "competition" between the G&T members can create an inefficient and wasteful situation of everyone making sure their DSM program is "on" at the time of the (expected) coincident peak. It is far more efficient for the G&T to dispatch DSM programs when they are needed, with full knowledge of the likely system-wide impacts in any given hour. Through dispatch coordination, system peak demands can be decreased far more with much less DSM effort. Again, having the G&T coordinate DSM programs is far less wasteful and more efficient, yet it does create the need for an alternative DSM incentive than the traditional coincident peak demand charge. This is discussed further in **Section 12**.
3. **The G&T cooperative will have a better idea of how effective DR and EE programs will be.** For example, with DR programs, the G&T will have better means to predict its projected peak days. With no coordination, distribution cooperatives may be left guessing as to when the G&T peak will be, and they may miss it, especially as other members' systems are also calling events.
4. **G&Ts can take advantage of economies of scale in both energy markets and in program offering.** The G&T will be more likely than distribution cooperatives to be able to sell DSM into the energy and capacity markets, and do this more cost-effectively than each distribution cooperative doing this

by themselves. Program offerings can be designed across the G&T system and then customized to each cooperative. DSM surveys and program M&V can also be conducted at the G&T level and then applied to each cooperative, thus saving money and increasing the accuracy of results relative to each cooperative going it alone.

6 DSM Business Structure and Process of Two G&Ts

In This Section:

Introduction

The business reasons for implementing DSM programs are often generalized so that concepts will speak to a broad range of cooperatives and utilities.[85] However, in practice, DSM evaluation strategies should vary based on the specific characteristics of the cooperative system, including wholesale power contracts and the regulatory environment. A DSM strategy that works for one cooperative may not be viable or as beneficial for another cooperative.

Needs and goals vary depending on many factors, including what type of cooperative is being studied (distribution, G&T, etc.) and what its capacity situation is. For example, a cooperative with excess distribution capacity may not place as much value on the peak reduction benefits some DSM programs offer. State regulations and member interest in energy efficiency services should also be key factors when considering how to optimize a DSM program.

DSM is an umbrella term that covers many strategies that can modify consumer demand in a way that is ultimately beneficial to the cooperative's or G&T's bottom line. This section offers details about how DSM strategies can—and should—be tailored based on the unique challenges and opportunities of local markets.

To do this, the DSM strategies of two G&T cooperatives—East Kentucky Power Company (EKPC) and Great River Energy (GRE, in Minnesota)—are described in detail. Only when looking at the full range of costs and benefits, starting with the wholesale power market and ending with the retail consumer, can the full spectrum of costs and benefits that comprise the DSM business case be seen.

How EKPC and GRE Approach DSM

Both EKPC and GRE consider DSM to be an important part of their resource mix and overall business strategy. However, they have different strategies and inputs when approaching DSM as a business opportunity. They are subject to different state regulations, operate within different regional transmission organizations (RTOs), and experience system peak at different times of the year.

The sections below describe each G&T's approach to DSM and how DSM provides value to their cooperative.

[85] Thanks to Pat Keegan of Collaborative Efficiency for primary authorship of this section.

EKPC: DSM PROGRAM BACKGROUND

East Kentucky Power Cooperative is a G&T located in Winchester, Kentucky. It provides electricity to 16 owner-members, which are distribution cooperatives that serve more than 520,000 homes and businesses. EKPC's major generation assets include about 1,900 MW of coal and 1,000 MW of gas combustion turbines. Its service area is depicted in Figure 6.1.

EKPC has offered DSM programs for more than 30 years "to meet the needs of the end consumer and to delay the need for additional generating capacity."[86] EKPC is regulated by its state commission and is required to file an Integrated Resource Plan (IRP) with the Kentucky Public Service Commission (PSC) every 3 years. The IRP must address demand-side measures and assess the cost-effectiveness of those measures.

The Commonwealth of Kentucky doesn't have mandatory energy-efficiency targets, but EKPC and other large utilities must go through the PSC for approval of the construction of new generation resources, rate increases, and new DSM programs. EKPC takes these requirements seriously and conducts a rigorous IRP.

EKPC formed the Demand-Side Management and Renewable Energy Collaborative (the "Collaborative"), whose purpose is to expand DSM and renewable energy and to promote collaborative implementation among participants. The Collaborative was a joint project of EKPC, its 16 owner-member distribution cooperatives, the Sierra Club, the Kentucky Environmental Foundation, and Kentuckians for the Commonwealth.

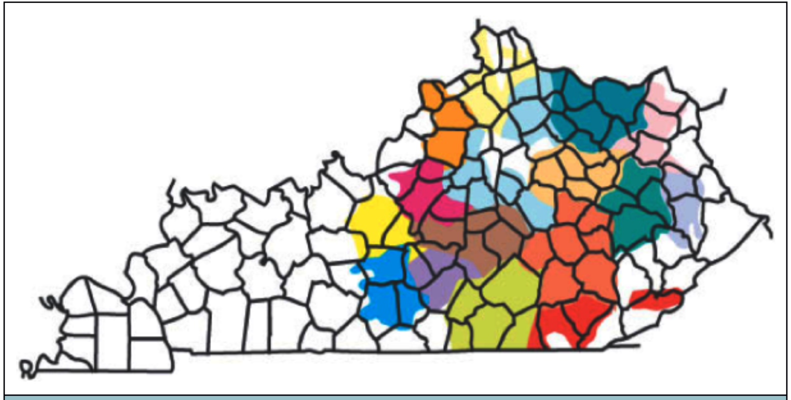

FIGURE 6.1: East Kentucky Power Cooperative Service Territory

The Collaborative met for about two and a half years, and a subset, the DSM Working Group, reviewed current DSM offerings and recommended new ones for consideration. The work of the Collaborative resulted in a renewed focus on DSM and renewable energy at EKPC; the group developed a series of recommendations urging EKPC to play a strong leadership role with its member cooperatives on DSM. The Collaborative recommended that EKPC:

- Offer analytic services to member cooperatives on their DSM programs
- Aggressively help member systems market programs
- Develop strong educational, marketing, and training programs
- Serve as a consultant to member system DSM programs
- Continually evaluate new and ongoing DSM programs
- Partner with member cooperatives on EM&V efforts

As the DSM Collaborative began, EKPC's approach to wholesale electricity markets was also changing. In 2013, EKPC joined PJM, an RTO that serves much of the Eastern time-zone, which provides opportunities for EKPC and other utilities to buy and sell DSM resources. The market value of DSM activities with a significant impact on peak loads was becoming clearer, but predicting the value became more complex because it could vary based on weather and overall demand across the whole PJM footprint.

As EKPC developed its IRP to be published in 2012, the co-op conducted a thorough evaluation of existing DSM programs and developed a portfolio of 103 possible new DSM measures. Then EKPC calculated the total resource cost (TRC) for each measure. Measures that scored greater than 1.1 made the initial cut. The program also evaluated the life of the measure and the expected participation rate.

[86] East Kentucky Power Company, *Integrated Resource Plan*, 2013.

The IRP was finalized in early 2012. It showed that the 11 existing programs produced very positive results and were projected to save, over the lifetime of the measures, $311 million in net present value (NPV). The IRP also concluded that 21 new programs could potentially provide value for the cooperative. According to projections, these new programs have the potential to contribute an NPV of $506 million in cost savings. Current DSM programs at EKPC include:

- Residential Lighting
- HVAC Duct Sealing
- Residential Weatherization
- Touchstone New Home Program
- Electric Thermal Storage
- Heap Pump Retrofit
- Direct Load Control for AC and Electric Water Heaters
- C&I Advanced Lighting
- Leak Detection of Air Compressors
- Energy Education

An important issue remained unresolved as the IRP was finalized—cost recovery. Utilities can offset some of the loss in revenue that occurs when energy-efficiency measures are implemented by reducing costs for wholesale power or generation, but many costs are fixed and cannot be easily reduced. This issue has proven to be a difficult one for many utilities. EKPC and its member cooperatives used the analysis to resolve this issue with a simple but innovative solution that could be a model for other G&Ts and distribution cooperatives.

EKPC followed the direction set in the IRP and increased DSM rapidly between 2012 and 2013, with a 50% increase in member participation in energy-efficiency programs and a 133% increase in direct load control programs. EKPC's 2013 DSM Annual Report found that 2013 installed measures cost just $0.012/kWh and demand savings were $454/kW. EKPC spent about $5.7 million on DSM in 2013. In 2014, EKPC added four new DSM programs.

EKPC updates its IRP every three years. The co-op is currently in the middle of an update and is reevaluating the business case of its programs. As a result, the G&T will likely make adjustments to existing programs and potentially add new programs.

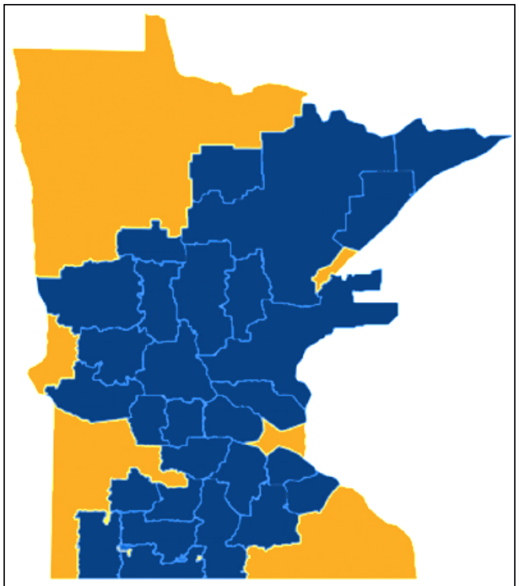

FIGURE 6.2: Great River Energy Service Territory

GRE: DSM PROGRAM BACKGROUND

Great River Energy formed in 1999 when two G&Ts founded in the 1950s combined operations. GRE is a generation and transmission cooperative that provides wholesale power to 28 member distribution cooperatives in Minnesota and a sliver of Wisconsin (see Figure 6.2). These distribution cooperatives serve members representing about 1.7 million people.

GRE takes a triple bottom line approach to business choices and investments. The G&T cites "affordable rates, reliable service, and environmental stewardship" as its top three priorities. GRE owns coal, natural gas, and renewable energy generation, but must sell all its energy supplies to the Midwest Independent Service Operator (MISO) energy market. GRE then purchases all of its energy from MISO.

GRE's demand-side programs are guided by state policies, which require all utilities in the state of Minnesota to try and achieve energy savings equal to 1.5% of their retail energy sales each year. DSM resources are also evaluated within the context of GRE's IRP efforts, which it must update every two years. GRE must submit its IRP to the Minnesota Public Utilities Commission (MPUC), which may review and advise GRE on its contents.

PREVIOUS VIEW

The Minnesota Legislature passed the Next Generation Energy Act of 2007 (the “Act”), which included a provision setting energy-savings goals for utilities equal to 1.5% of their annual retail energy sales.[87] Up to 0.5% of the mandated 1.5% energy savings can come from supply-side improvements that increase the efficiency of electricity generation, transmission, and distribution to reduce system losses.

In addition to energy-savings requirements, the Act also requires that utilities spend 1.5% of gross operating revenues on efficiency measures; however, up to half of that spending can go toward demand response programs. Therefore, many utilities—including GRE’s distribution cooperatives—seek to meet their energy savings goals as cost-effectively as possible while maximizing the allowable spending on demand response in order to meet the 1.5% spending requirement without forgoing more revenue as a result of energy efficiency. All utilities in Minnesota must comply with this Act. Although GRE doesn’t sell electricity to end users—and, therefore, technically isn’t required to comply with the Act—GRE serves as the reporting agent and submits one report for all of GRE’s 28 distribution members.

Additionally, although the MPUC doesn’t formally regulate GRE, GRE must go to the MPUC for a Certificate of Need before building a new generation resource. Before granting a Certificate of Need, the MPUC will typically do a review and consider whether the requesting utility has balanced its portfolio with DSM resources.

The DSM resources in GRE’s 2013–2017 IRP were assessed by EPRI in 2009 and then updated in 2011. GRE contracted with EPRI to evaluate energy efficiency potential over the 2009 to 2030 time period. The assessment determined cost-effectiveness using the TRC test. Two additional cost tests were then applied—the societal cost test (SCT) and the participant cost test (PCT). Market barriers and implementation difficulties were also evaluated in order to determine the amount of energy efficiency potential that could realistically be achieved. A major benefit accounted for in these tests is the avoided cost of the supply-side resource that is not needed if DSM is employed.

When evaluating the avoided costs of a resource, GRE considers both avoided energy and avoided capacity. GRE has a solid benchmark for its avoided capacity value. In 2009, GRE built the Elk River Peaking Station, a 175-MW natural gas peaking facility. Thus, if another similar plant were to be built, GRE has a good idea what it would cost. Natural gas peaking facilities of this size typically cost between $100 and $200 million. According to Eddie Webster, the Demand Response Lead at GRE:

> *Looking at the cost of the Elk River peaker gives us an upper bound for what demand response resources are worth: the cost of new entry. However, other values can be used to determine the value of a demand response resource as well. MISO conducts an annual voluntary capacity auction and the clearing price per megawatt in each zone sends a clear signal for the value of capacity provided by a DR program in that zone.*
>
> *Serving loads during peaks is expensive because peaking generation facilities are built with the knowledge they will only be utilized intermittently. These intermittent resources are expensive to build. Demand response helps us avoid investing in these resources and instead allows us to invest in a less expensive alternative, our members’ ability to reduce their consumption during critical times. Cost-effective DSM programs—especially demand response resources—are pools of resources that can be dynamically dispatched to help GRE minimize the costs of supplying power to distribution members.*[88]

GRE does not attempt to value avoided energy in any direct sense. It has an EE goal mandated by the state that it attempts to meet in the most efficient manner possible.

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[87] See Minnesota’s Next Generation Energy Act of 2007, www.revisor.mn.gov/data/revisor/slaws/2007/0/136.pdf.

[88] Interview with Eddie Webster, February 25, 2015.

Another compelling business reason for GRE to pursue DSM is because—in addition to energy conservation mandates—the State of Minnesota assigns environmental externality costs to six of the primary pollutants associated with generating electricity from fossil fuels within the state. These costs are assigned to generation resources based on the level of emissions of each resource. According to GRE, adding these costs to resources that emit pollutants results in their costs being much higher than resources that produce fewer or no emissions. These costs are used in inputs to studies, as described later in this section. Table 6.1[89] shows the externality costs of pollutants emitted by the generation of electricity.

As a result of both (1) the costs of peak power and (2) state regulations that mandate efficiency and charge utilities for the environmental externalities of their generation resources, GRE has developed an aggressive approach to load management and demand response and now has the ability to curtail about 15% of summer and winter load with DR programs.

TABLE 6.1: State of Minnesota Environmental Externality Costs Ranges (2012$/Ton) for Pollutants Emitted by the Generation of Electricity in Rural Areas

	Low	High
Carbon Dioxide (CO_2)	0.42	4.37
Carbon Monoxide (CO)	0.30	0.58
Lead (Pb)	567.00	632.00
Nitrogen Oxides (NO_x)	25.00	144.00
Particulate Matter Less Than 10 Microns in Size (PM_{10})	792.00	1,206.00
Sulfur Dioxide (SO_2)	0.00	0.00

GRE is a summer-peaking utility and has a broad suite of load management programs, including peak shaving and electric thermal storage:

- ETS Space Heating
- ETS Water Heating
- Dual Fuel Space Heating
- Interruptible Water Heating
- Interruptible Air Conditioning
- Interruptible Irrigation
- Interruptible C&I Loads
- Customer-Owned Generation
- Air-Source Heat Pumps
- Off-Peak Electric Vehicles

GRE also has energy-efficiency programs in the following areas:

- Agricultural Efficiency Improvements
- Compressed Air Improvements
- Engineering and Design Assistance for New Buildings and Existing Processes
- HVAC Efficiency Improvements and Retrofits, including Air-Source Heat Pumps, Ground-Source Heat Pumps, and Packaged Thermal Air Conditioning Units
- Energy-Efficient Lighting Retrofits, including LED Applications
- Premium Efficiency Motor Retrofits
- Custom Efficiency Improvements

Overall, GRE has been successful in meeting its DSM goals and has invested $138 million in DSM programs between 2008 and 2013, as seen in Table 6.2, provided by GRE.

TABLE 6.2: Summary of GRE's Expenditures and Savings

	2008	2009	2010	2011	2012	2013
Total DSM Expenditures	$23,009,820	$25,388,861	$26,337,053	$23,258,401	$20,327,872	$19,853,389
Total Kilowatt-Hour Savings	107,565,903	105,231,018	569,316,364	113,629,993	116,866,373	126,552,314
% Total Credited Savings/ Annual Energy Sales	1.0%	0.9%	5.0%	1.0%	1.0%	1.1%

[89] "Memorandum in Support of Clean Energy Organizations' Motion to Update Externality Values for Use in Resource Decisions." Docket No. E-999/CI-93-583 in the Matter of the Quantification of Environmental Costs. State of Minnesota Public Utilities Commission. October 9, 2013.

GRE is looking to use DSM programs as a way to take advantage of the centralized electricity markets in order to bring more value into its system. The G&T plans to register its DR resources with the Midwest Independent Service Operator (MISO) market, which would enable GRE to profit from several attributes of the DR resource. Although MISO doesn't currently allow for the aggregation of end points (i.e., combining DR resources from the residential sector), GRE is hopeful that MISO will accept these residential DR resources in the near future.

Table 6.3 lists the six different attributes GRE is able to sell into the MISO market currently. (The relative value of each attribute will change according to market fluctuations; the ranking is for general illustrative purposes.)

By selling DR into MISO, GRE will be able to receive the same value for 12 hours of load control that it would have taken the G&T 160 hours to derive without MISO. This is accomplished by offering the DR resource as supplemental energy and receiving reserve payments. A small reserve payment can be received 8,760 hours a year. Dispatch of supplemental resources in GRE's reserve zone occurs infrequently, roughly 12 hours annually. GRE can exercise less control and create less interruption, which means greater convenience to the cooperative participants while increasing the value of the DR programs.[90]

TABLE 6.3: Value of Products in Market

Electricity Attribute	Value Progression
Emergency	Lower Value
Capacity	↓
Energy	
Supplemental Reserve	
Spinning Reserve	
Frequency Regulation	Higher Value

The Process of Developing the DSM Business Case

The previous section describes the business and regulatory reasons that EKPC and GRE used to support and pursue DSM strategies. This section describes the information gathering, analysis, and collaboration that occurs at each G&T as specific decisions are made about how to approach and implement those DSM strategies.

EAST KENTUCKY POWER COOPERATIVE

After EKPC completes IRP updates, a planning process begins for each DSM program. EKPC has established a DSM planning process that relies on a close partnership between the G&T and its member cooperatives. EKPC leads a DSM Steering Committee led by Scott Drake, Manager of Corporate Technical Services. Mr. Drake is an engineer with more than 20 years of utility experience and balances the technical aspects of DSM planning with an understanding of the need for collaboration with and ownership from all member cooperatives involved. The DSM Steering Committee is comprised of a range or representatives from member cooperatives—from CEOs to member services staff to CFOs.

This inclusive planning approach is producing positive results. Rick Ryan, Vice President Member Services for Nolin Rural Electric Cooperative, explains:

> *Having an opportunity to serve on the DSM Steering Committee gives cooperatives an opportunity to discuss programs that will work in their respective territories. Having diversity on the committee allows us to develop programs that all 16 member systems can offer their membership. This allows us, as distribution cooperatives, to have ownership of these programs.*

Through regular planning meetings, the DSM Steering Committee determines collectively what will be offered to end-use members and how the programs will be implemented. The entire process is a partnership with the owner-member distribution cooperatives. "After all," says Scott Drake, "energy efficiency happens at the meter. It's a power plant, but it's located at the retail members' meters."[91]

[90] Source: Interviews with GRE staff.

[91] Interview with Scott Drake, February 25, 2015.

EKPC funds all program development costs and, as part of this development effort, hires a consultant to conduct a benefit-cost analysis on all potential DSM measures suggested by the Committee. The outcome of program development efforts is a five-year DSM work plan with associated kilowatt-hour savings and cost goals, which help EKPC and the member cooperatives manage program delivery. Almost all of the interaction with end-use members is driven by the distribution cooperative, which supplies a keen sense for the viability of a program. As Drake says, "If a program doesn't work for cooperative members, or it doesn't work for the distribution cooperative, it's not going to work at all."

TABLE 6.4: Cost/Benefit Comparison Between Direct Load Control and Appliance Rebate

Cost or Benefit	Residential Direct Load Control DR Program	ENERGY STAR Appliance Rebate Program
Present Value Calculations		
Distribution Cooperative Administrative Costs	$0	$0
G&T Cooperative Administrative Costs	$23,034,823	$2,471,852
Distribution Co-op Rebates to Participant	$7,187,731	$19,028,599
G&T Payments to Member Co-op	$7,187,731	$32,877,988
Participant Investment	$0	$41,925,626
Value of kW Savings (Generation & T&D Capacity)	$52,043,096	$27,885,058
Value of kWh Savings (Avoided Energy Costs)*	$686,663	$30,082,995
Reduced Customer O&M Costs**	$0	$2,567,340
Retail Revenue Loss by Distribution Co-op	$1,160,316	$52,996,725
Wholesale Bill Savings by Co-op (and Revenue Loss by G&T)	$14,955,718	$39,087,413
Cost-Effectiveness Tests		
Total Resource Cost Benefit-Cost Ratio	2.29	1.43
G&T RIM	1.17	0.78
Distribution Co-op Ratepayer Impact Model (RIM)	2.65	1.00
Distribution Co-op RIM Without Transfer Payment	1.79	0.54

* In both programs, the value for energy savings comes from PJM
** Value of water and sewer cost savings of ENERGY STAR dishwasher

EKPC supports marketing by designing all the materials to ensure the programs are promoted consistently across the system. EKPC also provides a reimbursement of 75% for DSM advertising (up to 75 cents per meter) to support each of its member cooperatives' promotion of the programs. EKPC also provides an allotment of $10,000 per year to each member co-op for direct load control advertising.

EKPC retains consultants to do evaluation, measurement, and verification of program implementation. Online interactive auditing programs for its member co-ops have been provided, as well as a tracking software system called EECP for tracking each member's DSM measures and reimbursement to the member cooperatives.

DSM has many positive attributes, but utilities are often reluctant to implement programs because of the loss in revenue they create. EKPC uses an ingenious method to solve this problem for its owner-member distribution cooperatives. EKPC calculates the Ratepayer Impact Measure to calculate the lost revenue for the distribution cooperative and the G&T. It is not a simple "system average" calculation, so it can be a more realistic measure of projected impacts. The distribution cooperative is then compensated by EKPC for the NPV of the lost revenue. Each distribution cooperative is reimbursed for the lost revenue it experiences when the energy efficiency programs are implemented and sales are reduced. Thus, the disincentive for implementing energy efficiency is removed.

