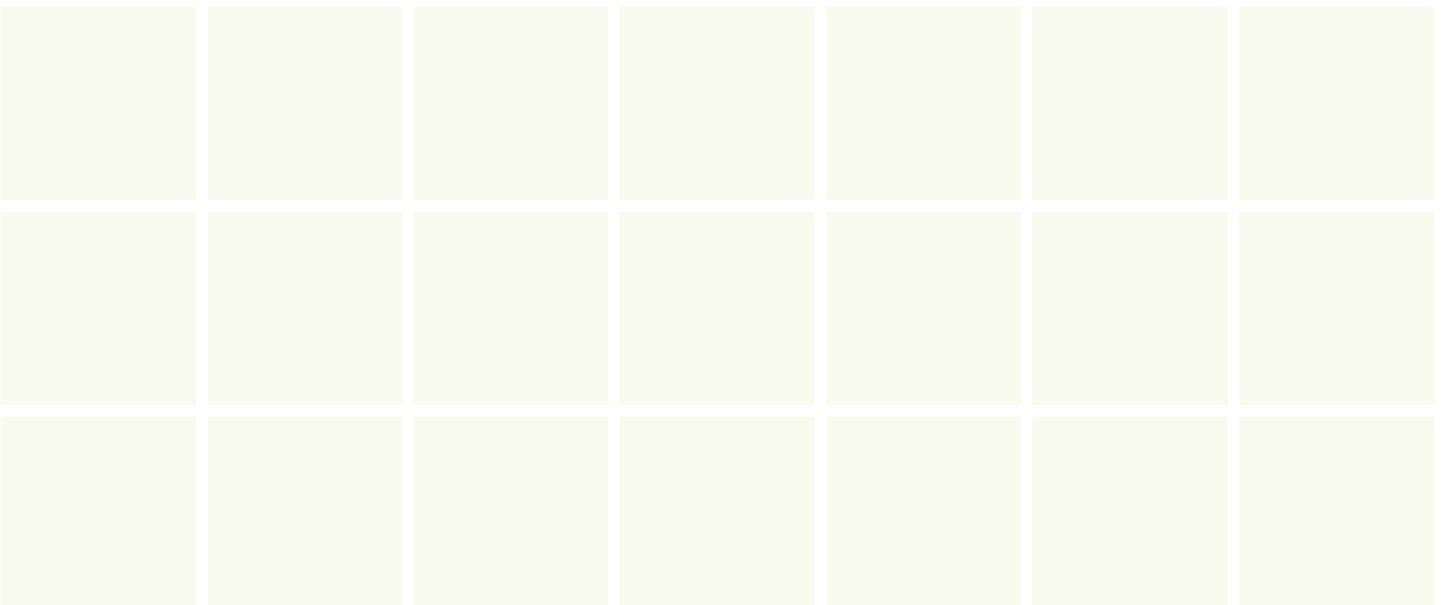
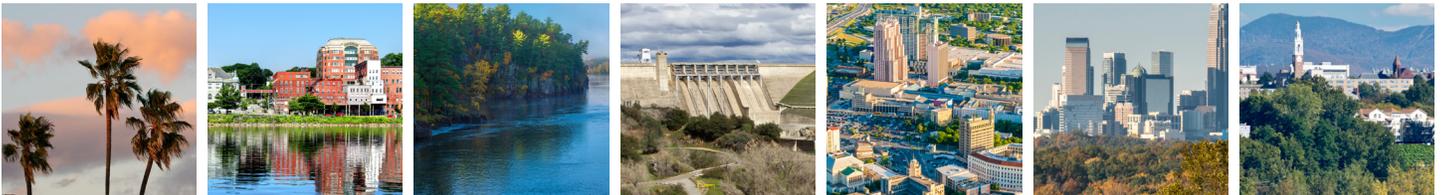


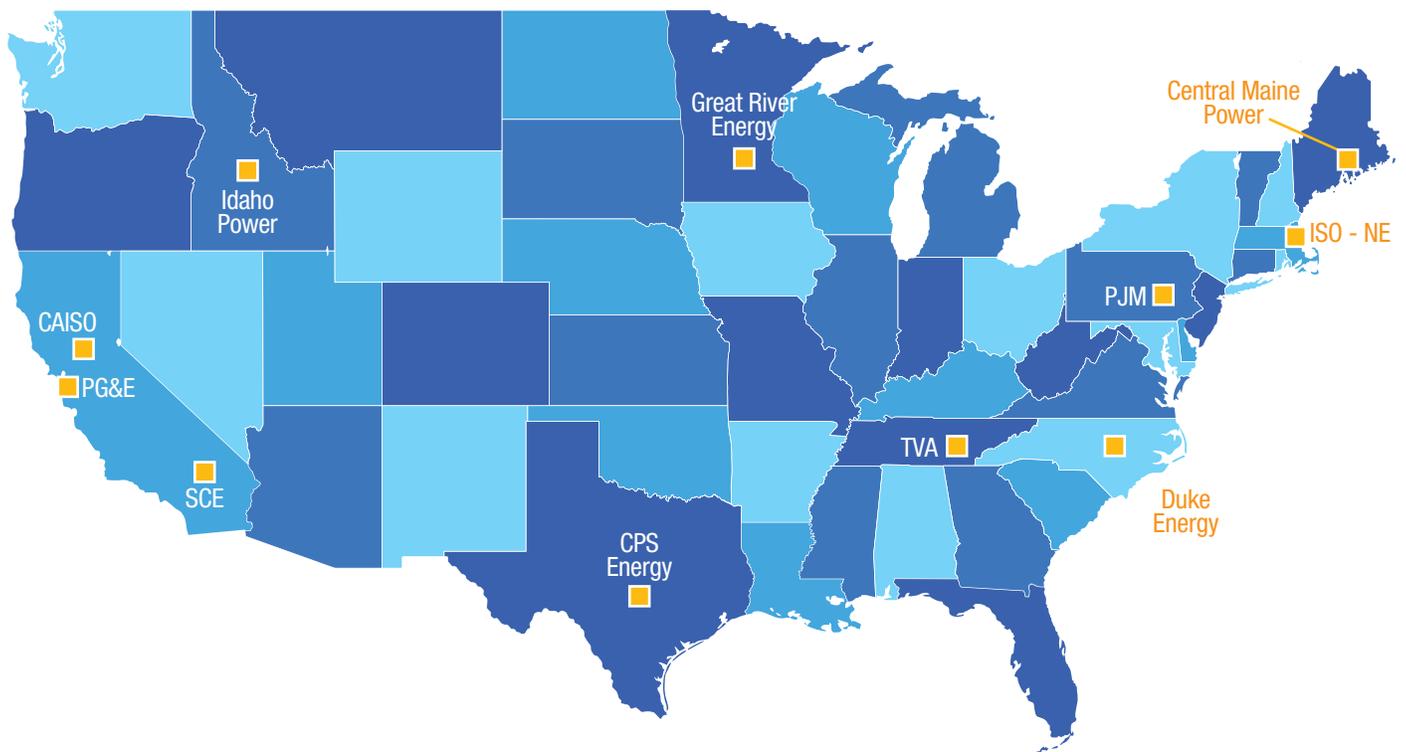
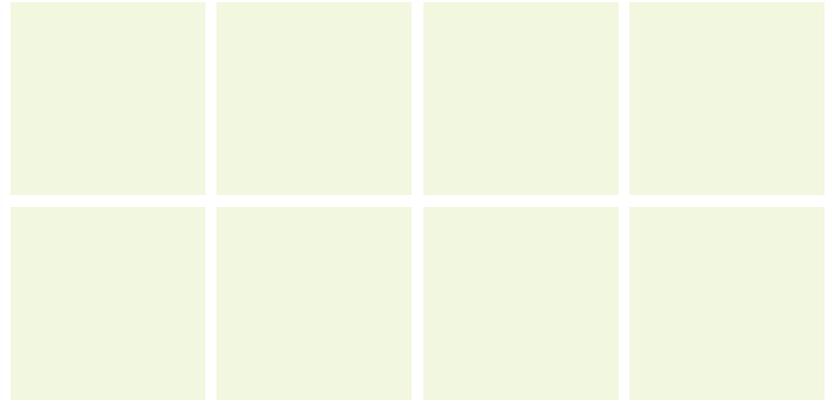
BPA Distributed Energy Resource Benchmarking Report



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distributedenergyresources](http://www.bpa.gov/goto/distributedenergyresources)

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DER BENCHMARKING PARTICIPANTS



LETTER FROM BPA

THE BONNEVILLE POWER ADMINISTRATION has served the Pacific Northwest through the Federal Columbia River Power System for over 75 years. We have been able to meet regional needs with the robust, flexible and low-cost capacity provided by the FCRPS and the typically available Northwest market for wholesale electricity. Today, regional capacity needs that exceed supply appear on the horizon, both in terms of aggregate system balance (as identified in the recently released Seventh Power Plan) and on a localized level with prospective use of demand response for non-wires initiatives.

These looming constraints have led BPA to look for ways to provide additional capacity beyond that of the FCRPS. Demand response has been used as a long-term source of capacity elsewhere in the U.S. where utilities do not have access to the robust and ready supply of flexible capacity we have in the Pacific Northwest. Recently, BPA has supported demand response pilots and demonstrations in public utility service territories throughout the region. We now look to commercialize its proven capability by funding and using demand response to supplement agency power and transmission needs alongside other resources. In support of this move, we sought to evaluate the existing successful distributed energy resource programs of utilities across the country to better inform us for future research, new technology tests and overall program design. Distributed energy resources focuses on a broader spectrum of programs which includes not only demand response but also energy generation, storage and advancing renewable technologies.

BPA staff met with 11 entities throughout 2015 and early 2016 to better understand how they use DER programs within their service territories. We learned how other utilities manage their programs, including their organizational structures, specific products and uses, enabling technology and their future plans for distributed energy resources. This report provides summaries of what we learned during these discussions

As manager of the distributed energy resources program, I'd like to sincerely thank our many utility partners who generously contributed their valuable time and knowledge to participate in this benchmarking effort. We look forward to continuing these discussions and will evaluate developments in this important area of our business as they unfold.

Sincerely,

Paul Garrett

MANAGER OF POWER SERVICES' DISTRIBUTED ENERGY RESOURCES



BPA Distributed Energy Resources Benchmarking Report



CALIFORNIA INDEPENDENT SYSTEM OPERATOR

The California Independent System Operator is a nonprofit that first opened its control centers in 1998. The CAISO acts as a traffic controller by routing electrons, maximizing the use of the transmission system and its generation resources and supervising maintenance of the lines. It serves over 30 million customers and constantly looks for ways to improve operations in the fast-paced five-minute markets that the CAISO operates. In 2014, the CAISO opened its energy imbalance market to other grids in the West to share reserves and integrate renewable resources across a larger geographic region — reliably and efficiently.

There are two key wholesale demand response initiatives at the CAISO, proxy demand resource (PDR) and reliability demand response resource (RDRR). These initiatives were developed in response to Federal Energy Regulatory Commission orders and California Public Utilities Commission rulings that called on the CAISO to integrate utility programs and provide open access to third-party participants. PDR and RDRR rely on the same technical functionality and infrastructure but have different participation requirements. These initiatives enable:

- Direct participation from existing retail demand response programs.
- Simplification of forecasting and scheduling.
- Participation independent of load serving entity.
- Comparable treatment.
- Enabled demand response participation all hours and days of the year.

High level product information provided in following table.



HEADQUARTERS

Folsom, California

FAST FACTS

- Manages 80 percent of California's power grid and a part of Nevada's.
- Facilitates over 28,000 market transactions every day.
- 26,000 circuit miles.

