Demand Response

NARUC Webinar

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This is another in a series of webinars created to support smart grid activities of the FERC/NARUC Collaborative. This webinar addresses the hardware, technical, and policy issues regarding automation equipment on the customer side of the meter.

Agenda

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Webinar Objectives

1. Provide an overview of evolving smart grid demand response requirements.
2. Identify demand response regulatory and policy issues.
3. Examine the status and implications of demand response standards development.

Note:
This presentation addresses demand response principles and concepts, not specific retail or wholesale programs.

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While it is considered a critical element of Smart Grid, little information is provided in Title XIII, Section 1301 of the Energy Independence and Security Act of 2007 to define or clearly identify Smart Grid requirements for demand response. Utility programs to directly control residential air conditioners and water heaters have dominated utility offerings since the mid 1970's and tend to be considered synonymous with the term demand response. While direct control will continue to be an option, demand response for Smart Grid will require fundamental changes and major expansion in the scope, technical structure, technology, and customer role.

Under Smart Grid, demand response will need to provide capability to support:

- all classes of customers,
- provide economic, reliability, ancillary services, as well as transmission and distribution congestion management with advance notice and in near-real time, and;
- provide capability to manage and integrate PHEV's, intermittent, and other renewable resources

The material that follows will construct a new description of demand response consistent with this understanding of Smart Grid.

Smart Grid Objectives

Smart Grid is System Integration

The Smart Grid is a system of information and communication applications integrated with electric generation, transmission, distribution, and end use technologies which will :

Promote Customer Choice	[1] **enable consumers** to manage their usage and chose the most **economically** efficient offerings
Improve Reliability	[2] use **automation** and alternative resources to maintain delivery system **reliability** and **stability**, and
Integrate Renewables	[3] utilize the most environmentally gentle **renewable**, **storage**, and **generation alternatives**.

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Fundamentally, smart grid is a combination of information and communication applications that link together generation, transmission, distribution, and customer end-use technologies. The need to integrate all of the systems that generate and supply energy with customer usage is one of the design principles and expectations for smart grid. System integration will be accomplished using information, communications, and automation systems .

This definition of smart grid is an essential starting point because it creates the foundation for the demand response principles that follow.

Smart grid is not necessarily a specific combination of parts as much as it is a process for using information and communications to integrate all the components that make up each electric system. In fact, this description applies equally to demand response. Demand response under smart grid is fundamentally a process for using information and communications to provide links and automate customer response.

Smart grid system and demand response integration shares three common objectives:

1. Promote customer choice – provide customers with information, rates and pricing, and technologies that will allow them to make better usage decisions,
2. Improve reliability – use automation on the grid and in the customer premise as well as alternative generation options to improve system reliability and stability, and
3. Integrate renewables – support alternative generation and storage options that minimize or reduce environmental impacts, improve overall system efficiency, and reduce carbon-based fuel usage.

Note: Title XIII, Section 1301 of the Energy Independence and Security Act of 2007 describes smart grid as a system capable of accomplishing ten specific objectives http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf

Defining Demand Response

"Demand Response: Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. "[1]

Issue :

The historic focus of DR on reducing usage during periods of high wholesale market prices or maintaining system reliability does not fully address potential new applications of DR in areas of distribution congestion management, renewable integration, balancing, and volt/VAR applications.

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Demand response (DR) has been around since the Detroit Edison storage water heater program was introduced in 1934* and since that time DR has principally been defined as a technique for reducing peak demand. As this definition in the FERC report illustrated, the definition of demand response is beginning to address other capabilities, however even some of the most recent definitions still do not capture the range of applications expected to support smart grid.

This definition of demand response from the "The Assessment of Demand Response & Advanced Metering, Staff Report", released by FERC in February 2011[1] substantially expands on historical definitions, however it still does not account for the full range of anticipated smart grid DR applications, specifically:

- Increased electricity use : Ancillary service applications for regulation may require demand response to quickly increase and decrease load in response help balance system load. For example, customers with refrigerated warehouses may use the storage capability of their facilities to quickly ramp (pre-cool) up or shed load in response to short-duration system needs. The ability to increase and decrease load will be limited to a narrow range of customers and end-uses but could prove to be a valuable system resource.
- Congestion management: Transmission or distribution congestion conditions can be addressed by targeting DR to specific sub-stations, line segments, and transformers, however wholesale and retail system prices may not provide the right trigger conditions. Movement to more specific locational pricing and time-varying distribution costs could correct this situation. To be effective, congestion management will also require higher saturations of controllable or responsive load on individual feeders which may require alternative recruitment and customer service options.
- Renewable integration: Again, wholesale or retail system prices will not address solar PV or electric vehicle integration, which will most likely require more specific transformer or distribution system metrics.

* Detroit Edison introduced its first load management program in 1934 using oversized water heaters and time clocks that pre-heated water at night, eliminating all on-peak usage.

Demand Response Options

2010 FERC Survey Program Classifications[1]		Description
1	Direct Load Control	Sponsor remotely shuts down or cycles equipment
2	Interruptible Load	Load subject to curtailment under tariff or contract
3	Emergency Demand Response	Load reductions during an emergency event Combines direct load control with specified high price
4	Load as Capacity Resource	Pre-specified load reductions during system contingency
5	Spinning Reserves	Load reductions synchronized and responsive within the first few minutes of an emergency event
6	Critical Peak Pricing w/Control	Combines direct load control with specified high price
7	Non-Spinning Reserves	Demand side resources available within 10 minutes
8	Regulation Service	Increase or decrease load in response to real-time signal
9	Demand Bidding and Buyback	Customer offers load reductions at a price
10	Time-of-Use Pricing	Average unit prices that vary by time period.
11	Critical Peak Pricing	Rate/price to encourage reduced usage during high wholesale prices or system contingencies
12	Real-Time Pricing	Retail price fluctuates hourly or more often to reflect changes in wholesale prices on day or hour ahead
13	Peak Time Rebate	Rebates paid on critical peak hours for reductions against a baseline
14	System Peak Response Transmission Tariff	Rates / prices to reduce peaks and transmission charges

79%

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This table, labeled as Figure 4.9 in the FERC Staff Report [1] , presents a list of reported potential peak load reduction options. The top four demand response programs, Emergency Response, Interruptible Load, Direct Load Control, and Load as Capacity Resource are basically emergency reliability based options which collectively account for 79 percent of the total U.S. peak load reduction potential. This table was included here because it highlights several issues with the definition, perspective, and understanding of demand response.

Within the first four DR options, direct control programs tend to focus on residential customers, while the remaining program options focus on non-residential large commercial and industrial customers.

According to the FERC report, direct load control programs are typically targeted to residential and small nonresidential customers, however small and medium nonresidential customers generally don't have the opportunity to participate in DR options. Load control is usually accomplished with utility control switches installed directly on a load (air conditioner, water heater, etc.) or with a utility-provided Programmable Communicating Thermostat (PCT) that replaces the existing facility thermostat. According to the FERC report control signals rather than price-based radio or other communication signals sent by the program sponsor are necessary for effective control of the large numbers of small loads. What is difficult to reconcile is that results from most pricing pilots demonstrate that price not direct control produces greater load impacts.