A Member Services Advisory Group that includes energy advisers and member services staff meets four times per year to discuss the full range of DSM topics, including implementation, marketing, and advertising. During these meetings, program challenges and changes are discussed, evaluated, and agreed upon.

The EKPC DSM planning process depends upon a thorough analysis of costs and benefits. Producing this kind of analysis requires EKPC staff and management expertise and strong support from consultants who employ the latest analytical tools.

Table 6.4 is an example of the calculations that EKPC's consultant produced for a DR program and an energy-efficiency program.

Note that the two programs provide both energy and capacity savings. The capacity values are calculated differently, though. A single-cycle combustion turbine provides the generation value for the DR program and a combined-cycle plant provides the value for the energy-efficiency program.

GREAT RIVER ENERGY

GRE has mandated targets set by the Minnesota Department of Commerce's Division of Energy Resources as part of the state's energy-efficiency portfolio standards. A mandate such as this, which is similar to the energy-efficiency portfolio standards that many cooperatives around the country must comply with, completely changes the way a DSM business case is put together. GRE's business case helps GRE and its member cooperatives meet the state mandate in the most cost-effective manner.

GRE's member services group manages the energy-efficiency portfolio on behalf of its 28 member distribution cooperatives. GRE involves the distribution cooperatives in planning DSM strategies and together they look to create demand response efforts and support programs that build member satisfaction while meeting state energy-efficiency mandates. A group of managers from the G&T and leadership-level staff from member cooperatives make recommendations about the DSM strategies.

Once a DSM strategy is agreed upon, GRE develops a rebate budget for 20 of its 28 distribution cooperatives. These 20 distribution co-ops are "all requirement cooperatives" that purchase power only from GRE. GRE builds the cost of rebates into the wholesale power costs that they charge the 20 all-requirements cooperatives. The other 8 cooperatives have a fixed amount of energy that comes from GRE, and their wholesale rates do not have rebate dollars built in.

Rebate budgets for the 20 distribution cooperatives are allocated based on the projected kilowatt-hour sales for the coming year. The state of Minnesota requires utilities to use a 3-year energy sales average in developing each utility's 1.5% energy savings goal.

Once these budgets and goals are developed, GRE offers distribution cooperatives a number of tools to help them meet energy-savings goals on budget: a budget and kilowatt-hour savings planning tool, a software platform to track ongoing progress towards kilowatt-hour savings and associated spending, and consultations with GRE Account Executives.

Table 6.5 is an example of a budget worksheet GRE uses with distribution cooperatives to determine the appropriate level of rebate spending by each distribution cooperative. Once total rebate amounts are determined, distribution co-ops can use the budget tool to determine the budget for each program category.

According to Jeff Haase, GRE's Energy Efficiency Program Coordinator, "We leave it up to the cooperatives to determine how they are going to allocate rebate resources in a way that best meets the needs of their membership." All administrative costs related to running programs are covered by the distribution cooperatives.

GRE staff coordinate the dispatch of the demand response controllers installed by the distribution member cooperatives. Coordinated control at the G&T creates an environment where wholesale power costs can be managed efficiently to reduce the collective costs that must be recovered from the 28 distribution member cooperatives. Clearly, if each distribution cooperative was attempting to call its own peaks to avoid demand charges, it would be inefficient in terms of scaled resources and the cooperatives would be in competition with each other, thus negating their efforts.

Demand response programs include demand and energy credits to distribution members to motivate them to install equipment on key loads that can be curtailed during peak times. The incentives offered are decided by a Rate Review Committee consisting of member CEOs. The rate review committee meets annually.

The framework for DR can be set on an annual basis, but the business case for GRE's demand response programs is a dynamic one because decisions must be made in real time. GRE staff constantly monitor the value of each electricity attribute on the MISO market and calculate the benefits of various DR actions on a spreadsheet model they have devised.

Throughout the year, distribution cooperatives enter rebate spending and energy saving data on an Energy Savings Platform (ESP) (**www.energyplatforms.com**) configured specifically for GRE. ESP is software developed

TABLE 6.5: Example of GRE's Budget Worksheet to Determine Rebate Spending

Stearns					
2015 Budget Planning Worksheet	**INPUT DATA**				
2015 Rebate Budget $ Allocation	$ 325,075				
2015 Income Eligible Spending Budget	$ 48,164				
Remaining Allocation:	$ 276,911				
kWh Goal – 1.5%	7,430,747				
kWh Goal – 1%	4,953,831				
kWh Goal – 1% less 11.5% Line Losses	4,384,141				
kWh Goal less 25% Banked Savings	1,096,035				
RESIDENTIAL		**$ Dollars**		**kWh**	
	Budget units	$ per unit	Total $	Deemed kWh	Total kWh
APPLIANCES	–		$ –		0
Dehumidifier		$ 25	$ –	435	–
Freezer, new with recycling of replaced unit		$ 75	$ –	1,196	–
Freezer Harvest (recycling only)		$ 75	$ –	1,134	–
Refrigerator, new with recycling of replaced unit		$ 75	$ –	1,047	–
Refrigerator Harvest (recycling only)		$ 75	$ –	915	–
HVAC					
CAC Units	–		$ –		–
QI SEER 13 CAC		$ 50	$ –	302	–

by Energy Platforms, LLC, and used for the State of Minnesota. (It can also handle other states, according to the website.) ESP is a cloud-based platform that allows states and other entities to manage and report on energy programs. After distribution cooperatives fill out required fields in the ESP, GRE aggregates all the data and submits it to MPUC.

GRE staff coordinates the filing of its distribution cooperative members' energy-efficiency obligations to the Minnesota Division of Energy Resources.

Some Lessons Learned/ Conclusion

A DSM business case is a tool that can help cooperatives set a DSM target or it can be used to help cooperatives decide how to reach a target set by a regulator.

A DSM business case will not lead cooperatives in the right direction unless it considers the cost of generation, the wholesale price for electricity, the financial impact on end users, and the costs of delivering DSM. G&Ts and distribution cooperatives each have data and perspectives to contribute.

A DSM business case should compare the financial impact of DSM measures to conventional electric generation. **Table 6.6** shows several factors that were considered by both G&Ts in their business cases, and one factor that was considered by EKPC but not by GRE.

An integrated resource plan is a critical step in developing a business case for DSM. It can include all the factors in **Table 6.6**. It requires a sophisticated analysis in order to fairly evaluate all the resource options. And it needs to be updated on a regular basis, because technologies and markets change.

Many states mandate the level of DSM for some or all cooperatives. These mandates fundamentally change the goals of a DSM business case. Instead of developing a business case that will optimize the value of DSM, the business case under a mandate will help determine the most cost-effective way to meet the mandate while incorporating other goals the cooperative may have, such as member satisfaction.

Calculating the financial impact of DSM is complex because the wholesale market for electricity is complicated and because DSM can be delivered and measured in many ways. This suggests two things:

TABLE 6.6: Factors Considered in the DSM Business Case

Factors	EKPC	GRE
Full DSM Costs, including Program Administration	X	X
Cost of DSM Energy (kWh) Compared to Alternatives	X	X
Cost of DSM Demand (kW) Compared to Alternatives	X	X
Daily and Hourly Savings Profile	X	X
Market Value of DSM Savings	X	X
Lost Revenue	X	

1. Cooperatives will need to be educated. The G&T should provide education and training about the wholesale market, DSM program designs, delivery systems, and EM&V.
2. Even sophisticated utilities and G&Ts hire expert consultants or staff and purchase analytical tools or services to conduct their analyses, demonstrating that the right expertise and right tools are necessary to manage the integration and implementation of DSM. This is similar to the approach cooperatives have taken with other complex tasks involving electric generation and transmission.

If regulators review the DSM business case, they will expect accountability and transparency. This means evaluation, monitoring and verification, rigorous analysis, and reporting.

One final note: the EKPC and GRE cases show that DSM plans run at the G&T level have the advantage of economies of scale. When distribution cooperatives agree to run programs together and make the G&T responsible for some program planning and implementation functions, these G&Ts have been able to provide a level of support that would be unaffordable to a single distribution cooperative.

7 The New Face of DSM—Large-Scale Technologies ('Game Changers')

In This Section:

- **Beneficial Electrification—General**
- **Plug-In Electric Vehicles**
- **Batteries and Other Storage Systems**
- **Distributed Generation**
- **The Changing Nature of Electric Utilities**

The landscape of DSM is changing. The change is not happening so much in the cost/benefits tests themselves; the standard tests have remained the same (the Societal Test, the Total Resource Test, the Ratepayer Impact Test, etc., discussed in **Section 3**). However, the categories of *inputs* that go into these tests is growing and the DSM programs themselves are becoming more varied. Cooperatives now need to consider the costs and benefits of new inputs and programs such as:

- New consumer technologies, including those related to beneficial electrification (e.g., electric plug-in vehicles)
- Smart grid technologies (AMI, MDM systems, voltage regulators, automatic switches, etc.)
- Third-party products (Nest, iHome, etc.)
- Programs related to emerging renewable markets (e.g., net metering for rooftop solar, distributed generation)
- DSM sold in energy or capacity markets run by regional transmission organizations (RTOs) such as PJM and MISO
- Regulatory requirements, such as the impacts of greenhouse gas (GHG) emissions (**see Section 11**)

These new elements allow DSM programs that were not technologically or financially feasible 10 years ago. In addition to the new possibilities, there are still the more "traditional" DSM programs, like EE appliance rebates, and load management programs, such as direct load control. Some traditional programs intertwine with the newer DSM programs; for example, the business case for home area networks may be bolstered if paired with time-of-use pricing or a smart thermostat/load control program.

In this section, some new technologies and techniques that qualify as possible "game-changers"—programs that may have major effects at the national level—are discussed:

- Beneficial Electrification, including plug-in electric vehicles
- Battery and Other Storage Systems
- Distributed Generation

Section 8 covers new DSM technologies that deal with cooperative-level information. **Section 9** reviews new DSM technologies that are more specific to individual residential and commercial members (e.g., ground-source heat pumps, home-area-networks). **Section 10** discusses DSM in the ISO/RTO market.

Beneficial Electrification—General

One large-scale trend that could greatly impact cooperatives is the potential for "beneficial electrification" using new technologies.

Currently, many cooperatives look to resistance electric water heaters as a possible source for beneficial electrification. However, natural gas is currently cheap and is expected to remain fairly cheap for the near-term. With cheap natural gas (where available), new homes tend to use natural gas as a home heating source; this often translates into using natural gas for water heating as well. Cheap natural gas also tends to increase the purchase of gas water heaters over electric resistance water heaters in existing homes.

Cooperatives should look beyond traditional electric resistance water heaters and consider electric heat pump water heaters. Heat pump water heaters are competitive with natural gas water heaters (on a $/year-spent-by-the-member basis), even with the current low natural gas prices. Cooperatives could consider rebates for efficient heat-pump water heaters. This can offer a "win-win" to both the cooperative and the end-use member.

There are also many other arenas of beneficial electrification aside from water heaters. One of the biggest potential "game changers" in this area is the plug-in electric vehicle (PEV), discussed in the next section. However, even outside of PEVs, there are many other areas of beneficial electrification. Heat-pump HVAC units are becoming more common. Plug-in or battery yard tools such as lawn mowers, hedge trimmers, chainsaws, weed-eaters, and leaf blowers are coming onto the market. Cooperatives should consider EE rebate programs for PEVs, heat pumps, and smaller appliances as well.

There are also possible areas for beneficial electrification in the agricultural sector. For example, many irrigation motors and other pumps in remote areas are powered by diesel generators. This is due to the fact that three-phase lines can be too costly to extend to remote areas. Three-phase power is often the responsibility of the member and involves very high installation and equipment costs. Three-phase service line installation can range from $50,000 to $150,000 per mile. However, most induction motors (e.g., irrigation pumps) require three-phase power and cannot be run on single-phase power.

Therefore, many members with irrigation or other motors in remote areas use diesel generators (even if they have single-phase service to that area). However, single-phase lines can be combined with variable frequency drives (VFDs) to make the electric option cost-efficient. VFDs vary the voltage and frequency supplied to motors, thus varying the speed of the motor. VFDs can convert single-phase power to three-phase power, thus allowing the use of three-phase motors on single-phase lines. VFDs can also save members money by only using the load appropriate for the job.[92]

Cooperatives should keep an eye out for instances in which these two benefits from VFDs can be combined—i.e., a variable load on a geographically remote account, which also uses a diesel generator. In this case, cooperatives should consider a rebate for the VFD (and the installation of a single-phase line, if needed); this will add load and can, in some cases, result in a short pay-back period for the consumer. For more on this issue, see the paper *An Introduction to the Economics of Variable Frequency Drives*.[93]

Despite the large potential for beneficial electrification from water heaters, yard tools, heat pumps, and agricultural equipment, there is another sector that could result in a "game-changing" amount of electrification—plug-in electric vehicles.

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[92] Since VFDs can change the speed of a motor, there are significant energy savings available by varying the speed of a motor serving a variable load. For example, if an irrigation system requires a maximum of 10 horsepower (HP) during peak watering times but only 3–4 HP most other times, it is inefficient to run the irrigation motor at 10 HP at all times. A VFD can vary the speed of the motor according to the actual work required, thus saving both energy and demand on the system.

[93] *An Introduction to the Economics of Variable Frequency Drives* by David Williams, NRECA CRN, 2013.

Plug-In Electric Vehicles

Plug-in electric vehicles (PEVs) are one of the new technologies that could alter the landscape for electric cooperatives in the coming decades. PEVs have the potential to provide large amounts of beneficial electrification for cooperatives. While introducing PEVs onto distribution networks may present certain challenges, the possible benefits are enormous.

Therefore, cooperatives should become "PEV-friendly" by: (1) encouraging and incentivizing its members to purchase plug-in electric vehicles, and (2) considering converting at least part of its own fleet to PEVs. This encouragement could come in the form of PEV-friendly rate structures or other incentives for PEV owners, such as rebates. Cooperatives could also support state or local initiatives to incentivize PEVs and the associated infrastructure.

There has been a movement by utilities to increase the fixed customer charge and lower the volumetric charge to better align electricity rates with cost causation principles. This move is often met with opposition from solar and environmental advocates. However, decreasing the volumetric charge will increase the economic value of PEVs to members. Thus, increasing fixed charges will help encourage members to adopt PEV technology.

Other sections discuss some challenges that electric utilities are likely to face in the coming years. For example, consider the issue of declining revenues for utilities, or even a possible "death spiral" (see **A Possible Utility 'Death Spiral'?**). While we don't believe a death spiral is imminent, electric sales have flattened out in many areas of the country and many regions may see a continued lull, or even a decline, in electric sales in the future. PEVs are a good candidate to help stop, or even reverse, this possible decline. Thus, there are multiple benefits for cooperatives from PEVs:

- PEVs have the potential to be a large source of added revenue for cooperatives.
- PEVs can be charged at night, so as to fill in "valleys" in a cooperative's load profile.
- If two-way charging technology is developed, PEV batteries may also be used as emergency power or frequency regulation sources (i.e., as demand response).
- PEVs may count toward state or federal emission reduction targets.
- PEVs may help increase member satisfaction rates, as the cooperative will be seen as a trusted energy partner.
- In some cases, PEVs can help with the cooperative's own expense levels, by reducing fleet costs.

A discussion of fleet electrification and some of the possible benefits of PEVs on cooperative systems follow a brief introduction to PEVs.

INTRODUCTION TO PEVS[94]

Plug-in electric vehicles, or PEVs, are cars and trucks that run at least partially on electricity from the grid; they're charged by plugging into an outlet. PEVs should be distinguished from "hybrid electric vehicles" (HEVs, often just called "hybrids"). HEVs are vehicles that combine a conventional combustion engine with an electric propulsion system. The Toyota Prius is the most popular hybrid, but, in its original and most popular model, the Prius is never plugged in an outlet to recharge.

In contrast, PEVs are charged from the grid. There are currently two main types of PEVs: battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). BEVs are all-electric, with no gas combustion engine. Examples of BEVs include the Nissan Leaf and the Tesla models.

PHEVs typically have both a gas motor and an electric propulsion system. Examples of PHEVs include the Chevy Volt and the Toyota Prius Plug-in Hybrid.

Designs of PHEVs vary, but the general idea is that the PHEV is powered by batteries at some times and by the combustion engine at other times. The battery can be charged from the grid, unlike the battery of a "traditional" hybrid. Batteries for PEVs can be charged at the owners' houses, at their workplaces, or at charging

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[94] See also (1) CRN's *Resource Guide: Plug-In Electric Vehicles*, Dan Greenburg and Bryan Jungers, April 15, 2013, and (2) "Plug-in Electric Vehicles as Load," Jim Hanson, *TechSurveillance*, April 2013, for more on the basics of electric vehicles.

stations, which can be public or private.

The range of BEVs can be anywhere from around 75 miles to more than 250 miles, depending on the exact model. The 2015 Tesla Model S (with 85-kWh battery pack) has a range of 265 miles, but it costs around $80,000. The 2015 Nissan Leaf has a range of around 84 miles, and costs $29,000–$35,000.[95]

Residential charging can use a standard 120-V household plug (Level 1 charging); it can also use a 240-V charger (Level 2), which requires some specialized equipment in the home. Level 1 charging adds about 2 to 5 miles of range per hour of charging time; a night's charging (8 hours) on a standard outlet might give 40 miles of charge. A Level 2 charger adds about 10 to 25 miles of charge per hour, so it can often charge a car overnight (8 hours).

Public charging stations are often of a third type: "DC fast chargers" or "DC Level 2." These stations can add 50 to 70+ miles of range in around 20 minutes.[96] Public charging stations are sometimes free, but usually charge a fee. The number of charging stations in a region can make a big difference in convenience for PEV owners. A charging station at a workplace could be a Level 1, Level 2, or DC fast charger. Public charging stations make electric car ownership a lot easier.

Cooperative members who own an all-electric car, like a Nissan Leaf, can use their own houses to charge their cars and, with no special charging equipment, they will be able to store 30 or 40 miles' worth of charge overnight (8 hours). A family who buys Level 2 charging equipment for their home will be able to charge all or most of their range overnight (8 hours).

However, electric car ownership may not "take off" in an area until there are public charging stations. For example, California utilities are being aggressive in charging station implementation. Pacific Gas and Electric Company (PG&E) recently requested the California Public Utilities Commission (CPUC) to install 25,000 Level 2 stations and 100 DC fast charging stations, although the implementation of this plan is currently a source of controversy.[97]

Cooperatives should be aware that PEV technology is maturing rapidly, is already fairly robust, and that, for some of its members, the cost of ownership of a PEV may already be equal to or less than that of a gasoline-powered car. This is also true of cooperative fleets, discussed in the next section. The market adoption of PEVs will depend in large part on the technology advances and PEV prices offered by auto manufacturers, along with future gasoline and electricity prices.

Should cooperatives start thinking about installing charging stations in their territories? The answer to this is complicated and will depend on the demographics of the cooperative. It is likely that electric vehicle penetration will accelerate in the coming years. The penetration will increase at a higher rate in urban and suburban areas, and will be slower in rural areas (where population densities are low and driving distances are high). For some service territories, especially the more rural ones, the penetration of PEVs may not be high over the next 10 years. However, for cooperatives with suburban areas or other areas near urban centers, penetration will likely occur more rapidly.

COOPERATIVE FLEET ELECTRIFICATION

When considering the prospect of PEVs on their systems, cooperatives should also consider electrifying their own fleets, at least partially. This topic has been covered recently in a few *TechSurveillance* articles; see those articles for details.[98] There are many factors that should be considered, such as the typical range of a fleet car, what kind of driving is typically done, cargo-hauling needs, etc.

One thing to keep in mind regarding fleet electrification is that PEVs, in some cases, already have lower operating costs and/or lifetime costs, even without factoring in government incentives

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[95] See the U.S. DOE website www.fueleconomy.gov/feg/evsbs.shtml to search specs on current and past PEVs.

[96] All charging times are estimates and may vary depending on the charging equipment and the car. There are also other types of charging stations. See www.afdc.energy.gov/fuels/electricity_infrastructure.html.

[97] See "PG&E Proposal to Build 25,000 EV Charging Stations," by Herman Trabish, *Utility Dive,* February 12, 2015.

[98] *Fleet Electrification 101,* Christine Grant, Rebecca Hsu, and Patrick Keegan, November 2014; *A Guide to Adopting Plug-In Electric Vehicles to Your Fleet,* Christine Grant, Rebecca Hsu, and Patrick Keegan, November 2014.

or other benefits (e.g., the added load to the cooperative).[99] When the additional benefits are factored in (see bullet points in the section above), the cost/benefit analysis for fleet electrification looks even better.

There is also another consideration beyond the "hard" cost/benefit consideration: if the members see that the cooperative is using PEVs and installing charging stations, they will feel like the technology is less of a risk and may be more likely to switch to PEVs themselves. This also solidifies the cooperative as a "trusted energy advisor" to the membership and on the cutting edge of technologies involving electricity. This can have important ramifications for related topics, such as distributed generation.

HOW DO PEVS RELATE TO DSM?

PEVs add load, so, in that sense, they are usually good for cooperatives, but how are PEVs related to DSM? We have already touched upon some of the reasons. Here are some of the main ways in which DSM and PEVs intersect:

- A PEV program that provides incentives, advertising, or assistance to members in making proper PEV purchasing decisions is, in effect, very similar to DSM. The difference compared to DSM programs is that the PEV program encourages increased electrical load (while also encouraging reduced gasoline consumption).
- PEVs are good candidates for load control programs. In many cases, shutting PEV charging off for an hour would not be a big inconvenience for members. If a member is charging her car while at work, stopping the charging from 3 p.m. to 4 p.m. will often not make a big difference to her charging performance. For example, in 2015, Southern California Edison (SCE) began piloting a PEV demand response program.[100] SCE is using its own employees with electric cars in the study, and the employees pay different charging rates depending on which option they sign up for:

  > *SCE employees with electric vehicles can opt in to demand response when they plug in at one of the 80 chargers, which are provided by the company EVSE LLC. They are given three options to choose from. In the future, the options could all be pushed to a mobile app.*
  >
  > *The first option is to get a full charge, no matter what the price. The second option is to allow charge curtailment if there is a demand response event. The third option is to just have a Level 1 charge throughout the day.*

- PEVs can help flatten out load profiles by charging at night. Time-of-use pricing and other means to assure PEV loading occurs during nonpeak times is essential to proper integration into the grid. This flattening is a goal of many DR programs, so PEVs are great candidates for DR-like programs.
- As technology advances, PEVs may be used as a source of power quality or ancillary services (e.g., frequency regulation, fast reserve). For example, ERCOT has been experimenting with using electric trucks for frequency regulation. Results so far have been mixed, as this technique is still in its infancy, but results are expected to improve.[101]
- PEVs can help with intermittent renewable (PV solar, wind), since PEV load is somewhat flexible and can be programmed to come on when (for example) wind generation is highest. Again, this serves as a kind of DR-style load flattening.