PEAK DEMAND

47,358 MW

DR TOTAL

2,500 MW

LARGEST DR PROGRAMS

- Proxy demand resource
- Reliability demand response resource

PRODUCT	DESCRIPTION	SERVICES	MARKET DISPATCH
Proxy demand resource	Aggregated loads are economically bid into the ISO market as energy supply.	Energy, residential unit commitment and ancillary services both non-spinning, and spinning.	Economic day-ahead and real-time markets.
Reliability demand response resource	Aggregated loads are bid into the ISO market as supply and deployed for emergency demand response, meaning they can be online within 40 minutes of dispatch.	Energy.	Primarily for reliability real-time but may participate in economic day-ahead market.

WHAT'S NEXT for CAISO?

The CAISO has communicated three core strategies it will focus on in the coming years. The first is to lead the transition to renewable energy which will include

advocating for increased price transparency. This will enable consumers to make smarter choices about their energy use and ensure reliability while integrating more diverse and less predictable resources. The second strategy is to maintain reliability during industry transformation. This effort will include improved price transparency to incentivize demand at the right time

and support flexible resources to successfully deploy renewable resources. The final strategy is to lead regional collaboration, which will include developing market mechanisms to bring online resources offering operational flexibility.





BPA Distributed Energy Resources Benchmarking Report

CENTRAL MAINE POWER



Central Maine Power started over 100 years ago with one hydroelectric project serving just one small Maine community. Today, CMP serves the major manufacturing centers and metropolitan areas of Maine with a large and varied resource mix. Aging infrastructure and expanding populations have created a need for CMP to invest in its bulk transmission system in a big way. Part of that investment is to look at solutions that may not involve any building at all, which is how CMP started its first ever demand response program.

Potential to avoid building new transmission

Central Maine Power's demand response efforts are part of a pilot program. The demand response program exists thanks to an agreement with the Maine Public Utilities Commission.

In 2012, the commission approved the Maine reliability power program, a \$1.4 billion investment in Maine's bulk transmission system. The MPUC approved the investment on the condition that pilot programs were tested to evaluate non-wires alternatives as well as the effectiveness of distributed energy

resource technologies to defer infrastructure upgrades. CMP is particularly interested in deferring or eliminating the need for a costly \$18 million subtransmission line.

Demand Response pilot program

CMP is working with a third party non-wires alternative coordinator to establish Maine's first pilot program in Boothbay, Maine. The pilot includes a mix of traditional infrastructure upgrades and a 2 megawatt resource portfolio of demand response, energy efficiency measures, solar panels, backup diesel generation



HEADQUARTERS
Augusta, Maine

FAST FACTS

- Founded in 1899
- Serves 78 percent of Maine's population and the major manufacturing centers
- Territory covers 11,000 square miles with over 23,000 miles of distribution lines

PEAK DEMAND

1,680 MW

DR TOTAL

2 MW

LARGEST DR PROGRAMS

- Dispatchable battery
- Diesel generator
- Ice Bear

and energy storage. The program has been running for three years and aims to reduce summer peak load.

The portfolio has 1 MW of active resources that CMP's energy control center can call upon, including a dispatchable battery, diesel generator and Ice Bear demand response units. The other half of the portfolio is 1 MW of passive resources so-called due to their behind-the-meter load reductions, which include energy efficiency measures and solar panels.

Participants that own active resources are compensated based on their performance to reduce load when resources are dispatched. The passive resource owners are compensated monthly based on the capacity they provided in rated load relief by their resources.

Although the pilot effect is limited to Boothbay, a number of CMP's other customers already participate in ISO New England's demand response programs.

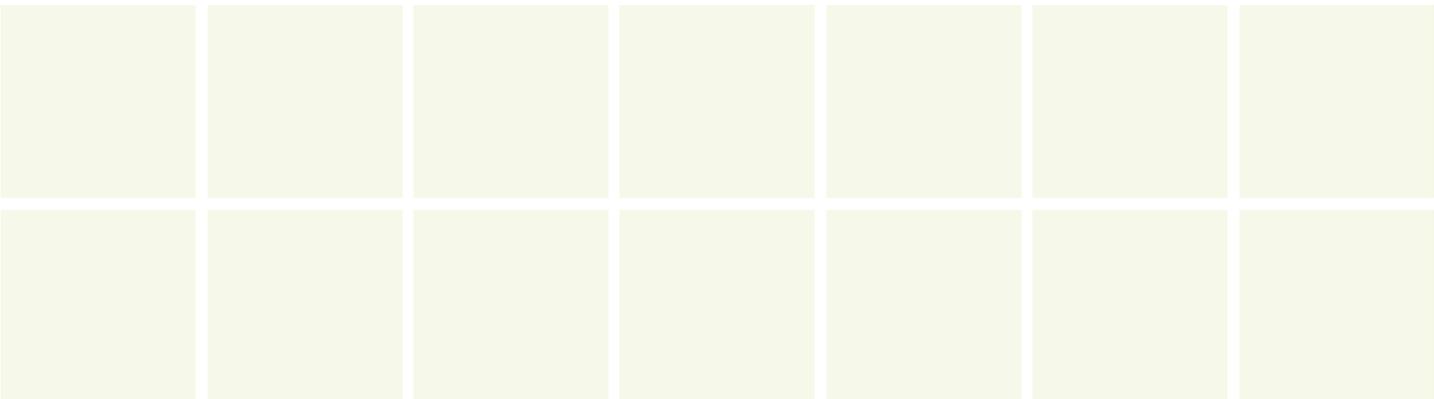
ICE BEARS HELP WITH AC LOAD RELIEF

One unique program CMP offers is an ice storage solution from Ice Energy that provides CMP with demand response and peak load shifting capabilities. Small-scale units called Ice Bears are integrated with packaged HVAC systems. They create ice at night during off-peak hours and then use that ice during the day for cooling needs. These units are deployed at small commercial buildings.

WHAT'S NEXT for Central Maine Power?

There is potential for additional pilot programs in Maine's cities of Camden and Portland. The need for peak reductions in these cities is larger than it was in Boothbay, so if approved, the pilots will be planned at a larger scale.

Future non-wires initiatives will continue to use a competitive procurement process and may continue to include demand response options.





BPA Distributed Energy Resources Benchmarking Report

CPS ENERGY



CPS Energy provides electricity and natural gas to the citizens of San Antonio, Texas. Owned by the city since 1942, the utility produces and purchases power and ranks among the nation's lowest-cost energy providers. CPS Energy is working hard to use demand response to reduce its energy needs in the future. It is already big in renewable energy as the largest solar energy provider in Texas.

Demand response at CPS Energy

CPS Energy uses demand response for peak management in summer months, June through September, between the hours of 1 and 7 p.m. CPS Energy currently manages programs for 120,000 residential and small commercial customers in addition to more than 300 large commercial customers. The demand response program is funded through CPS Energy's Save for Tomorrow Energy Plan that outlines a goal to reduce electrical demand by 771 megawatts by 2020. The following organization chart highlights where the Demand Response function is within CPS Energy.

An overview of demand response products at CPS is provided on page 10.



Demand response enabling technology

CPS Energy is working on consolidating all of its existing communication systems into one system. The new demand response management system will be the central hub for all demand response activity.



HEADQUARTERS
San Antonio, Texas

FAST FACTS

- Serves 786,000 electricity customers and 339,000 natural gas customers.
- 1,566 square mile service area.

PEAK DEMAND
4,800 MW

DR TOTAL
185 MW

LARGEST DR PROGRAMS

- Residential thermostat control
- Commercial curtailment

DEMAND RESPONSE PROGRAMS AND USES

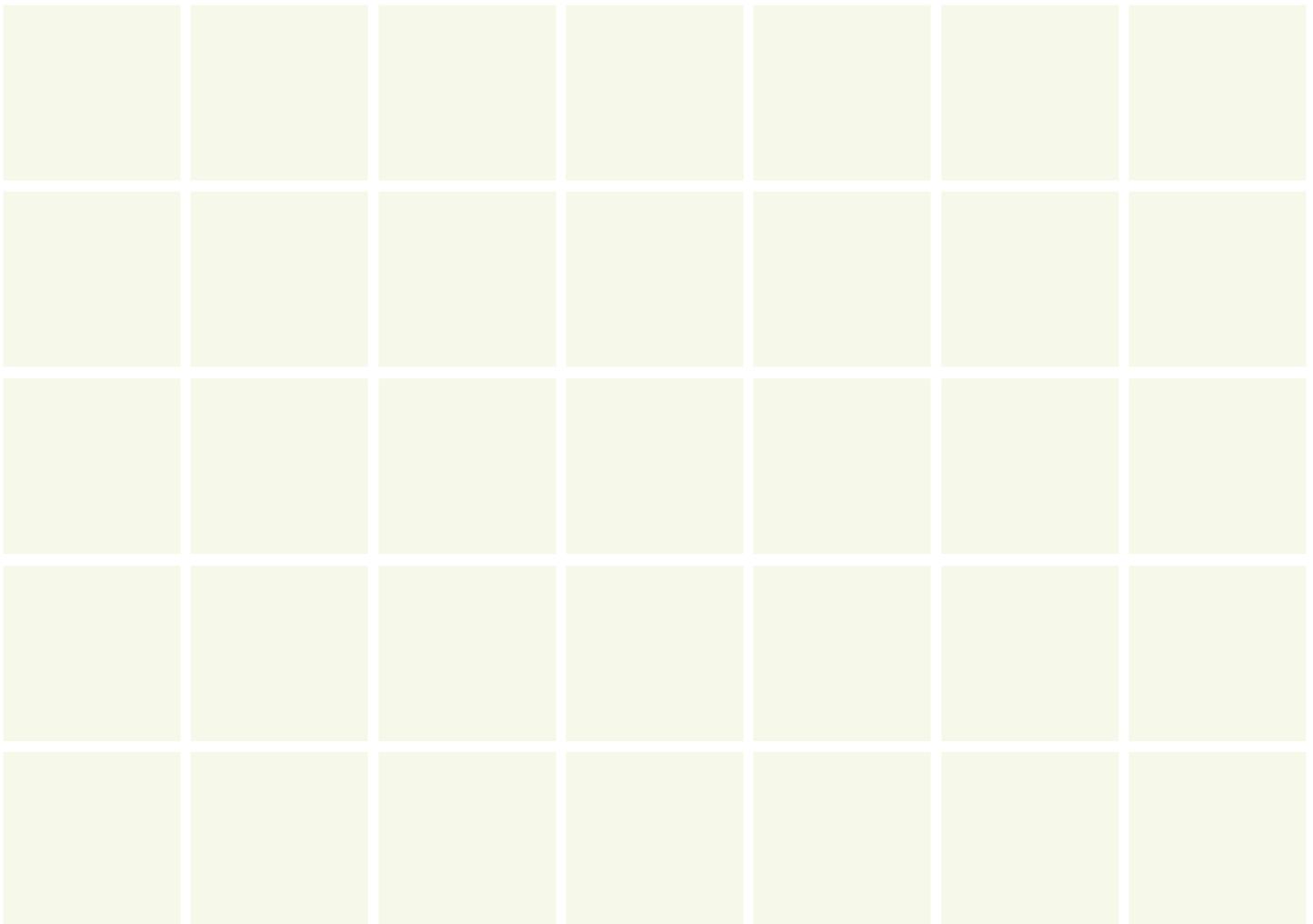
PROGRAM	SIZE	PURPOSE	ACQUISITION METHOD
RESIDENTIAL			
Smart Thermostat	75 MWs	Summer peak reduction for apartments and small commercial buildings.	Incentive provided for free thermostat and installation.
Home Manager		Curtail larger new homes for AC, water heater and pool pump using customer portal to manage.	
Cool Energy Program		Curtail customers with window AC units by increasing temperature a few degrees, covers about 17 percent of CPS Energy customers.	Enrollment incentive of a free SmartAC Kit, valued at \$13, and a participation incentive bill credit of \$30 at the end of the summer.
BYOT Qualified Thermostats: Nest, Honeywell, Ecobee (certain models) and many more		Summer peak reduction via a smart thermostat.	Customer receives a one-time \$85 credit on bill to offset qualified thermostat purchase; this is in addition to a \$30 credit at the end of the summer for participating.
COMMERCIAL			
C&I Demand Response	110 MWs	Curtailment for summer events with two-hour advance notice.	Customers directly acquired by CPS energy.
Automated Demand Response		Curtailment enabled with auto DR, available in less than 10 minutes year-round.	
Emergency Demand Response		Customers use back-up generators with one-hour advance notice. Program will end in December 2016.	