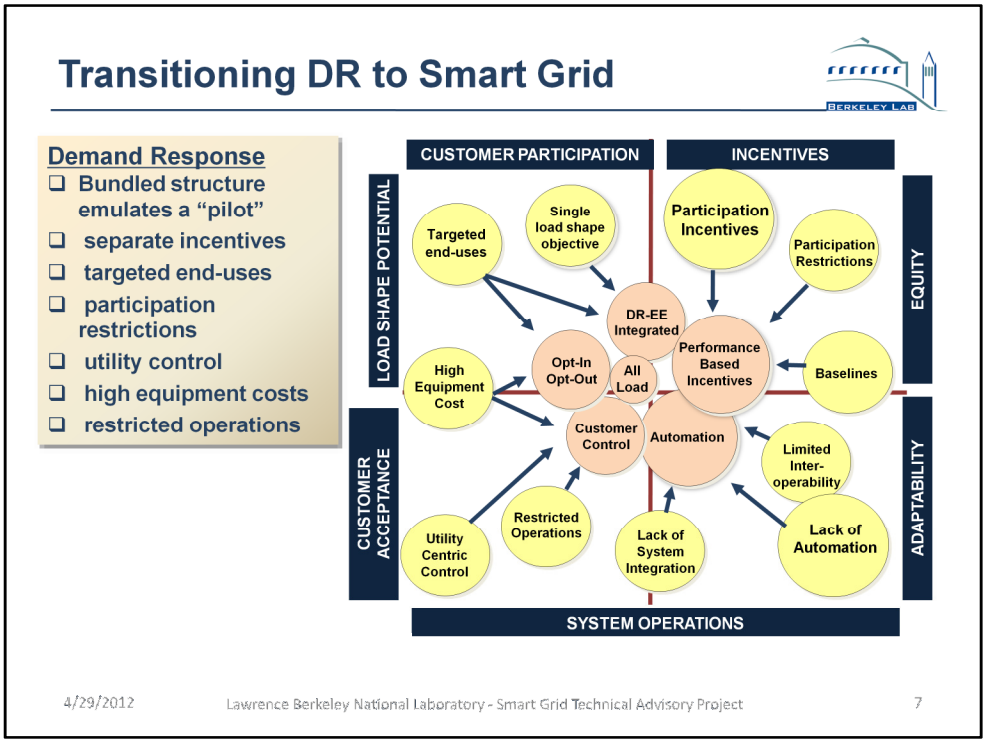
Note: #1-2 are traditional DR options that had their origins in some of the original PURPA pilots

Options #3-9 have really evolved from ISO markets over the last ten years. Good examples of evolution that will continue.

What this table from the FERC report describes is an approach to DR that depends upon utility-centric options that bundle incentives (rates or payments), control technology, and control strategies to achieve a very specific load shape objective. To change the load shape objective in most cases requires a major change in the 'program'. This FERC listing also comingles specific DR options (e.g. Direct Control, Demand Bidding, and Regulation Service) with basic rate designs (e.g. Time-of-Use, Real-time, and Peak-Time Rebate) which tends to mask the real functional differences and similarities that actually characterized the components of every DR option.

For example, how does each DR or rate option interact or impact the actual customer loads and usage patterns? Which loads are impacted? Do the impacts vary from one option to the next? Do utility control strategies produce similar impacts from one customer to the next customer and if not how does this impact the equity and fairness of incentive structures? What should distinguish one DR option from another - the 'program bundle', the automation option, the incentive, or some combination of features?

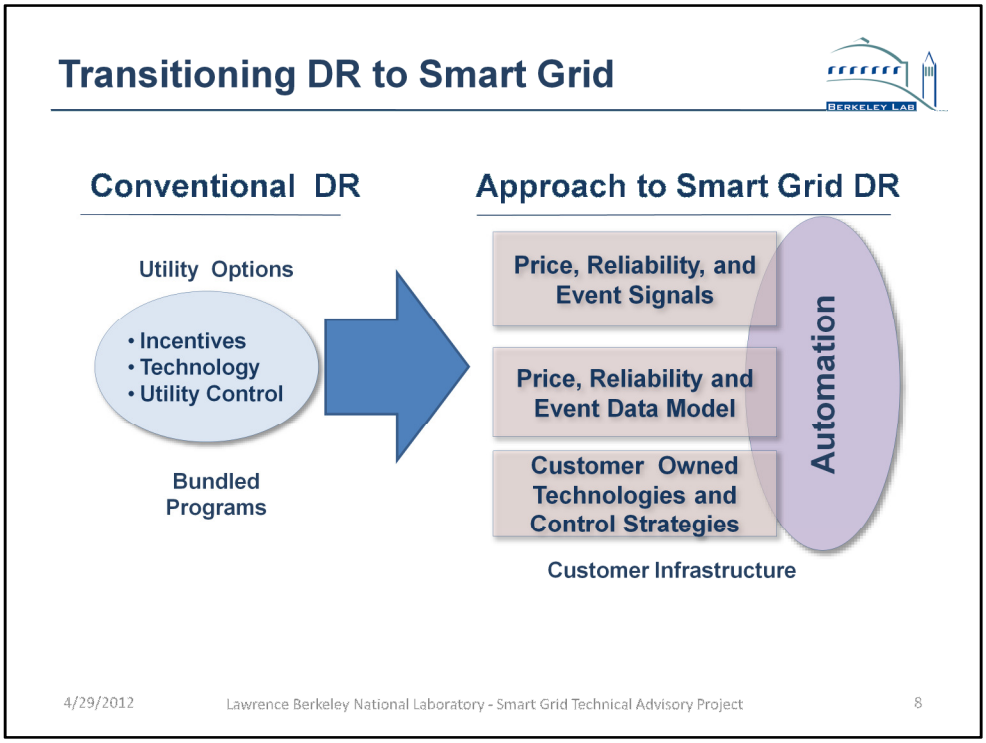
This lack of clarity between a 'DR Program' and a 'Rate' makes it difficult to fully identify the strengths and weaknesses of different approaches to demand response, and how price or control signals and different automation technologies can impact customer response or be combined in innovative ways to provide both the



This slide provides a more detailed perspective of demand response problems. The labels around the outside of this matrix categorize the problems into seven (7) categories:

1. Customer Acceptance
2. Load Shape objectives
3. Customer participation
4. Incentives
5. Equity
6. Adaptability and
7. System Operations

Within each quadrant we've highlighted very specific features and issues.



Notes:

•What is certain is there will be uncertainty on both the utility and customer sides of the meter until the RPS, EE, and other smart grid efforts settle out

•How do you build in flexibility to accommodate DR without wasting rate payer investments and disrupting customers every time a program changes?

•One option – build in the infrastructure on the customer side of the meter to automate load and energy management and link that to price and event signaling capability on the utility side of the meter.

The distinguishing characteristic with all conventional demand response options is their program structure. All elements of a typical demand response option are packaged together and designed from the outset to be fully integrated. While integration is good, problems occur when political, economic, or regulatory issues cause the rate or incentives, control requirements, or other key elements to change. The bundled approach also tends to limit customer flexibility to adapt controls to work or personal situations or to substitute one load for another.

Under Smart Grid, the expanded flexibility and scope of demand response requirements, the need for interoperability, and need for active customer participation requires an alternative to a bundled program structure. Under Smart Grid, the demand response model will be comprised of three parts:

A Technology Platform - that supports the communication and automation of price, reliability and event signals. Stabilizing the communication and automation platform minimizes customer investment cost, allows for a stable, logical integration with premise and appliance level controls, and supports continuous interoperability within the customer facility.

Price, Reliability, and Event Signals – separating out the 'signal' (a) provides customer choice by presenting options that appeal to both simple operation and complex financial and economic modes, and; (b) allows the 'signal' to change without also having to change the technology or other parts of the program.