REVENUE FROM PEVS

It is a bit early in the game for cooperatives to incorporate PEV DSM benefits such as frequency regulation into their DSM business cases, as the technology is still in the early stages. However,

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[99] Cooperatives can look at total cost of ownership calculators such as those at www.afdc.energy.gov/calc and http://driveclean.ca.gov/pev/Costs/Calculate_Your_Costs.php to compare gasoline vs. PEV costs.

[100] "SCE Tests Electric Vehicles for Demand Response" by Katherine Tweed, *Greentech Media*, February 17, 2015.

[101] See "Electric Trucks Provide Frequency Regulation in ERCOT" by Katherine Tweed, *Greentech Media*, February 4, 2014. For some results of this program, see *Frito-Lay Electric Vehicle Fleet: Fast Responding Regulation Service (FRRS),* by Sean Mitchem.

TABLE 7.1: Nissan Leaf Charging Times and Revenue								
Charging Level	kW Draw	Time for Full Draw (hours)*	Annual kWh from Full Draw Each Day	Annual kWh from Half Draw Each Day	Annual Revenue from Full Charge Each Day		Annual Revenue from Half Charge Each Day	
					10¢/kWh	14¢/kWh	10¢/kWh	14¢/kWh
Level 1	1.4	22.0	11,242	5,621	$1,124.20	$1,573.88	$562.10	$786.94
Level 2	6.6	5.0	12,045	6,023	$1,204.50	$1,686.30	$602.25	$843.15

* The common 2015 Nissan Leaf battery is 24 kWh[102] and a typical Level 1 draw is 1.4 kW, based on a 15-amp maximum. The Nissan Level 2 charger can draw 6.6 kW. The Level 2 charger takes about 5 hours to fully charge the battery, according to Nissan.[103] The Level 1 full-charge time will depend on factors such as the maximum amperage draw from a household outlet, which can vary quite a bit from house to house. The 22-hour charge time used in this table is a composite based on various sources.

it is worth noting what an electric car will use (in kWh) on a cooperative system. A chart for the 2015 Nissan Leaf is shown in Table 7.1, using typical kW draws and charge times for Level 1 and Level 2.

This is assuming that all charging is done on the cooperative system. With these revenue streams, cooperatives may wish to offer incentives for PEV purchases by its members. Cooperatives could tie the rebate to (1) a demand response program, or (2) a PEV charging rate that encourages night-time charging.

MANAGING THE ADDED PEV LOAD

One challenge with additional PEV load is that a large PEV saturation could result in the need for system upgrades or, at the very least, congestion where PEV concentration is the highest. However, with some careful planning, this load can be managed and the need for upgrades reduced or even eliminated.

The two main tools in this regard have already been touched on: rate design and demand response. PEVs fit in very well with real-time pricing or other TOU rates, or with a specialized PEV rate. If charging at night is the norm for PEVs, the members and the cooperative will benefit. If the PEV tied to a demand response program gets a slightly lower charging rate, again there is a win-win situation—the member gets a reduced rate and the cooperative can control a large load and shift it to mostly nonpeak hours. This can increase the load factor of the system without substantially increasing peak demands.

While the discussion of such a rate design is beyond the scope of this guidebook, there are some resources that discuss the issue. Two such resources are:

1. *Lessons Learned—The EV Project Regulatory Issues and Utility EV Rates.*[104] This paper gives a good survey of how utilities across the country are designing PEV rates.
2. *Electric Vehicle Rate Issues* (prepared for the Kansas Corporation Commission).[105] This report serves as a good overview of the rate issues faced by PEVs.

EXAMPLE COOPERATIVE PEV PROGRAM

One example of a PEV incentive program comes from Dakota Electric Association in Minnesota. Dakota Electric has more than 100,000 members southeast of Minneapolis and is one of the 25 largest distribution cooperatives in the nation. Dakota Electric offers two PEV charging rates, both of which represent cost savings for members who charge their PEVs at the designated times.

Under the “Electric Vehicle Storage Program,”

[102] See www.nissanusa.com/electric-cars/leaf/versions-specs/version.s.html.

[103] See www.nissanusa.com/electric-cars/leaf/charging-range/charging.

[104] ECOtality North America for the U.S. Department of Energy, 2013.

[105] Laurence D. Kirsch, Mithuna Srinivasan, Daniel G. Hansen, April 11, 2012.

TABLE 7.2: Dakota Electric EV1 PEV Rates

June-August	Mon	Tues	Wed	Thurs	Fri	Sat/Sun	Holidays*
9 pm – 8 am	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢
8 am – 4 pm	11.544¢	11.544¢	11.544¢	11.544¢	11.544¢	5.85¢	5.85¢
4 pm – 9 pm	37.85¢	37.85¢	37.85¢	37.85¢	37.85¢	5.85¢	5.85¢
Other	**Mon**	**Tues**	**Wed**	**Thurs**	**Fri**	**Sat/Sun**	**Holidays***
9 pm – 8 am	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢	5.85¢
8 am – 4 pm	10.144¢	10.144¢	10.144¢	10.144¢	10.144¢	5.85¢	5.85¢
4 pm – 9 pm	37.85¢	37.85¢	37.85¢	37.85¢	37.85¢	5.85¢	5.85¢

* Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

members can charge an electric vehicle at home for $0.04/kWh from 11 p.m. to 7 a.m., year-round. This electricity is available only during off-peak hours; this rate option requires a separate sub-metered circuit installed at the homeowner's residence.

In the second program, the "Electric Vehicle EV1 Program," PEV charging is available at all times, with rates depending on the time of day the charging occurs, similar to a time-of-use rate. The rates are shown in Table 7.2.[106]

The "off-peak" rate of $0.0585 is almost half the "normal" rate (i.e., the rate for Dakota Electric residential members not on any special rates). This rate is available 61% of the time. Dakota Electric also offers a rebate up to a $500 on a qualifying Level 1 or Level 2 charger installation.

The Dakota Electric PEV program is a good example of a program that can benefit both (1) the cooperative as a whole, and (2) individual members. The cooperative adds beneficial electrification load during the night. Members with PEVs get a beneficial charging rate (overnight is when most PEV users charge their cars, even with no special rate). This program offers a great value to Dakota Electric PEV members who are considering PEV purchases.

Batteries and Other Storage Systems

Energy storage in the electric industry refers to the ability to store electricity for use at a later time. The later time could be one day from storage or five minutes from storage. Strictly speaking, many energy storage systems do not constitute demand-side management programs because most storage currently takes place on the utility side of the meter and DSM typically refers to actions taken on the consumer side of the meter.

However, many energy storage systems can enhance existing DSM programs. In fact, many storage systems *act like* demand response programs by flattening peak usage and/or shifting peak usage to other times. Furthermore, some storage technologies—such as ice/chilled water AC rooftop storage or using batteries from PEVs as short-term storage or regulation—would exist on the consumer side of the meter and would, therefore, count as DSM.

Pumped hydro storage is still the largest source of storage (in megawatts) by far. In 2015, the U.S. Department of Energy gave the following numbers for "operating" and "under construction" electricity storage projects in the U.S.:[107]

Pumped Hydro	20,380 MW
All Other Storage	1,170 MW

However, capacity from other storage methods (aside from pumped hydro) is rapidly increasing,

[106] See information on Dakota Electric PEV programs at www.dakotaelectric.com/residential/programs/electric-vehicles.

[107] See at www.energystorageexchange.org/projects/data_visualization.

whereas pumped hydro capacity has remained essentially flat for two decades.[108] Cooperatives should be aware of the various storage technologies, since utility-scale storage systems are already cost-effective in some circumstances and, as battery and other technologies improve, these systems may become more prevalent for cooperatives.

Readers should turn to the comprehensive SANDIA/NRECA report described in the next section for an overview of the different types of energy storage options. Tesla's PowerWall/PowerPack systems are discussed briefly as an example of how battery storage might affect cooperatives.

THE SANDIA/NRECA REPORT

The U.S. Department of Energy, through Sandia Laboratories and in conjunction with NRECA, released a 2013 report titled *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*. The Handbook, updated in 2015,[109] is described as a "how-to guide for utility and rural cooperative engineers, planners, and decision makers to plan and implement energy storage projects."

The Sandia Handbook is a great resource for cooperatives regarding energy storage. It covers storage options in detail and describes costs and engineering aspects of storage. Cooperatives should refer to the Handbook for a good overview of storage options and technologies.

ENERGY STORAGE BENEFITS AND COSTS—THE BIG PICTURE

Although this Guidebook only considers storage as it relates to DSM, a brief overview of storage options will be helpful. There are many types of energy storage systems. The main categories include pumped hydro, compressed air storage, electrochemical (e.g., batteries), electromechanical (e.g., flywheels), and hydrogen.

The benefits of energy storage are also quite varied and depend partially on (1) how long the energy can be stored and (2) how long the discharge can last. For example, with pumped hydro, the energy can essentially be stored indefinitely and the discharge can last for many hours, so pumped hydro stations serve any number of functions. Other technologies may only have an hour or less between storage and discharge, or may only be able to discharge for a few minutes, so applications could be limited to voltage control and other short-term operations.

There are many possible benefits of energy storage, including:

- Reduced risk of blackouts and brownouts
- Increased power quality (voltage, frequency, angular stability)
- Reduced T&D costs
- Reduced peak-time losses
- Load shifting (a similar effect as demand response)
- Integration of renewable, especially wind and solar
- Wholesale power market revenue (energy and capacity)
- Wholesale power market revenue (ancillary services)

Estimates for the cost of energy storage at the present time range from $700 to $3,000 per kilowatt-hour of installed electricity storage. Prices for energy storage can be somewhat misleading and confusing because some prices cover the product only (e.g., the battery), whereas some prices cover the product and installation/connection to the grid. Furthermore, some products may only be able to deliver power for an hour or two, whereas some may deliver for over five hours. It can be difficult to make apples-to-apples comparisons.

For an example of how to look at storage costs, here's an excerpt from the Sandia/NRECA 2015 Handbook mentioned in the previous section. In the Handbook, the authors note that there are three common ways to evaluate storage costs:

> *Storage system costs have a "power" and an "energy" component. The* ***power cost component*** *is the cost of the power conditioning system and its auxiliaries, that determines*

[108] Again, only "operating" and "under construction" projects are considered here.

[109] Akhil, Abbas A., et al. *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*. Sandia National Laboratories. Report SAND2015-1002. February 2015.

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the kW or MW capability of that particular storage system, and contributes to the $/kW component of the system cost. The ***energy component*** *is the cost of the storage components—battery, flywheel, or the upper reservoir capacity in pumped hydro and related aux—that determines the kWh or MWh capability of the same system and contributes to the $/kWh of the system cost. The total cost of any storage system is the sum of these components and is specific to that system size, in MW and MWh, and is not linearly scalable in most cases due to the modularity of system's design as offered by that particular system vendor.*

For example, if a particular system vendor offers a 4 MW/8 MWh system, then its cost in $/MW and $/MWh cannot be linearly extrapolated to a 6 MW/8 MWh system unless that or another system vendor offers such a system. However, the unit costs in $/MW or $/MWh would be the same for multiples of the 4 MW/8 MWh system.[110]

To illustrate the concepts in the quote above, the Sandia Handbook evaluated costs for eight utility-level lithium ion battery systems used for "T&D Grid Support." (The Handbook uses "grid support" as a stand-in for load-shifting.) Sandia reported equipment, interconnection, and installation costs for all eight systems, but here we are only concerned with the cost of the storage system itself. Details are discussed in the next section.

Storage costs are coming down every year; some forecasts have the price of installed battery systems coming down to $350/kWh by 2020. Tesla recently announced that utility-scale storage will be sold in 2016 for $250/kWh (this is a battery-only cost and would not include installation and integration). The lower storage prices get, the more valuable solar and wind will get.

HOME STORAGE BATTERY UNITS

Home storage units can act like DSM in many circumstances. The home storage battery units that currently have the largest market presence are the Tesla products, so we will look at those for illustrative purposes. In 2015, Tesla announced the release of a home-use storage system (PowerWall) and a utility-scale storage system (PowerPack).

The selling points of PowerWall systems are described as (1) avoiding peak rates by using solar to power the pack during the day and drawing power from the pack during the evening, and (2) energy security in case of a power outage. If you are a consumer with flat rates, you could still benefit, because you would no longer have to sell your excess energy to the utility (maybe at a disadvantageous rate), only to buy it back later in the day.

PowerWalls are sized at 10 kWh for $3,500 and 7 kWh for $3,000. PowerPacks, to be used for large businesses and utilities, are 100 kWh and will cost $25,000 each (again, this does not include other needed equipment or installation).[111] Thus, the PowerWall is $350/kWh and the PowerPack is $250/kWh; the price is essentially an energy component price as described above, and added inverters, solar panels, and installation would be extra.

However, even though the $250/kWh does not include other equipment and installation, it is still a substantial improvement over other lithium ion battery systems on the market. The Sandia report summarized eight utility-level lithium ion storage projects (all used for T&D grid support, with a discharge from one to five hours). The equipment-only prices for these systems (i.e., just the batteries) ranged from around $735/kWh to $1,375/kWh; thus, Tesla's $350/kWh for the PowerPack is a big step change in the field.[112]

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110 *Ibid.*, p. 30.

111 See Specifications for the PowerWall. Specifications for PowerPacks are not on Tesla's website; the cited figures are from "All You Need to Know About Tesla's Big Battery Announcement," Davide Savenije, *Utility Dive*, May 1, 2015.

112 See the Sandia 2015 Handbook, page B-46, Table B-29. Again, it is worth noting that installation cost and extra equipment (e.g., external inverters) are not included in the Sandia figures. Since the Tesla products are not on the market yet, there are no estimates for these costs for the PowerPack. The Sandia Handbook lists the installation and interconnection costs for the measures it studies. The systems studied by Sandia were in the years 2010 and 2011. These systems may not be able to be scaled down to a smaller size at the same $/kWh cost.

The "total plant costs" for the eight systems studied by Sandia range from around $1,000/kWh to $2,120/kWh. The total plant costs include interconnection, external required equipment (inverters, etc.), engineering fees, etc. Tesla's "total plant costs" are not yet known.

Cooperatives should keep an eye on the developing battery storage market; as prices drop, the associated business cases will improve over time. A good general guide for designing cost/benefit analyses for storage systems is CRN's *Financial Screening for Energy Storage,* written by SRA International, Inc., published in October 2013.

Distributed Generation

"Distributed generation" or "distributed energy" units are grid-connected generation units that are decentralized and small-scale (compared to traditional utility generation units)—in the 1 kW to 10,000 kW range of generation. DG units can use a number of technologies, including natural gas, diesel, wind, solar PV, biomass, combined heat and power, and more. These DG units can be owned by the cooperative or by members. Some larger DG units can be linked to the system operator (whether cooperative, RTO, etc.) and can be dispatched, but smaller units—such as residential rooftop solar—may not be monitored by the system operator.

According to the EIA's *Electric Power Annual 2013,* there were 2,563 MW of DG in the U.S. in 2013, generated by around 38,650 DG units. However, this data is from EIA Form 923, which only counts units over 1,000 kW.

Even when smaller units are counted, there is evidence that the EIA and other government agencies drastically underestimate the number of DG units in the country. For example, a recent report from the Solar Energy Industries Association estimated that, from April 2014 to March 2015, solar power produced 30.4 million MWh, rather than the 20.2 million MWh estimated by the EIA for the same period.[113] Much of this power came from residential solar DG units.

The benefits from distributed generation mainly relate to flexibility, reliability, security, reduced risk, and the fact that these units are much closer to actual electricity users. The possible benefits are summarized in Table 7.3.

It should be noted that, as a whole, DG (including solar PV) is essentially in its infancy and many of these benefits are untested on a cooperative-wide level. For example, while on

TABLE 7.3: Benefits of Distributed Generation[114]

Reliability and Security Benefits	Economic Benefits	Emission Benefits	Power Quality Benefits
• Increased security for critcal loads • Relieved transmission and distribution congestion • Reduced impacts from physical or cyberattacks • Increased generation diversity	• Reduced costs associated with power losses • Deferred investments for generation, transmission, or distribution upgrades • Lower operating costs due to peak shaving • Reduced fuel costs due to increased overall efficiency • Reduced land use for generation	• Reduced line losses • Reduced pollutant emissions	• Voltage profile improvement • Reduced flicker • Reduced harmonic distortion

113 "U.S. Solar Electricity Production 50% Higher Than Previously Thought," Jason Kaminsky and Justin Baca, *Greentech Media,* June 30, 2015. (Note: These figures may include some solar that is not grid-connected.)

114 From U.S. Department of Energy, "The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005" (Washington, D.C., 2007), as reported in "The Future of the Electric Grid," MIT Study, 2011.

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the one hand, DG can theoretically be used to *improve* power quality, there is also the problem that DG units with inverters can *contribute* to power quality problems.

DG is expected to grow in the coming decades; many states already have DG standards or targets built into their renewable portfolio standards. Utilities are still learning how to handle growing amounts of DG on the system:

> *The integration of DG presents new challenges for distribution system planning and operations, principally because the configuration of power lines and protective relaying in most existing distribution systems assume a unidirectional power flow and are designed and operated on that assumption. Historically, the penetration of DG was sufficiently small to be regarded as simply a reduction in load, but this will change if DG penetrations grow. While the physical wires and transformers can carry power flow in the reverse direction, DG nonetheless can have adverse impacts on system reliability, power quality, and safety.*[115]

The standards that are used to measure the costs and benefits of DG are still in their infancy. The U.S. Department of Energy is working on some standards in this area; some of the early discussion can be found at the DOE website: **www.energy.gov/under-secretary-science-and-energy/downloads/estimating-benefits-and-costs-distributed-energy**.

As a back-of-the-envelope baseline, DOE estimated the installed costs for various DG options in 2013 (Figure 7.1). Solar costs have been declining over the last decade and are expected to continue to decline as technologies improve and the "soft" costs of solar are reduced.

Figure 7.1 illustrates why many cooperatives are offering community solar to their members. The installed costs for larger solar systems can be considerably lower than the <10-kW panels put on rooftops. Cooperatives can provide for this solar demand of their members by offering a lower-cost option and selling panels to members. The cooperative can then properly maintain the panels and also site the project where it may be advantageous from a system perspective.

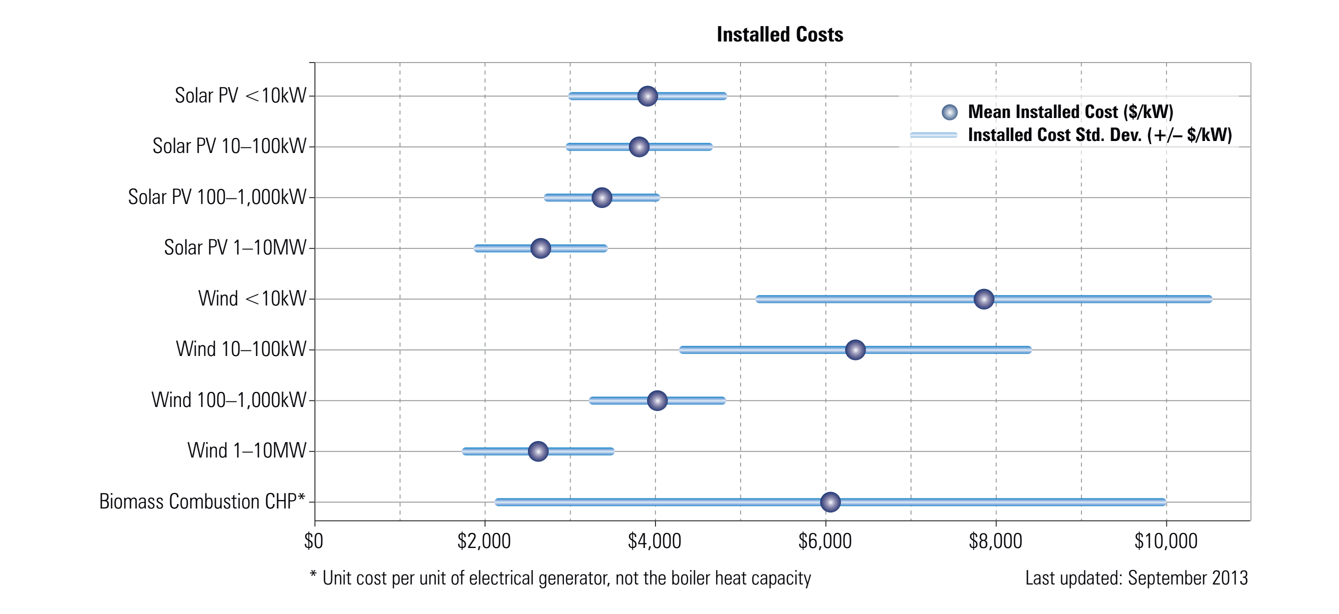

FIGURE 7.1: Distributed Generation Energy Technology Capital Costs[116]

[115] *The Future of the Electric Grid,* MIT Study, page 112.

[116] Energy Analysis: Distributed Generation Energy Technology Capital Costs. NREL.

Cooperatives may wish to become proactive with regard to community solar projects (in areas where solar makes sense). NRECA has papers in *TechSurveillance* and other publications to determine if solar is right for your cooperative. Community solar projects are in line with the recommended DSM strategy of being the "go to" energy advisor for members.

Cooperative members interested in becoming PV producers ("prosumers") either are or will soon be approached by third-parties, such as Solar City. By offering members a lower-cost alternative, cooperatives can maintain the utility-consumer relationship that is imperative to a well-functioning and efficient electric system.

HOW DISTRIBUTED GENERATION RELATES TO DSM

Distributed generation relates to demand-side management in a number of ways. For example, some DG can serve directly as demand response, as when diesel generators are used during spiky peak times to limit the need for natural gas peaker plants (although there may be emissions restrictions governing this practice). Another effect of DG on DSM is that load curves produced by DG such as solar can increase the need for DSM programs, as we will see in the following sections. DG such as solar and wind can also be used with energy storage (e.g., batteries) to act like a DR program.

The next section describes how solar affects the load curve, which, in turn, affects how DSM will be used to address the load curve.

ROOFTOP AND COMMUNITY SOLAR—EFFECTS ON THE LOAD SHAPE

This section deals with distributed solar—i.e., rooftop solar and community solar—and how DSM plays into these DG sources.[117] The main effect of solar on DSM programs is that solar will change the daily load shape, which will result in a need for DSM that takes the new shape into account. The "duck curve" load shape that results from solar will be discussed in more detail in the next section; in this section, we briefly examine rooftop and community solar and how it relates to DSM.