“CPS Energy’s Commercial and Industrial demand response program includes 300 customers who are retail stores, multi-tenant office buildings, data centers, hospitals, schools and universities.”

WHAT'S NEXT for CPS Energy?

CPS Energy is exploring ways to increase customer participation in demand response programs. The options include expanding existing programs like the BYOT program to offer a wider range of thermostat models. In addition, CPS Energy would like to increase the number of programs offered to small and mid-sized commercial customers and provide rebates on building control systems to help further reduce customer energy use.

CPS Energy is exploring the opportunities to leverage its new advanced metering infrastructure network to offer peak-time rebates that could be coupled with behavioral demand response practices.





BPA Distributed Energy Resources Benchmarking Report



DUKE ENERGY

Duke Energy serves a vast service territory of six states and nearly 7.3 million electric retail customers. It faces a variety of different climates and customer sets that make it a great sample of what demand response can achieve. Duke customers provide over 3,000 megawatts of demand response in summer months to help the company keep costs low and avoid new builds.

Demand Response at Duke Energy

Duke's primary driver for building up demand response programs is for seasonal peak management. Duke has developed successful summer and winter programs. These programs can vary greatly across its territory as each region has its own unique programs and needs.

Duke Energy Carolinas and Progress

Duke Energy Carolinas and Duke Energy Progress are two public utilities engaged in the generation, transmission, distribution and sale of electricity in North Carolina and South Carolina. Carolinas is the larger of the utilities with 2.5 million

customers over 24,000 square miles. Progress' service area covers 32,000 square miles and 1.5 million customers.

Both Carolinas and Progress have residential, commercial and industrial programs that target both summer and winter peak load management. An overview of programs is provided on page 14.

Duke Energy Midwest

Duke Energy Indiana, Ohio and Kentucky are regulated utilities primarily engaged in the generation, transmission, distribution and sale of electricity in portions of these states. Indiana's service area covers 23,000 square miles and supplies electric service to 810,000 residential, commercial and industrial customers.



HEADQUARTERS
Charlotte, North Carolina

- FAST FACTS**
- Serves six states: Florida, Indiana, Kentucky, Ohio, North Carolina and South Carolina.
 - 104,000 square-mile service territory.

PEAK DEMAND
49,626 MW total generating capacity

DR TOTAL
3,048 MW in summer
2,195 MW in winter

- LARGEST DR PROGRAMS**
- Residential AC and heat controls
 - Interruptible commercial loads
 - Smart thermostats

Ohio/Kentucky service area covers 3,000 square miles and supplies electric service to 840,000 residential and commercial and industrial customers.

Duke Energy Midwest has residential, commercial and industrial programs that target summer and winter (Indiana only) peak load management. A high level program overview is provided on page 15.

Duke Energy Florida

Duke Energy Florida is a regulated utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Florida's service area covers 13,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers.

Duke Energy Florida has residential, commercial and industrial programs that target summer and winter peak load management. An overview of demand response programs in Florida provided on page 16.

DISTRIBUTION SYSTEM DEMAND RESPONSE PROGRAM

Duke Energy Progress has another demand response tool for specific areas that require load reductions for reliability called the distribution system demand response program, or DSDR. DSDR leverages the latest technologies to support a least cost mix of demand reductions and generation measures to meet needs. The program consists of a system of electric equipment and operating controls, which includes voltage regulators, capacitor banks, medium voltage sensors and demand monitoring software that enable DEP to reduce peak loads. DEP does this using the distribution system to reduce the generation requirements during peak load times for four to six hour periods. The distribution management system processes data from line sensors, analyzes power flow, determines MW-reduction capability and executes commands to control and operate equipment to deliver the demand reduction during peak load periods.

Currently, DEP deploys DSDR first out of its demand response options when targeting specific reduction in a geographic area. DSDR has been in full operation for two years and was in development for five years before that. It is included today as a demand side resource in DEP's integrated resource plan.

DEMAND RESPONSE ORGANIZATION

The demand response organization is included in the retail programs portion of the business.



DUKE ENERGY CAROLINA AND PROGRESS

PROGRAM	MWS	PROGRAM	ACQUISITION METHOD
Power Manager Duke Energy Carolina	~775 MW (SUMMER)	Residential direct load control for central AC and heat pumps.	Outbound calling by contractor.
Energy Wise Home Duke Energy Progress	~10 MW (WINTER)	Residential direct load control for central AC and heat pumps (SYSTEM WIDE), water heaters and HP heat strips (WESTERN REGION).	Outbound calling and door-to-door canvassing by contractors.
PowerShare Duke Energy Carolinas	~900 MW (SUMMER) ~677 MW (WINTER)	Large commercial and industrial curtailment.	Large account management.
Demand Response Automation Duke Energy Progress		Large commercial and industrial curtailment.	Large account management.
Legacy Curtailable Tariffs DEC & DEP		DEC – Rider Interruptible Service and Rider Standby Gen DEP – Rider Large Load Curtailable.	Large account management.
EnergyWise Business DEC & DEP	~0.5 MW	Small and Medium Business Program leveraging 2-way Wi-Fi thermostats or switches for AC and HP heat strips.	Email, business energy advisors, cross-sell with small business EE program.

DUKE ENERGY MIDWEST

PROGRAM	MWS	PROGRAM	ACQUISITION METHOD
Power Manager Duke Energy Indiana, Kentucky and Ohio	~120 MW	Residential direct load control for central AC and heat pumps.	Outbound calling by contractor.
HoM Energy Manager Duke Energy Ohio		Smart thermostat program for residential load control.	Direct mail, email.
PowerShare Duke Energy Indiana, Kentucky and Ohio	~517 MW (SUMMER)	Large commercial and industrial curtailment (ECONOMIC AND EMERGENCY CURTAILMENT PROVISIONS).	Large account management.
Large Transmission Customer Limited DR Program Duke Energy Ohio	~410 MW (WINTER, INDIANA ONLY)	Eligible customers must be served at transmission voltage and have demand over 10 MW.	Large account management.

DUKE ENERGY FLORIDA

PROGRAM	MWS	PROGRAM	ACQUISITION METHOD
EnergyWise Home	~357 MW (summer) ~651 MW (winter)	Residential direct load control for central heat/cool, HP heat strips, water heaters and pool pumps.	Direct mail, email.
SunSense Solar Water Heating		Residential direct load control for central AC, heat pumps, water heater supplemental elements and pool pumps.	Direct mail, email.
Domestic Commercial		Residential-like direct load control for central heat/cool, water heaters and HP heat strips.	Not currently marketed.
Commercial Load Management		Small commercial direct load control of HVAC units during summer months.	Not currently marketed.
Standby Generation	~447 MW (summer and winter)	Commercial accounts voluntarily transfer load (minimum 50kW) to their generators.	Large account management.
Interruptible Service		Large commercial and industrial interruptible direct load control.	Large account management.
Curtable Service		Large commercial & industrial voluntary curtailment of load upon receipt of notification.	Large account management

WHAT'S NEXT for Duke Energy

Duke Energy is looking to expand its demand response programs,

especially in the summer. The goal is to increase demand response by 14 percent over the next five years. The plan includes adding participants to established programs; creating new programs that target residential customers using smart thermostats, water heaters, smart cir-

cuit breakers and behavioral demand response; and upgrading existing technologies to allow for better visibility and reporting of system operability.



BPA Distributed Energy Resources Benchmarking Report



GREAT RIVER ENERGY

Great River Energy provides a unique perspective as a wholesale power cooperative whose membership includes 28 electric distribution cooperatives in Minnesota. Demand response helps GRE avoid construction expense and keeps costs low by reducing peak energy purchases. With peak growth rising, demand response is the cheapest option to keep costs down going into the future.

Demand response at Great River Energy

GRE uses load management to reduce demand for electricity to avoid building high-cost peaking plants and purchasing high-cost peak energy in the wholesale market. Its large portfolio includes over 350,000 controlled loads. GRE targets high-demand periods in all seasons including hot summer days or extremely cold winter days. GRE has also found load control to assist in helping to balance the system during system emergencies, resource adequacy limitations and to lower monthly demand peaks for billing.

GRE resembles BPA in the way it must work with its 28 member cooperatives to implement programs. The cooperatives are directly responsible for running the

demand response programs that are initiated by GRE. An overview of GRE's Demand Response programs is provided on page 18.

In-depth look, economic demand response

GRE participates in the Midwest Independent Service Operator's energy market. GRE owns resources but there are times when it needs to purchase additional energy or market excess energy. MISO is responsible for keeping the entire electric system it oversees, which includes GRE, balanced throughout the year. When MISO must increase its generation to meet peak times, those additional generation costs are passed back to participants, or in this



HEADQUARTERS
Maple Grove, Minnesota

FAST FACTS

- Fifth-largest generation and transmission cooperative in nation owned by 28 member cooperatives.
- Second-largest utility in Minnesota with 660,000 customers.
- Elected board of directors establishes rates and develops policies.

PEAK DEMAND

2,452 MW

DR TOTAL

About 450 MW
(plus over 1,000 MWs in storage)

LARGEST DR PROGRAMS

- Air conditioner cycling
- Interruptible water heaters
- Dual fuel

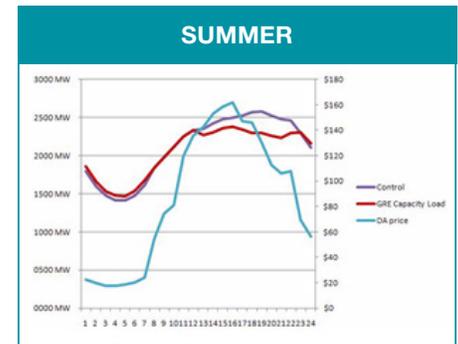
case, GRE. If GRE can reduce its load during these peak times, it reduces the cost of purchasing the additional power and can save itself and its member co-ops money.

An example of seasonal control

The summer control graph below is an example of GRE's loads on a hot summer day. The blue line is the day-ahead price in the MISO market. Prices peak in the

late afternoon when loads are at their highest due to cooling. The red line shows GRE's member consumption at each hour of the day with the current portfolio of interruptible load management programs in place. This is compared to the purple line which shows what the energy profile would have looked like without the energy curve. The programs provide about 300 megawatts of reduction from controlled air conditioners, crop irrigators, water heaters and commercial generators. The ETS water heating program does add load overnight

but it shifts the load from high-cost times to low-cost power.



