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Commercial Demand Response—Basics and Beyond

BY **DAVID HOUGHTON**, P.E., RESOURCE ENGINEERING GROUP AND
LAURA MOOREFIELD, MOOREFIELD RESEARCH & CONSULTING
MAY 2014

Demand response programs serve a necessary role in the electrical system. When generation and transmission (G&T) resources are near their limits, the choice is often to import expensive power or run costly peaking plants. Taking action on the other side of the meter can be very cost-effective in comparison. This report provides an overview of existing and emerging commercial demand response programs, with examples and lessons learned from cooperative, public, and investor-owned utilities.

The idea of controlling electrical loads is not new, but modern communication and grid technologies offer possibilities that make it even more attractive, while providing multiple benefits for co-ops. Demand response—also called load control, load curtailment, peak shaving, or the abbreviation DR—has applications in all customer segments. Commercial DR is often the most compelling, since that sector can generate large results with relatively few transactions.

DEMAND RESPONSE BASICS

What exactly is demand response? According to the FERC,[1]

> *An electric demand-response activity is an action taken to reduce electricity demand in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices.*

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[1] Federal Energy Regulatory Commission, "Assessment of Demand Response & Advanced Metering," Staff Report, September 2007, www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf, page i.

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Demand response can be viewed as part of a spectrum of actions to reduce energy use during a specific timeframe. Figure 1 shows that DR events typically reduce load for periods of six hours or less. Demand response actions can include:

- **Shifting loads from electric to other fuels.** "Dual-fuel" equipment, such as compressors and transportation systems, can temporarily switch to alternative shaftpower, usually from natural gas or diesel engines.
- **Interruptible Air Conditioning.** Buildings can often coast through peak load periods without running chillers or compressors.
- **Variable air volume (VAV) system pressure reduction.** Air-handling systems with variable-speed drives can reduce duct pressure by 10–20 percent. Because of the "cube law" that applies to fluid systems, this can result in power reductions of up to 50 percent. This turndown can often be done with little or no impact to occupant comfort, especially if the time period is short (one hour or less).
- **Pump speed reduction.** Similarly, systems that circulate chilled water, hot water, and condenser water can slow down to reduce power consumption without compromising performance, using the inherent thermal mass in cooling and heating circuits.

Energy Efficiency	Permanent Load Shifting	Demand Response
• 8,760 hrs/yr • Reduced usage all year	• 120–1,000 hrs/yr • Move load from summer on-peak periods	• 2–6 hrs/event • 2–20 events per summer • Reduced usage when requested

FIGURE 1: Comparison of Demand Response to Other Load Management Measures. *Credit: Ryan Hoest, EcoVox*

- **Pump scheduling.** Pumps that lift liquids to storage tanks are essentially storing gravitational energy, a task that can be deferred to off-peak hours.
- **Chilled water reset.** Another incremental Heating, Ventilation, and Air Conditioning (HVAC) load reduction, a chilled water temperature setpoint increase temporarily reduces chiller operation.
- **Ventilation control.** Restricting outside air ventilation can reduce cooling demand, especially if normal operation provides more outside air than required by code.
- **Lighting dimming.** Reductions of 10–20 percent in electric light output can shed significant load, often without being noticed by occupants.
- **Shutdown of non-essential equipment.** This might include devices such as refrigerated vending machines, decorative lighting, or landscaping fountains.
- **Production scheduling.** Batch-production facilities may adjust their schedules to take advantage of demand control events.
- **Battery charging.** Commercial customers such as golf courses can forgo battery charging during peak periods.

In contrast to demand response, *permanent load* shifting uses equipment that runs off-peak every day during peak demand seasons, usually through thermal storage. Examples include chilled water and ice storage for commercial buildings in cooling climates, and electric thermal storage in heating climates. This equipment typically does not respond to a call from utilities, but includes controls that prevent the load from turning on during the hours of the day when they would contribute to peak demand. *Interruptible loads* are a variety of demand response that typically involve shutting down industrial operations or shifting loads from electricity to other fuels. *Energy efficiency* measures also reduce demand, but fall into a different category

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since they tend to save energy (kWh) and power (kW) throughout the year, regardless of the utility's load.

DEMAND RESPONSE PROGRAM MECHANICS

Like all utility programs, commercial demand response programs consist of several elements, from the technical aspects of identifying which loads to control and how, to participant payment schemes, program management, and marketing plans. In addition, while DR programs are effective at reducing demand, they may have unintended consequences for sites that need to be considered, such as increasing overall energy use.