A Typical Net Load Curve of Solar

Solar power itself obviously has a load curve that only produces during the daylight hours. Depending on the time of year and latitude, solar power will begin in the morning, peak in the mid-afternoon, decline in the evening, and will be zero overnight. This is shown in **Figure 7.2** from EIA, depicting loads for three sample days for the California ISO (CAISO). The solar and wind loads are in yellow and blue at the bottom, and the total load and net load of renewables are shown at the top.[118]

The net load for October 22 in Figure 7.2 shows the problem: as the solar load grows, the afternoon peak becomes more "spiky" (blue line). The EIA article says that the figure "does not include smaller-scale (e.g., residential) distributed photovoltaic (PV) capacity that does not participate directly in CAISO's market," so, in actuality, the net load is even "spikier." This problem is expected to get worse as solar penetration increases, as shown by the projection in **Figure 7.3** from CAISO.[119]

Figure 7.3 is called the "duck curve" because it looks like a flying duck (see **The 'Duck Curve'** for more information). The more solar is added, the less net load is required from noon to 3 p.m., but this also means the ramp-up from 3 p.m. to 7 p.m. becomes even steeper, which results in inefficiencies. DR is a very useful tool to flatten the ramp-up shown in Figure 7.3; the more solar that is added, the more useful DR becomes.

Other Distributed Generation Issues

In many areas, solar power will soon be the largest source of distributed generation. It is worth a few words regarding rooftop solar in

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[117] For a comprehensive guide to utility-scale solar, see NRECA's SUNDA project. The SUNDA (Solar Utility Network Deployment Acceleration) project gives step-by-step guidelines for most aspects of solar projects, including business models, financing options, planning, design, installation/interconnection, commissioning, operations, maintenance, and monitoring.

[118] *Increased Solar and Wind Electricity Generation in California are Changing Net Load Shapes*, EIA, December 9, 2014.

[119] *What the Duck Curve Tells Us About Managing a Green Grid*, CAISO white paper.

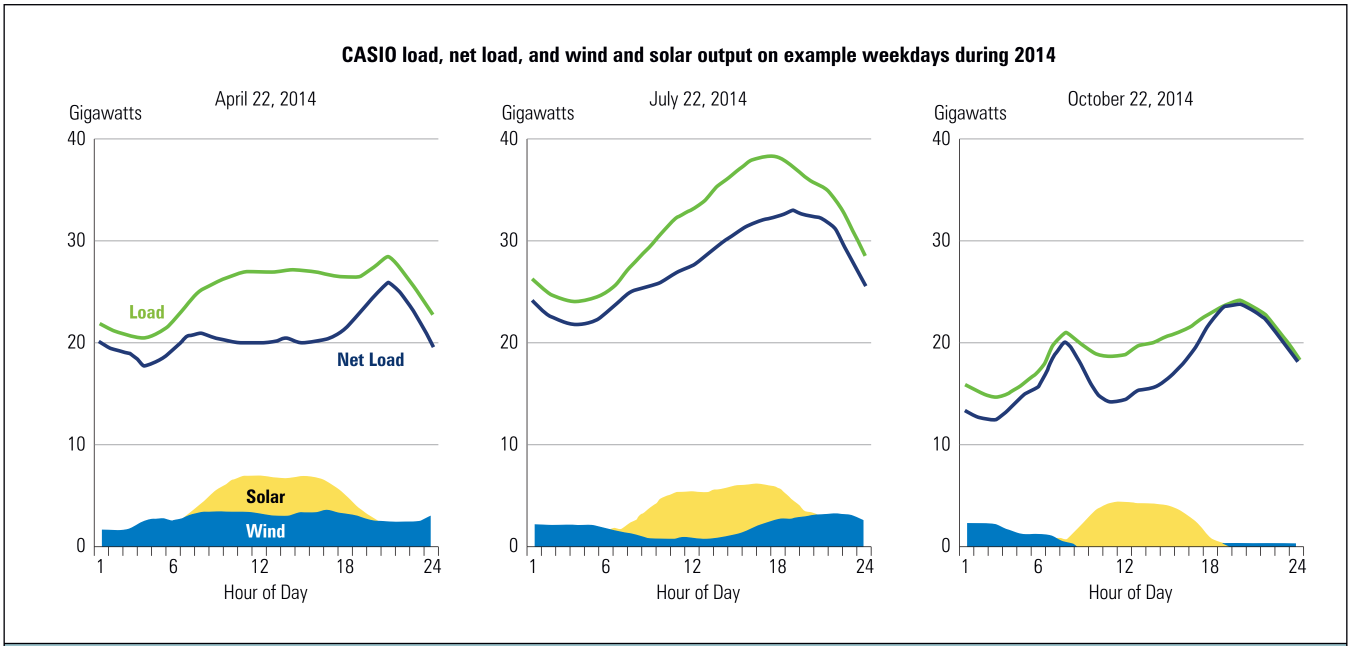

FIGURE 7.2: EIA Example of Net Load of Renewables

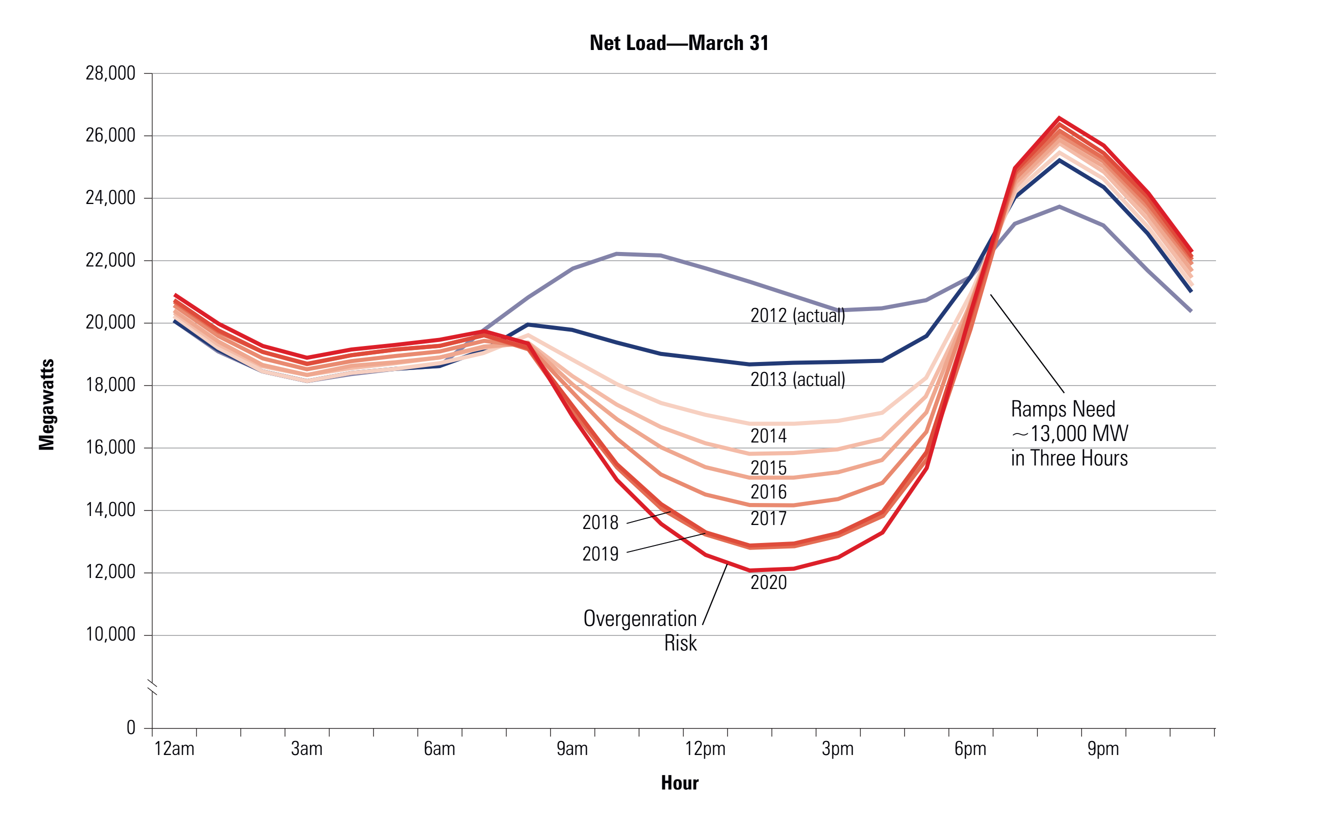

FIGURE 7.3: CAISO Projected Net Load of Solar

general and how cooperatives can integrate it with DSM. The first step is to see solar as an opportunity, rather than reacting to it as a threat. The fact is that distributed solar *is* a threat in some sense. In theory, if solar panels became cheap enough, and storage systems became cheaper and more effective, solar could serve as a threat to the traditional utility model, and could eventually serve as a replacement to grid electricity; members could "cut the cord."

The important words are "in theory." We do not believe that such a "utility death spiral" will be caused by solar any time soon (see **The Changing Nature of Electric Utilities** for more on the "death spiral"). Hawaii is a very special case because it has high electricity costs and high amounts of sunlight, and we do not yet see Hawaiian utilities getting out of the electric delivery business. Certain other areas of the country (e.g., Arizona) have similar considerations and more areas will become relevant in the coming years as solar prices drop.

However, just because a death spiral is not imminent does not mean that solar is not a threat to the traditional utility model, especially when combined with storage. For example, after the announcement of Tesla's new home storage battery, Solar City announced plans to offer "off-the-grid packages" to Hawaii residents:[120]

> *Incorporating Tesla's new battery technology, Solar City is now able to configure a solar system (along with other energy management technologies) as a stand-alone, off-grid power supply. Solar City plans to first offer these off-grid systems to eligible Hawaii customers that might otherwise be prevented from using solar power.*

There are likely not many Hawaii residents at this time who can go completely off-grid, but the number will grow as costs for rooftop solar and battery storage continue to drop.

Therefore, it is in cooperatives' best interest to get in front of the distributed generation wave, rather than being swept along with it. In this Guidebook, we will only cover rooftop solar and other DG sources as they relate to DSM, but cooperatives should keep the big picture in mind. Following are some thoughts about distributed solar as it relates to DSM:

1. Cooperatives could consider a system whereby they own the rooftop solar systems, especially fixed systems. This way, cooperatives can orient the panels toward the west, so that more power is generated during the late afternoon, which is the daily peak for many cooperatives. This set-up would effectively act as a DSM system, by flattening the remaining (nonsolar) generation curve.
2. Similar to the last point, cooperatives could consider owning battery storage systems such as the Tesla PowerWall (as opposed to the member owning them), under the condition that it be controlled by the cooperative. This would turn rooftop solar into a dispatchable DR program. The cooperative could own and lease the battery whether or not the member owned the rooftop solar system.
3. Cooperatives should carefully consider how their rate structure will look for distributed solar projects.

THE 'DUCK CURVE': HOW DR AND DG COMPLEMENT EACH OTHER

As mentioned above, the "duck curve" is a term for how a typical load shape looks with and without renewables and DG. **Figure 7.4** shows the duck curve (the space between the two lines in the top figure is supposed to resemble a duck).[121] In the top half of the figure, the blue line is total load, the red line is load with renewables subtracted. A goal for load management is to flatten the spike at hours 17–20 and, generally, make the load without renewables less "spiky," as seen in the bottom half of the figure.

This can be done with a variety of DSM and DG options. In general, these two strategies complement each other very well. In a 2014

[120] See *Solar City Introduces Affordable New Energy Storage Services Across the U.S.*, April 30, 2015. Also see Bizjournals, *Solar City Offers Off-Grid, Tesla Battery Storage Systems to Hawaii Residents,* by Duane Shimogawa, May 1, 2015.

[121] Figure from Lazar, Jim. *Teaching the "Duck" to Fly*, p. 3. Regulatory Assistance Project (RAP). January 2014.

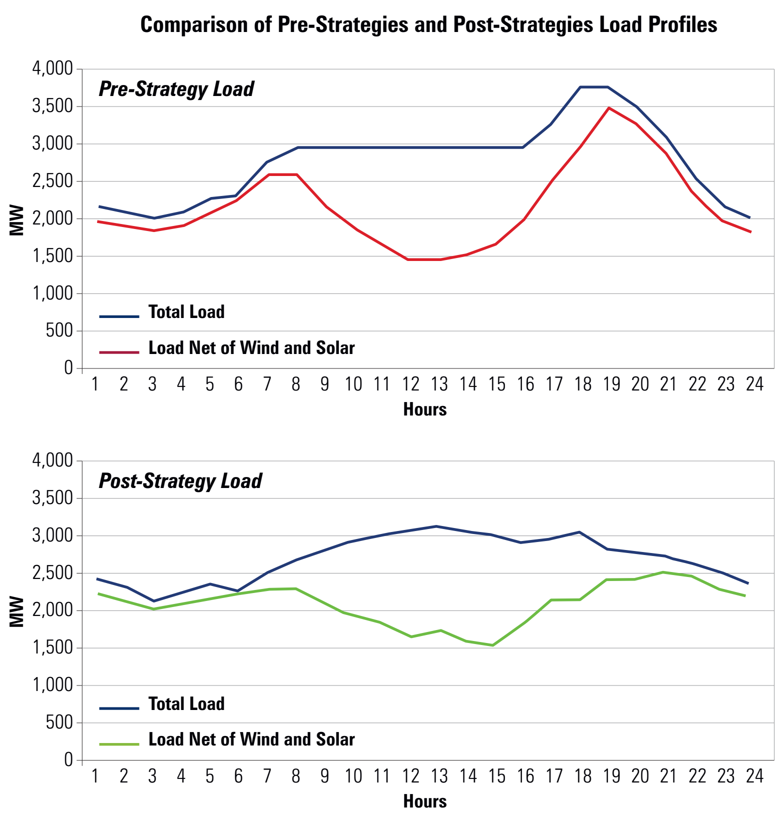

FIGURE 7.4: The RAP "Duck Curve": Before and After DR

paper by Jim Lazar, the following strategies are recommended:[122]

Strategy 1: Target energy efficiency to the hours when load ramps up sharply.
Strategy 2: Orient fixed-axis solar panels to the west.
Strategy 3: Substitute solar thermal with a few hours' storage in place of some projected solar PV generation.
Strategy 4: Implement service standards allowing the grid operator to manage electric water heating loads to shave peaks and optimize utilization of available resources.
Strategy 5: Require new large air conditioners to include two hours of thermal storage capacity under grid operator control.
Strategy 6: Retire inflexible generating plants with high off-peak must-run requirements.
Strategy 7: Concentrate utility demand charges into the "ramping hours" to enable price-induced changes in load.
Strategy 8: Deploy electrical energy storage in targeted locations, including electric vehicle charging controls.
Strategy 9: Implement aggressive demand-response programs.
Strategy 10: Use interregional power transactions to take advantage of diversity in loads and resources.

These strategies fall into three main categories (some fall into more than one): (1) Increasing the load factor, (2) Decreasing the need for steep ramp-ups or ramp-downs of the nonrenewable load, and (3) Decreasing the peak load. Note that increasing the load factor typically has the effect of decreasing the difference between the peak load and the minimum load on any given day.

For example, Strategy 1 (targeted EE during ramp-up period) will have the effect of lowering the peak load, making the ramp-up less steep during the 4 p.m. to 7 p.m. time (when people are coming home and turning things on). Lights, TVs, AC, and cooking could all be good appliances to target with EE programs for this strategy.

Distributed generation is a good tool for implementing many of the strategies that appear in Jim Lazar's 2014 paper.[123] For example, Strategy 2 involves pointing DG solar panels more towards the west, rather than the south or southwest, so that the solar load will be higher during the ramp-up period, which occurs in the afternoon. Strategy 3 involves a couple hours of solar thermal storage. Strategy 8 involves targeted electrical energy storage (functionally, this is very similar to distributed generation).

DISTRIBUTED GENERATION—NEXT STEPS

On a general level, cooperatives should embrace DG to the extent that it is cost-effective, while remaining vigilant regarding the possible impacts onto nonsolar ratepayers. As the grid becomes

122 *Ibid.*, p. 3.

123 *Ibid.*

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"smarter," the cost of micro-renewables comes down, regulators continue to press, and the market matures, the number of cooperative members with DG is expected to rise. For example, rooftop solar is growing steadily, as is the number of industrial consumers with DG "plants" at their facilities.

We realize this DG can be thought of as a threat to the traditional cooperative model. Sometimes DG seems like the first step in a process that ends with complete defection from the grid. However, there are market opportunities for cooperatives that become trusted energy advisors. In many cases, it is better for cooperatives to become involved in the DG process, rather than risk being seen by members as a roadblock. We discuss some strategies in this area in the next section.

The Changing Nature of Electric Utilities

COOPERATIVES AS 'TRUSTED ENERGY ADVISORS'

Cooperatives have a different relationship with their members than IOUs do with their customers. In many cases, an IOU must be concerned with its shareholders, whose interests may or may not be aligned with its customers' interests. For cooperatives, its customers *are* its owners.

For reasons detailed in the following few sections, cooperatives should strive to become "trusted energy advisors." There are many reasons that cooperatives want to be the "go-to" source for members who have questions or concerns about energy issues:

- If members do not turn to their cooperative, they will turn somewhere else. This "somewhere else" is often a third party, such as an appliance dealer or a customer advocacy group. These third parties may or may not give advice that is consistent with cooperative goals.
- Cooperatives which engage their members, and listen and respond to their members' concerns, will tend to have higher customer satisfaction.
- Cooperatives which are trusted energy advisors will be better positioned to retain market share in some cases.

A POSSIBLE UTILITY 'DEATH SPIRAL'?

Some prominent economists and researchers have recently projected a "death spiral" for the traditional utility model.[124] The fear is that something like the following will happen:

- Solar, wind, distributed generation, and storage become cheaper.
- Utilities raise their monthly charges or their connection charges.
- Utilities either (1) charge solar and wind users a higher fee to connect to the grid, or (2) reduce the price they pay these customers for solar and wind.
- At a certain tipping point, customers begin to "cut the cord" with the utility and disconnect altogether.
- Utilities then face stranded costs, which they respond to by raising rates.
- As the utilities raise rates, even more customers cut the cord, thus creating a feedback loop, i.e., a "death spiral."

It is worth noting that the notion of a death spiral is not coming only from isolated academics and alarmists; the threat is recognized by many major think tanks and organizations. For example, Edison Electric Institute (EEI, the trade organization for IOUs) published an article on "disruptive challenges" to a changing retail electric business[125] which concludes that:

> *The threats posed to the electric utility industry from disruptive forces, particularly distributed resources, have serious long-term implications for the traditional electric utility business model and investor opportunities. While the potential for significant immediate business impact is currently low (due to low DER [distributed energy resources]*

[124] See, e.g., Graffy and Kihm, "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?" *Energy Law Journal*, Vol. 35, No. 1, 2014.

[125] Kind, Peter. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. Prepared for Edison Electric Institute. January 2013.

> *participation to date), the industry and its stakeholders must begin to seriously address these challenges in order to mitigate the potential impact of disruptive forces, given the prospects for significant DER participation in the future.*[126]

The potential impact of disruptive forces, according to EEI, include "the longer-term threat of fully exiting from the grid (or customers solely using the electric grid for backup purposes)" and "a vicious cycle… that, in the worst-case scenario, would leave few(er) customers remaining to support the costs of a large embedded infrastructure system, some of which may be stranded investment."[127] In the EEI article, this cycle is depicted much as we described in the bulleted points above and in Figure 7.5.[128]

PSE does not believe that such a death spiral is imminent, but the declining cost of solar PV, along with improved storage options and microgrids, is eventually going to make some consumers consider cutting the cord. Cooperatives have service territory characteristics that may make such actions more likely: cooperatives have fewer customers per line mile, which means that their assets are more spread out and vulnerable to stranding. Rural electricity users may also have the land and motivation to take advantage of solar, wind, and distributed generation.

Thus, even if there is no death spiral, cooperatives should prepare themselves for possible flat or declining usage. A recent ACEEE report[129] states that:

> *A [possible] sales decline of 10% over nearly 30 years cannot be called a death spiral. On the other hand, such a decline in sales would be very significant for an industry that has historically relied on load growth to fuel profits. Therefore, the industry does need to rethink the best ways to earn a return on investments going forward.*

Here the notion of being a trusted energy advisor comes into play. Electric cooperatives can hedge against the "stranding" issue, and other related issues, by focusing on becoming a trusted energy advisor, one that offers more services than just the providing of electricity. Cooperatives should consider providing services that embrace solar and DG, instead of viewing those things as threats. For example, cooperatives could offer a bundling package, with solar PV, energy storage, standby emergency power (e.g., generators), and/or grid access when needed. This way, the cooperative is not viewed as a barrier to new energy solutions, but rather a facilitator. Cooperatives could also learn to service some of the new technology or, at the very least, provide guidance on purchasing or maintaining these items.

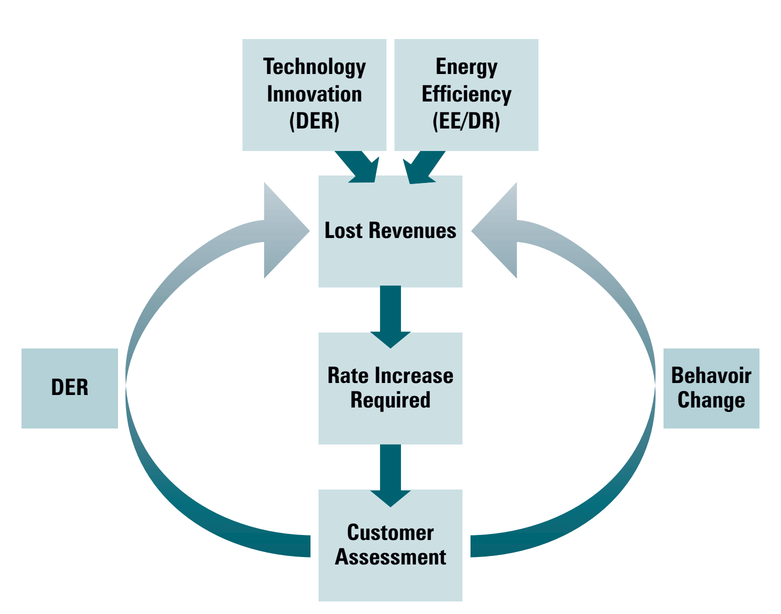

FIGURE 7.5: Vicious Cycle from Disruptive Forces

[126] *Ibid.*, p. 19.

[127] *Ibid..*, p. 3, p. 11.

[128] *Ibid..*, p. 18.

[129] *The Future of the Utility Industry and the Role of Energy Efficiency*, Steven Nadel and Garrett Herndon. June 2014, ACEEE Report Number U1404.

If cooperatives can position themselves as energy advisors, they may be able to better cope with flat revenues by offering products beyond electricity. Since properly designed DSM programs generally benefit all stakeholders anyway, a cooperative is getting extra bang for its buck when it embraces DSM and related programs—it saves members money in the short term, it avoids energy and capacity upgrades, it makes the cooperative a trusted energy advisor, and it can lay the groundwork for cooperatives branching out into other offerings, if needed. If no death spiral ever occurs, then the cooperative has still reaped the benefits of DSM.