DEMAND RESPONSE PRODUCTS AND USES AT GREAT RIVER ENERGY

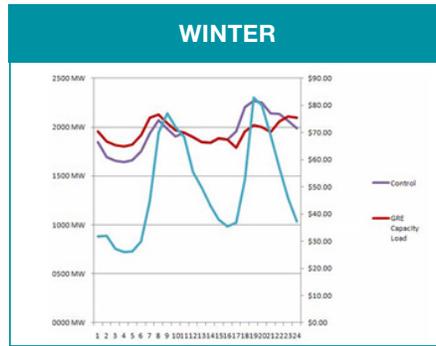
PROGRAM	MWS	CUSTOMER GROUP	PROGRAM	SEASONAL OR ECONOMIC
Cycled Air Conditioning	150	Residential	Air-conditioners cycle on and off during peak hours.	Seasonal and Economic
Interruptible Water Heater	40	Residential	Cycle water heating component off in four to eight hour increments.	Seasonal and Economic
Dual Fuel	150	Residential	Loads switch over to back-up generators	Seasonal and Economic
ETS Water/Space heating	1000 of storage	Residential	Electric thermal storage water heating system that supplies hot water needs over an extended period each day from its storage capacity when the electric supply is interrupted.	Economic
ChargeWise	NA	Residential	For customers with plug-in electric vehicles to use approved load control device that limits the recharge to 11 p.m. to 7 a.m.	Economic
Interruptible Irrigation	20	Irrigation	Interrupts controlled irrigation systems for up to four hours during the cooling season, which is May through September.	Seasonal
Interruptible metered C&I	NA	Commercial	Interrupt all or a portion of a customer's electrical load during peak load conditions. The program defines a set number of hours that can be called upon in a calendar year that has typically stayed under 80 hours per year.	Seasonal
C&I with GenSet	120	Commercial	Customers agree to transfer electric service to a customer-owned backup generator during an event for a set event period.	Seasonal

Winter control option

The winter graph shows what loads look like on a cold winter day when GRE experiences two peak consumption times, in the morning and the evening. The peak events correspond with lights turning on, thermostats turning on, uncontrolled water heaters cranking up and higher demand as people turn on their appliances going to and from work. GRE's winter programs, like the dual fuel program, help to reduce electric use during higher priced times of the day. On the flip side, the program adds additional load during the overnight recharge period when low-priced energy is available.

Dispatch of events

GRE establishes the event dispatch strategy for each of its programs. Centralized dispatch and control is



provided to each member cooperative to initiate events as needed. Each load control program has rules including which loads qualify, the length a control period may last and the total number of hours a program can be deployed in a year. GRE also set a hierarchy of program dispatch order, which is: interruptible water heaters, followed by air conditioners, irrigators and finally C&I interruptible programs.

Dispatch technology

GRE's direct load control dispatch is handled through one-way switch technology on Cannon Technologies' Yukon platform. Seventy radio towers transmit a signal to load control devices installed in customers' homes and businesses. In the future, GRE would like to upgrade to a new load control system that includes two-way switches on technology.

Reporting

Measurement and verification of demand response events remains difficult for GRE due to the lack of advanced metering infrastructure on the system. Currently, only 35 percent of the system uses advanced meters.

WHAT'S NEXT

for Great River Energy

GRE recently developed a future grid steering team to focus on next steps for distributed energy resources and to develop a more holistic approach going forward. GRE's pro-

grams have been successful to date, but they are fairly traditional and have been static over the years. In the future, GRE would like to focus on shaping its load curve. This will involve greater interactions with the co-ops and their customers to install devices in customer homes, placing solar on rooftops and integrating electric vehicles. GRE has already selected four pillars that

will help lead it into the future – robust telecommunications, advanced metering infrastructure, meter data management and distributed energy resource management systems to manage all loads and resources.



BPA Distributed Energy Resources Benchmarking Report



IDAHO POWER

Idaho Power is an investor-owned utility which serves over 500,000 customers in Idaho and Oregon. Founded 100 years ago, the utility offers some of the lowest rates in the nation to its residential, business and agriculture customers. A growing economy means more load growth and, facing constraints with its current resource mix, Idaho Power is actively engaged in demand response programs to defer the need to acquire more resources. Idaho Power is preparing for a future that will allow it to serve Idaho well into the next century.

Seventy years of load control programs

Idaho Power first implemented a load control program in 1945 and still continues to offer them today. Today's programs look to help alleviate capacity constraints that usually occur during hot weather, lower water and high loads. This set of conditions usually occurs during peak hours in July and August between 2 and 8 p.m. IPC has the ability to call upon 385 megawatts of demand response across its system to reduce peak loads.

Since the programs are designed to reduce extreme peak demand on Idaho Power's electrical system, it could delay

the need for Idaho Power to build new generation resources.

IPC only implements demand response events when it is cost effective. However, the programs are deployed a minimum of three times each season to ensure reliability and keep customers engaged in the program details. An overview of programs provided on page 21.

IPC's organizations

The demand response programs are managed from IPC's Customer Relations and Energy Efficiency group. Three program specialists, who are also involved in other programs, handle the details of each program. Regional



HEADQUARTERS

Boise, Idaho

FAST FACTS

- Founded in 1916.
- Serves customers in Idaho and Oregon.
- 515,763 customers over 24,000 square miles.

PEAK DEMAND

3,407 MW

DR TOTAL

385 MW

LARGEST DR PROGRAMS

- Irrigation Peak Rewards
- Flex Peak
- AC Cool Credit

Demand response products

PROGRAM	MWS	CUSTOMER GROUP	PROGRAM	ACQUISITION METHOD
Irrigation Peak Rewards	327	Irrigation	Irrigation curtailments.	Incentive payments.
Flex Peak	28	Commercial Industrial	Customer curtailments.	Pay for performance incentive.
AC Cool Credit	30	Residential	Air conditioner cycling.	Flat credit on bill.

customer representatives help market and field questions from customers about the program.

The actual events are called and dispatched by Idaho Power’s Load Serving Operations group.

Irrigation Peak Rewards Program

The Irrigation Peak Rewards program is IPC’s largest at 320 megawatts and seeks to limit its impact on irrigators as much as possible. Customers can participate if they have a metered service point that serves water pumping or water delivery systems used to irrigate agriculture crops or pasturage.

Idaho Power has restricted participation in the program to a limited set of service locations from its previous levels in the past. IPC selects participants based on criteria that may include but are not limited to billing demand, location, pump horsepower, pumping system configuration or electric system configuration.

Flex Peak program

The Flex Peak program pays commercial and industrial customers to curtail their energy use. Customers earn incentive payments by managing their peak demand during summer months. Participants receive their payments at

the end of the summer, based on the amount of load they reduced when called upon by IPC. The exact amount will vary depending on the participant and how much electric load can be reduced during events. Both fixed and variable payments are available.

AC Cool Credit program

The AC Cool Credit program is an air conditioner cycling program. Idaho Power expects peak demand to continue rising annually for the next 20 years, much of it due to increased air conditioning use. The program is

expected to help slow demand growth during peak hours.

Any customer with a central air conditioning system in good working order who lives in the service area and has the equipment required to support the AC cycling installed can participate. The installed device can cycle an air conditioner off for a portion of an hour for up to four hours. Intermittent cycling is safe for the air conditioner and helps to ensure the customer’s home stays cool.

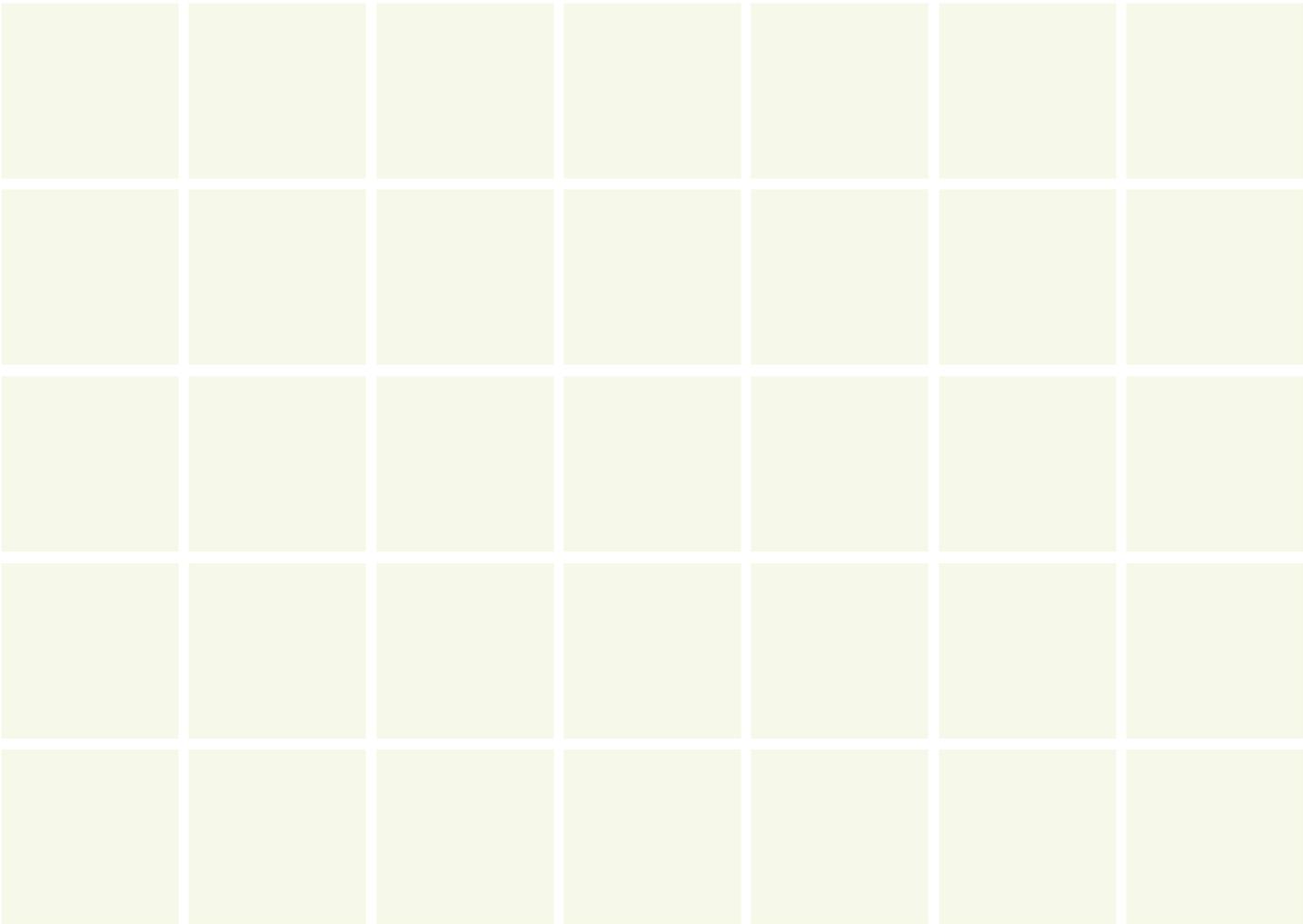
TECHNOLOGY

Idaho Power uses a power line carrier advanced metering infrastructure system as its primary way to communicate with devices that are part of the demand response programs. All of their AC Cool Credit participants receive an automated signal from the AMI system that begins cycling their air conditioning units. IPC began this program using paging technology, however paging service coverage continues to decrease and it was no longer feasible to use this as a communication method. Idaho Power upgraded everything to be compatible with its AMI system.

WHAT'S NEXT

for Idaho Power?

Idaho Power has each program evaluated by a third party and reports each program in the demand side management annual report it files with the public utilities commission. Idaho Power plans to continue including demand response in its integrated resource plan in the future and may expand programs if future IRPs support the expansion.