Control method

In the early days of demand response, a load reduction event precipitated phone calls, faxes, or pager notices to program participants, who then could decide whether or not to take action. This *manual control* method still exists—although the communication paths have been updated—but has been largely eclipsed by *automated control*, where equipment is directly controlled by the utility or a third-party. Manual control has the advantage of simplicity, and does not require any special equipment. Automatic control offers a faster and more certain response.

Payment schemes

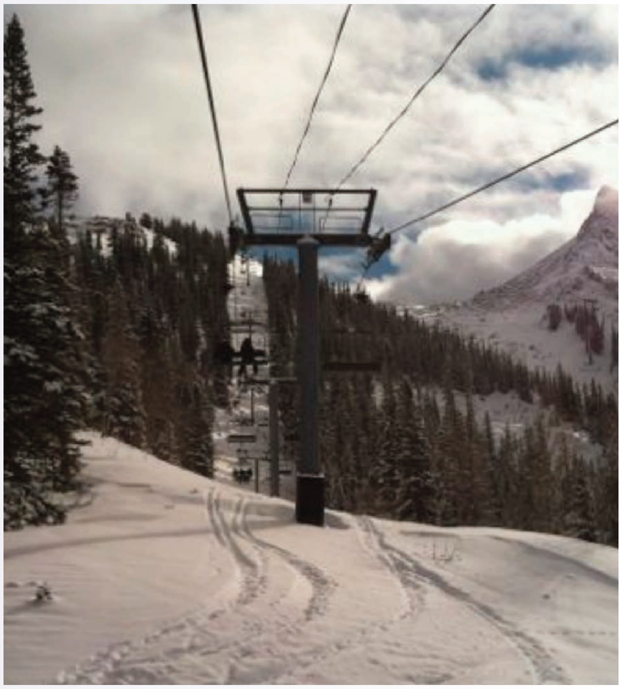
Utilities can offer several types of economic incentives for demand response participants.

- **Rate-based incentives.** Rates such as time-of-use or critical peak pricing alone can be enough to encourage demand response, especially if combined with a ratchet that extends the effective cost of a member's coincident peak use.

Manual Load Control Case Study: Chairlifts Provide Gunnison County with Several MW of Demand Reduction.

Gunnison County Electric Association is a rural winter-peaking retail co-op with about 14,000 meters, mostly residential. One commercial member, however, is the single biggest customer—the local ski area, with several megawatt-plus chairlifts, as well as large compressors and pumps for snowmaking. The chairlifts run primarily with electric motors, but diesel backup engines can be activated for safety in case of power outages, or for demand response during peak load events. With one phone call, the ski area could shed nearly 7MW of load—about 23 percent of the total utility peak—within 15 minutes. The load response reduced peak demand for the G&T, trimmed the monthly demand charge for the retail co-op, and saved the member thousands of dollars in peak demand charges. Usually, an hour or two of diesel operation was all that was required, several days each winter.

Note: Rate structure changes have alleviated this situation; however it still stands as an interesting example of the demand response.



- **Cost sharing.** The utility may offer to share in the cost of installing demand response equipment. This usually involves communication and control systems, but may also include retrofits to HVAC or lighting systems such as variable-speed motors or dimming ballasts.
- **Monthly payment for having DR "on call."** This is an attractive option for the customer, since they get paid just for having available DR resources, whether or not they have to be controlled. This can also be looked at as a "reverse demand charge." Customers electing this option often face the potential for Non-Performance Penalties, if they fail to curtail during a called event.
- **Payment by DR event.** In this arrangement, each call to shed load results in a payment to the member per kW reduced. The amount of the payment is typically similar to the monthly demand charge per kW. The payment can be applied as a credit to the member's bill or sent out as a check.
- **Payment/penalty by DR event.** Payment programs may also include a penalty, if the load is not reduced per the agreement. Since these contracts include a downside, the payment for performance is often higher than with non-penalty agreements.
- **Capacity bidding.** Members, utilities, or load aggregators may bid blocks of demand response into capacity auctions at the ISO/RTO level, just like supply resources. This requires some expertise in power contract management and is more applicable to G&T co-ops than retailers.