8 The New Face of DSM—Utility DSM Information Technologies

In This Section:

- **Core DR Transport Technology**
- **Head-End Software**
- **Load Management Backhaul Technology**
- **Customer Premises Equipment**

The technology to support demand-side management and its associated information has evolved greatly over the last five years. The technology components can best be explained by separating them into the following four categories:

1. Core load management transport technology (150/900 MHz RF, AMI-based, PLC, or cellular)
2. Head-end software to support DSM
3. Backhaul load management transport technologies
4. Customer premises equipment

We look at some recent advances in each of these areas in turn.

Core DR Transport Technology

"Core DR transport" refers to the process of getting a DR signal to the end-user (for example, a one-way system that communicates a signal to a device that shuts off an appliance or system). At the present time, the one-way technologies still represent the highest market share for the cooperative use of direct load control. The 150-MHz and 900-MHz paging technology from Comverge and Eaton lead the way, along with older power line communications (PLC) technology from Eaton.

More recently, the distribution members' AMI technology (mostly PLC) is also being used as a transport of load control signals. Still, Comverge and Eaton own about 70% of the market share of the load management subscriber base, primarily with older, analog technology.

Both Eaton and Comverge have recently deployed digital VHF technology with new infrastructure at the base station transmitter sites, along with new vintages of switches and thermostats. The new digital VHF technology can require a new spectrum to be purchased or coordinated, which would transmit digital signals between new transmitter sites and end-points, by vendors that have FCC type-accepted product lines.

AMI vendors all offer the capabilities to transport DR signals over their AMI infrastructure and into customer premises. Some vendors also bundle cellular for transporting into their product lines by combing the head-end software, customer premises equipment, and cellular in a combined, turn-key solution. Therefore, there are several DR transport technologies that cooperatives have to choose from.

Some of the key technology selection factors to be considered include:

- The service territory terrain
- The density and quantity of DR subscribers
- Whether the deployment is a replacement of old DR technology or a "greenfield" new deployment
- The age of the existing AMI technology
- The availability of towers
- Other factors

Many cooperatives believe it is most effective to take advantage of their AMI infrastructure and use it for the deployment of DR signals. When closely evaluating the merits of purchasing new one-way digital DR technology versus leveraging an existing AMI system, in some cases, the cooperative will be much better off with selecting new one-way digital DR technology and, in other situations, selecting AMI will be most effective. Many factors will go into the eventual technology decision.

Head-End Software

A "head-end" system is hardware and software that receives AMI data. Head-end systems may perform some data validation before sending the data to other systems such as an MDMS.

There are several components of head-end software that come into play with a DR program. The first is DR transport technology that communicates between the head-end and the switch; this could be a very basic system, which does not receive data back from the end-user. There is also demand response manager (DRM) software that enhances a DR program by providing services related to other DR areas and programs, including:

- Program enrollment
- Integrations between the members' CIS and the G&T's DR Master
- Other technology integrations, including multiple AMI vendors, cellular, paging with the DR Master and the SCADA Master
- Software to provide program analytics and forecasting software to target a specific load shed target
- MDM software that provides additional forecasting tools
- Load shape data
- Capabilities for program and post-event evaluation

For a G&T-driven load management program, the DRM is becoming a critical component and the amount of difference related to vendor capabilities is significant. Much like technical specifications, many vendors will state compliance for a given requirement in an RFP. How each vendor complies, however, and the effectiveness of the compliance, will vary greatly from vendor to vendor.

Load Management Backhaul Technology

"Backhaul" technology is the system used to connect the AMI head-end system to utility access points, such as MDMS. Backhaul systems typically might use fiber-optic cables or wireless connections (usually the volume of data is high).

Thus, it is a way of getting the meter data from a DR event back to the utility so it can be analyzed. For selecting the backhaul communications tools for DR technology, the network designer must understand bandwidth, latency, and reliability requirements for the DR program. If purchasing new VHF DR equipment, it may be necessary to replace the old VHF DR antennas at the tower sites, pass a new tower structural test, or address any aging infrastructure issues.

As part of an overall DR program, backhaul communications are a key component, with various technology options to choose from, including fiber optics, microwave, and other wireless alternatives. The backhaul component should not be underestimated and needs to be designed and deployed appropriately. Typically, the backhaul technology for DR is part of a larger communications infrastructure plan and combined with the communications for SCADA, AMI, land mobile radio (LMR), and other applications.

Customer Premises Equipment

With most load management vendor solutions, the DR switches and the head-end software are proprietary to a specific vendor (e.g., the Yukon Master from Eaton will communicate with Eaton DR switches, a Comverge IntelliSOURCE Master will communicate with the Comverge VHF, and a cellular-based switch like the Aclara head-end will communicate with an Aclara switch). Thus, even a cellular-based DR switch would be tied to a specific vendor's software.

However, new third-party vendors like Google, Microsoft, Honeywell, etc., have new home automation products communicating with cloud-based software that emphasize energy efficiency and cost savings that are not coordinated by the utility. We expect to see a significant growth trend in this area, which, in some respects, offers both a positive opportunity and a potential threat to the cooperative.

Another opportunity that could be classified as a breakthrough is the advent of the OpenADR protocol (**www.openadr.org**). This allows a standard protocol to communicate between a central server over the public internet to the energy management devices in the factory, business, or home. The communications within the premises are typically WiFi, with the wide area network communications between the premises and the central server being the internet or cellular technology. OpenADR presents new DR-related flexibility that did not exist just a few years ago.

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9 The New Face of DSM—Home and Business DSM-Related Technologies

In This Section:

- **Home Area Networks and Home Energy Management**
- **Third-Party Challenges—Technology Providers**
- **Demand Response Management Systems**

In addition to the new technologies specifically related to gathering and processing DSM information (discussed in the previous section), there are many other emerging smart technologies at the home and business that enhance and manage DSM. To make matters more complicated, many of the new technologies are produced and marketed by third-party companies, and cooperatives may be left of out of the process if they are not proactive.

The notion of a "death spiral" was discussed earlier; and while we do not believe such a spiral is imminent, there is a concern that third-party products may bypass cooperatives and relegate them to the status of a mere power provider. To avoid this outcome, cooperatives need to be conversant with the new technologies and understand how they can be integrated into the cooperative business plan.

In this section, we will cover the general types of new technologies and how they fit into other parts of the new DSM landscape, like energy markets. An underlying theme is that cooperatives need to use third-party products to position themselves as trusted energy advisors, rather than simply passive producers/deliverers of electricity.

It should be noted that new technologies are arising every year and this Guidebook cannot hope to cover all of them. We will, however, discuss some of the main categories of new technologies. Cooperatives should keep an eye on *TechSurveillance* and other NRECA publications to keep abreast of emerging technologies.

Home Area Networks and Home Energy Management

DEFINITIONS AND CATEGORIES

A **home energy management** (HEM) system is a system (hardware, software, or both) that allows consumers to manage their household energy usage. There are two main categories of HEM systems.[130] The first category consists of **informational systems**: systems that provide information to consumers, so that the consumers can then modify their usage if desired. An example of an informational HEM system is an in-home display, which gives real-time energy usage.

The second category of HEM systems consists of **control systems**: systems which allow the consumer to control home energy usage via

[130] Adapted from the Neme and Grevatt NEEP Report, *Op. cit.*

remote control or via a set of programmed rules. An example of a control system is a smart phone connected to a smart thermostat, so that HVAC temperature settings can be controlled remotely. Some systems can fall into both categories.

Another term that is used is **home area network** (HAN); this is a local network in a home or small business that connects digital devices so that they can "talk" to each other. A simple HAN might involve a laptop, a thermostat, and a cell phone. These three devices might require a fourth device, a portal, to facilitate the connection, or the three devices might be built to communicate directly with each other.

Either way, when the three devices communicate with each other, a HAN is created. For example, a person might use his cell phone to adjust his thermostat, and information about energy usage may be accessed through the laptop. The system may also be connected to the smart meter, if one is present.

HAN and HEM are sometimes used interchangeably; there is not yet uniformity in the terminology used in this area. A HAN system is better described as a subset of a HEM: the HAN is the communications network in a home that connects the various components of a home energy management system.

TABLE 9.1: Summary of HEM Technology Categories

Category	Short Definition
Smart Lighting	Lighting, controls, and fixtures with automated control
Smart Plug	Hardware plug that controls or provides feedback for connected devices
Smart Hub	Device that enables and manages interaction between existing smart hardware within a home
Smart Switch	Wall switch that controls or provides feedback for connected devices
Smart Appliance	Appliance which can be controlled remotely and/or can provide usage data to another device
Smart Thermostat	Thermostat with remote control, programming, and/or communication features
Energy Portal	Online dashboard
Data Analytics Platform	Cloud-based analytics platform that analyzes large volumes of data collected from existing smart hardware
In-Home Display	Physical display in home that collects data from existing hardware and provides real-time feedback and/or prompts
Load Monitor	Noncommunicating hardware that displays energy data of the connected appliance or devices
Smart Home Platform	Software platform that enables multiple hardware devices to operate as a home automation system
Web Service	Cloud-based platform that focuses on more than just energy

THE IMPACT OF HEM SYSTEMS

The energy and demand impacts of HEM systems, as with any DSM program, varies widely. HEM technology is in its infancy, so the data is somewhat spotty. In 2010, the ACEEE released a report summarizing the effects of residential feedback programs, such as enhanced billing statistics, daily/weekly energy feedback, and real-time feedback.[131] The ACEEE estimated that kilowatt-hour impact ranged from around 4% for indirect feedback programs (e.g., enhanced billing statements) to 12% for real-time programs with direct feedback (e.g., sophisticated in-home displays with real-time feedback).[132]

Other estimates for savings and cost ranges appear in the Neme and Grevatt NEEP Report (pp. 61–68) and a PG&E report[133] (pp. 40–45). However, these HEM programs are still in their early stages of development; detailed studies should be coming in the next several years.

BRIEF SUMMARY OF SELECTED HEM TECHNOLOGY

There are many categories of HEM technologies and the market is evolving quickly. Table 9.1 gives the major categories as reported in the PG&E and NEEP reports cited above (table has been modified in some respects).

[131] Ehrhardt-Martinez, Karen, Kat A. Donnelly, and John A. "Skip" Laitner. *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities*. American Council for an Energy-Efficient Economy Research Report E105 (2010).

[132] *Ibid.*, p. iii.

[133] Karlin, Beth, et al. *Characterization and Potential of Home Energy Management (HEM) Technology*. Pacific Gas and Electric Company. January 20, 2015.

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All of these HEM categories can be used to enable or enhance DSM programs in some respect. This Guidebook covers a few of the most critical categories.

Smart Thermostats

One prominent example of a device that may facilitate a HEM system is the smart thermostat. As mentioned above, a simple HEM is created when a smart thermostat, a cell phone, and a laptop all communicate with each other to manage home energy. There are many smart thermostats on the market; several of the prominent companies include Ecobee, Nest, Honeywell, and Carrier.

Smart thermostats integrated into a HEM system work very well with time-of-use rates, PTR programs, and other programs with "called events": they enable members to remotely change energy consumption when signaled by the cooperative.

Smart Appliances

Smart appliances can also participate in HEM systems. For example, smart refrigerator/freezer units may be able to reduce usage based on a signal from the utility or the homeowner. When combined with a smart thermostat, this could result in an effective demand-response program. Smart thermostats such as Nest and Ecobee can detect when a consumer is not at home and relay this information to the refrigerator, which can then use this information to "time" cooling activity.

To see how a smart appliance might work, consider a smart fridge/freezer unit, connected to a smart thermostat. Suppose a critical peak period is forecasted for a workday from 3 p.m. to 5 p.m.; the smart thermostat "knows" that the consumer will be at work for that period. The refrigerator can "pre-cool" in the morning, and then shut off at 2 p.m. Since nobody is home during the day, no one will open the refrigerator door, and the effect of the shut-off will be minimal. The refrigerator can resume cooling at 5:30 p.m., after the critical peak period has ended. The freezer defrost cycle, which uses a lot of energy, can also be timed to avoid peak periods.

Connection to Cell Phones

One important feature of HEMs is that many consumers may be able to operate them by using their cell phones. The interface on a cell phone need not be detailed, but, typically, consumers may be able to use their phones to manage "big-ticket" items such as the HVAC system. For example, the Nest, Ecobee, and Honeywell smart thermostats have an associated cell phone application (app) that allows users to adjust their house thermostat from their phones.

Most current apps are limited to smart thermostat settings, since most consumers do not yet have other "smart" appliances. However, smart grid technology for other big-ticket appliances, such as refrigerators, will become more prevalent.

Home Energy Management and EM&V

One important aspect of HEM systems involving energy portals, data analytics platforms, and smart home platforms is that, in the future, they can possibly be used for EM&V of DSM programs. For example, HEM systems could incorporate EM&V software, which, in turn, could be used to show compliance with state or federal EE targets.

Cooperatives should keep an eye on *TechSurveillance* and other NRECA products for new advances in HEM systems and how other cooperatives are putting them to use.

Note: In this Guidebook, the term "smart" refers roughly to an ability to interact with the grid. Some appliance makers call their appliances "smart" based on other features. For example, some refrigerators might somehow keep track of the contents of the fridge, or have an internal camera so that users can view items without opening the door. For the purposes of this Guidebook, only an appliance that can alter energy usage or otherwise integrate into a DSM program will be considered "smart."

COOPERATIVES' ROLE IN HEM SYSTEMS

The number of HEM systems in the U.S. is increasing rapidly. Cooperatives would do well to become versed in what the different types of systems are and how the systems can be used to further cooperative values and goals.

HEM systems represent an opportunity for cooperatives to engage with their members. Strategies for cooperatives include the following:

- Have a section on your website that explains what HEMs and HANs are, along with links to any related EE or DR programs offered by your cooperative.
- Offer rebates for smart thermostats, smart appliances, in-home displays, etc., on the condition that the member sign up for a DR program (such as direct load control, PTR, and time-of-use rate). HEM systems work well with DR programs.
- Partner with manufacturers to design DR or EE programs using HEM technology.

Third-Party Challenges—Technology Providers

It is natural for cooperatives to think or hope they would be the "go to" source for all issues related to electric energy, but third parties are hard at work to make it so this is not the case. Third parties—such as smart thermostat makers and solar installers—wish to simply bypass the utility and establish a relationship with the consumer directly.

There is not much cooperatives can do about the existence of these third parties. But cooperatives can be proactive and keep their status as a "trusted energy advisor," rather than assuming an adversarial stance. Cooperatives do not want get in the way of member choices regarding home rooftop solar, home energy networks, and other member technologies.

Another problem is that many third parties—such as device manufacturers or DSM aggregators—do not typically use open-source communication standards (such as Open ADR); these companies would rather lock the customer into their own proprietary systems. Cooperatives may have a certain amount of leverage in this area, as cooperatives' smart meters are the source of real-time usage data.

One way to address the third-party issue is to position the cooperative as the interface between the members and third parties. Members will be purchasing many devices related to the smart grid—smart thermostats, smart appliances, home energy systems—and cooperatives can manage the integration of all these devices.

Members will eventually want a dashboard system that controls all these devices, rather than a disconnected group of separate interfaces. This is especially true if DSM programs need to be coordinated with the devices. So there are several areas cooperatives could look into, each of which could produce a revenue stream:

- Offer turn-key services that install a DSM program for members, connecting it to all available devices. In this case, the cooperative would be responsible for connectivity.
- Partner with a third party to install and maintain connected devices.
- Develop standards that connected devices must meet, and develop a platform whereby consumers can control all their devices.
- If your cooperative is in an ISO/RTO footprint, consider partnering with the ISO/RTO (or an aggregator) to help set up a DR or EE program that uses HEM; the technology can assist with selling EE or DR into the market.
- HEM systems can be used for EM&V purposes.

Demand Response Management Systems

The third-party issues discussed in the previous section show that an advanced DSM program can become very complicated, with different parties managing different data. For example, a cooperative could have the following systems, all with associated data and storage:

- Home energy networks
- Load management systems
- Energy management systems
- RTO/ISO interfaces
- Distribution management
- Customer technology
- MDMS
- AMI
- Aggregator portals

One DR technology that is becoming more common, and is intended to manage the various systems described in the preceding sections, is the "demand response management system" (DRMS). A DRMS is a single-point portal for DR management, from both the utility perspective and the member perspective. A robust DRMS for a residential member would probably also count as a home energy management (HEM) system.

For example, a fully-functioning DRMS would serve as a portal for members to look at a menu of DR programs, obtain information about the programs, sign up for the programs, and monitor results. (Note: Most companies that offer a DRMS can also integrate EE programs. However, EE programs tend to be more "set it and forget it" and do not require as much interface.) If the cooperative created a new DR program, the DRMS would have the ability to integrate the new program into the lineup.

The idea is that anything that might be DSM-related has a single interface for both the member and the cooperative—the DRMS portal. We realize that cooperatives with more limited DSM programs will probably not be jumping into these complex systems right away. However, cooperatives should, at the very least, familiarize themselves with the terminology so, as their DSM programs grow, they can consider their options.

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10 Energy and Capacity Markets

In This Section:

- General Description of Market Products
- PJM Energy and Capacity Markets
- Other Markets
- Markets: Conclusion

One of the major changes in DSM cost/benefit analyses in the past several years is the increased ability for some utilities or their large C&I consumers to sell DSM into the capacity or energy markets. Each RTO or ISO will have its own procedures for qualifying DSM, and each RTO's procedure is different. Please consult the appropriate manuals of your RTO for "official" rules and procedures. This Guidebook focuses on some examples from PJM, as it has some of the more advanced energy and capacity markets.

General Description of Market Products

It varies by RTO, but, generally, there are three main categories of wholesale RTO markets available for DSM programs: **energy markets** (real-time or day-ahead markets), **forward capacity markets**, and **ancillary services** (reserve markets and regulation markets). As we will see, DR is offered into markets more often—and in more kinds of markets—than is EE.

ENERGY MARKETS: COOPERATIVES PAID TO CONSUME LESS

Energy markets plan for upcoming energy needs of the RTO footprint. The two common types of energy markets are day-ahead markets and real-time markets (aka "spot markets"). RTOs use day-ahead markets to procure and balance energy for the next day. Spot markets deal with near-real-time ups and downs in energy needs.

EE is usually not offered into energy markets. EE programs are usually long-term measures that reduce energy usage whenever the measure is "on" (e.g., an energy-efficient air conditioning unit). EE programs are not built to ramp up and down or respond to daily energy needs.

DR can be offered in energy markets, although the main benefit of DR is usually in the capacity markets, not the energy market. Most DR programs attempt to reduce kilowatts during a few key hours, but this reduction does not last for days or weeks, so kilowatt-hour reduction from DR is not the main goal. However, DR programs do reduce energy and this can be sold into the market, especially if energy prices spike to high levels.

Many types of cooperative-dispatchable DR could be eligible for the day-ahead market, assuming all other RTO qualifications were met. For DR to be available in the spot market, it would need to have near-instant reaction times (e.g., direct load control) and would most likely need to be controlled directly by the RTO. In both cases, DR acts much like a generation resource. The difference is that, with a DR resource, the cooperative is paid to consume less energy, thus easing the burden during days with high energy requirements.

CAPACITY MARKETS: COOPERATIVES PAID TO HAVE DSM AVAILABLE

When DR is sold in the energy market, the cooperative is paid to consume less energy on a specific day and at a specific time. When DSM is sold in the capacity market, the goal is for that capacity to be available at some future date—three years later, for example. In a sense, especially with DR, when DSM is sold into the capacity markets, the DSM resource is compensated for being available, not necessarily for being used. The RTO wants to know that the DR resource in question is available to be called upon if needed. The RTO uses the capacity market to ensure that the region has enough capacity down the road. Both EE and DR are sold in capacity markets, although DR is typically more prominent.

There are several types of capacity markets in some RTOs, like PJM and MISO. There is the **forward capacity market**, which is the market that ensures capacity a year or more down the road. There are also one or more "**reserve markets**," which are technically "ancillary services" and which require capacity to be available at 10 to 30 minutes' notice. There could be an emergency response market as well, which could require a response in less than a minute or two.

In all of these markets, the resource is paid to be available; the resource can be compensated the same whether it is used five times or no times at all. (Typically, the RTO would call the resource at least once in a year, if only to test it and make sure it delivers demand reduction at the promised level.)

EE can be sold in the forward capacity market to the extent that the program in question reduces the kilowatt requirements of the system. For example, suppose an RTO always peaks on hot summer days. Also suppose that a cooperative has 1,000 air conditioners—each rated at 3,000 watts—that are always running (with the compressor on) at peak times. If these 1,000 air conditioners were all replaced through a rebate program with more efficient models that ran at 2,800 watts each, the demand savings at peak would be 200 kilowatts (1,000 units × 200 watts each = 200,000 watts). If the EE program met the RTO qualifications, these projected 200 kilowatts could be sold in the RTO forward capacity market.[134] EE is not sold in the reserve or emergency capacity markets.

When DR is sold into the market, it acts much like a peaker plant. A cooperative pledges that the resource will be available for a certain number of times throughout the year. The RTO market determines when demand will be high and DR resources are "called" to reduce demand.

It is important to remember that both DR and EE resources can be bid into the capacity market. When it comes to capacity, it is easy to only focus on DR and forget EE. It is true that EE generally provides less capacity reduction on a $/kW basis, but EE programs can, nonetheless, have a substantial capacity reduction component.

ANCILLARY SERVICE MARKETS

There are two main types of ancillary service markets: reserve and balancing. Reserve services are designed to respond to contingency events (e.g., a resource is not generating as expected). Balancing services (sometimes called "regulation" services) are meant to respond to typical "every-hour" changes in load or power quality requirements as a result of normal fluctuations.

These markets deal with short-term market needs (on the scale of hours, minutes, and seconds). EE typically will not serve as a resource in the ancillary markets, since it generally is not dispatchable.

Although definitions vary slightly from market to market, ancillary service products generally fall into the following categories:

- **Spinning reserves** are reserve sources that are "online" and synchronized to the grid. They are designed to **respond to contingency events** within 10 minutes.

[134] Note that the assumptions in this case are unrealistic and are for illustrative purposes only. For example, even on hot summer days, air conditioners do not run at full wattage; the compressor cycles on and off.

- **Non-spinning reserves** are not synchronized to the grid, but can be quickly. These are designed to **respond to contingencies** within 30 minutes.
- **Load-following reserves** are somewhat similar to spinning reserves; however, they are not responding to contingencies, but are rather **correcting for "every day" load fluctuations**.
- **Regulating reserves** are online and capable of responding in the 5-second to 5-minute range, usually on automatic control from the load balancer (i.e., the RTO).
- **Frequency regulating reserves** are generally designed to respond in under 5 seconds, on automatic control from the load balancer.

Different reserve markets have different required response times, but the general idea is that reserve resources should be available within 0–30 minutes to respond to hour-to-hour capacity requirement fluctuations. The response time could be 30 minutes (non-spinning reserves) or 10 minutes (spinning reserves) or a couple of seconds (frequency reserves).