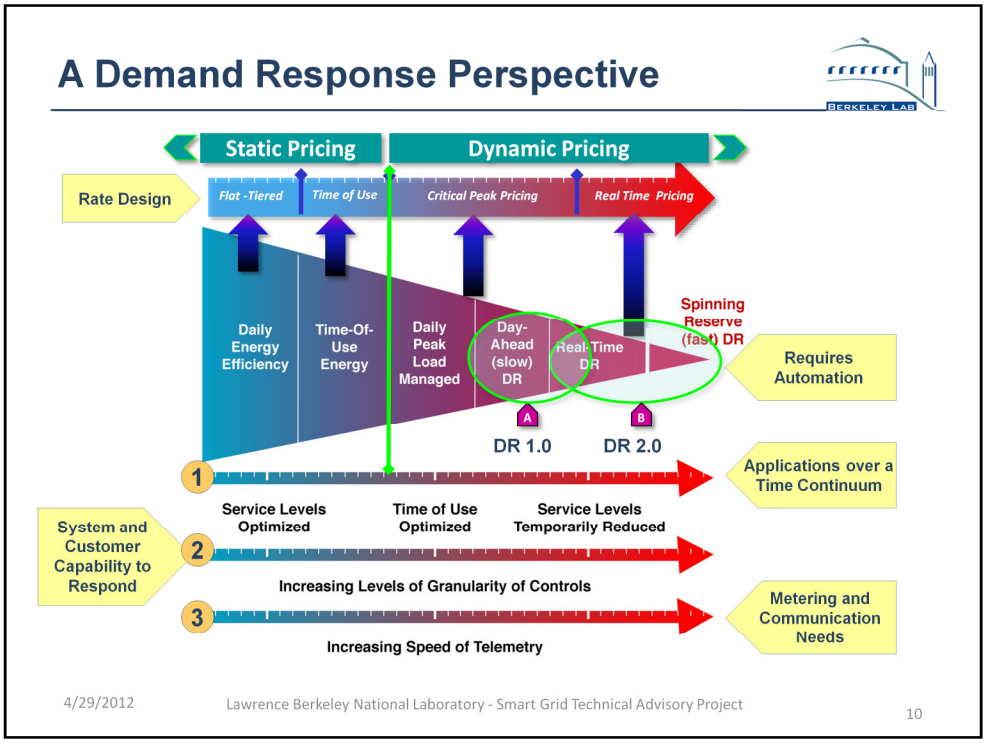
Customer Provided Automation and Control Strategies – control strategies and other options that customers use to reduce, shift load, or otherwise response to price, reliability, and event signals are often unique to the facility/premise. Utility direct control strategies don't do a good job of capturing the differences between customer preferences or values. Smart Grid emphasizes price response, which translates into customer-determined and managed control strategies and a shift away from utility direct control. Customer automation systems and customer developed response strategies produce less chance of adverse impacts and more long-term stability. Distributing control to the customer eliminates the need for the utility to redo the strategies each time a program element changes. Allowing the customer to define how they respond to a price, reliability or event signal customizes the response to each individual customer's unique economic and operating environment.

Why Should Regulators be Concerned ?

- Conventional DR signaling is not necessarily compatible with system operating or customer needs, automation, or smart appliances.
- DR control strategies may not be compatible with smart appliances, evolving customer automation technologies, or carbon mitigation.
- DR rate and incentive options do not provide capability to support integration of intermittent resources or electric vehicles.
- Conventional retail DR cost effectiveness will be influenced over time due to appliance and building efficiency gains and renewable penetration.

Conventional DR does provide the full range of capability to address smart grid requirements or expectations.

More significantly, existing conventional DR substantially under performs what is technically feasible.



Demand response options are consistently viewed as independent programs controlled by a utility rather than part of a continuum of customer response to price, reliability, and event signals. In other words, DR is usually viewed from supply perspective rather than a rationalization of utility supply and customer demand .

One of the underlying assumptions of the preceding material is that Smart Grid will require a fundament set of changes to existing demand response options. This exhibit provides a roadmap that describes the continuum of demand response options under Smart Grid and how the options within this continuum relate to three areas; rate design/pricing, customer service levels, and meter and communication functional capability.

The focal point of this slide is the multi-segment triangle located in the middle of the graphic. This triangle depicts a hierarchy of customer and utility energy management options, that tend to increase in priority and system value as you read from left to right . Across the top of the triangle are a series of labels that map the segments of the triangle to various rate forms or pricing options.

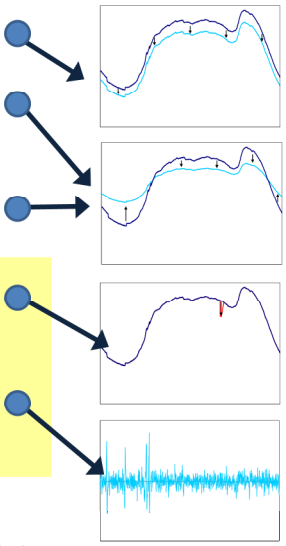
There are three arrow scales below the triangle successively addressing (1) customer service levels, (2) granularity of controls, and finally (3) increasing speed of telemetry. Again, for each of these scales, complexity, system value, and cost increase as you move from left-to-right.

The green circle on the left labeled “A” encompasses “Day-Ahead” and part of the “Real-time” category of DR options. The “A” group encompasses what are considered traditional demand response options, also referred to as DR 1.0. These options are generally supported by fixed incentives (participation or capacity payments) or rate forms (CPP, PTR, or RTP). DR 1.0 options are typically limited to a maximum number of events, targeted to a specific season and fixed block of hours. Controlling actions are relegated to peak load shedding or load shifting from peak to off-peak periods.

The green circle on the right labeled “B” highlights real-time DR applications to support balancing, spinning reserve, and other ancillary service applications. These options can be facilitated by rate design and fixed incentive payments, however they are more likely to be associated with contractual agreements that require special terms and conditions that can also include fixed load reduction obligations, automated controls, and supplemental advanced metering, telemetry, or other special communication equipment. Based on the specifics of the rate design real-time pricing can be classified as both a DR 1.0 and DR 2.0 option. For real-time pricing, DR 2.0 opportunities require short-duration pricing intervals and short advance notice (5-15 minutes). DR 2.0 options are generally available year-round and have few if any limitations on either the frequency of occurrence or time-of-day. DR 2.0 options may only be required for 10-20 minutes at a time however, controlling actions can not only include load shedding and shifting, but load building.

Smart Grid Load Shaping Objectives

1. **Energy Efficiency** programs reduce overall electricity consumption, generally also at times of peak demand.
2. **Price Response** programs move consumption from times of high prices to times of lower prices (real time pricing or time of use) – expanded to address transmission distribution congestion management.
3. **Peak Shaving** programs require more response during peak hours and focus on reducing peaks on high-system load days – expanded to address transmission distribution congestion management.
4. **Reliability Response** (contingency response) requires the fastest, shortest duration response. Response is only required during power system "events." – This is new and slowly developing.
5. **Regulation Response** continuously follows minute-to-minute commands from the grid in order to balance the aggregate system load and generation – This is also very new and appears to be very promising for certain loads.



1. Adapted from: Demand Response Spinning Reserve Demonstration Project, Consortium for Electric Reliability Technology, LBNL, Joseph Eto presentation October 19, 2009.

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These load shaping objectives generally correspond to the segments of the triangle on the preceding slide. For example, the fist segment of the triangle 'daily energy efficiency' matches the first load shaping example that illustrates a general lowering of usage in most hours. Unfortunately energy efficiency focuses only usage, not time, consequently, a reduction in any one hour or all reductions grouped into a single hour would all be consistent with the efficiency objective, even if these changes aggregated the peak or reduced the load factor.

What is most significant in this slide are the Reliability and Regulation response, which illustrate very different load shaping objectives than what is usually representative of most existing utility demand response programs.

From Load Shedding to Load Shaping

Load Shedding (DR 1.0)

- Text, email or phone call to building manager
- Manual control of building load
- "Best guess" at results
- Can't calculate comfort impacts

Load Shifting (DR 1.5)

- Electronic signal to BMS or EMS
- Pre-programmed static control strategies to shift building load
- Results determined by pre-calculated setting in BMS
- Limited provision for tenant comfort
- Validate results after the event (or billing cycle)

Load Shaping (DR 2.0)

- Electronic signal to building IQ DR event incorporated into optimization parameters
- Predictive energy optimization plans response tailored to building, weather and specific DR structure
- System adapts in real-time to changes in conditions
- Results are managed to precise DR program
- Tenant comfort parameters incorporated into building response
- Real-time tracking of impact and results.

