Demand Response Potential And Target Setting Workshop

June 8, 2020

Current Clean Energy Rulemaking Overview

Upcoming Dates

June 10 - Markets Stakeholder Workgroup

June 16 - Joint UTC/Commerce incremental cost of compliance workshop

June 29 - Comments due on PoE rules

July 6 - Comments due on EIA rules

July 28 - EIA Adoption Hearing

Ongoing UTC Dockets

- UE-190652
  - Energy Independence Act (EIA)
- UE-190698
  - Integrated Resource Plan (IRP)
- UE-190837
  - Purchases of Electricity (PoE)
- UE-191023
  - Clean Energy Transformation Act (CETA)

Workshop Goals

Integrated Resource Plan

UE-190698

Determine if guidance is needed for new requirement to:

Identify the potential cost-effective demand response and load management programs that may be acquired.

Clean Energy Implementation Plan

UE-191023

Determine if guidance is needed for new requirement to:

Propose specific targets that pursue all cost-effective, reliable, and feasible demand response.

Today's Agenda

- **1:30** Welcome and introduction
- **1:40** Potential for Load Flexibility – The Brattle Group
- **2:55** Ten minute break*
- **3:05** DR insights for the northwest – Pacific Northwest National Laboratory
- **4:00** Facilitated discussion on DR potential and CEIP targets
- **4:45** Next steps

* Additional 5 min bio breaks will be announced verbally

Virtual Workshop Instructions

Do:

✓Try to participate using your computer.

✓Mute your mics and turn off your video camera.

✓Use Skype chatbox.

✓Wait to be called on to speak.

✓ Respect the pause.

✓ Ask clarifying questions during the presentation.

Don't:

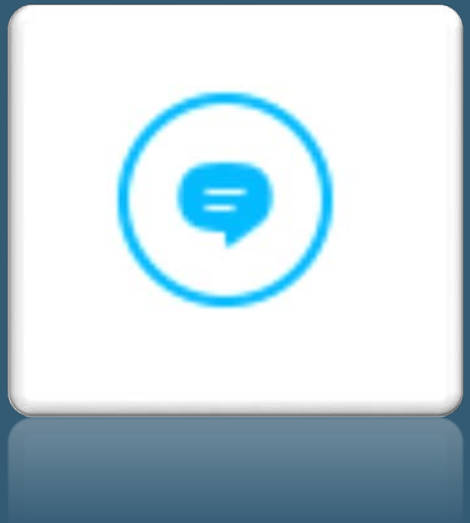
×Hesitate to "raise your hand" or ask a question!

×Speak over the presenter or a speaker who is voicing a question or thought.

×Forget this is a public workshop. The presentation and comments will be recorded and posted.

The Skype chat box

Look for this icon on your Skype window to open the meeting chat box.



Type “Raise hand” or type out question in chat box to ask questions during presentations.

“Raise hand” for discussion after the presentations.