BPA Distributed Energy Resources Benchmarking Report



ISO NEW ENGLAND

ISO New England is an independent system operator that delivers energy to New England's homes and businesses over a high-voltage electric power system. ISO-NE, a not-for-profit company, spans six Northeast states and makes sure that the lights never go out. Grid operations, market administration and power system planning are all part of ISO-NE's job to keep the lights on. ISO New England administers three wholesale electricity markets that include energy, ancillary services and capacity markets.

ISO-New England Overview

ISO New England has three roles in the region to ensure that the power stays on. First, ISO-NE manages grid operations to coordinate and direct power flows to balance the system every minute of every day. Second, ISO-NE designs, runs and oversees billion-dollar wholesale energy markets. Finally, it is the responsibility of ISO-NE to study and plan to ensure that New England's electricity needs will be met for the next 10 years. All of these functions require a complex, interconnected organization to ensure proper planning.

New England is unique because electricity customers have a choice among retail suppliers. Utility companies are essentially just wires companies that do not own the generation supplying their customers. These utilities, rather than ISO-NE, provide demand side management services to their customers. Vermont utilities are the only ones that have remained vertically integrated.



HEADQUARTERS
Holyoke, Massachusetts

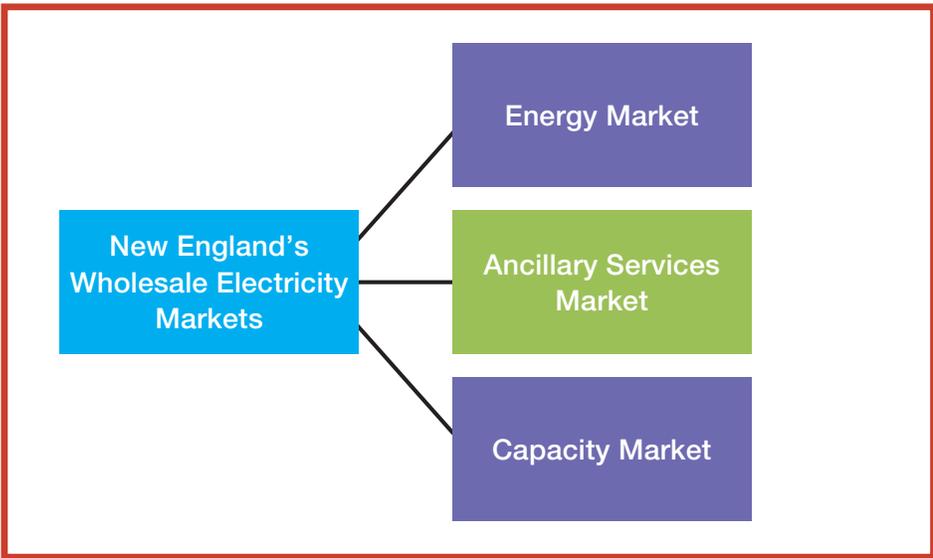
FAST FACTS

- Serves six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- Operates 32,000 megawatts of New England's bulk electricity power generation.

PEAK DEMAND
28,130 MW (summer)
22,818 MW (winter)

DR TOTAL
N/A

LARGEST DR PROGRAMS
■ Capacity market



This chart displays information on ISO-NE's three wholesale electricity markets. Today, demand response falls under the capacity market but in the future it will also play a role in the energy market.

Demand Response at the ISO-NE

Demand response currently falls under the ISO-NE's capacity market. The capacity market pays resource owners based on their ability to deliver capacity during peak energy demand periods. There are approximately 2,800 megawatts of demand side resources in the market, of which 90 percent are energy efficiency measures.

ISO-NE also uses demand response in real time as a product to address capacity deficits on its system. In its current function, demand response is essentially an emergency or reliability product. It is dispatched whenever operating reserves are expected to be depleted or when there is a need to reduce voltage. ISO-NE requires five-minute telemetry for all of its demand response assets as well as a frame relay to dispatch events – this is essentially a

communication method that allows them to be hard wired to the control center. Data on baseline operations and from events must be provided to ISO-NE to allow it to measure performance of the resource.

WHAT'S NEXT for ISO New England

The ISO-NE plans to integrate demand response resources into its energy market starting in 2018. Demand response will be dispatched as an energy product on economic merit but could also be

used as a reserve response on 10 or 30 minute reserves. Demand response assets will still be allowed to participate in the capacity market but will not be required to do so.



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PACIFIC GAS & ELECTRIC COMPANY



Pacific Gas & Electric Company is one of the largest natural gas and electric utilities in the United States. PG&E employs 20,000 people who serve 16 million customers through its 70,000 square-mile service territory that includes the city of San Francisco. With ever-growing demand for electricity during peak demand times, PG&E has deployed an array of demand response programs to shave load during peak periods.

Demand response at Pacific Gas & Electric

PG&E has one of the largest and most well-established demand response programs in the West, dating back 50 years. Whether the program has been headed under the names interruptible, load management or demand response, the company ensures that programs evolve over time to meet the needs of the utility and its customers. The Demand Response organization is a part of PG&E's Customer Care portion of the business. Their organization structure is provided on page 26.

PG&E uses demand response primarily to maintain system reliability and prevent

power interruptions to its customers, but also to lower electricity procurement costs and to delay or replace the need for additional generation or transmission. Demand response is typically deployed when the system is constrained due to high temperatures, high energy prices or transmission line or power plant outages.

Demand response products

PG&E's current portfolio of demand response programs targets peak load reductions to avoid high peak prices and provide reliability. PG&E acquires customers through three targeted approaches: general marketing via mail



HEADQUARTERS
San Francisco, California

FAST FACTS

- Incorporated in 1905.
- 5.4 million electric customers.
- 141,215 circuit miles of electric distribution lines and 18,616 circuit miles of interconnected transmission lines.

PEAK DEMAND

22,000 MW

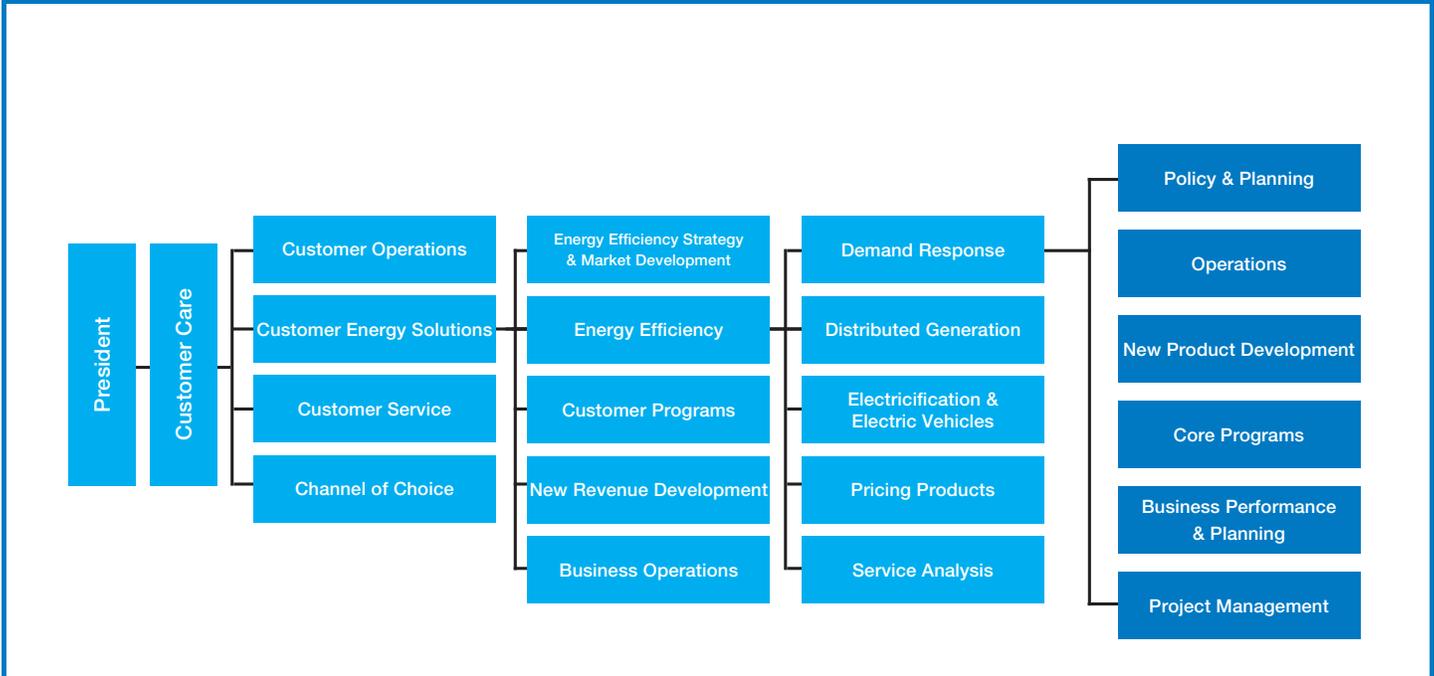
DR TOTAL

530 MW

LARGEST DR PROGRAMS

- Base interruptible load
- Aggregator
- Smart AC

DEMAND RESPONSE TEAM



or email, sales department for large commercial and industrial outreach and by using aggregators.

SmartAC

SmartAC targets residential and small-to-medium-sized businesses to join in a direct load control program. PG&E sends a signal remotely to cycle air conditioners on and off over short increments. The program can leave the fan on while the cooling mechanism is turned off to improve air circulation. There is a one-time \$50 sign-up incentive provided to customers. SmartAC is used to support reliability of the grid.

Base Interruptible Program (BIP)

The base interruptible program is offered to commercial and industrial customers and is only used for reliability to preserve grid stability. PG&E dispatches the

PG&E's Portfolio of DR Programs		Enrolled Accounts	Currently Enrolled MW
SmartAC	<ul style="list-style-type: none"> Reliability program to preserve grid stability Immediate, direct load control of AC units One-time enrollment incentive for sign-up For residential and SMB customers 	~160,000	~90
Base Interruptible Program (BIP)	<ul style="list-style-type: none"> Reliability program to preserve grid stability 30-minute minimum notification of events Large C&I customers; annual capacity payment w/ high penalties for non-performance 	~200	~250
Aggregator Programs (CBP & AMP)	<ul style="list-style-type: none"> Peak shaving or reliability dispatch 30-minute or day-ahead notification of events Monthly capacity payments based on nominated / committed load reduction Capacity and energy payments for actual energy conserved with penalties for non-performance 	~2,300	~130
Demand Bidding Program (DBP)	<ul style="list-style-type: none"> Economic / peak shaving dispatch, "best efforts" Day-ahead notification of events Payment for actual energy reduction at \$500/MWH during DR events 	~500	~20
Peak Day Pricing (PDP) and SmartRate	<ul style="list-style-type: none"> Peak shaving dispatch – "critical peak pricing" Day-ahead notification of events Elevated pricing during events but discounted rate all other hours 	~290,000	~70
Legend: L Locationally dispatchable P Bid as PDR into ISO in 2015		Portfolio-Adjusted* Total: ~530 MW <small>* Discounted total to adjust for customers participating in multiple programs.</small>	

program to reduce load at these facilities and participants must respond with load reductions within 30 minutes. Participating customers receive an annual capacity payment but they can also incur high penalties for non-performance.