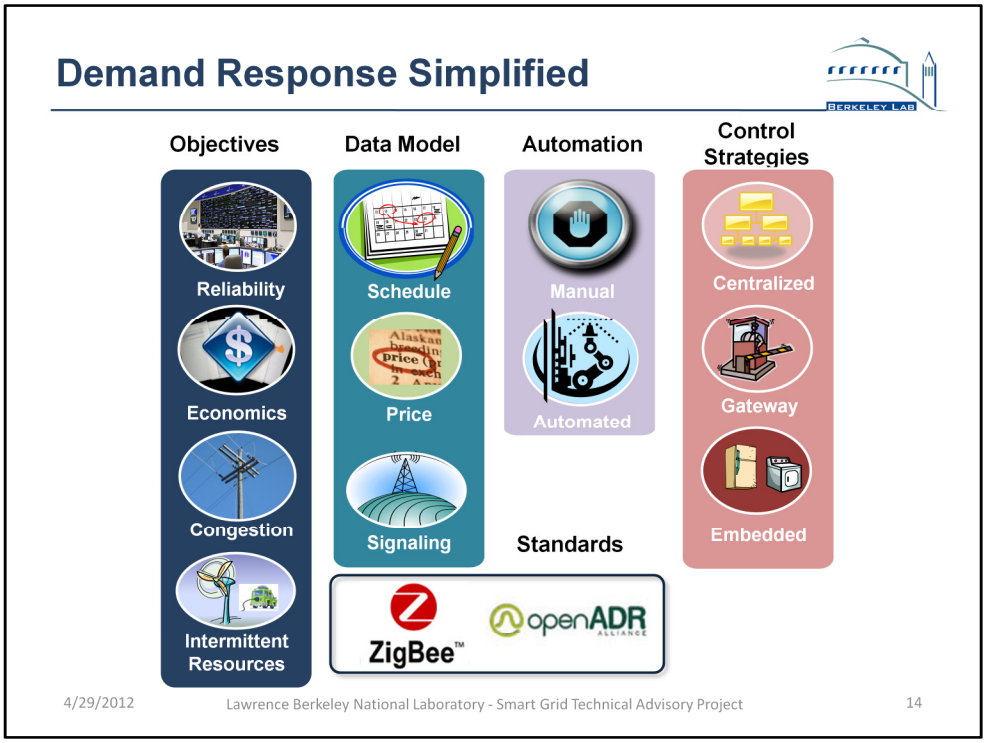
DR 1 — DR 2

Control Signal → Event or Relative Price → Price

Source: "Toward Demand Response 2.0," M.Zimmerman, greentechgrid, September 27, 2010, http://www.greentechmedia.com/articles/read/toward-demand-response-2.0/

DR Smart Grid Requirements

	Requirements	Description
Incentives	1. Performance-Based Incentives	• Customers rewarded based on their actual performance. • Customers not paid only to participate.
Operations	3. Dispatchability	DR automated and dispatchable.
	4. Ubiquitous Availability – Participation Implications	• DR available on all circuits throughout the utility system. • Capacity and energy are inseparable from a customer perspective • EE a condition of service for all customers, why not DR?
	5. Control Strategies – Customer Choice	The customer determines what, when, and how to control their loads.
	6. Simultaneous Economic and Reliability Options	Customers allowed to simultaneously participate in day-ahead economic and real-time reliability options.
Costs	7. Market-based Technology	Customers acquire automated systems and DR equipment and services through open market providers.
	8. Integrated Demand Response and Efficiency	Incentives and operations integrate DR and EE.


Demand Response Simplified
Objectives
Data Model
Automation
Control Strategies
Reliability
Economics
Congestion
Intermittent Resources
Schedule
Price
Signaling
Manual
Automated
Centralized
Gateway
Embedded
Standards
ZigBee™
openADR
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Demand Response Issues

- Market Model: Utility versus Customer Centric?
- Participation: Opt-in versus Opt-out
- Rates and Incentives – is dynamic pricing necessary ?
- Control Strategies: utility vs. customer control ?
- Automation – necessary or not ?
- Standards – ZigBee SEP and OpenADR

Market Model: Bundled versus Open ?

	Utility Centric DR	Customer Centric DR
Participation	• Targeted loads • Limited to Large C/I & Residential	All Customers
Who Controls	Utility	Customer
What is Controlled	• Interruptible Rates • Res. HVAC, Water Heating	All Loads Available
Control Equipment	• Utility Provided • Few Suppliers	•Customer Provided •Many Market Suppliers
Incentives	• Fixed / Participation Payments • Baseline metrics	•Retail Dynamic Prices •Reservation payments •Pay-for performance
DR Products	Generally limited to Reliability and Economics	Capacity, Energy, Ancillary Services Markets; Congestion Management
DR, EE, Renewable Integration	No	Yes

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The prior slides have highlighted several structural and logical differences necessary to make demand response Smart Grid compatible.

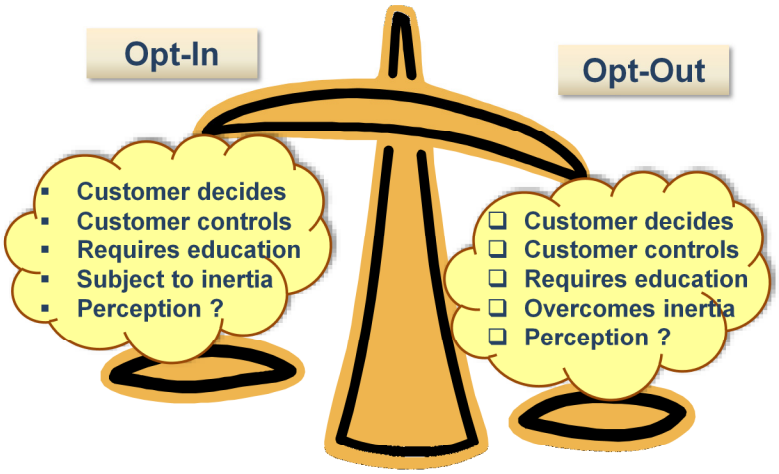
This slide highlight seven key differences between conventional demand response and what is necessary to support Smart Grid. Two key differences are highlighted by the red circles, specifically: (1) smart grid will require a move to distributed, price responsive control and away from direct control, and (2) demand response control strategies will have to consider options that integrate efficiency, reliability and renewables.

Structurally, demand response needs to move toward a modular structure based on a technology platform that can provide an electronic automated utility-customer link. On the utility side, this interface will provide capability to receive price, reliability and event signals. On the customer side this interface will provide a stable platform for connecting customer energy management and control options and smart appliances. This linkage can be provided by an energy management system, home automation system, or by capability embedded in individual appliances. A move away from integrated, stand alone programs to a technology platform approach should reduce the cost of demand response and improve flexibility to adapt to changing needs.

Operationally, demand response needs to move toward distributed, price response and away from centralized direct control. Distributed control provides greater potential load impacts, more flexibility and options for customers, and eliminates many of scale and control issues associated with implementation of very large scale direct control.

Participation: Opt-in versus Opt-out

***"..how a choice is presented can affect the actions of decision makers, who have a tendency to stick with the default option."* ***



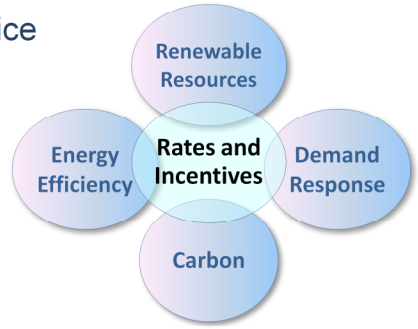
* Choi, JJ, Laibson D, Madrian B, Metrick A. Optimal defaults. American Economic Review 2003; 93(2): 180-185.