The Potential for Load Flexibility

PREPARED BY
Ryan Hledik
Ahmad Faruqui

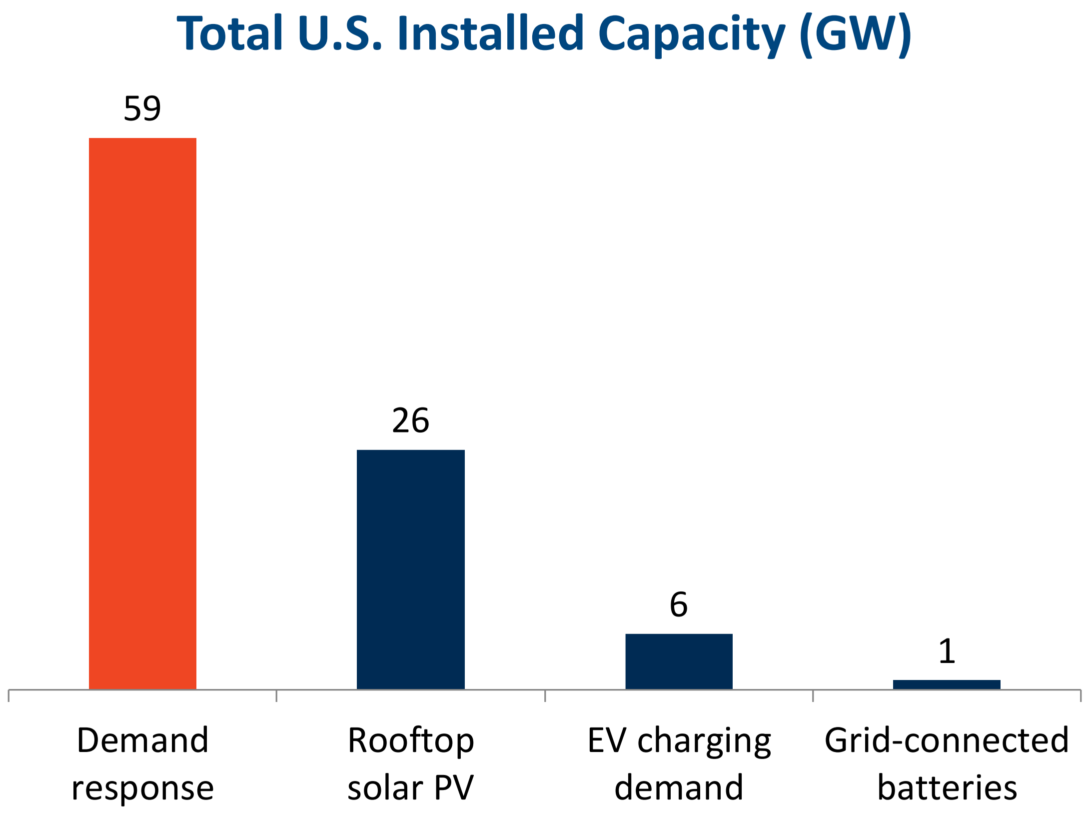
Washington UTC Demand Response Potential and Target Setting Technical Workshop

June 8, 2019

THE Brattle GROUP

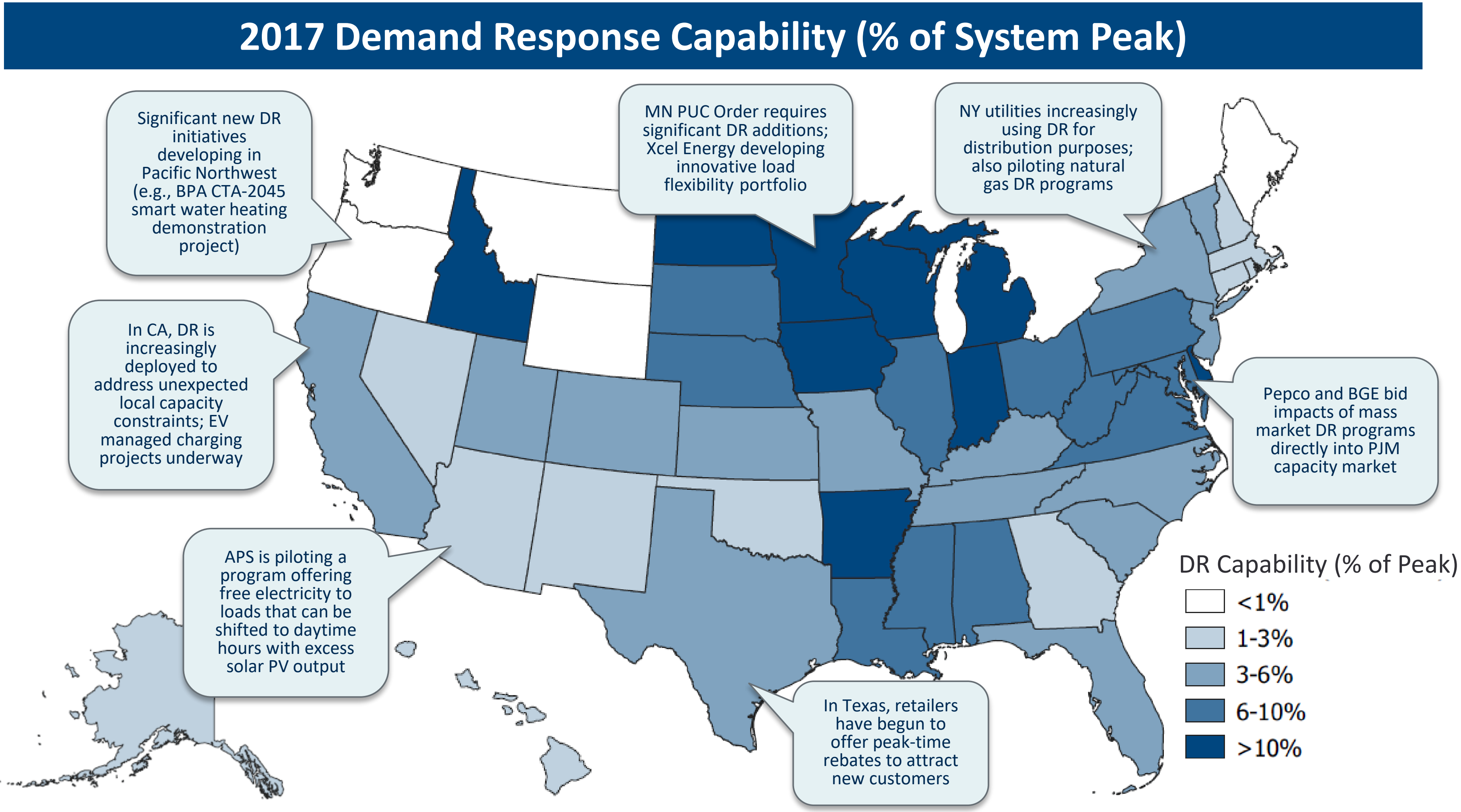
You can't spell "DER" without "DR"