There are often two types of payments for ancillary services: a fixed payment for the resource being available and a variable payment if the resource is actually called. The fixed payment is paid whether or not the resource is ever called; the crucial point is that the resource be available. The difference between DR as a capacity resource and DR as an ancillary reserve resource varies among RTOs, but common differences might include: when the resource is available (time of day or time of year), length of time of a called event, and how far ahead of time the resource is planned.

Frequency regulation services provide almost real-time support to the market, e.g., 5 seconds or less. These services are used to respond to second-by-second variations in demand, or to keep the system frequency constant. DR candidates for this market include devices whose demand or frequency can be adjusted up or down essentially instantaneously: water pumping, water heating, plug-in electric vehicles (PEVs), variable speed drives, etc. Thus, real-time communications are required and dispatch is usually controlled by the RTO.

PEVs in particular may serve as an important source of short-term regulation support in the future as they have many desirable features that are suitable for short-term regulation services (on the scale of minutes or seconds). Most of the time, brief interruptions in the charging process may not even be noticed by the consumer; all the consumer cares about is that the battery is (for example) charged by some point later in the day. In the future, PEV regulation service may be "two-way" or "bidirectional": PEV batteries may be able to *supply* short-term ancillary capacity by discharging electricity to the grid (in addition to reducing usage).

ANCILLARY SERVICE PRODUCTS

- **Spinning Reserves**
  - online
  - synchronized to the grid
  - respond to contingency events within 10 minutes
- **Non-Spinning Reserves**
  - not synchronized to the grid
  - can quickly respond to contingencies within 30 minutes
- **Load-Following Reserves**
  - do not respond to contingencies
  - correcting for "every day" load fluctuations
- **Regulating Reserves**
  - online
  - respond in 5 seconds to 5 minutes
  - automatically controlled by the load balancer (the RTO)
- **Frequency Regulating Reserves**
  - respond in under 5 seconds
  - automatically controlled by the load balancer

PREVIEW VIEW

PJM Energy and Capacity Markets

This section, for illustrative purposes, goes into some detail about PJM's markets. Other RTO/ISO markets will differ. As always, consult your RTO/ISO for details, as market rules change frequently. PJM's electricity markets are divided into energy markets and capacity markets. (There are also other markets—such as ancillary services and transmission rights markets—which will not be discussed in much detail.)

The main DSM "player" in the market—from a total dollars perspective—is demand response, so it will be addressed first. EE plays a role in PJM markets, but it is a smaller role.

DR IN PJM MARKETS[135]

There are two main classifications of demand response in PJM markets: emergency and economic. A cooperative member could participate in either or both of these markets.

Emergency DR is usually a *mandatory* commitment; when PJM needs assistance to maintain reliability/capacity under supply shortage or emergencies, it will call on DR resources to perform. There are penalties for noncompliance. These resources are provided by a Curtailment Service Provider (CSP). A CSP could be a third-party aggregator, a utility, or some other type of energy company. There are three types of emergency DR:

- **Limited DR.** The resource is available for up to 10 weekdays from June through September, where each request may be up to six hours in duration.
- **Extended Summer DR.** The resource is available for all days from May through October, where each request may be up to 10 hours in duration.
- **Annual DR.** The resource is available for all days from June through May of the following year, where each request may be up to 10 hours in duration.

The procurement of this emergency DR mostly takes place in PJM's capacity market. However, there are also some voluntary DR products, where CSPs can decide to participate when PJM calls an emergency. These resources receive revenue, but not from the capacity market.

In contrast to emergency DR, **economic** DR is a *voluntary* reduction in load in response to a price signal (however, if the resource is bid into the market on this basis and "clears" the bidding process, it is expected to perform as promised). In this case, the economic DR will be used to displace a generation resource. However, economic DR may also be used to provide ancillary services:

> *There are three Ancillary Services markets in which economic demand response resources may participate: Synchronized Reserves (the ability to reduce electricity consumption within 10 minutes of PJM dispatch), Day Ahead Scheduling Reserves (the ability to reduce electricity consumption within 30 minutes of PJM dispatch), and Regulation (the ability to follow PJM's regulation and frequency response signal). Participation in the market is voluntary; however, if a resource clears, performance is mandatory.*[136]

As stated above, the main revenue stream for DR products in PJM comes from the capacity market.

PJM CAPACITY MARKETS

The PJM capacity market is designed to ensure the PJM footprint has enough capacity in upcoming years. Each load-serving entity in PJM is required to have the capacity resources to meet its projected load (plus a reserve). This requirement can be met by owning capacity, purchasing capacity from others, or through PJM's capacity market.

The PJM capacity market uses the Reliability Pricing Model (RPM); the capacity market itself is sometimes called by that name. In the RPM system, capacity is procured three years before it is needed through a competitive auction, which is called the Base Residual Auction, or "BRA."

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[135] From PJM's "Retail Electricity Consumer Opportunities for Demand Response in PJM's Wholesale Markets."

[136] *Ibid.*, page 3.

PREVIOUS VIEW

There are three separate follow-up auctions: (1) 23 months before delivery; (2) 13 months before delivery, and (3) 4 months before delivery. These secondary auctions help square up changes in the load forecast and changing circumstances after the BRA.

In the PJM capacity markets, each capacity resource must bid into the BRA auction at its total operation cost. Each resource bids in its capacity at its chosen cost, in $/MW-day. If a resource bids 100 MW at $120/MW-day, it is saying "we will provide 100 MW of capacity three years from now, and we are willing to take $120/MW-day in compensation for it."

PJM selects the lowest-cost combination of resources that are needed to meet projected demand. It adds resources, starting with the lowest-cost resources and moving up the list, until the projected demand is met. As PJM gets close to its projected load, at a certain point it adds one more resource, and that resource puts PJM "over the threshold" to its required load. The cost of that last resource is the "clearing price," since it allowed PJM to "clear" its required load. No matter what each resource bid, each resource gets paid the clearing price, which is the most expensive resource needed to meet demand. This is important and bears repeating: *no matter what a particular resource bid, in the end, all resources get paid the clearing price*. (Note: There are sometimes different clearing prices for different PJM subregions.)

The clearing prices vary by location and year, but have generally ranged from $40 to $240 per MW-day.[137] As an example, suppose a qualifying participant bids 20 MW of demand response, at $100/MW-day, into the 2014 PJM BRA, which is for the 2017–2018 season. In 2017, the participant delivers the 20 MW as promised. The participant would get

20 MW × $100/MW-day × 365 days = $730,000

This would be spread out in payments monthly or weekly throughout the year. Recall that EE programs can participate in the capacity market as well.

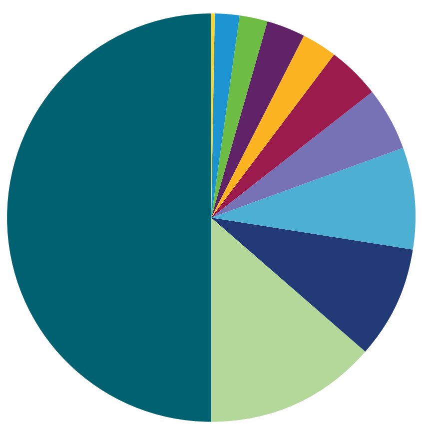

FIGURE 10.1: PJM Delivery Year 2015/2016 Confirmed Load Management DR Registrations Business Segments

WHO CAN SELL DSM INTO PJM CAPACITY MARKETS?

To participate in the RPM, a consumer needs to either: (1) deal with a curtailment service provider (CSP) that is a member of PJM, or (2) become a PJM member themselves. A CSP is an agent for PJM that collects DSM and provides it to the PJM markets in bulk. G&T cooperatives can be CSPs, as can distribution cooperatives.

According to the 2015 PJM DR market report, in Figure 10.1 are the business segments (by percentage of nominated capacity) that provide DR into the market. (Note: These are future resources bid into the capacity market, which is why the "Delivery Year" is 2015/2016).[138]

Figure 10.1 shows that much of the DR in PJM (from a megawatt percentage perspective) comes from commercial and industrial customers. If cooperatives have large C&I plants in their service territories, and are in an RTO footprint that allows DR in the capacity market, they could look into selling DR into that market.

The load reduction methods used by these entities is shown in **Figure 10.2**.[139]

[137] In some regions in some years, prices have spiked to above $300/MW-day, but this is uncommon. See Figure 5-5 in the *2014 Quarterly State of the Market Report for PJM: January through September.*

[138] *2015 Demand Response Operations Markets Activity Report,* by James McAnany. May 2015, p. 7.

[139] *Ibid.*, page 8.

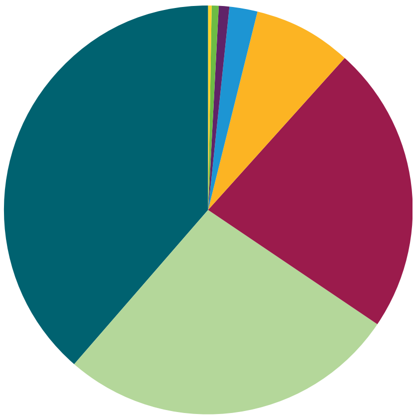

FIGURE 10.2: PJM Delivery Year 2015/2016 Confirmed Load Management DR Registrations Customer Load Reduction Methods

This shows that HVAC and manufacturing processes are the most common DR load reduction targets (by percentage of nominated capacity in MW).

PJM ENERGY MARKETS

The PJM energy markets consist primarily of two markets: the **Day-Ahead Market** and the **Real-Time Market** (5-minute balancing). There are also other markets that may accept DR.[140] DR can be bid into either the Day-Ahead Market or the Real-Time Market as an energy resource. EE is not bid into energy markets.

The Day-Ahead Market is a forward market where hourly prices are determined for the next operating day. Generation offers, demand bids, and bilateral transactions operate much in the same way as a stock exchange: supply and demand establish a "locational marginal price" (LMP), which "reflects the value of the energy at the specific location and time it is delivered."[141] If transmission congestion is not a problem, LMPs will be similar across the PJM footprint. When congestion is a problem, LMPs can vary quite a bit from location to location.

The Real-Time Market is a five-minute balancing market, "in which current locational marginal prices are calculated at five-minute intervals based on actual grid operating conditions." There is an LMP for the five-minute balancing requirements, and this is separate from the day-ahead LMP.

MOST DR REVENUE FOR UTILITIES IN THE PJM MARKETS COMES FROM CAPACITY

Monitoring Analytics, which monitors and reports on PJM markets, reports that, in 2014, most DR revenue came from the capacity markets:

> *In 2014, emergency revenue, which includes capacity and emergency energy revenue, accounted for 96.8% of all revenue received by demand response providers, credits from the economic program were 2.5% and revenue from synchronized reserve was 0.7%.*[142]
>
> (Note: The 96.8% figure for "emergency revenue" is composed mostly of capacity.)
>
> In 2015, the story was similar:
>
> *In 2015, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.4% of all revenue received by demand response providers, credits from the economic program were 1.0% and revenue from synchronized reserve was 0.6%.* [143]

Total revenue for DR in PJM capacity markets was around $430 million in 2013. In 2014, this figure rose to more than $600 million. Although DR can be effective as an energy resource, it appears to be more often bid into the markets as a capacity resource. One reason for this is that most dispatchable DR is already bid into the market as capacity, so that on days of high demand, that DR is already assigned to the capacity market.

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[140] For example, PJM has two ancillary markets. **Synchronized Reserve** resources supply electricity (or reduce demand) if the grid has an unexpected need for more power on short notice. **Regulation Markets** correct for short-term changes in electricity use.

[141] Fact Sheet: *PJM Markets.*

[142] *State of the Market Report for PJM 2014*, p. 222. Monitoring Analytics, LLC.

[143] *State of the Market Report for PJM 2015*, p. 234. Monitoring Analytics, LLC.

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HOW TO FIND (OR BECOME) A CSP

As stated above, in order to bid DSM into the PJM markets, your cooperative would need to do one of two things: (1) Bid through a CSP (Curtailment Service Provider), or (2) Become a CSP. If you wish to use a CSP, there is a list of available CSPs on the PJM website. [144] Recall that there are three kinds of CSPs: third-party aggregators, utilities, and other types of energy companies. Cooperatives would probably not use another utility as their CSP, but instead would use a third-party aggregator or other energy company. Examples of these include EnerNOC and EnergyConnect, Inc.

The second option is to skip the middleman and have your cooperative become a CSP. This would be a good option for G&Ts with large controllable load on their systems, especially C&I and air conditioner load. Cooperatives that wish to explore this option should contact PJM directly (the general toll-free number is 866.400.8980).

Other Markets

In this section is a brief summary of how DSM operates in other markets. As the role of DR and EE in the ISO/RTO markets is constantly changing, this information should not be considered up-to-date; all cooperatives should contact their specific ISO/RTO directly for the current procedures and policies.

SPP

The Southwest Power Pool (SPP), serving a strip of states from Oklahoma to North Dakota, does not have a capacity market. It has a day-ahead market and a real-time balancing market. SPP is in the process of integrating DR into the markets, but it does not yet have a large DR market presence. The 2014 SPP *Annual Report* lists 48 MW of wholesale DR and 1,284 MW of retail DR for 2014.

MISO

The Midcontinent Independent System Operator (an ISO/RTO in the central U.S. and Canada) has a forward capacity market, similar in overall design to PJM in some respects. DR can be bid into the capacity markets and can also be bid into day-ahead and regulation energy markets. Table 10.1 shows the amount of DR that cleared the last two capacity auctions.[145]

The clearing prices for MISO are done by zone. Six zones had a clearing price of $3.48/MW-day, two had a clearing price of $3.29/MW-day, and one zone cleared at $150.00/MW-day. MISO explained the high clearing price for Zone 4, which consists mainly of Illinois (excluding the Chicago and northern areas), as follows:[146]

TABLE 10.1: DR Cleared in Last Two Capacity Auctions

Resource	2014/2015	2015/2016
Generation	124,556 MW	122,965 MW
Behind the Meter Generation	3,743 MW	3,986 MW
Demand Response	5,457 MW	5,938 MW
External Resources	3,156 MW	3,469 MW

> *The MISO footprint is comprised of nine resource zones. This year, electricity providers in Zone 4 (largely Illinois) offered more capacity through the auction (45% of offers this year, compared to 35% last year) instead of using their own resources or relying on contracted resources. This resulted in more generation units being offered as price sensitive in this year's auction.…*

In the 2014/2015 auction, cleared prices ranged from $3.29/MW-day to $16.75/MW-day, with eight of nine zones being at or near the latter figure. It should be noted that, in PJM, participation in the capacity is mandatory for qualified existing resources, whereas, in MISO, load-serving entities can self-schedule resources and avoid the clearing prices.

In MISO, DR can be bid into both the capacity market and the energy markets (day-ahead, real-time, reserve, and regulation). An overview

[144] See www.pjm.com/markets-and-operations/demand-response/csps.aspx.

[145] *2015/2016 Planning Resource Auction Results,* MISO Supply Adequacy Working Group, April 30, 2015.

[146] MISO 2015-16 Planning Resource Auction Results Frequently Asked Questions.

of the role of DR in MISO can be found in ***Demand Response as a Resource*** and the MISO ***Demand Response Business Practices Manual***. Energy efficiency can serve as a capacity resource in the auction; see Chapter 4.2.9 of MISO's ***Resource Adequacy Business Practices Manual***. However, in two recent capacity auctions (2014/2015 and 2015/2016), zero megawatts of EE resources cleared the auction.[147]

ISO-NE

At ISO-NE (an RTO in New England), "demand resources" can be either active or passive. Active demand resources are dispatchable (i.e., traditional DR) and passive demand resources include EE. Both active and passive demand resources can participate in the forward capacity auctions, which are held every year, three years before the year in question.

Active demand resources can also partially participate in energy markets, but passive demand resources cannot. Active demand resources can also participate in the price-responsive demand program, which replaced the Day-Ahead Load-Response Program in 2012. Full integration of demand resources into the energy markets is planned for June 1, 2017.

For the 2018–2019 auction, the cleared resources were as follows: 30,442 MW of generation, 1,449 MW of imports, and 2,803 MW of demand-side resources.[148] Of the demand-side resources, around 77% are passive and 23% are active. More information can be found at ISO-NE's website on the Demand Resources page.[149]

The 2018–2019 capacity auction price for ISO-NE was $9.55/kilowatt-month for the majority of new and existing resources (around 70%). In certain specific zones, the price was $17.73/kW-month for new resources and $11.08/kW-month for existing resources. Import and previously cleared resources were paid at other prices.

ERCOT[150]

The Electric Reliability Council of Texas does not have a forward capacity market. ERCOT does have many ways in which DR can be bid into its other markets. There are two main kinds of DR participation: DR dispatched by entities other than ERCOT and DR dispatched by ERCOT.

In the former category, retail electric providers (REPs), T&D utilities, DR providers, or customers can be the entity that controls the dispatch. These DR programs are typically a matter between consumers and the REP.

For ERCOT-dispatched DR, there are two main types of market programs:

1. Emergency Response Services consist of 10-minute ramp-up programs or 30-minute ramp-up programs.
2. In Ancillary Services (AS) Markets, DR can serve as a Load Resource in a number of ways, depending on response time and other responsiveness features.

For the second type of program (AS), each load-serving entity has a responsibility for AS, to preserve margins and other reliability metrics. Each market participant can provide its own AS or can procure its AS in the Day-Ahead Market. Thus, DR can function as AS in the Day-Ahead Market.

DR can also participate in the real-time energy market (Security Constrained Economic Dispatch or SCDE). Specifications for all products can be found in the Excel sheet "ERCOT DR Attributes" at **www.ercot.com/services/programs/load**.

In its 2014 ***State of the Grid*** report, ERCOT listed the following amounts of Demand Response Resources:

> More than 2,100 MW in demand response resources, include:
> - Load Resources (mostly large industrial) ~1,390 MW

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[147] See, e.g., *2015–2016 PRA Detailed Report* (Excel file).

[148] ISO-NE Finalized Capacity Auction Results Confirm Resources, Prices for New England Power System in 2018–2019.

[149] www.iso-ne.com/markets-operations/markets/demand-resources.

[150] Most information in this section is from *Load Participation in the ERCOT Nodal Market,* ERCOT Staff, April 23, 2015 (click on title of paper).

- Emergency Response Service (commercial and industrial) ~850 MW
- Utility Load Management Programs ~220 MW

However, as 2014 had a mild summer for the region, the ERCOT-dispatched resources were not called much at all.

ERCOT does not have a forward capacity market that would allow for EE to be bid as a resource.

NYISO

Demand response can serve four purposes for the New York Independent System Operator:

- Emergency Demand Response Program (EDRP),
- ICAP Special Case Resources (SCR),
- Day Ahead Demand Response Program (DADRP), and
- Demand Side Ancillary Services Program (DSASP).[151]

The SCR is part of the capacity market (ICAP). The EDRP is a separate DR program that works in tandem with the ICAP. The DADRP is offered in the day-ahead energy market. The DSASP can offer ancillary services (operating reserves and regulation) into either the day-ahead market or the real-time market. Energy efficiency is not bid into the ICAP.

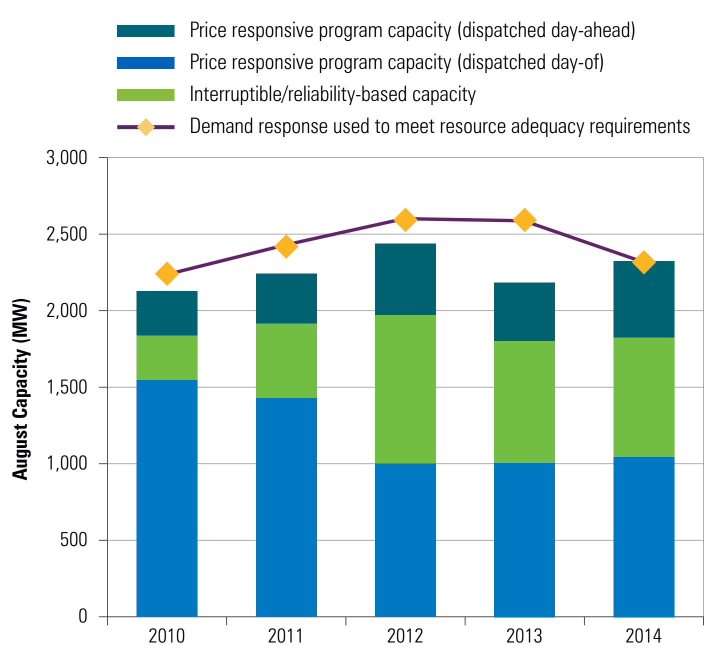

FIGURE 10.3: CAISO Utility-Operated DR

CAISO

The California Independent System Operator does not have a forward capacity market. CAISO has day-ahead, hour-ahead, and real-time energy markets. CAISO also has four ancillary services: regulation up, regulation down, spinning reserve, and non-spinning reserve.

DR can be bid into the day-ahead, real-time, and ancillary services markets under two separate products. The Reliability Demand Response Resource can be bid into two energy markets: the economic day-ahead market and the reliability real-time market. The Proxy Demand Response can be bid into energy and ancillary services markets: the economic day-ahead market and the real-time market.[152]

There is also an emergency scenario under customers (primarily large retail customers) that have interruptible tariffs and air conditioning cycling programs, which come into play when the ISO experiences certain emergencies and which pays between $950 and $1,000/MWh. No emergencies were called in 2014.

It should be noted that the California PUC has recently encouraged more in the way of CAISO DR products. One proposal would allow direct participation from third-party aggregators. A second proposal is the Demand Response Auction Mechanism (DRAM), which would function as a kind of forward capacity market for DR for the upcoming year. The amount of utility-operated DR over the last few years is shown in Figure 10.3.[153]

[151] There is also a Targeted Demand Response Program, which is intended to postpone a specific transmission problem. See *NY-ISO 2014 State of the Market Report* (Patton, et al.).

[152] See CAISO's current *Demand Resource User Guide* and FAQs.

[153] CAISO *2014 Annual Report on Market Issues and Performance*, p. 33.

Markets: Conclusion

It bears repeating that the DR/EE market landscape is constantly changing as ISOs/RTOs add product and as decisions such as FERC 745 (see **Section 11**) get sorted out. The information in this Guidebook is for illustrative purposes only; the ISOs should be contacted directly for their current policies.

With that caveat in mind, cooperatives should be on the lookout for RTO/ISO opportunities. Some DR/EE programs could be a source of revenue stream if they can be bid into the market as capacity, energy, or regulation/ancillary services. In particular, dispatchable DR is a good candidate for capacity or emergency services.