Aggregator programs

PG&E contracts with aggregators who recruit customers and manage load reduction programs on behalf of the utility. PG&E has two programs, the Capacity Bidding Program and the Aggregator Managed Portfolio, that are used for peak shaving. These programs can be dispatched locally to meet a particular region's need and can also bid into the CAISO wholesale market as of 2014. Participating customers receive monthly capacity payments based on their committed load reduction amounts as well as energy payment for the actual energy amounts conserved. Participants can also receive penalties for non-performance.

Demand Bidding Program (DBP)

PG&E uses the demand bidding program for economic peak shaving dispatch. PG&E provides day-ahead notification of events when it believes it is going to need load reductions during peak times. During demand response events, savings are passed on to participants in this program for actual energy reduction at the rate of \$500 per megawatt hour.

Peak Day Pricing (PDP) and SmartRate Program

The Peak Day Pricing and SmartRate Program is a critical peak pricing program designed specifically for peak shaving. Participants receive an elevated price during event hours in exchange for buying at a discounted rate during the rest of the season.

DR-enabling technology

PG&E uses several systems to support DR functions using different system capabilities. Data management is the key challenge to integrating all of the data types. The utility is working to implement a more holistic system to help with current data issues and provide better integration with CAISO.

PG&E uses direct load control and auto demand response technologies to support participation in events with a subset of customers. For example, in the SmartAC program, one-way communication to a device is used by PG&E to cycle specific loads. Auto demand response sends a signal from the Demand Response Automated Server to the energy management system at a customer's facility to adjust equipment, such as HVAC or lighting, based on the pre-determined curtailment strategies.

Even though automated options are available for demand response, they are not required for participation. For example, a large industrial customer still receives DR event notifications via fax and with experience, may be as successful as an automated system.

Event triggers

PG&E uses a variety of criteria to trigger a demand response event including:

- Forecast temperatures meet a predefined trigger temperature.
- PG&E's procurement stack requires the dispatch of generation with a heat rate of 15,000 British thermal units per kilowatt hour or greater.
- CAISO day-ahead load forecast exceeds 43,000 MW.

- CAISO issues an alert notice or is expected to issue a warning notice for the following day.
- PG&E requires a discretionary event, such as for testing.
- PG&E forecasts that generation resources or electric system capacity will not be adequate.
- There were no more than three consecutive events called in the past four days.

PG&E reserves the right not to call an event when these triggers are met due to opportunity costs or for operational reasons. PG&E has a tailboard that meets to decide whether to trigger economic events. The group includes the demand response team, electric procurement and meteorology teams. These meetings are scheduled when the following criteria are met: forecasted temperature is close to trigger temperature; the area is experiencing a heat wave; or forecasts call for high energy prices or heat rates. The tailboard participants meet to review all the potential triggers and determine which programs should be dispatched.

Reporting and program evaluation

The California Public Utilities Commission requires an annual review of the load impact of demand response programs throughout the state. A third-party consultant performs the evaluation using a methodology that is consistent among the three investor-owned utilities and determined by the Demand Response Measurement Advisory Council. The final report is publically available. In addition, PG&E publishes monthly reports on its enrollments, budget and estimated load impacts.

WHAT'S NEXT for PG&E



As demand response continues to evolve at PG&E, it will be tailored to the following five areas:

1. Develop and enhance demand response programs and data-related products that target the most valuable needs of customers and the grid (help with integration of higher levels of renewables).
2. Pursue policies that unlock the most valuable opportunities for DR, including third-party participation and continued integration into the CAISO wholesale markets as proxy demand resource and reliability demand response resource products.
3. Increase customer engagement in our programs through proactive outreach and support.
4. Execute robust, efficient and flexible operations by continuously developing systems, processes and the organization.
5. Explore new opportunities for customers to support regulatory and grid needs through the use of pilots, such as the Supply Side DR Pilot and the Excess Supply DR Pilot.



BPA Distributed Energy Resources Benchmarking Report



PJM INTERCONNECTION

PJM Interconnection operates the world’s largest wholesale electricity market as the regional transmission organization for the area that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM was the first fully functioning independent system operator approved by the Federal Energy Regulatory Commission. With over 183,000 megawatts of generating capacity, PJM is responsible for keeping the lights on for over 61 million people.

PJM markets overview

PJM’s competitive wholesale electricity market includes four products: energy, capacity, financial transmission rights and ancillary services. Today, demand response is employed in the capacity, energy and ancillary services markets.

Demand response at PJM

Demand response is a voluntary program at PJM that allows end-use customers to reduce their electricity usage during

periods of high power prices. In exchange, they are compensated through PJM members, known as Curtailment Service Providers (CSPs), for decreasing their electricity use when requested by PJM.

In 2002, FERC authorized PJM to pay an incentive for demand response to gain the interest of market participants and encourage market entry. That authorization allows PJM to pay an incentive equal to full locational marginal pricing when the price was \$75 per MWh or higher, up to a total of \$17.5 million per calendar year. Today, the PJM region has



HEADQUARTERS
Valley Forge, Pennsylvania

- FAST FACTS**
- RTO with 900+ member companies.
 - 61 million people served.
 - 243,417 sq. mile territory.

PEAK DEMAND
165,492 MW

DR TOTAL
12,663 MW

- LARGEST DR PROGRAMS**
- DR capacity
 - Economic energy DR
 - DR synchronous reserve
 - DR regulation

more committed demand response than any other organized wholesale electricity market in the country. The demand response org structure is provided below.

Participation in PJM markets

End-use retail customers can only access PJM's wholesale electricity market through CSPs. CSPs are any load-serving entity, electric distribution company or third party specializing in demand response. It is the CSPs, not PJM, that determine which assets will be a part of their portfolio. They do not have exclusive territories, which means they compete for end loads that they will ultimately bid into the markets.

CSPs aggregate the load reduction capability of retail customers and register that capability with PJM. It is each CSP's responsibility to submit the verification of demand reductions for payment to PJM. The allocation of the PJM payment between the CSP and the retail customer is left up to individual customer agreements.

Demand response in the capacity market

Capacity in PJM's case means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity they purchased from others under contract or with capacity obtained through PJM capacity-market auctions.

Demand response and energy efficiency resources can participate in the capacity market and receive payments for being ready to reduce their electricity demand or implementing energy efficiency measures. Demand response, through CSPs, can bid demand reductions into the market. The ability to call on demand response gives system operators greater flexibility in managing the grid during summer heat waves and other challenging conditions.

Demand response in the energy market

PJM's energy market operates like a stock exchange, with market participants establishing a price for electricity by matching supply and demand in both day-ahead and real-time markets. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. A CSP customer can offer to reduce its electricity usage in the day-ahead energy market. If the offer is accepted, the energy consumer will receive payments based on the day-ahead price for the amount of load that is reduced.

CSP customers can also participate in the real-time energy market. CSPs help customers determine the quantity, time and price at which to offer their load reduction capabilities for dispatch. Demand response offers are put into the bid stack along with generator offers and dispatched by PJM using security constrained economic dispatch. If a load reduction is dispatched, PJM pays the CSP based on real-time prices.

Demand response in other markets

PJM also enables demand response efforts to participate and submit bids for participation in the synchronized reserve, regulation and day-ahead scheduling reserves markets.

Enabling Technology

For members to participate in PJM's markets, the RTO provides the eLRS tool for CSPs, electric distribution companies and load-serving entities. This is an online tool for processing the registration of demand resources and demand reduction activity and transactions in all of the PJM markets.

PJM plans to replace the eLRS application with DR HUB, an enhanced tool, in 2016.

DEMAND RESPONSE ORGANIZATION

There are six people who work in support of demand response at PJM. The team includes:

- Demand response lead.
- Operations lead.
- Settlements lead.
- Reports/analysis lead.
- Registration process/system administration lead.
- Policy/emerging markets/applied solutions lead

MARKET	OVERALL MARKET SIZE	DR CAPABILITY (MW)
DR Capacity	164,561 MWs cleared the base residual auction for the 2015/2016 delivery year.	9,360
Economic Energy DR	The real-time energy market clears 17 percent of the load requirement on average.	2,973
DR Synchronous Reserve	The greater of the reliability minimum or the largest contingency on the system, usually between 1,000 and 2,000 MW. (DR cannot provide more than 33 percent of the requirement in the RTO reserve zone or a sub-zone).	320
DR Regulation	500 MWs requirement during off-peak hours (0000 to 0459) and 700 MWs requirement during on-peak hours (0500 to 2359). DR cannot provide more than 25 percent of the requirement.	10

WHAT'S NEXT for PJM Interconnection

PJM has been successful in its use of demand response in its current markets. Now, the goal is to encourage the integration of wholesale and

retail prices to expand DR opportunities. PJM is working with state commissions and stakeholders to support the industry's movement in this direction. In addition, PJM will continue transitioning to new capacity market rules, also known as capacity performance. PJM is also undertaking a complete assessment of demand response in the PJM markets.



BPA Distributed Energy Resources Benchmarking Report



SOUTHERN CALIFORNIA EDISON

Southern California Edison provides electricity to almost 15 million people living in California and has been doing so for over 125 years. Its 50,000-square-mile service area includes most of Southern California. SCE has been an innovator in the demand response arena since the 1970s and continually looks for ways to create innovative programs. Today, SCE operates programs that engage residential, commercial and industrial customers to achieve almost 1,400 megawatts in demand response assets to avoid potential power outages.

Demand response at SCE

SCE first used demand response programs in the 1970s, introducing interruptible tariffs. These tariffs allowed customers to provide load relief for the utility, which could be aggregated with other customers, in exchange for a rate discount on their bill. SCE continued to explore demand response in the 1980s with new direct load control programs targeting demand reduction through air conditioners and agricultural pumps. These programs continued to evolve until the energy crisis of 2000.

The crisis made it apparent there was a greater need for price-based long-term demand side management to deal with future energy resource needs. The Califor-

nia Public Utilities Commission issued new and improved policies to address these needs that made SCE change direction and fully engage in developing more price-based demand response programs. Regulatory initiatives and a few hot summers in the 2000s helped accelerate the need for smart meters to help move demand response programs forward. With five million smart meters now installed, SCE is generating innovative momentum and has significant demand response activity.

Today, SCE uses demand response to shift energy use from high-demand and high-priced periods to less costly times of the day. This allows customers to save money on their electric bills but also helps to prevent power shortages that could lead to brownouts or outages.



HEADQUARTERS
Rosemead, California

FAST FACTS

- Power delivered to more than 15 million people and 180 incorporated cities.
- 50,000 square miles of service area.
- 53,000 miles of overhead lines, 38,000 miles of underground lines and 800 substations.

PEAK DEMAND

23,000 MW

DR TOTAL

1,390 MW

LARGEST DR PROGRAMS

- Time-of-use interruptible load
- Summer Discount Plan
- Aggregator

DEMAND RESPONSE PROGRAMS AND USES

The following table provides a high level overview of demand response products at SCE.

PROGRAM		PURPOSE	ACQUISITION METHOD
COMMERCIAL, INDUSTRIAL & AGRICULTURAL			
Time of Use Base Interruptible Program	660	Customer-controlled reduction of energy usage to a pre-determined level during emergency situations.	Utility's general marketing and recruiting efforts and/or aggregators.
Agricultural Pumping & Interruptible	60	Interrupt electric service temporarily to customers during emergency situations through utility direct load control.	
Demand Bidding Program (DBP)	110	Reducing power during a DBP event — for economic, day-ahead energy.	
Critical Peak Pricing Program	25	Reduce energy costs by reducing usage at specific times during the summer months.	
Summer Discount Plan	65	Air conditioner cycling direct load control (both economic and emergency use).	
Aggregator Managed/ Capacity Bidding Program	145	Flexible bidding program that pays for reducing energy when energy prices are high, demand reaches critical levels or supply is limited.	Participation is required through an aggregator.
RESIDENTIAL			
Summer Discount Plan	295	Air conditioner cycling direct	Utility's general marketing and recruiting efforts and/or aggregators.
Save Power Day/Peak Time Rebate	30	Reduce energy costs by reducing usage at specific times during June through September.	