Rates and Incentives

Is dynamic pricing necessary ?

Yes, especially to achieve consumer benefits:

- Rate structures provide price signals that link the utility system and the customer.
- Price establishes the customer value function.
- Price enables benefits of smart grid to be achieved.

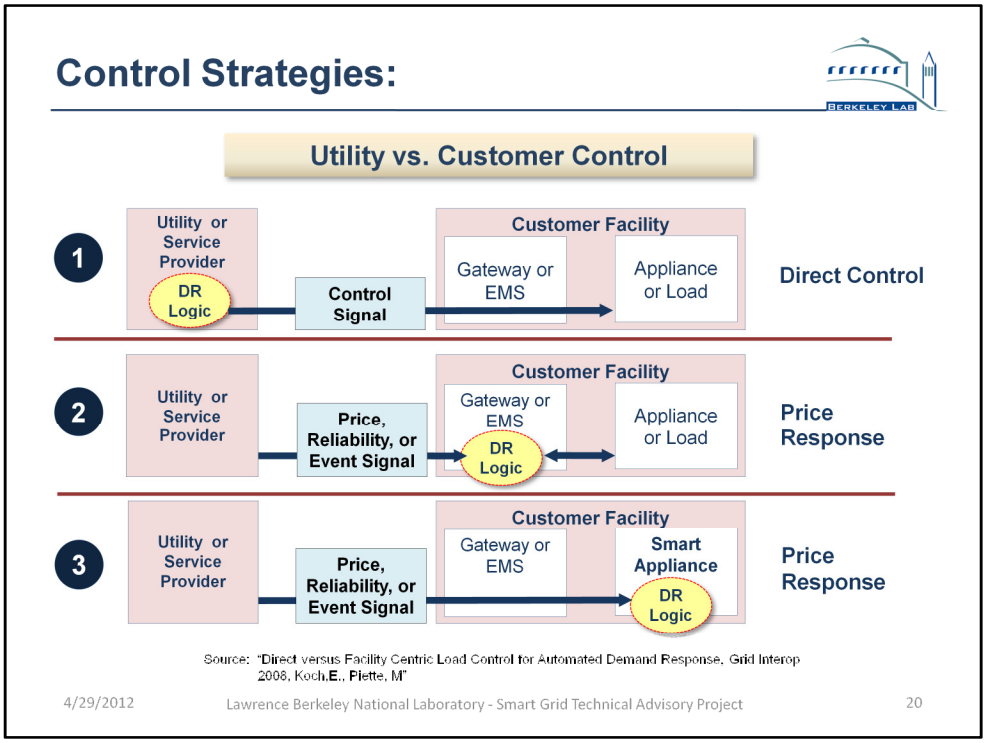


Rates and Incentives

Is dynamic pricing necessary ?

	Non-Dynamic Rates		Dynamic Rates		
Smart Grid Goal	Tiered*	Time of Use (TOU)	Peak Time Rebate No TOU	Critical Peak Price + TOU	Real Time Price
Energy Efficiency	Need longer-term studies and coordination with demand response and distributed resource programs.				
Demand Response – Reliability (Day-ahead)	No	No	Yes	Yes	Yes
DR – Congestion Mgt, Ancillary Services (Day-of)	No	No	No	Yes	Yes
Solar Photovoltaic's	No	Yes	No	Yes	Yes
Energy Storage	No	Yes	No	Yes	Yes
Electric Vehicles	No	Partial	No	Yes	Yes

*Flat rates contribute nothing toward these goals. Tiered (inclining block) rates theoretically incent conservation. Peak time rebates and dynamic pricing require advanced metering systems.



There are three conceptual approaches for developing and providing demand response control strategies, one characterized as direct control and two characterized as price response or distributed control.

Direct control (graphic #1) has been the overwhelmingly dominant approach to demand response since PURPA legislation was introduced in the mid 1970's. With direct control, the utility creates and manages the control strategy, represented by a control signal that is usually sent directly to a switch or control logic in the targeted end-device. Direct control signals mirror the command-and-control approach that utilities employ for managing power plants essentially telling the end-device either how much time it can run or how much time it is off, during each time interval.

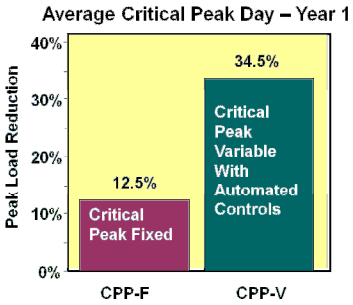
Price response or distributed control strategies have been historically associated with rate implementation, not demand response. However, critical peak and real-time rates that can be dispatched, convert price signals into proxy demand response signals. The primary difference with price response is that the customer is responsible for translating and acting upon the price, reliability or event signal.

In graphic #2, the price, reliability or event signal is processed in a gateway device, either an energy management system or home automation system that the customer has programmed to control their energy using end-devices using these signals as activation variables. The customer gateway device translates the price, reliability and event signals into control strategies and settings established by the customer that are passed on to the end-devices.

In graphic #3, the price, reliability or event signals are processed directly by the end-devices. Again, logic in the end-devices translates the signal into a control action or setting established by the customer.

Automation: Necessary or Not ?

- Automation increases load response.
- Provides customers with "set and forget" it capability.
- Improves persistence of response over time.
- Provides fast response necessary for real-time response.

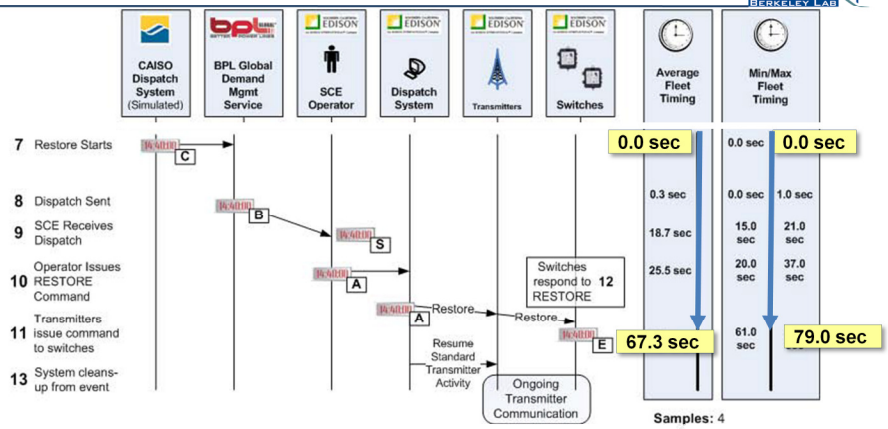


California SPP 2003

Rate Group	No Smart Thermostat	With Smart Thermostat
Residential-CPP	29%	49%
Residential-Peak Time Rebate	11%	17%
All Electric-CPP	22%	51%
All Electric-Peak Time Rebate	6%	24%

PowerCents DC 2010

Automation: Necessary or Not ?



"NERC and WECC rules for contingency reserve response (both spinning and non-spinning) require full response in 10 minutes.

The SCE load management dispatch system consistently demonstrated full response from all four distribution feeder groups in less than 80 seconds."

1. Demand Response Spinning Reserve Demonstration Project, Phase 2 Findings from the Summer of 2008, April 2009, LBNL, Joseph Eto, http://certs.lbl.gov/pdf/lbnl-2490e.pdf

Standards: ZigBee-HomePlug SEP Status

DEFINITION:

- ZigBee is the brand name for a low-power wireless radio communication standard built on the IEEE 802.15.4 standard.
- HomePlug is the brand name for a power line communication standard built on IEEE P1901.
- ZigBee (wireless) and HomePlug (power line) require hardware and software components certified by each groups alliance-designated testing facilities.