DR is the largest distributed energy resource (DER) in the U.S.



Notes:
EV charging demand assumes 6 kW charging demand per EV, does not account for coincidence of charging patterns. Rooftop solar PV estimate is installed capacity, does not account for derated availability during peak. Existing DR is the sum of retail DR from 2017 EIA-861 and wholesale DR from 2018 FERC Assessment of Demand Response and Advanced Metering; values are not modified to account for possible double-counting between wholesale and retail DR.

DR capability varies significantly by state

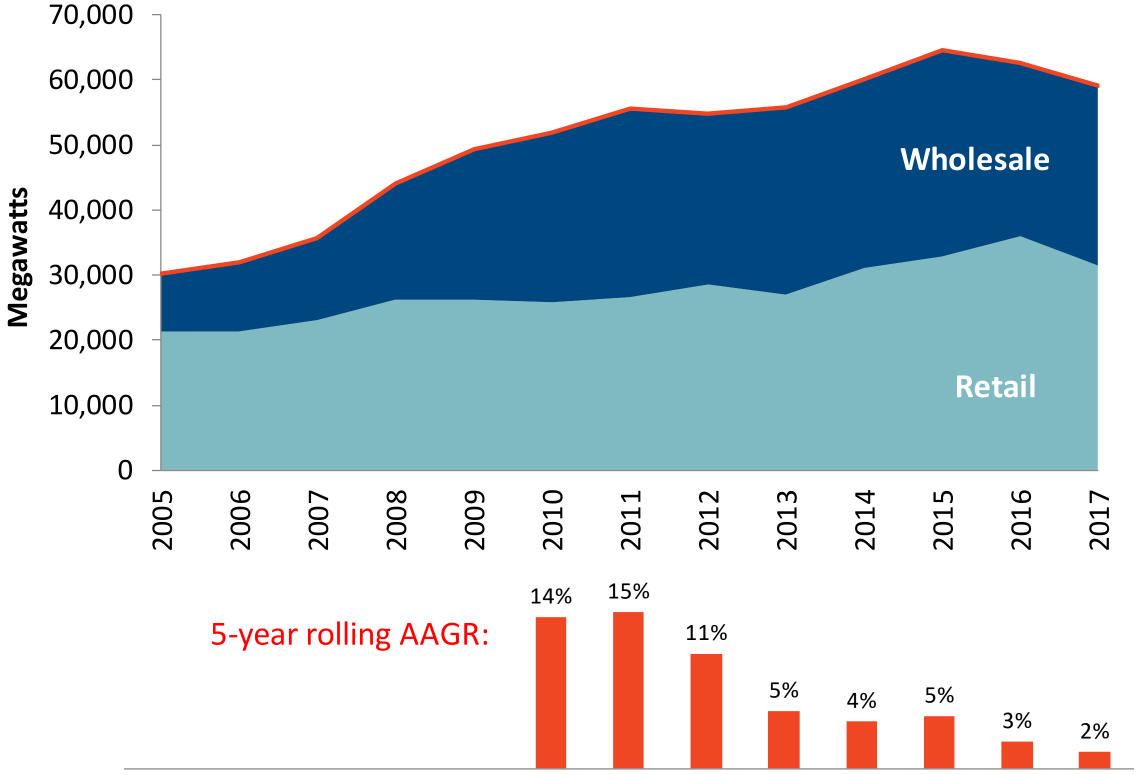


Notes and sources: Brattle analysis of data from 2018 FERC Assessment of Demand Response and Advanced Metering and 2017 EIA-861. Wholesale DR capability from FERC Assessment allocated to states proportional to estimated state share of ISO peak demand (according to 2015-2017 EIA-861 data). Values are not modified to account for possible double-counting between wholesale and retail DR.