Program management

Utilities can develop and manage their own demand response programs, or they can outsource this effort. Third-party companies have developed mature businesses that market and execute DR programs. These offerings can target different market sectors and work at whatever scale is appropriate for the situation. Examples include firms such as EnerNOC, Energy Curtailment Specialists, and Constellation Energy.

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Energy impacts—playing catch-up

Demand response may or may not result in lower overall energy use. Most DR measures create short-term postponement of electrical loads that are offset by load increases before or after the demand-response event. In some cases, demand response may actually result in a net increase in energy use, although the demand savings reduce the cost of that energy.

When DR actions forgo a service that must be compensated for after the event, a period of catch-up ensues, referred to a "snapback." Chillers will run longer and harder, production will ramp up, or battery chargers will come back online. DR program staff and members need to be sure that the controlled systems have the capacity to get back to normal operation, usually through a combination of analysis beforehand and observation after the fact. Demand response actions that result in unhappy or underserved members won't last long.

Marketing

Commercial demand response can be marketed through channels including direct mail, emails, newsletters, and website offers. Larger customers can be approached through key account managers, where relationships can be built on participation in other programs. While mass media outreach is more appropriate for residential program marketing, commercial members are generally smaller in number, so a more targeted approach makes sense.

Members may have different interests in joining a DR program—for some the attraction might be reliability, while others will appreciate a path to upgrade older equipment. Often, DR can be packaged with other programs, including rebates, or the installation of new, controllable equipment.

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It's safe to say that all members will appreciate an opportunity to reduce their energy bills through DR programs. However, some members may value predictability more than deep savings. Those with full-time facility managers may be willing to manage their participation, while others will want to be "hands off."

Explaining demand response to customers can be difficult. For example, says Eric Linkugel, Energy Solutions & Service Manager for Pacific Gas & Electric, "I might go over our DR programs with a fish store owner, but he might not understand it all—his business is fish," not energy management.[2] Many commercial members are in the same boat—they want reliable service and low bills, but don't necessarily want to wade through all the details.

CO-OP DR CASE STUDY: AGRICULTURAL PUMPING

Midwest Energy, a retail co-operative based in Hays, Kansas, started an agricultural pumping demand response program in 2009. About 15 percent of Midwest Energy's 380MW peak load is due to highly coincident agricultural pumping (Figure 2). The typical irrigation account is a single 45hp well pump that pushes water through a center-pivot sprinkler system.

FIGURE 2: A Center-Pivot Sprinkler System.
Photo: Michael Volker, Midwest Energy

Because the utility is vertically integrated (they own most of their own peaking generation) and capacity-constrained during summer peaks, they reap the benefits of their own DR efforts. Midwest's Michael Volker, Director of Energy & Regulatory Services, worked with Judd Moritz of EnerNOC, a demand-response aggregator, to design a program (called Pump$mart) to cost-effectively take the pumps off peak.[3]

Volker pitched the program to their irrigation members—about 2,000 accounts representing some 60MW of total load. The upside to the farmers: earn up to $28 per kW per year (nearly a thousand dollars per pump) by agreeing to turn their pumps off for four hours at a time during peak events. The co-op promised a maximum of 20 events per year, and no more than a total of 80 hours per year of interruption. To make it even more palatable for farmers, up to three events can be bypassed per year, although they earn more if they don't bypass.

The pilot program proved popular—2MW of pumping were signed up the first year. The utility has added more members each year since, and now over 23MW of pumping (close to half of the entire sector) are subscribed under DR control. John Blackwell, a farmer with six thousand acres of crops and twelve center-pivot irrigation systems, likes the program, saying, "Pump $mart gives irrigators more options to save money and manage their water use."[4]

The hardware and software for the system—electrical contactors and communications gear

[2] Eric Linkugel, Manager, Energy Solutions & Services, Pacific Gas & Electric Company, EPL3@pge.com, (805) 595-6335, personal communication, 10-4-2013.

[3] Michael Volker, Director of Energy & Regulatory Services, Midwest Energy, mvolker@mwenergy.com, (785) 625-1476, personal communication, 10-18-2013.

[4] John Blackwell, Director, Midwest Energy, personal communication, 11-5-2013.

for each controlled pump—are installed by EnerNOC, which also assists Midwest Energy in program marketing. DR events are planned by the utility staff at least two hours and often one day ahead, and initiated by a phone call to EnerNOC, who then contacts participating members at least twice through a combination of text messaging, email, or voicemail. At the appointed event start time—always in the afternoon, EnerNOC shuts down the pumps. One more message goes out to members just before the pumps come back online.