Preferred resources pilot

The preferred resources pilot project is an important initiative to determine if preferred resources can be used to offset growth in a particular area and provide needed reliability. Preferred resources refer to demand response, energy efficiency, solar generation and energy storage. The pilot also satisfies an interest at the state level to see if preferred resources can meet reliability

requirements so they can offset or defer the need for transmission upgrades or gas-fired generation. After the loss of San Onofre, a nuclear plant, as well as expected load growth in the region of about 300 MW by the year 2022, SCE is looking to defer the need build a gas-fired peak plant to cover needs between 10 a.m. and 6 p.m. in June through September.

The pilot started in 2013 and focuses on the southern part of SCE's service

territory in central Orange County. The plan is to complete this pilot by early 2018. The program has three phases. Phase one sets the overall plan to deploy and run the pilot. Phase two creates the automation and determines the best way to measure the effects. Phase three operationalize the pilot within the company. SCE hopes to identify other pockets within its service territory to see whether this is a sustainable model to defer construction costs.

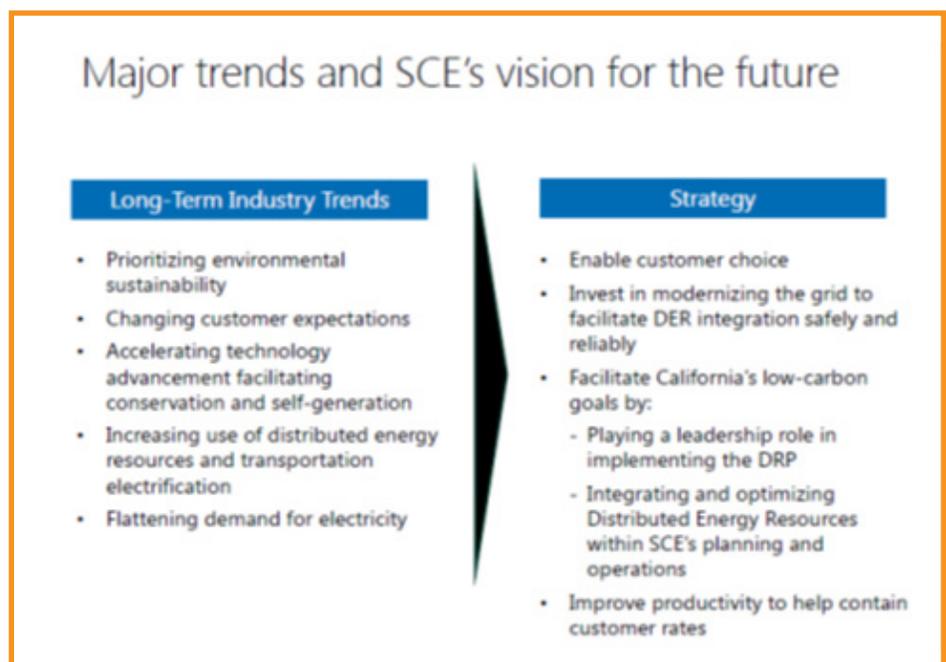
DR ENABLING TECHNOLOGY

SCE uses several different systems to manage its demand response programs which include the following:

- CSC platform that sends signals to air conditioners.
- Honeywell platform, which uses OpenADR, is used to dispatch SCE-managed programs.
- Energy Analytics platform that is used for the demand bidding program to house usage information, event performance and provide customers with visibility into the program.
- APX platform, used for the aggregator-managed programs, that sends notification to the aggregator who then notifies the customer.

WHAT'S NEXT for Southern California Edison

SCE plans to evolve its demand response programs based on the industry trends and strategies depicted to the right.





BPA Distributed Energy Resources Benchmarking Report



TENNESSEE VALLEY AUTHORITY

The Tennessee Valley Authority is a corporate agency of the United States that provides electricity to nine million people in parts of seven Southeastern states. In addition to operating and investing its revenues in its electric system, TVA provides flood control, navigation and land management for the Tennessee River system and assists local power companies and state and local governments with economic development and job creation. Demand response helps TVA meet its commitments to its customers and distributor utilities.

Demand response at TVA

TVA implements demand response to lower wholesale power prices, improve system reliability and support customer engagement. TVA is similar to BPA in that it works collaboratively with local power companies to implement products and programs. The firm also works with its 58 direct service customers, who make up 8 percent of TVA's revenue.

Energy Right Solutions implementing demand response

TVA offers demand side management programs through their EnergyRight® Solutions (ERS) organization. ERS partners with local power companies, directly-served customers and other stakeholders to deliver energy efficiency, demand side management and renewable energy solutions. These options enable homeowners and businesses to save money, improve the economy, protect the environment and enhance the quality of life of the people living within TVA's service territory. The



HEADQUARTERS
Knoxville, Tennessee

FAST FACTS

- 80,000 square-mile service territory.
- Delivers power from 53 power plants over 16,000 miles of high-voltage power lines.
- 58 direct service customers and 154 municipal and cooperative distributors.

PEAK DEMAND

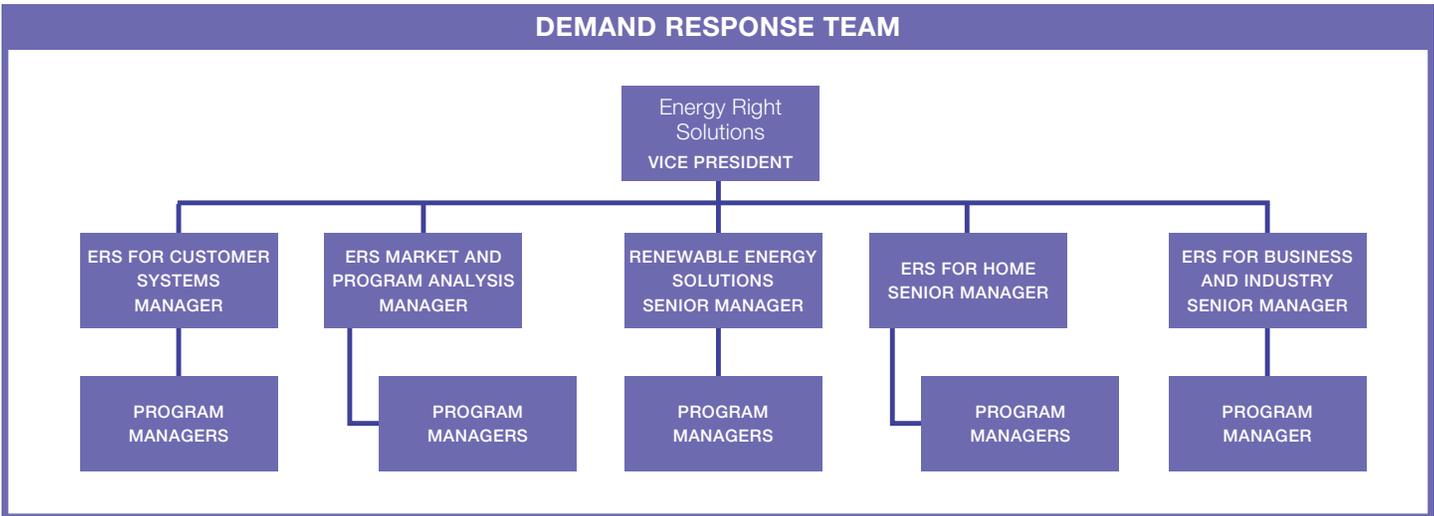
33,176 MW

DR TOTAL

Around 197 MW

LARGEST DR PROGRAMS

- Dispatchable voltage reduction
- Aggregated demand response
- Direct load control



organization is currently a six person team that is within the External Relations group at TVA. A high-level chart is provided for an understanding of how the group fits into the overall organization.

ERS products are integrated into normal business operations and can be called on by the trading floor. Aggregated demand response is dispatched first, followed by dispatchable voltage reduction and then direct load control. TVA does not allow behind the meter diesel generation for any of its programs. High level program information is provided in the table on page 37.

TVA has a separate Technology Innovation function outside of ERS that works closely with EPRI for early stage demand response technology and concepts.

Enabling technology to implement demand response

TVA dispatches demand response events through a homegrown, proprietary system called the demand response management system. It was designed considering regulatory-compliance, cost and consistency of information analysis for demand response products and the pricing overlays required by

several TVA business units. The system interfaces with local power companies and aggregators to initiate the demand response events and serves the balancing authority and power trading organizations who determine when an economic or reliability event is required.

Evaluating, measuring and verifying the numbers

Evaluation, measurement and verification are used to assess the performance of demand side management activities and can help to ensure greater certainty and effectiveness in future activities. Program evaluation is performed by the Marketing and Program Analysis group, which is housed outside of the demand response and energy efficiency program areas.

At TVA, ERS products are viewed as a resource. They employ a formal third party entity to design and conduct all program evaluation. TVA uses a nationally recognized firm to assure that all evaluations meet internal performance measurement and verification protocols, ensuring validity and confidence in the results of the evaluation. To count as a resource, it must be measurable and be evaluated with sufficient rigor to prove the energy savings are real. TVA requires

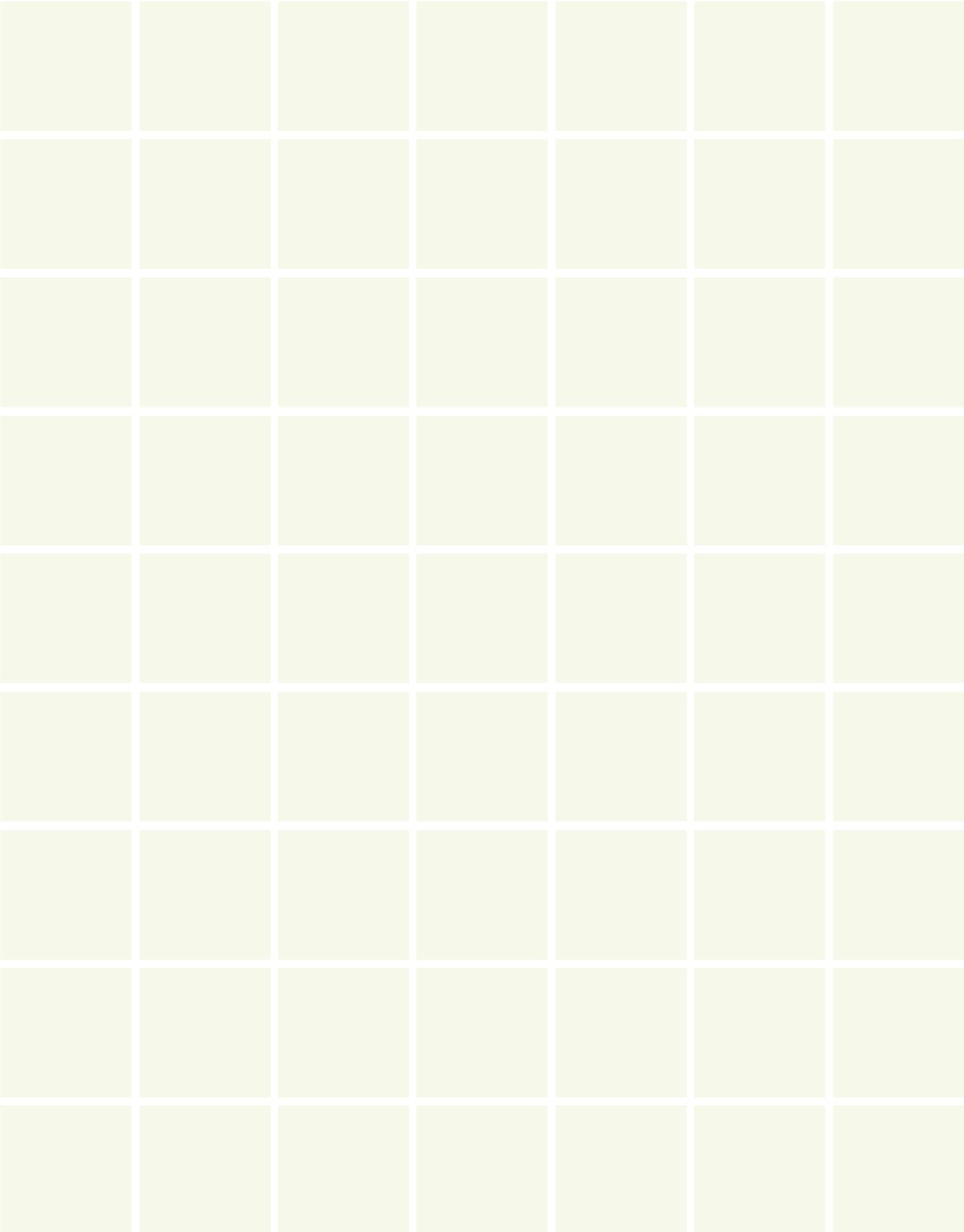
a higher level of rigor than is assigned by many investor owned utilities due to the “ERS as a resource” requirement. Program evaluation is performed every two to three years on a rotational basis, and results are made public.