The "DR 1.0" market has matured

Once a rapidly growing resource, conventional DR is reaching a saturation point in markets where peak capacity needs have stalled

Total U.S. DR Peak Reduction Capability



Contributing Factors

- Increasingly stringent wholesale market participation rules
- Low capacity market prices
- Flat/depressed hourly energy price profile
- 5+ years of excess peaking capacity projected by many utilities

Source: Brattle analysis of FERC Assessment of Demand Response and Advanced Metering reports (2006-2018) and EIA-861 Data (2005 – 2017). Post-2012 values are not modified to account for possible double-counting between wholesale and retail DR across data sources.

“Load flexibility” provides improved system operational capabilities

DR can be repurposed to address three emerging industry megatrends

Mega-trend	Challenges	Load Flexibility Solution
Renewables growth	• Low net load leads to renewables curtailment and/or inefficient operation of thermal generation • Intermittency in supply contributes to increased need for grid balancing	• Electricity consumption can be shifted to times of low net load • Fast-responding DR can provide ancillary services
Grid modernization	• Costly upgrades are needed to improve resiliency and accommodate growth in distributed energy resources	• Geographically-targeted DR can help to defer capacity upgrades
Electrification	• Rapid growth in electricity demand may introduce new capacity constraints	• Controlling new sources of load can reduce system costs while maintaining customer comfort and adding value to smart appliances and EVs

Quantifying Load Flexibility Potential

Understanding load flexibility market potential & value

DR 1.0 market potential studies took a narrow view of DR capabilities. They need to be expanded to capture the full value of load flexibility.

Scope of “DR 1.0” Market Studies

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral
Direct load control	X	X	X
Interruptible tariff	X	X	X
Demand bidding	X	X	X
Time-of-use (TOU) rates	X	X	X

Programs typically focus on demand reductions during a limited peak window and are constrained to a small number of hours per year

Quantified value and associated market potential are derived only from reductions in system peak demand

See appendix for a description of load flexibility programs.

Understanding load flexibility market potential & value

First, consider innovative new applications of DR. Load flexibility will do more than just shave the peak.

1 Extend DR value streams

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted T&D capacity deferral	Load shifting/ building	Ancillary services
Direct load control	X	X	X	X		
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Time-of-use (TOU) rates	X	X	X			

Several new uses of DR are possible, but existing programs are limited in their ability to provide those services

See appendix for a description of load flexibility programs.

Understanding load flexibility market potential & value

Second, broaden the definition of DR. Load flexibility has the potential to provide higher value at a lower cost.