PURPOSE:

- ZigBee-HomePlug Smart Energy Profile (SEP 2.0) is expected to provide software applications and code to support pricing, demand response, and related energy applications.
- Expected to operate within the customer premise, supporting device registration, device monitoring, and utility control.

STATUS AND POTENTIAL ISSUES:

(a) lack of backward compatibility between SEP 1.0 and SEP 2.0
(b) SEP 1.0 built into existing meters, not activated due to security concerns
(c) SEP 2.0 still in development, originally due out May 2010.
(d) March 2011, SGIP forms 90-day emergency PAP 18 to resolve SEP 1.0-2.0 compatibility issues.

Review.

Standards: OpenADR Status

DEFINITION: OpenADR is an open standards-based communications data model designed to promote common information exchange for demand response price and reliability signals between the utility, aggregator, or Independent System Operator and electric customers.

PURPOSE:

- Provides Internet-based interoperable price, reliability, or event signals to customer programmed automated facility energy management or control systems.
- Customer systems listen for OpenADR signals, which preserves the customer firewall and internal system security.
- Applications support all customer types and DR options allowing demand response to be a dispatched, fully automated event, with no manual intervention.

STATUS AND POTENTIAL ISSUES:

(a) Developed and commercialized by the Demand Response Research Center
(b) Pilots began in 2003, commercialized in 2006
(c) Broad implementation support by over 60 control vendors, with implementations planned and in process in multiple states and countries.
(d) National standard work due for completion 2011.

Resource Links: http://newscenter.lbl.gov/press-releases/2009/04/27/openadr-specification/

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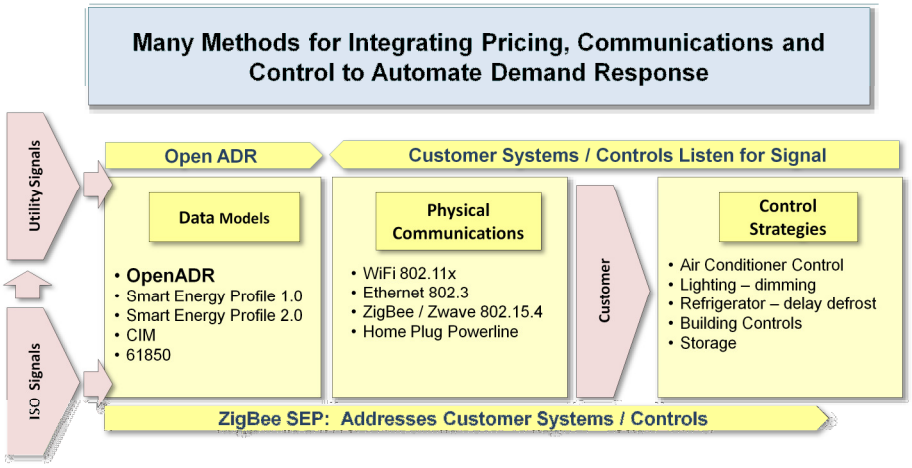
- NIST standard #13 – Open Automated Demand Response – OpenADR
- Review

Standards: System Architectures



OpenADR and ZigBee included among the original NIST 16 Smart Grid Standards.

Standards: OpenADR

What is the Demand Response Research Center ?

- **Established:** in 2004 at the Lawrence Berkeley National Laboratory by the California Public Interest Energy Research Program (PIER) as an initiative of the California Energy Commission
- **Objective:** to develop, prioritize, conduct and disseminate multi-institutional research to facilitate demand response.
- **Scope:** technologies, policies, programs, strategies, and practices, emphasizing market connections and implementation
- **OpenADR** – initially established as a research project in 2003 to automate and expand demand response in large commercial and industrial facilities.

Standards: OpenADR Design

OpenADR Data Models for Price and Reliability

Automation

- Allows DR to be a dispatchable resource
- Improves DR reliability, predictability, and value
- Increases customer participation and reduces response cost

Open Data Models

- Simplify and reduce cost of DR
- Creates interoperability among customer systems
- Creates interoperability between wholesale and retail systems

Price and Reliability Signals

- Allows customers to choose level of response and how to enable DR strategies
- Provides ability to embed automation in customer control systems.

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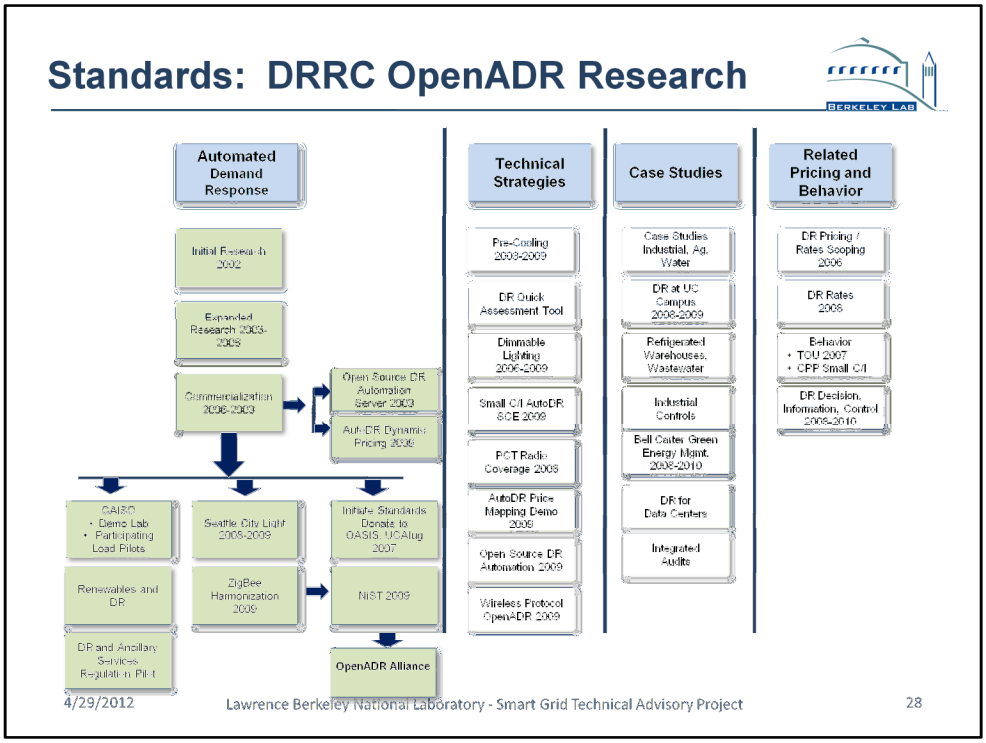
Key Points:

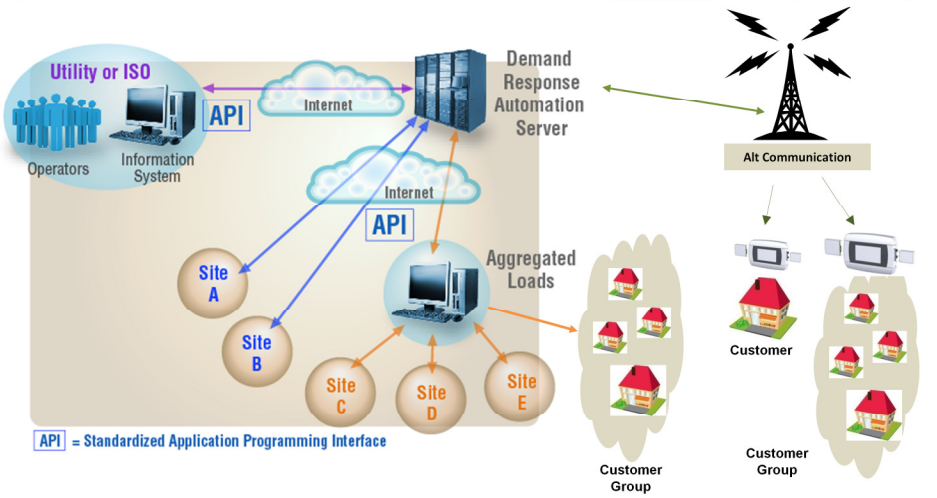
- OpenADR using existing Internet infrastructure to support standardized, high speed communication, leverage existing security and privacy capability
- Price, reliability and event signals are posted to a server – which the customer listens for and reacts to. OpenADR does not go into the customer site – this preserves the customer firewall and existing customer security.
- Automation equipment is integrated into the customer site – EMS, EMCS or control units for individual lighting or other specific loads. This approach clearly cements customer buy-in and provides the foundation for building in EE and permanent load shifting opportunities.
- The customer determines what to control, how to control, and when to control. Even with that level of choice, 8 years of implementation continually demonstrate reasonably consistent peak reduction response.