11 Regulation

In This Section:

- FERC Order 745

FERC Order 745

In March of 2011, the Federal Energy Regulatory Commission (FERC) issued Order 745, which required that regional, organized, wholesale energy markets pay market price for demand response energy. Order 745 (the "Order") provided that, when certain conditions are met, demand response resources must be compensated at the locational marginal price (LMP) for the services they provide to the energy market. The conditions were as follows:

1. The order only applied to ISOs and RTOs that had the appropriate tariff provision permitting demand response (DR) resources to participate as resources in the energy market. Customers who were not ultimately served by an ISO/RTO need not be compensated at LMP for their demand response resources.
2. In order to be compensated at LMP, the DR resources must reduce consumption of electricity from their expected level in response to price signals.
3. The demand response resources to be compensated must have the ability to balance supply and demand.
4. Payment of LMP to the resource must be cost-effective, as determined by a FERC-approved net benefits test.

If these conditions were met, then the ISO/RTO must:

A. Pay the LMP to those demand response providers; and
B. Allocate the costs associated with DR compensation proportionally to all entities that "purchase from the relevant energy market in the area where the DR reduces that market price for energy at the time when the DR resource is committed or dispatched."

FERC's stated reasons behind the Order were that, by removing barriers to the participation of DR resources, the Order would help to ensure the competitiveness of organized wholesale energy markets. This, in turn, would ensure "just and reasonable" wholesale rates.

The obvious effect of the Order is to incentivize DR programs. FERC felt that DR replaces generation and reduces customers' prices by reducing load. FERC thought that the lack of uniformity regarding how to pay for DR resources had scared off some potential DR programs. With a uniform payment system in place, FERC's hope was that more cost-effective DR programs would be implemented.

Opponents to the Order thought that FERC exceeded its authority to regulate DR prices and that the compensation issue is best left to states or to individual ISOs/RTOs. Another issue was "double-counting." If a consumer is paying LMP for electricity (say, $40/MWh) and chooses to forgo one megawatt-hour at the appropriate time, it will save $40 for the megawatt-hour it did not buy, and receive $40 for the megawatt-hour of DR it reduced, thus effectively receiving a "double payment" for the megawatt-hour of DR. According to some, this "double payment" will lead to inefficiently large amounts of imputed DR.

NRECA'S POSITION ON THE ORDER

During the period before the rule was adopted, FERC invited comments on the proposed rule. NRECA expressed concerns about the proposed rule, including the following:[154]

1. Local and regional differences should be taken into account when setting prices for DR in RTO markets, instead of an across-the-board LMP. Varying consumer load profiles, market structures, and weather patterns dictate different DR payment structures.
2. The rule fails to recognize substantial DR activity that already occurs in areas of the country without ISO/RTO markets.
3. The lack of a uniform compensation for DR is not in itself a barrier to DR programs, as evidenced by the fact that, although cooperatives provide only about 10% of the country's retail energy, their combined DR resources are about 20% of electric DR capacity. The cooperative members who are not in an ISO/RTO would not be fairly compensated for their DR programs (when compared to their ISO/RTO counterparts).
4. The payment of LMP for all DR does not reflect the reality that many customers pay a retail price different from the wholesale price. There should be an offset to reflect this.
5. The double payments will create an unreasonable and inefficient subsidy for DR resources.
6. The Order's LMP payment will have a proportionally worse effect on not-for-profit load-serving entities (LSEs). LSEs like municipally owned utilities and rural electric cooperatives have an obligation to serve all those in their service territories. Under the Order, however, the large industrial and commercial customers would be able to engage in DR sales at their sole discretion, while the LSE would have to maintain its peak load capacity at all times, not knowing when or if the large customers would activate their DR programs. The load maintenance costs could be large for the nonprofit LSE.

THE ORDER IS OVERTURNED; FERC APPEALS TO THE SUPREME COURT

The NRECA and other industry associations, after exhausting appeals at FERC, petitioned the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) to review the rule. The D.C. Circuit ruled that DR was a retail transaction —not wholesale—and, thus, was under the purview of state utility commissions, not FERC (i.e., FERC had no statutory authority for the rule).

The D.C. Circuit also found that, even if we assume FERC had authority, the requirement of payment of the LMP was "arbitrary and capricious." Thus, the D.C. Circuit vacated Order 745 in its entirety.[155]

In January 2015, the U.S. Solicitor General and FERC appealed the D.C. Circuit's decision to the U.S. Supreme Court. The Supreme Court agreed to take up the case.

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[154] NRECA's comments were made in conjunction with the American Public Power Association (APPA), the trade association for municipal utilities. The comments can be found at FERC's docket search. The Docket no. is RM10-17.

[155] The court's mandate has been stayed pending FERC's Cert Petition to the U.S. Supreme Court. [A Petition for Writ of Certiorari is a document a losing party files with the Supreme Court asking the Court to review the decision of a lower court.] See Electric Power Supply Association v. FERC, No. 11-1486 (D.C. Cir., Oct. 20, 2014, per curiam order granting FERC motion to stay issuance of mandate).

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IMPLICATIONS FOR COOPERATIVES

In early 2016, the Supreme Court upheld FERC Order 745. As a result, DR will probably, on average, be worth more than if the ruling went the other way, as now the LMP will be paid for DR in the energy market. Cost/benefit analyses will be a little more uniform; cooperatives using the markets can simply use the LMP to measure the benefit of DR.

Greentech Media estimated the value of U.S. DR with and without FERC Order 745, as seen in Figure 11.1. If a cooperative is not in the footprint of an RTO with an established market, FERC Order 745 issues are not as immediate. However, the price of DSM in bilateral transactions will ultimately be affected by prices for DSM in RTO markets, so this issue will affect all cooperatives, even if only indirectly.

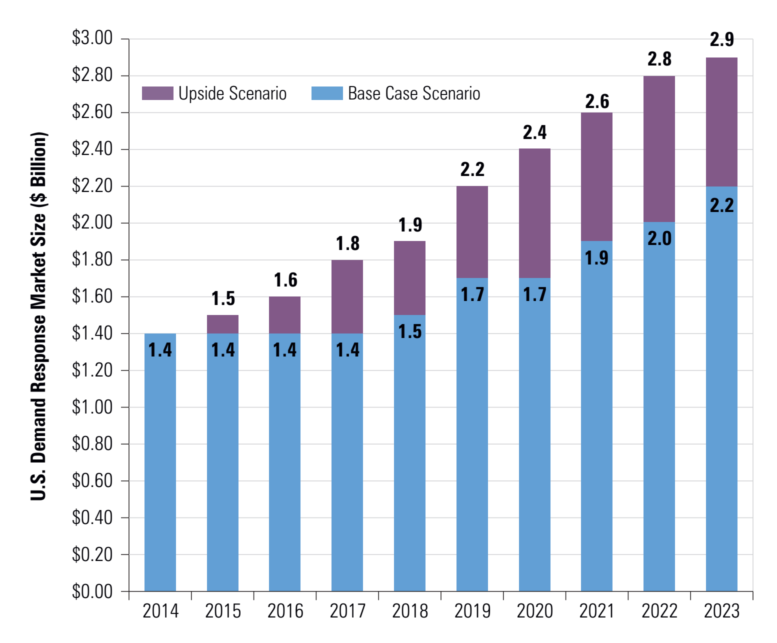

FIGURE 11.1: U.S. Demand Response Forecast, With and Without FERC Order 745, 2014–2023[156]

[156] Munsell, Mike. "Ruling Against FERC Order Could Cost U.S. Demand Response Market $4.4B in Revenue," *Greentech Media*. September 18, 2014.

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12 Wholesale and Retail Rate Considerations

In This Section:

- **Fixed Costs vs. Variable Costs**
- **Possible Changes to the Rate Structure**
- **Rate Design Based on Marginal Costs**

"**The 'Lost Revenue' Barrier to DSM**" briefly touched on the subject of possible revenue erosion due to EE programs. Although this issue may be mitigated by overall sales increases or other EE benefits, the fact is that, in some cases, revenues may be affected by EE programs. This section considers the revenue issue in light of cooperative rate structures, along with other DSM rate issues.

Fixed Costs vs. Variable Costs

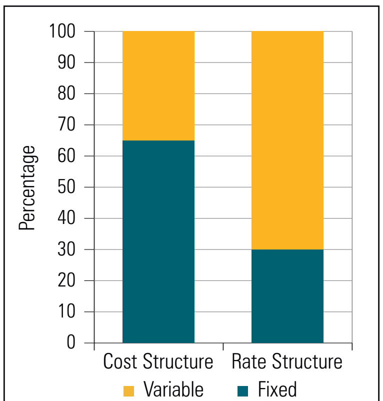

FIGURE 12.1: Variable vs. Fixed Allocation: Cost vs. Rates

To understand how DSM issues fit into rate structures, first we must examine the categories of costs that cooperatives face. For most retail consumers in the U.S., electric rates are based on the cost of providing service, which includes two components: operating expenses and a return or margin.[157] For distribution cooperatives, the majority of the cost of providing service is comprised of **fixed costs**, which do not vary with output. Depreciation, long-term interest, and most distribution operation and maintenance costs are incurred independent of how much energy is sold.

Variable costs vary with the amount of electricity used. In the short run, the main variable costs for distribution cooperatives are the wholesale energy costs. For a distribution cooperative, variable costs typically represent one-third to one-quarter of total costs. Thus, for distribution cooperatives, the fixed/variable cost split is often around 75/25 or 65/35. (For a G&T cooperative, the fixed/variable cost split is usually closer to 50/50.)

The problem is that the traditional rate structure—and, therefore, revenues—are skewed toward the variable side (see Figure 12.1). Traditionally, the majority of a distribution cooperative's revenue stream comes through variable charges (i.e., energy rates) versus fixed charges (i.e., customer charges). This mismatch can

[157] Even for cooperatives in competitive retail electric markets, consumers typically have a choice of providers with cost-based rates. Furthermore, in these competitive markets, the local delivery costs remain cost-based, independent of the power supplier.

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cause problems and the revenue erosion (with no corresponding reduction in costs) that occurs when energy sales decrease is one of those problems. If the majority of costs are fixed, but the majority of revenue is variable, then changes in revenue as a result of EE can have an outsized impact on the margins of the utility.

Possible Changes to the Rate Structure

Historically, not many cooperatives have changed their rate structures solely to address EE revenue. However, when combined with flat sales growth, distributed generation, appliance saturation, and the recent recession, revenue erosions from these sources have caused some changes in rate structures.

The general trend is to shift cost recovery out of an energy charge and into other charges. This mitigates the effects of EE revenue erosion. The main categories of increased non-energy charges are as follows.

- **Customer Charge.** When the customer charge is increased, members shift costs from energy to a fixed monthly charge. Many cooperatives which perform rate assessments have been increasing their customer charges, due to the imbalance noted in **Figure 12.1**. As of 2015, in 34 of 35 recent rate studies performed by PSE, the result was an increased customer charge.
- **Increased Minimum Charge.** This is similar to a customer charge, but it only affects members whose energy use falls below a certain minimum threshold.
- **Demand Charge.** Demand charges are becoming more prevalent for end-use members, especially for commercial and industrial members. This is still a variable charge, but it at least tracks the infrastructure related to that customer more closely. Residential demand charges are not as common, but are becoming more prevalent. Demand charge rates could be voluntary, opt-out, or mandatory.
- **Straight-Fixed Variable.** A straight-fixed variable (SFV) charge is usually similar in effect to an increased customer charge. Under an SFV rate, all fixed costs are placed in the fixed charge and all variable costs are placed in a variable charge. This is not a popular option, as the fixed charge would be quite high.

ADVANTAGES AND DISADVANTAGES OF CHANGING THE RATE STRUCTURE

As cooperatives look to move towards increasing the proportion of revenues derived from customer charges, there are a number of possible criticisms of changing rates that cooperatives should be aware of. The first criticism is that increasing the customer charge and decreasing the volumetric charge will tend to lessen member incentives to invest in EE (or solar PV, for that matter). For example, take investing in a LED light bulb. If a cooperative moves from a customer charge of $10 to $30, and its kilowatt-hour charge is reduced from 12 cents to 11 cents, then every kilowatt-hour saved by the LED bulb will now save the member 11 cents rather than 12 cents. This reduces the financial incentives to make EE investments.

A second criticism is that moving to a higher fixed customer charge will harm low-use members, who tend to be lower income. It is true that, in general, increasing the customer charge will tend to harm low-use members disproportionally compared to high-use members. The customer charge portion of the bill is usually a higher proportion of the low-use members' bills (on average) and increasing the customer charge will increase these members' bills by a higher percentage than the high-use member.

However, the correlation with low-use members and income levels is location-specific and not a hard-and-fast truth. While higher income members will tend to live in newer, bigger residences, lower income individuals will tend to live in older, less-insulated residences. Thus, a rate change could be accompanied by a low-income weatherization project or other EE program. A survey or other instrument can help answer the question of the correlation between electricity use and income for your particular cooperative.

A third criticism (which is similar to the first one): increasing the customer charge will not only lower incentives for EE, but also for members' installing rooftop solar. If net-metering is present, or even if the member is just displacing his own usage, the kilowatt-hour volumetric charges serve as the payment mechanism for the rooftop solar production. If cooperatives shift charges from the volumetric charge to the customer charge, the financial incentives of installing rooftop solar are diminished.

These criticisms may be accurate in certain cases, yet the reality is that, by making the rate align more with costs, the cooperative is eliminating a current subsidy, and a change will better align revenue gathering with cost causation. It should also increase the incentive for beneficial electrification, such as the use of electric vehicles.

The traditional high volumetric charges provide a subsidy from high-use members to low-use members. From an economic standpoint, cost-causative rates are preferable. However, cooperatives should be aware of the current reasons for higher volumetric rates and the possible criticisms of eliminating or reducing the low-use subsidies.

Rate Design Based on Marginal Costs

Typically, rate designs should not be changed simply because of one factor. Rate design has multiple goals, and encouraging DSM could be one of those goals. DSM often comes up in the cost-allocation phase of a cost-of-service study when considering an embedded cost allocation versus a marginal cost allocation. Marginal costs also come into play when designing a rate structure for each class. Thus, the notion of the marginal cost of energy is one that can be used for both revenue allocation and rate structure design.

"Cost allocation" refers to the method by which the revenue requirement costs are assigned to different classes or groups of end users. On an "embedded cost" allocation, we start with the actual current costs and assign the costs to rate classes based on the cost-causation principle (i.e., the class that was the "cause" of the costs gets assigned those costs). For example, if smart meters are installed for the residential class, those meter costs are assigned to the residential class. An embedded-cost method is common for cooperatives. This method is back-looking in the sense that it looks at historical costs.

"Marginal cost" allocation, on the other hand, is forward-looking. It is based on the future cost needed to deliver one more kilowatt or kilowatt-hour through the system. This is typically related to the replacement cost of the marginal generating unit. Marginal cost allocation tends to be better at providing price signals to end-users. When supply is plentiful, wholesale energy prices tend to be similar to marginal energy costs. However, in times of high demand, the marginal price goes up and, under a marginal cost allocation approach, this increase would be reflected in the cost allocation to classes of consumers and individual consumers.

The marginal cost method provides better price signals for EE and DR, but there are controversies in how to determine the marginal cost. These controversies are similar to the problems faced in valuing avoided capacity (see **Valuing Avoided Capacity: Demand Response**).

If a cooperative wants to follow the marginal cost allocation method, class revenue requirements would be based on class marginal costs. Within each class, it will move toward a rate structure with energy prices that reflect the marginal cost of energy. A real-time pricing rate would be the "purest" form of this, but a time-of use rate, a critical peak price rate, and a peak-time rebate program would also reflect a marginal cost allocation, at least partially.

Now we see how the marginal cost allocation fits in with DSM. Just as a cooperative could assign costs based on the next kilowatt-hour produced, it can value DSM based on the last kilowatt-hour or kilowatt that was not produced due to the DSM program. Thus, DSM can be valued based on the avoided marginal energy, capacity, and T&D costs required to produce the energy that would have been required.

13 Evaluation, Measurement, and Verification

In This Section:

- EM&V Protocols for Energy Efficiency
- EM&V Protocols for Demand Response
- EM&V Case Study: Heartland Rural Electric's PTR Program

Evaluation, measurement, and verification (EM&V) is a necessary component of any DSM program. Of course, some of the "E" work is done before an EE project is implemented; when cooperatives perform cost/benefit studies, they typically estimate the impact of the programs. However, this evaluation also continues after the program has been implemented, to ensure the effects are occurring as expected.

Cooperatives need to verify that programs are providing the expected reduction in energy and/or demand usage. This is true for any DSM program, but is especially true for any program being used to help delay or eliminate the need for more capacity. If DSM is to be treated as a resource, it should be subject to robust EM&V to make sure it can provide capacity when needed.

EM&V for EE programs and DR programs typically follow the same general principles, although the details can sometimes vary for the two types of programs. The EM&V procedure may also vary, depending on whether the ultimate goal is regulatory compliance, internal capacity avoidance, etc.

EM&V Protocols for Energy Efficiency

There are numerous existing protocols for EM&V of EE programs. Some states have their own protocols.[158] There are also protocols given by government agencies, trade organizations, RTOs, and other entities. Unfortunately, no uniform standard has been widely accepted.

EM&V protocols will vary from state to state, and other non-state protocols may come into play as well. For example, PJM has its own EM&V standards for DSM programs. For EM&V protocol guidance, a cooperative should look to standards recommended by its state and, if the state does not have its own set of recommended standards, look to federal standards.

Instead of picking a particular state's EM&V protocols for illustrative purposes, this *Guidebook* will cover the EM&V principles in general.

[158] See, e.g., California Public Utilities Commission's *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals* (April 2006).

BACKGROUND EM&V CONCEPTS FOR EE PROGRAMS

All EE Savings Values are *Estimates*

There are three basic types of EM&V estimates:

- **Projected Savings**: values reported by a program implementer or administrator before the efficiency activities are completed.
- **Claimed Savings**: values reported by a program implementer or administrator after the efficiency activities have been completed, prior to independent evaluation of savings.
- **Evaluated Savings**: values reported by an independent third-party evaluator after the efficiency activities and an impact evaluation have been completed.[159]

Projected savings evaluate EE impacts *before* the program is instituted; claimed savings and evaluated savings take place *after* the program is implemented. In all cases, these savings are estimated, rather than directly measured. This is because the savings rely on what energy usage *would have been* in the absence of EE programs, as indicated in Figure 13.1,[160] and it is impossible to directly measure what energy usage would have been.

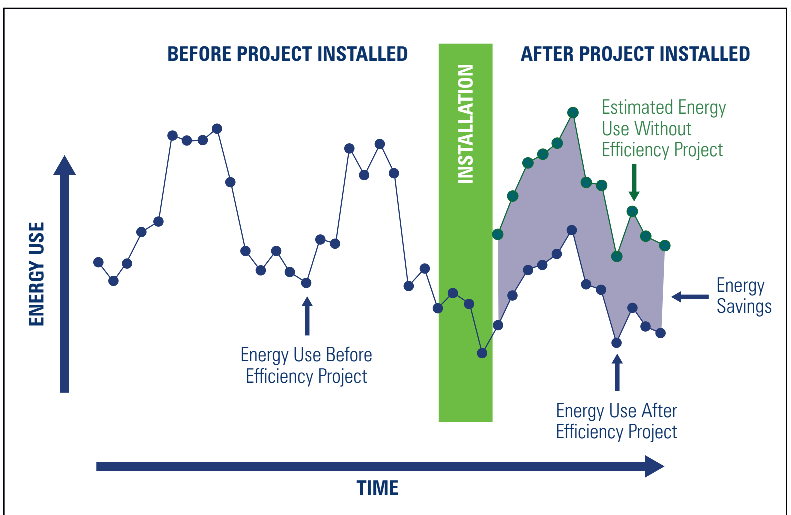

FIGURE 13.1: Energy Use Before, During, and After an Energy Efficiency Project is Installed

Range of EE EM&V Budgets

Studies show that the average EM&V budget is around 3.6% of a utility's total EE budget, with a range of 2% to 6%.[161]

When planning EE programs, cooperatives should try to make specific budget projections whenever possible. However, for "rough draft" purposes, cooperatives could budget between 2% to 6% of their EE budget for EM&V.

EPA DRAFT EM&V GUIDE

A draft guide prepared by EPA suggested three main strategies for quantifying kilowatt-hour savings of EE programs:

1. **Deemed Savings** are estimates for a single unit of an installed EE measure that has performed in the past using widely accepted methods. The per-unit kilowatt-hour values are determined prior to EE implementation. For example, if an acceptable study has shown that installing an electric water heater with a certain SEER rating saves X kWh per year over the average replaced electric water heater, then X kWh/year is "deemed" to be the savings of one such installed water heater.
2. **Project-Based Measurement and Verification** means "the process of determining savings from an individual EE measure or project (versus an EE program)." This involves direct observation of installed equipment. An example would be measuring the kilowatt-hours used for an irrigation pump before and after an efficient pump is installed.
3. The **Comparison Group Method** compares the electric use of two groups, one with the measure and one without. For example, a group of homes and businesses using one building code could be compared to a group that did not use the code. Statistical techniques such as regressions are used to estimate the impact of a single measure.

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159 *Ibid.*, p. 37.

160 *Ibid.*, p. 38.

161 *Ibid.*, p. 39 (citing Wallace, P.; Forster, H.J. *State of the Efficiency Program Industry Budgets, Expenditures, and Impacts 2011.* Consortium for Energy Efficiency, 2012). This budget percentage includes EE EM&V only, not DR EM&V.

The EPA Draft EM&V Guide gives Table 13.1 to determine which method is appropriate in which situation.

DEEMED SAVINGS

The EPA Draft EM&V Guide definition of deemed savings is:

> *Deemed savings values are estimates of electricity savings for a single unit of an installed EE measure that (1) has been developed from data sources (such as prior metering studies) and analytical methods that are widely considered acceptable for the measure and purpose, and (2) is applicable to the situation under which the measure is being implemented. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. With deemed savings, the per-unit MWh values are determined and agreed to by parties prior to EE implementation.*[162]

TABLE 13.1: Applicability of EM&V Strategies

Situations or Conditions for Applying EM&V	General Category of EM&V Method		
	Comparison Group	PB-MV	Deemed
Individual project	Method not applicable	OK	OK
Large numbers of relatively homogeneous participants (e.g., residential, small commercial)	Method requires this condition	OK	OK
Well-defined, simple, consistent EE measures and conditions	OK	OK	Method requires this condition
Large savings per participant, or very large number of participants	Method requires this condition	OK	OK
Inconsistent measures and conditions across units	OK	OK	Method not applicable
Complex, unique measures	Method not applicable	Method is required for this condition	Method not applicable
Valid comparison group can be defined	Method requires this condition	OK	OK
EE program contributes relatively little savings to total EE provider/ EE portfolio	Method cost may not be justified	Method cost may not be justified	Method may be preferred
EE program contributes relatively large savings to total EE provider/ EE portfolio	Method is recommended if method requirements are also satisfied	Method is typically recommended	Method is not typically recommended

The EPA's shorter definition is: "measure-specific stipulated values based on historical and verified data (in some cases using the results of prior EM&V studies)."