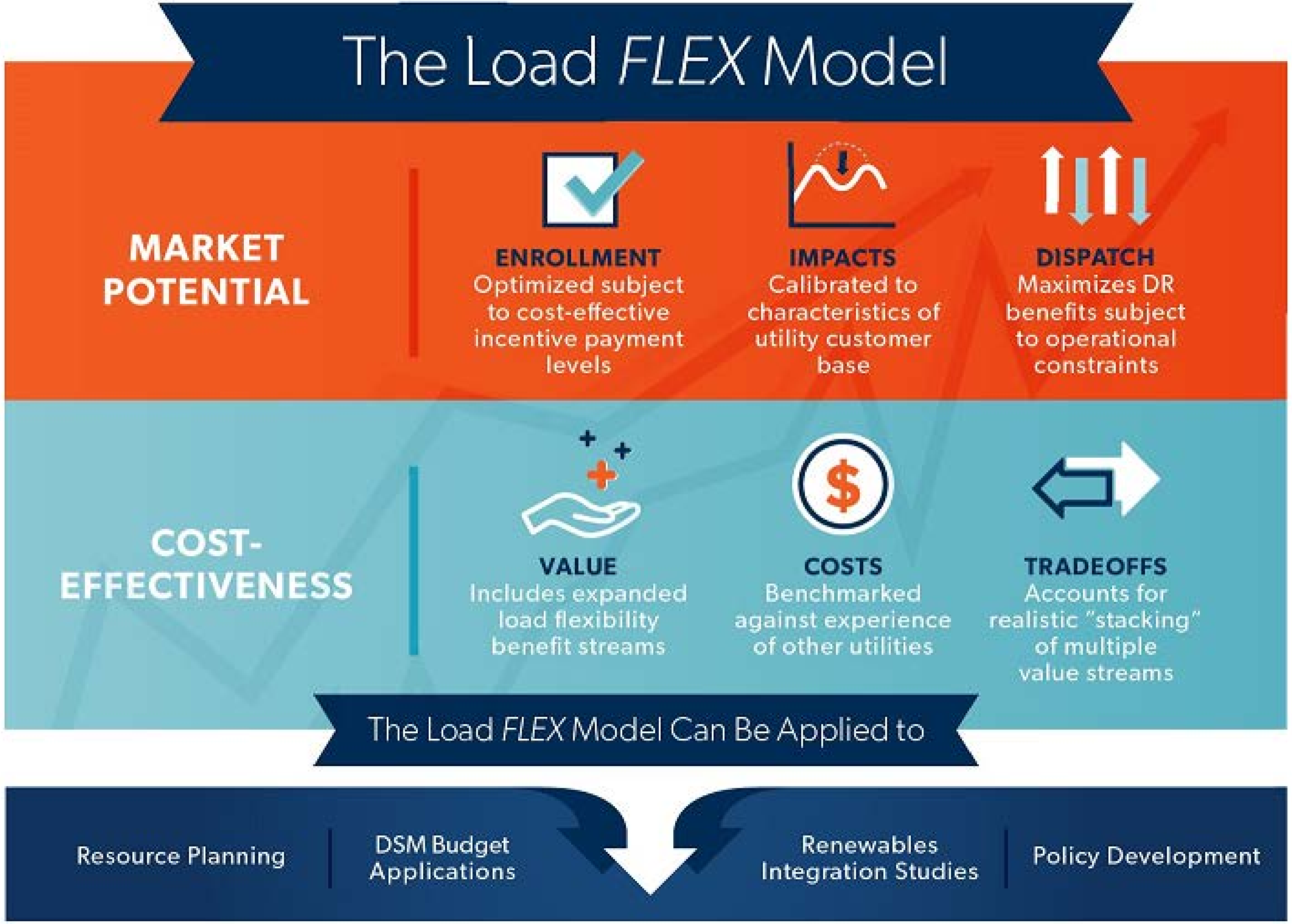
1 Extend DR value streams

2 Broaden definition of DR

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted T&D capacity deferral	Load shifting/ building	Ancillary services
Direct load control	X	X	X	X		
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	X
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Smart thermostat	X	X	X	X		
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

See appendix for a description of load flexibility programs.

Brattle developed the Load*FLEX* model to comprehensively assess load flexibility potential