Purpose of this slide:

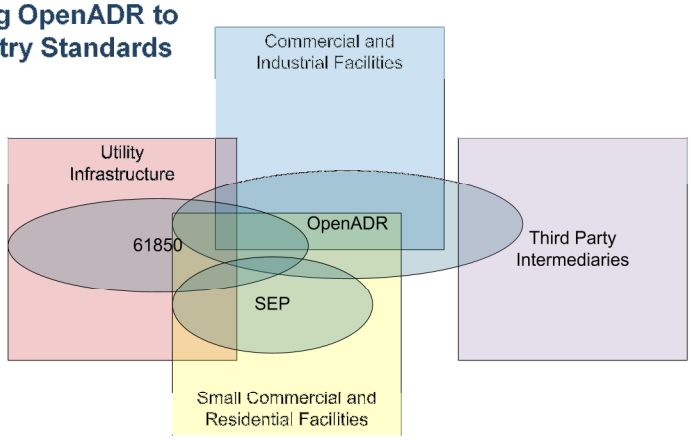
To illustrate that eight years of broad based research, field trials, and commercialization activity have gone into the development of OpenADR.

Standards: OpenADR System Architecture



Standards: OpenADR Conformance

Rationalizing OpenADR to Other Industry Standards



- **OpenADR - only existing open data model to bridge communications between utility and control systems in commercial, industrial and residential facilities.**
- **"Price Mapping Demonstration Project" extended OpenADR capability into small commercial and residential.**

Standards: OpenADR Data Model

Example of Price Data Models
Hourly Prices Mapped to Tiers

Literal Prices RTP or TOU/CPP

Time	Price
0:00	$ 0.06
1:00	$ 0.06
2:00	$ 0.06
3:00	$ 0.06
4:00	$ 0.06
5:00	$ 0.06
6:00	$ 0.06
7:00	$ 0.08
8:00	$ 0.08
9:00	$ 0.08
10:00	$ 0.10
11:00	$ 0.10
12:00	$ 0.10
13:00	$ 0.12
14:00	$ 0.12
15:00	$ 0.12
16:00	$ 0.12
17:00	$ 0.22
18:00	$ 0.22
19:00	$ 0.14
20:00	$ 0.14
21:00	$ 0.12
22:00	$ 0.10
23:00	$ 0.10

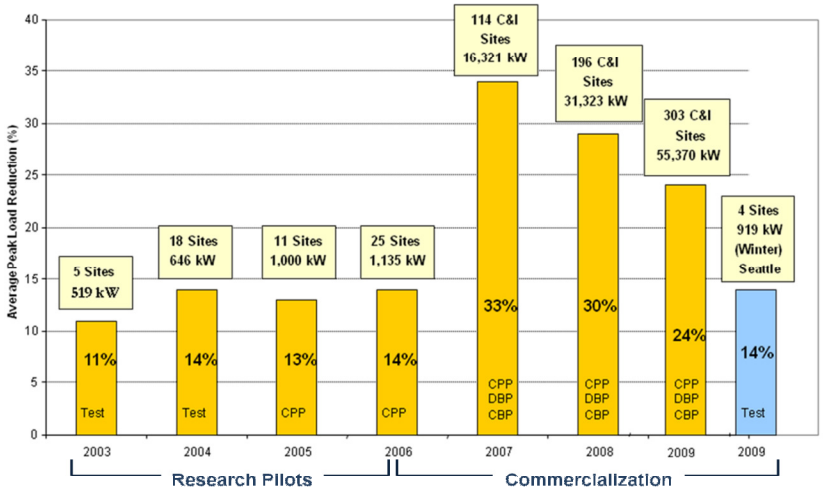
Prices Mapped to Price Tiers

Start	End	Price Tier
0:00	6:59	Low
7:00	12:59	Medium
13:00	16:59	High
17:00	18:59	Critical
19:00	21:59	High
22:00	23:59	Medium

Prices Mapped to Relative Tiers

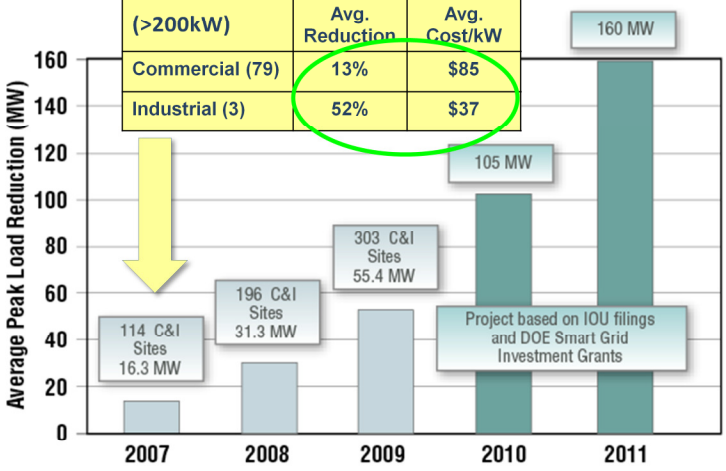
Price Tier	Price
Low	$0.00 - $0.06
Medium	$0.06 - $0.11
High	$0.11 - $0.18
Critical	> $0.18

Standards: OpenADR Price Response



Standards: OpenADR Price Response

Pacific Gas & Electric Company 2007		
(>200kW)	Avg. Reduction	Avg. Cost/kW
Commercial (79)	13%	$85
Industrial (3)	52%	$37



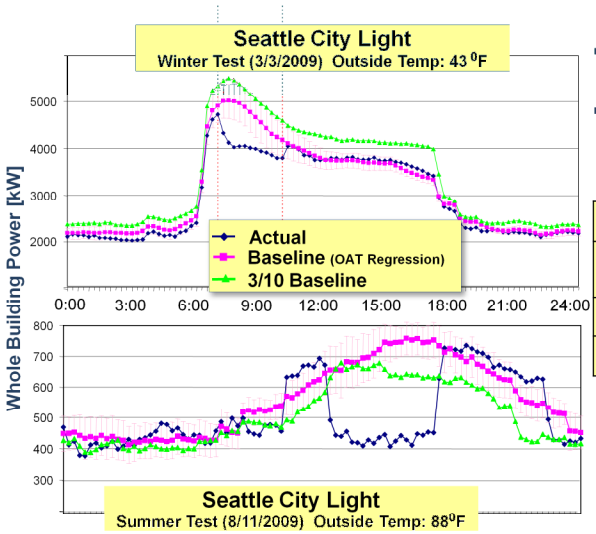
Standards: OpenADR DR-EE Integration

SMUD Small Commercial EE-DR Integration

Business Type	Program Option	Energy Efficiency	Demand Response	Monthly Bill
		% 2007 baseline	*% 2008 baseline*	*% Standard GSN Bill*
Office	Direct Control (11)	-27%	-38%	-27%
	CPP (23)	-32%	-24%	-32%
Retail	Direct Control (8)	-15%	-22%	-26%
	CPP (20)	-19%	-14%	-31%
Restaurant	Direct Control (1)	-8%	-1%	-7%
	CPP (8)	-10%	-3%	-12%
All Customers (71)		**-20%**	**-14%**	**-23%**