Coordinating DR programs across the G&T territory ... can potentially reduce costs for all co-op members.

Midwest Energy benefits directly from their demand response program because they are responsible for their own generation and transmission, but Volker contends that the program design could work with retail-only co-ops as well, as long as the details are coordinated with the Generation and Transmission (G&T) company. Judd Moritz of EnerNOC points out that the benefits of demand response need to be equitable between neighboring retail co-ops that are members of the same G&T.[5] For example, one co-op that can take much of its load off peak might just shift cost to its neighboring co-ops,if they don't have controllable loads. Coordinating DR programs across the G&T territory, however, can potentially reduce costs for all co-op members. These considerations vary across the country, so it is difficult to generalize, but the issue of inter-cooperative equity may need to be addressed in DR planning. After all, "cooperation among cooperatives" is number six of the seven cooperative principles.

INVESTOR-OWNED UTILITY DEMAND RESPONSE STRATEGIES

IOUs in capacity-constrained parts of the U.S. have accumulated plenty of experience with DR programs, which have evolved over more than two decades. Pacific Gas & Electric, for example, offers four separate DR options for commercial customers:

- **Peak Day Pricing.** This is an aggressive time-of-use rate that all commercial customers are automatically included in (although there is an opt-out option). Peak day events can occur between 9 and 15 times per year, and the events themselves last from 2–6 pm, during which time commercial energy prices jump from about $0.17/kWh to $1.20/kWh. The rest of the year, a small rate credit is applied to make the program revenue-neutral. Customers are notified of an impending event by email, texts, and, for larger customers, phone calls. Once customers understand the implications of the seven-fold increase in electricity cost, they take actions to reduce their energy use.
- **Aggregator Managed Portfolios.** In the AMP program, third parties take on the risk and reward of finding customers who can reduce their demand on call. The programs are coordinated with the utility, so they know how much capacity can be controlled. The utility has the flexibility to call DR events based on their own criteria. Outside companies have some advantages in the DR arena:
  - They can oversubscribe customers to buffer their DR commitment. For example, a company can enroll 120 MW to cover 100 MW of DR. This allows them not to penalize customers who choose not to participate in a given event (more carrot, less stick), since they generally have DR capacity to spare.
  - Because they are not spending ratepayer money on the program, they can use creative financial incentives, as long as they meet the terms of their contract with the utility. In other words, they can wheel-and-deal without direct regulatory oversight.

[5] Judd Moritz, Director, Utility Solutions, EnerNoc, jmoritz@enernoc.com, (314) 822-0707, personal communication, 10-11-2013.

Rewards offered by these programs are proportional to the risk that customers are willing to assume.

   - Third parties can employ staff with special expertise in large commercial operations and industrial processes. This allows them to find deeper DR potential in many sectors of the customer base.
- **Capacity Bidding Program.** The CBP program is similar to the AMP program. Events are triggered by conditions that would require the operation of particularly inefficient power plants.
- **Base Interruptible Program.** In this program, available only to commercial customers with 100kW of demand or greater, the customer establishes a minimum "Firm Service Level" which becomes a maximum allowable demand during a DR event. When the call comes, the facility must drop its load to the FSL within 30 minutes or pay substantial penalties. In return, the customer earns a monthly capacity payment on the controllable load, whether or not an event is called. Typical participants include petroleum facilities or factories that can afford to interrupt operations.

FIGURE 3: Example of a commercial-scale on-site generator.
Courtesy of San Luis Powerhouse

In general, the rewards offered by these programs are proportional to the risk that customers are willing to assume. Greater certainty and frequency of load response bring higher payments.

FUEL SWITCHING AS DEMAND RESPONSE

For retail co-ops, the call for DR usually comes from the G&T or other power supplier. "Load control is quite helpful—it works for the benefit of all members," says Lowell Stave, VP of Member Services for Minnkota Power Cooperative. This winter-peaking G&T can shed more than 350 MW to help handle a variety of adverse conditions, including generation outages, peak loading, or unusually expensive spot power prices.[6]

Minnkota's summer demand response portfolio—about 100MW total—consists mostly of dispatchable backup generation at small and medium commercial member premises. The winter portfolio includes the same amount of dispatchable backup generation as well as 270 MW of dispatchable dual heat, storage heat, and water heat. These resources are considered "load reduction" since the action occurs on the customer side of the meter. It is important to note that while fuel switching programs can be very effective at reducing demand for electricity, they typically do not result in a reduction in energy use since equipment is simply switched from electricity to gas. Program participants still must shoulder costs for fuel to power the generators.