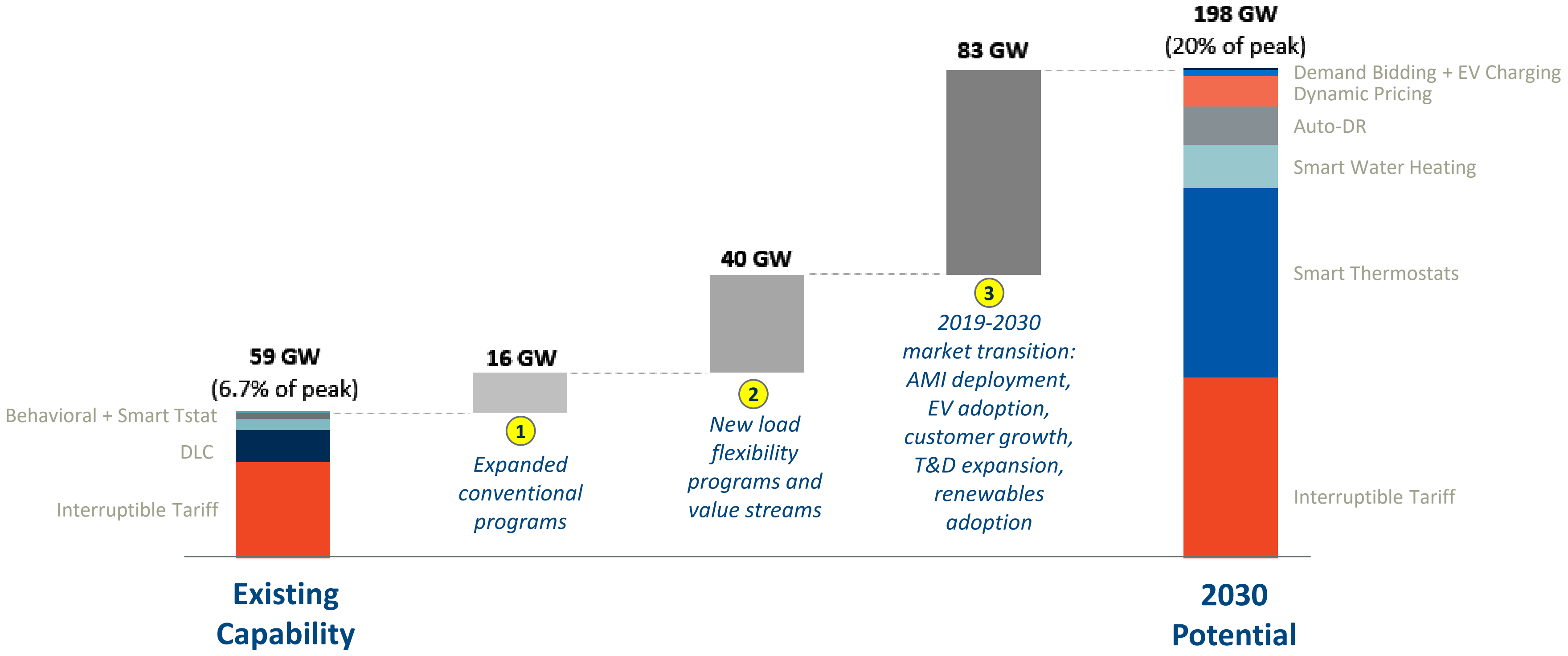


The National Potential for Load Flexibility

The national potential for load flexibility

A portfolio of load flexibility programs could triple existing DR capability, approaching 200 GW (20% of system peak) by 2030

U.S. Cost-Effective Load Flexibility Potential

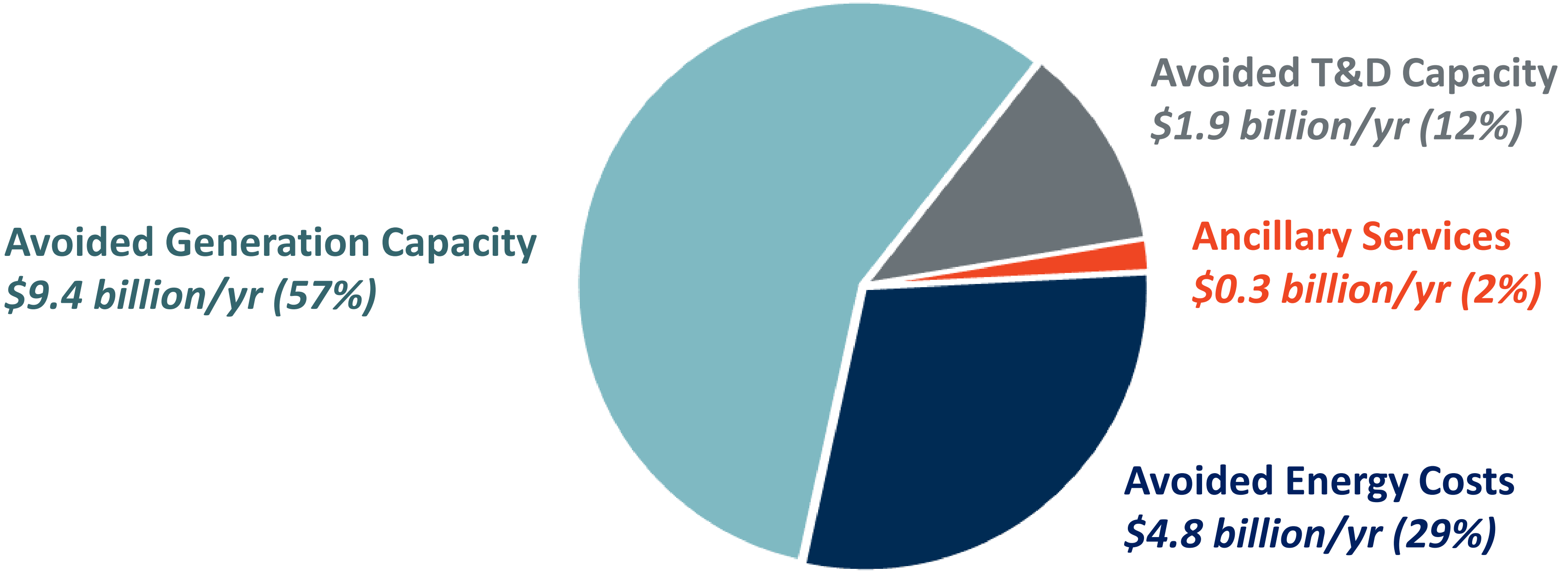


Notes: Existing DR capability does not account for impacts of retail pricing programs, as fewer than 1% of customers are currently enrolled in dynamic pricing rates and the impacts of long-standing TOU rates are already embedded in utility load forecasts. See appendix for summary of key modeling assumptions.