WHAT'S NEXT
for Tennessee Valley Authority

As TVA moves more deeply into the distributed energy resource environment, demand response will be evaluated in terms of implementation of locational application for transmission management, frequency response and other ancillary services.

Demand response products

PROGRAM	DESCRIPTION	MWS	PURPOSE	ACQUISITION METHOD
Direct load control – residential	Product is dispatched for up to 100 hours per year with local power companies controlling air conditioning and water heating two to six hours per event with day-ahead notification. Energy payments are made to the local power company after the event.	2.5	Qualified local power companies use direct load control switches or devices to reduce peak demand from the end-use customers.	Local power companies recruit customers and then contract with TVA to provide a pre-determined amount of peak load reduction for 10 years.
Direct load control – commercial and industrial	Product is economically dispatched up to 40 hours per year, with unlimited dispatch for reliability. Events have two to eight hours response duration with the average event lasting around three or four.	Cannot be provided per EnerNOC contract	Targets C&I customers that can provide dispatchable peak load reduction. Participating customers are incentivized for shedding load by EnerNOC.	EnerNOC serves as an aggregator for this program. There is a 10 year contract between TVA and EnerNOC.
Aggregated demand response	Product is economically dispatched up to 12 hours per year and is unlimited for reliability. There is a 30-minute notification window and customers are compensated by monthly capacity payments and energy.	10	Enables local power companies to aggregate and provide dispatchable peak load reduction to TVA.	Seven States Power Corporation serves as an aggregator for participating local power companies. There is only a one year proof of concept implementation currently.
Dispatchable voltage reduction	Product is economically dispatchable up to 100 hours per year during summer and winter program hours. Electric feeders, bus voltage regulators and events are monitored near real-time in the demand response management portal.	185	Qualified local power companies can provide reduction by optimizing distribution-level voltage.	TVA works with local power companies to promote DVR as a key program in support of reducing carbon emissions.



GLOSSARY

ADVANCED METERING INFRASTRUCTURE

(AMI): an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

AGGREGATOR: a marketing entity which gathers together a consumer pool for the purpose of locating a resource, resource mix or service that matches the quantity and shape of the desired energy, transmission or other service(s).

AIR CONDITIONER CYCLING: device connected to air conditioning unit turns the unit on and off intermittently throughout an event period to reduce peak load on the system while still keeping the area cool.

BEHAVIOR DEMAND RESPONSE: peak-shaving via targeted communications to electricity consumers that encourage consumers to save energy. By using smart meter data, the effects of these programs can be accurately measured and used to compensate consumers for changes to their typical energy consumption habits.

BROWNOUT: an intentional reduction of energy loads in an area by the partial reduction of electrical voltages which results in lights dimming and motors losing efficiency.

CAPACITY: the maximum load that a generator, piece of equipment, substation, transmission line, or system can carry under existing service conditions.

CURTAILMENT: a temporary reduction in electric power delivery under emergency conditions, taken after all possible conservation and load management measures have been tried, and prompted by problems in meeting minimum requirements rather than peaking deficiencies; reduction in the scheduled capacity or energy delivery in response to a transmission constraint.

DISTRIBUTED ENERGY RESOURCES: encompasses efforts to shave or reduce peak load through the means of demand response, distributed generation or energy storage.

DISTRIBUTED GENERATION: small generation systems located at a customer site.

DEMAND RESPONSE: a resource that allows end-use electric customers to reduce their electricity usage in a given time period, or shift that usage to another time period.

DISPATCHABLE RESOURCES: utility's ability to vary the output of a generating unit which includes technologies like batteries.

ENERGY STORAGE: technologies that allow electricity generated at one time to be used at another time.

HEAT PUMP: a combination device for heating or cooling living space. Has the same functional subsystems as a refrigerator (a compressor that pressurizes a gas, a condenser that gives off heat as the compressed gas changes to a liquid, and an evaporator that absorbs heat as the liquid changes back to a gas) but in which the cycles are reversible.

INTERRUPTIBLE LOAD: a load that, by contract, can be interrupted if the supplier needs the energy to meet its firm loads.

LOAD MANAGEMENT SYSTEM: technology which enables a utility to reduce, reshape or redistribute loads to match available resources and comply with long-term objectives and constraints. Generally, attempts to shift load from peak use periods to low use periods.

NON-WIRES: consumption measures that do not involve building a new transmission line including generation redispatch, demand response, distributed standby generation and energy efficiency.

PAGING TECHNOLOGY: a method of transmitting information to devices on demand response equipment through pagers.

PEAK TIME OR PEAK DEMAND (DEMAND): when energy consumption is highest.

PEAKING UNIT: an electric generating plant or unit dedicated to meeting the maximum (peak) demand, or to fill emergency requirements.

PREDICTIVE APPLICATIONS: software applications that learn by doing and become better at solving problems as they collect more and more data.

PROGRAMMABLE THERMOSTAT: a thermostat designed to adjust the temperature according to a series of programmed settings that take effect at different times of the day.

REGULATOR: is designed to automatically maintain a constant voltage level.

SMART EQUIPMENT: technology that can be controlled or managed regardless of location.

SMART CIRCUIT BREAKER: a switching device capable of making, carrying and interrupting currents which can be controlled to control loads from a central location.

SMART METER: an electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information back to the utility for monitoring and billing purposes. Smart meters enable two-way communication between the meter and the central system.

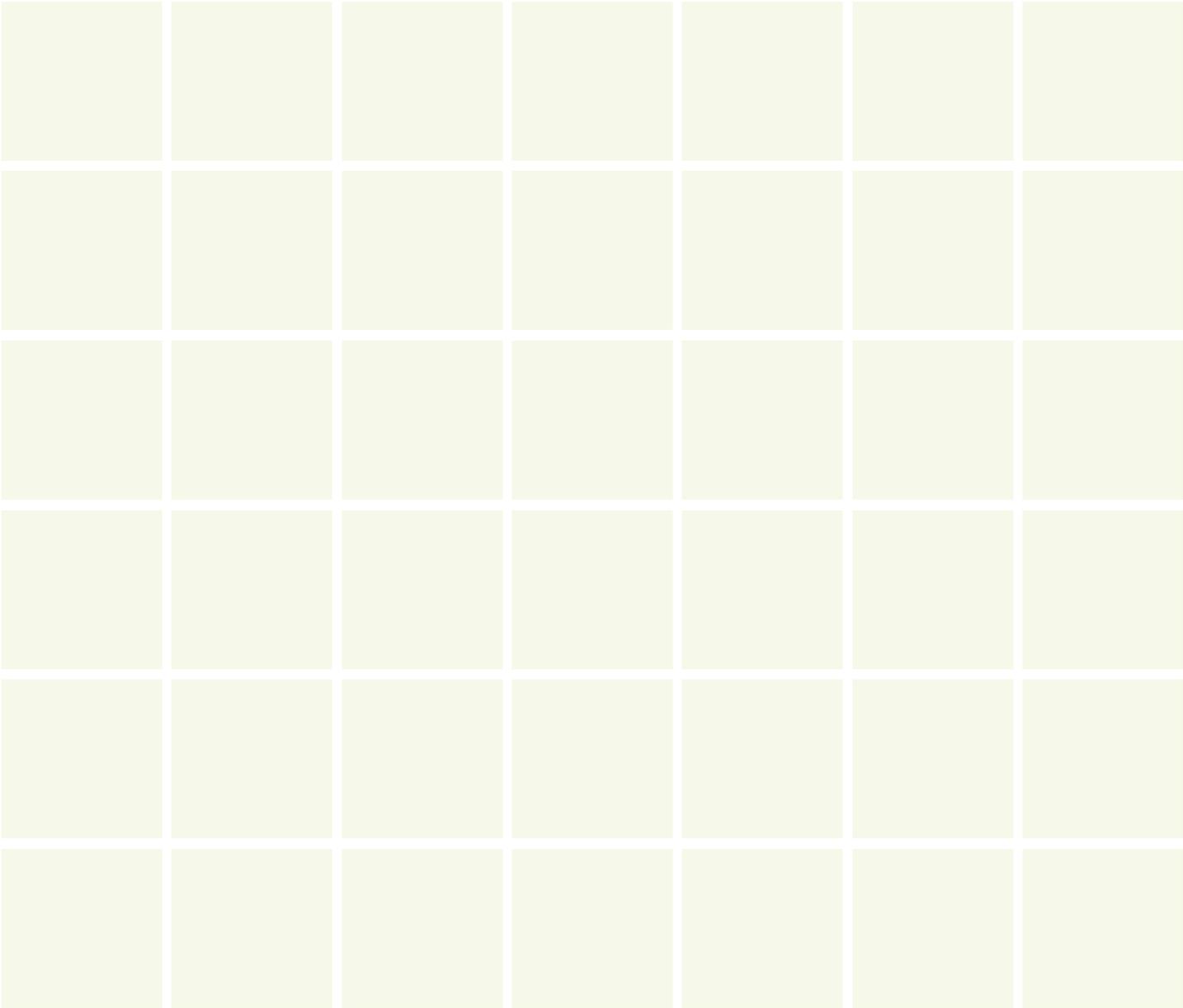
SMART THERMOSTAT: a Wi-Fi enabled thermostat that can be controlled regardless of location.

SUBTRANSMISSION: the part of an electric power transmission system that runs at relatively lower voltages, generally in the range of 69 kilovolts to 138 kV.

TRANSFORMER: an electrical device that transfers energy between two or more circuits through electromagnetic induction.

VOLTAGE OPTIMIZATION: uses a smart transformer to provide the exact amount of power that is needed and responds instantly to fluctuations within the power grid, acting as a voltage regulator to ensure that the optimized voltage is undisturbed.

WATER-HEATER DEMAND RESPONSE: controls when the water heater cycles on and off so energy usage can be shifted to off-peak times.



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