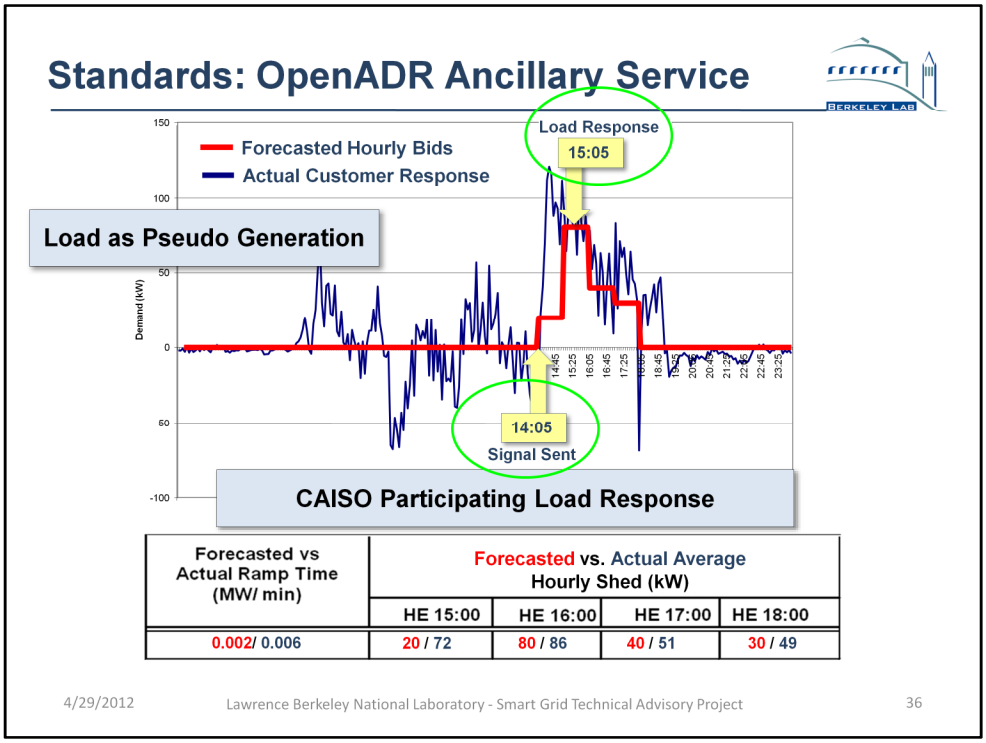
- Purpose of this slide is to illustrate another application of OpenADR, this time with small commercial customers and how demand response can be successfully integrated with energy efficiency.
- The SMUD pilot program in 2008 provided customers with Programmable Communicating Thermostats and a choice a convention direct control option (utility raised setpoint 4 degrees) and a Critical Peak Pricing rate where the customer determined how it would operate.
- While the samples were relatively small the results were statistically significant.
- The mix of utility direct control and customer-control mirrors what might actually occur in an offering that provides customer choice. The combined "All Customer" results are significant.
- Because the Programmable Communicating Thermostats at that time did not have OpenADR software clients (they do now) the OpenADR price signals were mapped to a bridge client and rebroadcast over an FM side band to the PCT.
- SMUD integrated EE with DR by offering customers full energy audits if they would agree to participate in the DR pilot.
- Energy usage was tracked prior to the pilot to create a baseline that was used to track energy usage during and following the pilot.
- The DR impacts were measured from the reduced usage baselines.

Standards: OpenADR Winter/Summer Impacts



- Same buildings in summer and winter DR events.
- Same infrastructure used to respond to signals during summer / winter events.

BPA Seattle City Light		
	Avg. Reduction	Avg. Cost/kW
Winter (4)	14%	$76
Summer (5)	16%	$108



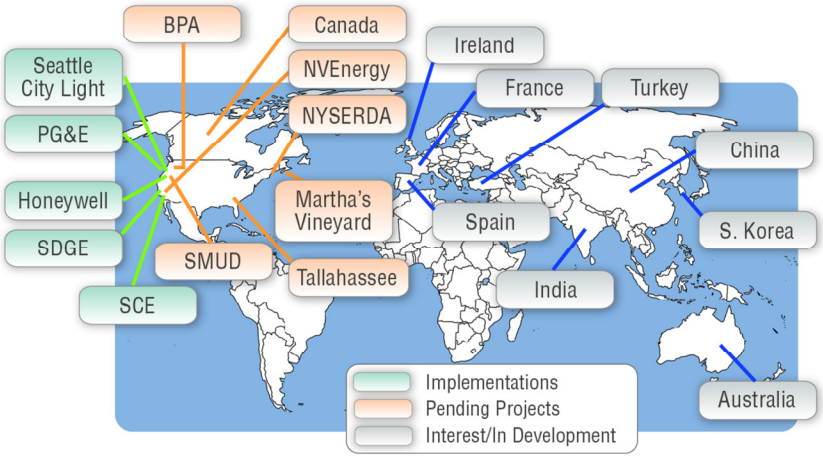
Forecasted vs Actual Ramp Time (MW/ min)	Forecasted vs. Actual Average Hourly Shed (kW)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.002/ 0.006	20 / 72	80 / 86	40 / 51	30 / 49

Objectives:

1. Can commercial buildings with HVAC DR Strategies meet non-spinning product requirements (10 minutes ramp, 2 hrs availability? Yes.
2. Does it require any infrastructure changes? None.
3. Additional cost? Telemetry.

Three buildings participating in PG&E's Critical Peak Pricing Program successfully participated in CAISO's Ancillary Services market as Non-Spinning reserves.

Standards: OpenADR Development



Standards: OpenADR Industry Support

Utilities, Aggregators, and ISOs

Research Organizations

Testing, Certification, & Alliances

Technology Integrators

Control and Technology

Industrial

Commercial & Industrial

Commercial

Small Commercial and Residential

Standards: OpenADR Lessons Learned

Automation

- Allows DR to be a dispatchable resource **(wholesale and retail DR).**
- Improves DR reliability, predictability, and value **(summer / winter).**
- Increases customer participation and reduces response cost **(transparent retail to wholesale DR conversion).**

Open Data Models

- Simplify and reduce cost of DR **(embedded clients).**
- Creates interoperability among customer systems.
- Creates interoperability between wholesale and retail systems.

Price and Reliability Signals

- Allows customers to choose level of response and how to enable DR strategies **(increases DR response).**
- Provides ability to embed automation in customer control systems **(increases DR reliability, customer participation).**

Cost

- Expanding support for OpenADR and use of embedded software clients reduces implementation costs.

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Key "Cost" bullet point - as OpenADR becomes more widely adopted, as use of embedded software clients expands, as EE integrated with DR, the marginal cost of implementation will continue to drop and eventually be insignificant.

We're already seeing that in PCT's with USnap based module communication modules.

6.30 Demand Response

References

	Title	Link
1	Assessment of Demand Response & Advanced Metering, Staff Report, FERC, February 2011	http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf
2	**Coordination of Energy Efficiency and Demand Response, LBNL, Goldman, Reid, Levy, Silverstein, January 2010.**	http://sites.energetics.com/madri/pdfs/lbnl-3044e.pdf
3	Demand Response Spinning Reserve Demonstration Project, Consortium for Electric Reliability Technology, LBNL, Joseph Eto presentation October 19, 2009	http://certs.lbl.gov/pdf/lbnl-2490e.pdf
4		
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