Load flexibility value

Avoided generation costs are the largest source of load flexibility value under national average conditions. There is significant regional variation in this finding.

2030 Annual Benefits of National Load Flexibility Portfolio



Notes: Values shown in 2030 dollars. Values are gross benefits, before netting out costs of the load flexibility programs.

Regional differences

Our results are based on national average conditions. Conclusions will vary significantly by region and should be evaluated accordingly

Case Study: Comparing Minnesota and California

State	Primary drivers of need for load flexibility	Primary source of renewable generation additions	System value: Generation capacity	System Value: Energy (load shifting)	System Value: Ancillary services	System Value: T&D deferral	Load Flexibility Study
Minnesota 	Pending retirement of 1,400 MW of coal generation	Wind	◕	◑	◔	◔	The Brattle Group, “The Potential for Load Flexibility in Xcel Energy’s NSP Service Territory,” June 2019
California 	Renewables integration, local capacity constraints	Solar PV	◔	◑	◑	Not Quantified	LBNL, “2015 California Demand Response Potential Study,” November 2016

◕ *= Primary source of value* ◑ *= Moderate source of value* ◔ *= Modest source of value*

Three predictions for the next decade

1. Utility load flexibility programs will get “smarter” before they get bigger
2. Residential load flexibility additions will exceed those of C&I
3. New regulatory incentives will drive growth in load flexibility

Load flexibility assessment opportunities

Improved assessment of load flexibility opportunities can reduce system costs, facilitate grid modernization, and provide environmental benefits

Applications of Load Flexibility Market Assessment	
Integrated Resource Plans	Ensures that the demand-side is fully reflected as a complementary alternative to generation resources
Renewables Integration Studies	Introduces load flexibility as an additional resource option for addressing supply intermittency challenges
Setting DR Targets / Policy Goals	Establishes achievable and cost-effective levels of load flexibility market penetration
"Value of DER" Proceedings	Provides a comprehensive framework for quantifying the value of a broad range of distributed energy resources

The Transition:

Potential → Pilots → Full Scale Deployment

There have been four generations of pilots with time-varying rates

First generation: 1975 to 1981

Second generation: 2003-2009

Third generation: 2010-2016

Fourth generation: 2016 onwards

These pilots have been designed with varying objectives in mind

Some have simply been demonstration projects

Others sought to measure the impact of time-varying rates

Some did not yield results because they were designed in haste

The best pilots conform to the scientific principles of experimental design, yielding results with both internal and external validity

Six steps for developing a scientifically valid pilot design

1. Clearly articulate the pilot objectives
2. Ensure internal validity
3. Ensure external validity
4. Determine sampling frame/eligible population for the pilot
5. Undertake “statistical power calculations”
6. Incorporate attrition assumptions in the final sample sizes

Different pilots have used different approaches to pilot design

Early pilots typically relied on **random sampling with voluntary participation + randomly selected control groups**

- California Statewide Pricing Pilot, 2003-04; Baltimore Gas and Electric Smart Energy Pricing Pilot, 2007-10)

Some of the more recent pilots used **"RCT" and "RED"**

- SMUD SmartPricing Pilot, 2014; Ontario RPP Pilots, 2018

However, practical considerations necessitated the use of **random sampling with matched control group**

- PC44 TOU Pilot in Maryland, 2019; PowerPath DC Pepco Residential TOU Pilot, 2020; Alectra Advantage Power Pricing Pilot, 2017.