Cass County Electric Cooperative (CCEC) is one of Minnkota's retail co-ops that participates in the program. "We can approach our

[6] Lowell Stave, VP Member Services, Minnkota Power Cooperative, (701) 795-4212, lstave@minnkota.com, personal communication, 8-12-2013.

commercial members with a good arrangement," says Marshal Albright, VP of Member and Energy Services for CCEC. "If they invest in a generator (**Figure 3**), they get a back-up power system. But, they also get to reduce their electricity bills, typically by 25 to 30 percent, via a reduction in the "coincident peak" portion of their bill." Participating members include hotels, schools, offices, retail big boxes, and hospitals.[7]

Generators in the Cass County system, like others that participate in the Minnkota program, are equipped with controllers that start the unit upon receiving a power-line-carrier (PLC) control signal from the G&T. CCEC has about 150 generators in the program, ranging from 50 kW to 2 MW in size, and averaging 600 kW. The units typically run for less than 50 hours per year, so they have generally been exempt from power plant emissions regulations as required by the Clean Air Act until May 2014. The co-op is working with members to retrofit oxidation catalysts (catalytic converters) to be in compliance with the Environmental Protection Agency's (EPA's) National Emissions Standards for Hazardous Air Pollutants (NESHAP) Reciprocating Internal Combustion Engines (RICE) standards.[8]

Electric co-ops like Cass County EC can also control agricultural loads, such as irrigation pumps and grain-drying blowers. Depending on weather and harvest cycles, several megawatts of blowers may be used for a period of days by the co-op's members. If scheduled appropriately, the co-op can avoid adding this load to the G&T's coincident peak, saving money for all their members.

CONCLUSION

Demand response programs are a viable alternative when supply capacity is constrained. Co-ops can choose from a number of different program approaches, and can use in-house or contracted staff to design and manage programs. DR efforts must be done in concert with G&T partners, and should attempt to lower costs equitably across their territory. Co-ops can start their DR efforts by understanding their member loads, examining their cost structure, and discussing the opportunities with their power suppliers. A small-scale pilot program is usually the next step, followed by scaling up and building on successes. ■

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[7] Marshal Albright, Vice President of Member & Energy Services, Cass County Electric Cooperative, malbright@kwh.com, (701) 356-4400, personal communication, 8-13-2013.

[8] www.epa.gov/compliance/monitoring/programs/caa/neshaps.html

About the Authors

David Houghton, P.E., Vice-President and Founder, Resource Engineering Group

In 1997, Dave founded REG to bring efficiency, sustainability, and simplicity to building engineering. The company has since grown to ten engineers, registration in over a dozen states, and projects spread across North America, with a focus on engineering excellence, innovative thinking, and clear communication. Under Dave's direction, REG has been consulting engineer or engineer-of-record for over four hundred building projects including multi-family and multi-house developments, large and small commercial spaces, schools, auditoriums, hospitals, and resorts. He is the author of dozens of technical papers and journal articles, and co-author of comprehensive books on energy efficiency in buildings. In addition to overseeing REG building projects, Dave provides energy technology consulting to clients including utility companies, property portfolio managers, and national organizations pursuing energy efficiency.

Laura Moorefield, Principal, Moorefield Research & Consulting LLC

Laura consults for utilities, state and federal governments, and non-profits on energy efficiency, renewables, and program design. Since 2005, she has been influential in the development of innovative programs and policies to spur energy savings. Research topics include: landfill gas-to-energy, smart meters, residential and commercial plug loads, on-bill financing, LEDs, and consumer and utility guidance on the recent federal light bulb standards. She is frequently a featured speaker at industry conferences and webinars. Formerly with Ecos Consulting and Ecova, Laura founded Moorefield Research & Consulting in 2013. Along with diverse technical expertise from consulting and manufacturing backgrounds, Laura brings flexibility, adept project management, strong writing and editing skills, and an ability to identify and address the key issues of any project. She currently resides in Durango, CO and is a member of La Plata Electric Association.

Questions or Comments

- Brian Sloboda, CRN Senior Program Manager, **brian.sloboda@nreca.coop**, or
- CRN online **feedback form**.

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