The deemed savings approach will be appropriate for many cooperative-wide EE rebate programs. In this method, one "average" appliance or piece of equipment is replaced with an efficient version and this process is repeated over a large number of members. An example of this would be a rebate for an air conditioning unit with a certain SEER rating. However, note that, if this program contributes a "relatively large" amount of savings to the EE portfolio, the comparison group method may be recommended instead.

The deemed savings approach can save costs in an EM&V effort. A cooperative would use a database to ascertain the effect of a certain EE measure. In other words, the cooperative doesn't make any measurements itself, but rather deems the savings to be the value supplied by the database. In our example—a rebate program that applies to a specific energy-efficient air conditioner—

[162] EPA Draft EM&V Guide, *Op. cit.*, p. 8.

the cooperative would look up the specific air conditioner in a database and multiply the deemed energy savings per air conditioner by the number of units installed. The deemed savings databases typically compare the new, efficient appliance to a generic, inefficient appliance.

Sample Deemed Savings Databases

Different states use different deemed savings databases. One well-established deemed savings database is CPUC's Database for Energy Efficient Resources (DEER). A good source for determining your state's preferred database, if any, is the ACEEE.[163] At the ACEEE website is a **downloadable Excel sheet** with summaries of state EE programs. Columns AD through AJ of that spreadsheet summarize some salient facts about each state's preferred EE programs. The ACEEE also has links for each state, including EM&V regulations, technical reference manuals, and more at: **http://database.aceee.org/state/evaluation-measurement-verification**.

Taking Wisconsin as an example, the ACEEE spreadsheet reveals that Wisconsin's IOUs fund an organization called "Focus on Energy," which administers their EE programs. The ACEEE link above gives links to the Focus on Energy website "**Technical Reference Manual**" for Wisconsin. The TRM lists deemed savings values for different commercial and residential measures. Sometimes there is a general deemed value, but often there is instead a formula, where the utility fills in some specifications of the new measure and the measure being replaced.

For example, for the commercial measure "Compressed Air Mist Eliminator," the Focus on Energy TRM gives an annual kilowatt-hour savings of 71 kWh/horsepower and demand savings of 0.014 kW/horsepower. The TRM gives a description of the measure and the assumptions that went into the deemed savings.[164]

Some deemed savings manuals can be quite complex for certain measures. For example, the CPUC system is quite comprehensive but can take a fair amount of effort for utilities to learn to use. The CPUC has a software interface called "READI," which allows users to select measures, enter certain inputs, and calculate energy or demand impacts.[165] Find out which deemed savings database your state commission recommends before learning the ins and outs of a new system.

It is important to remember that, while deemed savings databases are often used for EM&V, they are also used for planning purposes (i.e., potential studies).

Issues with Deemed Savings

The more detailed a deemed savings method is, the more precise it will be in its impact measurements. For example, if a cooperative has a rebate program for energy-efficient residential electric clothes dryers, the cooperative could individually track the efficiency and size of each dryer purchased under the program and compare those values to an "average" efficiency dryer of that size. Some dryers will meet the minimum efficiency standard needed to get the rebate and some will exceed the minimum standard. Dryers will also be different sizes. However, this tracking is not feasible in most cases.

The alternative to a detailed approach is to simply make estimates about the "average" purchase of a clothes dryer. In this approach, you estimate the average size of a residential electric dryer, the average efficiency of a dryer deemed efficient enough to receive the rebate, and the average efficiency of a dryer purchased with no rebate. Using this simple method, you get a single "kilowatt-hour saved" value for each dryer in the rebate program and multiply the number of rebates by the kilowatt-hour value to get the total kilowatt-hours saved by the program.

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[163] The ACEEE site is: http://database.aceee.org. Another reference source for state and regional technical reference manuals is CRN's "Ask the Expert" from January 2014, titled "Technical Reference Manuals for Demand-side Management Savings."

[164] PSC of Wisconsin. *Wisconsin Focus on Energy: Technical Reference Manual*, January 2015, p. 24.

[165] See CPUC/DEER website (may require log-in, which is free).

There is no individual tracking of what appliances are actually purchased under the rebate (other than making sure they meet the efficiency standard to get the rebate), and this saves cooperatives time and money. However, the accuracy of the energy savings is lowered.

Another issue with deemed savings databases is that many efficiency measure impacts vary by climate zone. The CPUC DEER database is designed to have California climate zones as inputs. Cooperatives should consider using a deemed savings database that is specific to their climate zone, if possible. Again, look to your state utility commission for guidance on this issue.

Similar tradeoffs exist when selecting a deemed savings database. The CPUC DEER database is very detailed, but it requires some training to learn how to use it. A simpler database is easier to use, but may be less accurate.

If cooperatives have any intention of exploring EE in an RTO capacity market, the RTO will have some EE EM&V protocols. But those may be geared more toward EM&V of EE as a capacity resource, rather than kilowatt-hour deemed savings.

If your state commission gives no guidance, pick a deemed savings database that matches: (1) your climate zone to the extent possible, and (2) your comfort level with detailed EE specifications (CPUC DEER for sophisticated programs, something simpler for more basic EE programs).

PROJECT-BASED MEASUREMENT AND VERIFICATION; COMPARISON GROUPS

For large, unique EE measures, the project-based measurement and verification (PB-MV) method is recommended by the EPA. An example of this would be an EE retrofit of a university or hospital. This retrofit would not be able to use a national database, since universities and hospitals are so different. A certain amount of deemed savings might be able to be used for some parts of the retrofit (e.g., replacement of incandescent bulbs with CFLs or LEDs), but, in general, specific measurements may have to be made of some of the bigger EE measures.

In most PB-MV cases, a baseline will be established, then post-program energy usage will be compared to the baseline. The EPA defines EE savings as the difference between observed electric usage and a "common practice baseline" (CPB). The EPA Draft EM&V Guide gives guidance on CPBs in section 2.2.2, and PB-MV in general in section 3.2.

When using the PB-MV approach, look to a national standard, such as the following:

- International Performance Measurement and Verification Protocol (IPMVP, an international PB-MV guidance document)[166]
- Federal Energy Management Program (FEMP) protocols and guidelines[167]
- American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) protocols and guidelines[168]
- U.S. Department of Energy's Uniform Methods Project (UMP): Methods for Determining Energy Efficiency[169]

The comparison group EM&V method will probably not be used by cooperatives very often. An exception is when the following apply:

- A valid comparison group can be defined.
- The program participants are relatively large in number and relatively homogeneous, such as residential or small commercial customers.
- The magnitude of expected savings is large compared to the expected random differences between the participant and comparison group averages.[170]

The EPA Draft EM&V Guide also offers many guidelines and protocols regarding expected useful life, line losses, and other metrics.

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[166] See www.evo-world.org.

[167] See www.energy.gov/eere/femp/downloads/mv-guidelines-measurement-and-verification-performance-based-contracts-version.

[168] See www.ashrae.org.

[169] See www.energy.gov/eere/about-us/ump-protocols.

[170] EPA Draft EM&V Guide, *Op. cit.*, p. 9.

EM&V Protocols for Demand Response

The EM&V protocols used for DR use some of the same principles as those used for EE, but the details can vary quite a bit. DR usually has "reducing peak demand" as its focus, so the issue is determining how much demand was reduced by the DR program in question. Just as with EE, the central "measurement" in DR EM&V is determining what the load would have been in the absence of the DR program.

Cooperatives can measure the actual load when a DR program is running, but they cannot directly measure what the load would have been in the absence of the program. This estimate of what the load would have been is often called the baseline. The effectiveness of the DR program is determined by subtracting the baseline load from the actual metered load.

In some circumstances, cooperatives can calculate the baseline easily. For example, consider a direct load control program whereby your cooperative can instantaneously shut off irrigation pumps during critical peak times. If you are confident about the technical specifications of the program, you can calculate the effect of the irrigation load control program with a good degree of precision. If you knew: (1) the load profile of each controlled pump, (2) that all load control devices are working properly, and (3) that all controlled pumps would be running in the absence of the program, then you could easily calculate the effect of the program. If you had 10 pumps on the program, and they would all be running at 5 kW each during peak hours, then you would cut 50 kW at peak by turning the pumps off. You might call this the "mere addition" method; to get the baseline, you merely add the kilowatts of all the controlled units to the measured load.

Most programs are not that simple, however. Consider a residential direct load control program, wherein the cooperative remotely shuts off air conditioners during peak hours. The following issues can all result in a baseline that is hard to calculate:

- Some load control devices may malfunction, or be disabled/bypassed by the consumer.
- Some consumers might run window units, thus "gaming" the load control program.
- AC kilowatt loads may vary from household to household.
- AC kilowatt loads within a single household will not be constant (e.g., the compressor cycles on and off).
- There is a chance that, even in the absence of the program, some AC units would not be running at peak time.

These and other factors make it more difficult to determine the baseline for a single residential AC load control participant, let alone a group of 1,000 participants. Complicating matters further is that many AC load control programs are cycled; that is, during peak hours the units are controlled on a schedule such as "15 minutes on, 15 minutes off." During the "15-minutes on" cycle, sometimes the AC compressor will only be on part of the time. For these reasons, it can be difficult to establish baselines for DR programs.

THE DUAL PURPOSE OF BASELINE CALCULATIONS

It should be noted that often there are two main purposes behind EM&V for DR programs: estimating the impact of a program as a whole, and determining the impact of each end-user's reduction so that payments can be made. For example, consider a DR "aggregator" who enlists 1,000 people into a load control program, then sells that capacity to PJM in the capacity market. From PJM's perspective, the main concern is that, when the aggregator "presses the button," the promised reduction in load occurs. Here PJM is concerned mainly with the baseline of the 1,000 program participants as a group. However, the "aggregator" may be interested in how much demand reduction each of the participants provided, in order to properly pay each participant.

These two purposes can necessitate different strategies in conducting a demand response EM&V. Furthermore, the desire for accuracy may vary depending on a program's use. When financial rewards to consumers or aggregators are an output of the EM&V, more sophisticated and accurate methods should be used.

METHODS OF CALCULATING BASELINES

Given the difficulties mentioned above, other methods beyond mere addition are used for calculating what energy use would have been in the absence of DR programs. There are three

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FIGURE 13.2: Three Baseline Calculation Methods

primary types of DR EM&V methods: day matching, difference-in-difference, and regression techniques. The regression technique is usually the most accurate and the most sophisticated.

Day Matching involves examining the hourly metered loads in days prior to a DR event and using previous days to formulate the baseline load. The day matching can be done either at each individual meter or using an aggregated set of meters all on a given program.

A simple day matching technique used by MISO is to average the last 10 "similar" days to set the baseline load during the DR event hour.[171] Day matching techniques can get progressively more complicated. For example, rather than the last 10 days, the baseline could include those same 10 days but only use the highest loads for 5 out of 10. Another common method used by other utilities uses the highest load in X of the last Y days; for example, PJM uses the highest 4 of the last 5 weekdays.[172]

Other modifications of day matching techniques can include a "morning adjustment" or "weather adjustments" that ramp up or ramp down the baseline based on event day usage prior to the baseline hour, or based on the weather during the event day relative to weather during the baseline days.

Day matching techniques can provide decent "ballpark" impact measurements, but can also be quite inaccurate at times. DR events are usually called during the hottest (or coldest) days and hours. Using historical usage during milder hours can underestimate DR impacts. Using day matching techniques for financial payments, such as in a peak time rebate program, can also open up the possibility of gaming.

Difference-in-Difference is a method that can be used to test the impacts of the program if data is available for both DR participants and non-DR participants before and during an event.[173] The difference-in-difference method is a nonparametric analysis which examines the differences in the DR and non-DR groups both prior to and during event hours. The advantage of this method is that it is relatively simple to understand and is a powerful tool in evaluating program impacts. It has an advantage over day matching techniques because it is able to correct for weather and other event day differences due to the inclusion of the non-DR group in the analysis.

In algebraic terms, for the difference-in-difference method the impacts are calculated using the following formula:

$$\mathit{Impact} = (DR_{event} - NDR_{event}) - (DR_{prior} - NDR_{prior})$$

Where:

DR_{event} = Average DR participant load during an event hour

NDR_{event} = Average non-DR participant load during an event hour

DR_{prior} = Average DR participant load during non-event hours (typically average of a number of similar non-event hours)

NDR_{prior} = Average non-DR participant load during non-event hours

The **Regression** EM&V method is typically the most accurate method; it uses econometric techniques to measure the hourly impacts of DR programs. The technique measures the impact of variables such as temperatures, day of week, hours, prior temperatures and loads, etc., to estimate a baseline. The technique can be used

[171] By "similar" we mean if the DR event day is a non-holiday weekday, then the 10 days included in the baseline should be the last 10 non-holiday weekdays. Similarly, if the event day is a weekend, then only weekend days should be included in the last-10-days baseline. This is a slightly simplified version of the MISO method; see the *Demand Response Business Practice Manual* for more details (BPM-026, effective date: APR-01-2013, section 4.8.1.3.2).

[172] See PJM *Manual 11: Energy and Ancillary Services Market Operations*, Revision: 77, Effective Date: August 27, 2015, p. 125.

[173] The difference-in-difference method can also be used for evaluating EE program impacts.

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for an individual meter or an aggregated group, or can use a panel data set that includes both DR participants and nonparticipants.

The technique is more sophisticated than either the day matching or difference-in-difference methods. In most cases, it is more accurate, due to its ability to include and adjust for a number of relevant variables.

The method can also provide valuable information on the impacts of the included variables. For example, this method can quantify how much residential load is expected to increase as temperatures increase by one degree.

For applications that involve financial payments or using DR to avoid capacity, using the regression approach is recommended. If cooperatives are fine with ballpark estimates that may have a higher degree of error, either the day matching or difference-in-difference methods can be used.

The next section describes a regression evaluation conducted by PSE for a cooperative's PTR program.

EM&V Case Study: Heartland Rural Electric's PTR Program

Heartland Rural Electric Company is a distribution cooperative in Southeastern Kansas with around 11,500 members. Heartland's G&T is Kansas Electric Power Cooperative, Inc. (KEPCO). In 2011, Heartland partnered with Power System Engineering, Inc. (PSE), to pilot a PTR program and, in 2012, the program was offered to the entire residential population. By 2014, Heartland had more than 2,400 residential members on the "PeakSavers" PTR program, which had expanded to include selected C&I members as well.

The program details of the Heartland PTR program are described in a CRN *TechSurveillance* article, "Peak-Time Rebate Programs: A Success Story."[174] This section describes how the impact evaluations were conducted both on an individual participant basis and on a system-wide basis.

PARTICIPANT BASELINES FOR REBATE CALCULATIONS

For the Heartland PTR program, Heartland and PSE worked together to develop defensible and accurate baseline calculations. Fair and accurate baselines are crucial to customer acceptance of PTR programs. Participants who make considerable reductions during event days will certainly expect to be compensated for their efforts. For this reason, the Heartland program uses individual participant regressions to estimate each individual's baseline and formulate the rebate amounts.

In 2014, PSE estimated more than 2,400 separate regression equations, one for each participant in the program. The same variables and functional forms were used for each participant. Hourly weather data was gathered from the Joplin, Mo., weather station. Some of the variables that were included and, thus, adjusted for in the baselines were:

- Binary variable if there was an event that day (0 = not an event day, 1 = event day)
- Binary variable if the day was a weekday or weekend (0 = weekend, 1 = weekday)
- Hourly air temperature
- Hourly wind speed
- Hourly humidity
- Morning electricity usage
- Variables for hours of the day
- Variables for hours of the day during events between 2:00 p.m. and 10:00 p.m.

Using these regressions, we can estimate what each member's electricity usage would have been absent an event. The difference between the baseline and the actual metered usage is then used to formulate the amount of energy each individual curtailed during the event hours.

A very interesting result was that most of the impacts came from less than 50% of the participants. In fact, nearly half of the PTR impacts came from only about 10% of the participants.

[174] Williams, Dave, et al. *Peak-Time Rebate Programs: A Success Story. Op. cit.*

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SYSTEM-WIDE PTR IMPACTS

The system-wide PTR impacts are also measured using a regression-based approach. This provides Heartland with a solid understanding of the benefits of the program. The regression approach is similar to the individual baseline approach described above, except all of the available data is now used in one regression.

As seen in Figure 13.3, 2014 included only two event days (July 22nd and July 25th). On each day, there were four event hours (Hours 16, 17, 18, and 19). The baseline is the zero axis.

The average reduction for the two days was around 0.28 kW. However, the actual system-wide peak hour was measured to be reduced by 0.32 kW per participant. Notice that, with a PTR program, you can see some variance in impacts between hours and between the specific event days.

Figure 13.3 serves as an example of the results of an EM&V effort for a PTR program.

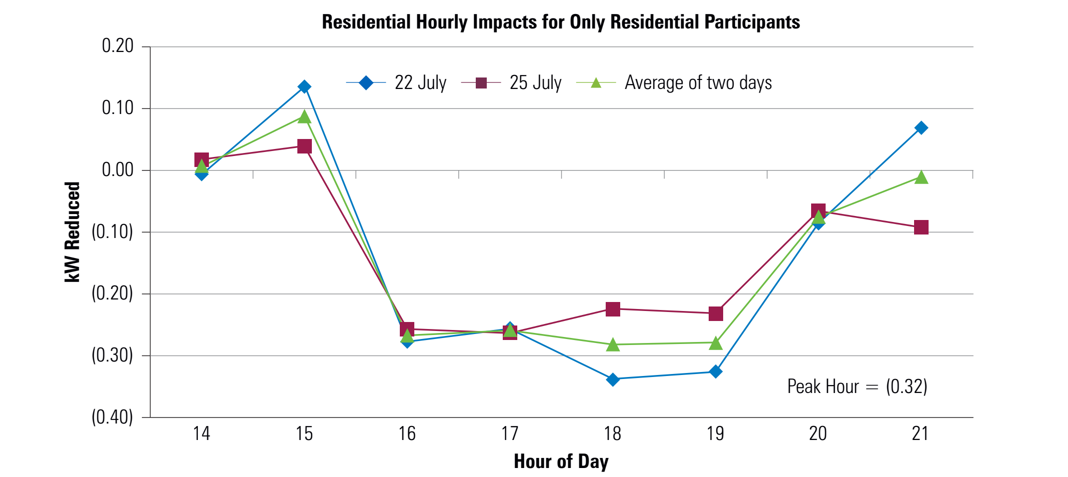

FIGURE 13.3: Heartland 2014 PTR Peak Reduction

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15 List of Abbreviations and Acronyms

AC	Air Conditioning
ACEEE	American Council for an Energy-Efficient Economy
AEO	Annual Energy Outlook (from EIA)
AESC	Avoided Energy Supply Components
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BEV	Battery Electric Vehicle (i.e., no gasoline)
BRA	Base Residual Auction
BTS	Business and Technology Strategies (NRECA)
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CALMAC	California Measurement Advisory Council
CFL	Compact Fluorescent Light Bulb
C&I	Commercial and Industrial
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPB	Common Practice Baseline
CPP	Critical Peak Pricing
CPUC	California Public Utility Commission
CRN	Cooperative Research Network (now NRECA's Business and Technology Strategies Group)
CSP	Curtailment Service Provider (PJM)
DADRP	Day Ahead Demand Response Program
DEER	Database for Energy Efficiency Resources (California)
DG	Distributed Generation
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
DRAM	Demand Response Auction Mechanism
DRMS	Demand-Response Management System
DSASP	Demand Side Ancillary Services Program
DSM	Demand-Side Management
EEC	Energy Efficiency Certificates
EEI	Edison Electric Institute
EERS	Energy Efficiency Resource Standard
EDRP	Emergency Demand Response Program
EGU	Electric Generating Unit
EIA	U.S. Energy Information Administration
EKPC	East Kentucky Power Company
EM&V	Evaluation, Measurement, and Verification (also see M&V)
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUL	Effective Useful Life
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission
GHG	Greenhouse Gas
GRE	Great River Energy
HAN	Home Energy Network
HEM	Home Energy Management
HEV	Hybrid Electric Vehicle
HVAC	Heating, Ventilation, and Air Conditioning

ICAP Installed Capacity Market
IOU Investor-Owned Utility
IRP Integrated Resource Planning (or Plan)
ISO Independent System Operator (see also RTO)
ISONE ISO New England (an RTO)

kW Kilowatt
kWh Kilowatt-Hour

LCOE Levelized Cost of Energy
LED Light-Emitting Diode
LMP Locational Marginal Price (used by RTOs/ISOs)
LMR Land Mobile Radio
LSE Load-Serving Entity

M&V Measurement and Verification (see also EM&V)
MDMS Meter Data Management System
MISO Midcontinent Independent System Operator (an ISO/RTO in the central U.S. and Canada)
MW Megawatt
MWh Megawatt-Hour

NAPEE National Action Plan for Energy Efficiency
NEB Non-Energy Benefit (see also OPI)
NEEA Northwest Energy Efficiency Alliance
NEEP Northeast Energy Efficiency Partnerships
NEI Non-Energy Impact
NERC North American Reliability Corporation
NO_x Nitrogen Oxides, such as NO and NO_2
NPV Net Present Value
NTG Net-To-Gross Ratio
NYISO New York Independent System Operator

O&M Operations and Maintenance
OPI Other Program Impacts (used in cost-benefit tests; see also NEB)

PACT Program Administrator Cost Test (see also UCT)
Pb Lead
PB-MV Project-Based Measurement and Verification
PCT Participant Cost Test
PEV Plug-In Electric Vehicle
PHEV Plug-In Hybrid Electric Vehicle
PJM PJM Interconnection (an RTO serving the eastern U.S.)
PM10 Particulate Matter Less Than 10 Microns in Size
PSC Public Service Commission
PSE Power System Engineering, Inc.
PTR Peak-Time Rebate
PUC Public Utilities Commission
PV Photovoltaic (in reference to solar power; also see PV below)
PV Present Value (also see PV above)

REC Renewable Energy Certificates
REP Retail Electric Provider
RIM Ratepayer Impact Test
RPM Reliability Pricing Model (used by PJM)
RTF Regional Technical Forum
RTO Regional Transmission Organization (see also ISO)
RTP Real-Time Pricing

SCDE Security Constrained Economic Dispatch
SCR ICAP Special Case Resources
SCT Societal Cost Test
SEER Seasonal Energy Efficiency Ratio (used for appliance efficiency ratings)
SFV Straight-Fixed Variable (charge)
SIP State Implementation Plan
SO_2 Sulfur Dioxide
SO_x Sulfur Oxides, such as SO and SO_2
SPP Southwest Power Pool (an RTO)
SPM Standard Practice Manual (California)

T&D Transmission and Distribution
TOU Time-of-Use (usually in reference to rate structure)
TRC Total Resource Cost Test
TRM Technical Reference Manual
TSD Technical Support Document (used with CPP rules)

UCT Utility Cost Test (see also PACT)

VFD Variable Frequency Drive
VPP Variable Peak Pricing

WACC Weighted Average Cost of Capital
WH Water Heater

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