Three ongoing TOU Pilots in Maryland (PC 44) are using the matching control group approach

BGE, Pepco and DPL are implementing the pilots

- For all three utilities, the TOU rate is applied to both energy and delivery charges
- Two year pilots commenced in June 1, 2019.
- The peak to off-peak ratio is very pronounced and varies from ~5-to-1 to 6- to-1 across the utilities
- The peak hours vary by season
  - HE 15-19 on summer weekdays (June 1 – September 30)
  - HE 7-9 on winter weekdays (October 1 – May 31)
- The treatment customers also get behavioral messaging
- The pilots were designed to allow impacts to differ between low- and medium-income (“LMI”) and non-LMI customers
- Interim impact evaluation (using Summer 2019 data) yielded promising results; first year analysis will be completed in the summer of 2020

Checklist for successful evaluation, measurement and verification (EM&V)

The experimental design of each pilot dictates the optimal evaluation method: differences-in-differences (ANOVA or ANCOVA); panel regressions (fixed-effects or random-effects); individual customer regressions

- Decide on the evaluation approach based on the experimental design
- Identify load impact metrics to be quantified (i.e. peak, mid-peak, off-peak impacts, average daily conservation impact, etc.)
- Estimate alternative models and select the one that leads to most accurate predictions
- Decide whether quantifying customers' overall price responsiveness would be useful in the form of price elasticities, beyond the ex-post load impacts quantified in the pilot
  - Own/daily price elasticity (captures the change in the level of overall consumption due to the changes in the average daily price
  - Substitution price elasticity (captures customer's ability to substitute inexpensive off-peak consumption for more expensive peak consumption)

Five steps to full-scale deployment

1. Design the rates
2. Market the rates
3. Include enabling technologies
4. Provide behavioral messaging
5. Roll out the new rates

Brattle's load flexibility expertise

Market sizing & resource planning	• What is the potential size of the load flexibility resource? • What is the potential value of the resource? • What barriers will prevent this potential from being realized?
Regulatory support	• What regulatory developments are on the horizon? • How should rates be redesigned to promote load flexibility? • Are new regulatory incentives needed? • How can markets be more effectively opened to the demand-side?
Pilot program design and evaluation	• How to design new pilots, programs, and participation incentives? • What are the measured impacts of the new programs? • How to communicate these findings to regulators & policymakers?
Strategy development	• Is the organization aligned around a consistent view of DR value? • What are successful DR business models in other markets? • What business models have failed and why?

Selected Brattle load flexibility & DR work products

- The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, prepared for Xcel Energy, June 2019.
- The Hidden Battery: Opportunities in Electric Water Heating, prepared for NRECA, NRDC, and PLMA, January 2016.
- Demand Response Market Research: Portland General Electric, *2016 to 2035*, prepared for PGE, January 2016.
- Valuing Demand Response: International Best Practices, Case Studies, and Applications, prepared for EnerNOC, January 2015.
- Exploring the Role of Natural Gas and Renewables in ERCOT, Part III: The Role of DR, EE, and CHP, prepared for the Texas Clean Energy Coalition, May 2014.
- Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory, prepared for Xcel Energy, April 2014.
- PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034, Volume 3: Class 1 and 3 DSM Analysis, prepared for PacifiCorp with EnerNOC Utility Solutions, May 2014.
- Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential, prepared for Xcel Energy with YouGov America, June 2013.
- Bringing Demand Side Management to the Kingdom of Saudi Arabia, prepared for ECRA with Global Energy Partners and PacWest Consulting, May 2011.
- The Demand Response Impact and Value Estimation (DRIVE) Model, developed for FERC, 2010. Available on FERC website.
- National Action Plan on Demand Response, prepared for FERC, June 2010.
- A National Assessment of Demand Response Potential, prepared for FERC with Freeman Sullivan and Global Energy Partners, June 2009.

Other load flexibility potential studies

- Abdisalaam, Ahmed, Ioannis Lampropoulos, Jasper Frunt, Geert P.J. Verbong, and Wil L. Kling, "Assessing the economic benefits of flexible residential load participation in the Dutch day-ahead auction and balancing market," Conference paper: 2012 9th International Conference on the European Energy Market, May 2012.
- Alstone, Peter, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, Julia Szinai, Travis Walter, Lucy McKenzie, Luke Lavin, Brendan Schneiderman, Ana Mileva, Eric Cutter, Arne Olson, Josh Bode, Adriana Ciccone, and Ankit Jain, "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results," March 1, 2017.
- D'hulst, R., W. Labeeuw, B. Beusen, S. Claessens, G. Deconinck, and K. Vanthournout, "Demand response flexibility and flexibility potential of residential smart appliances: Experiences from large pilot test in Belgium," Applied Energy, 155, 79-90, 2015.
- De Coninck, Roel and Lieve Helsen, "Bottom-up Quantification of the Flexibility Potential of Buildings," Conference paper: Building Simulation, 13th International Conference of the International Building Performance Simulation Association, January 2013.
- Dyson, Mark, James Mandel, Peter Bronski, Matt Lehrman, Jesse Morris, Titiaan Palazzi, Sam Ramirez, and Hervé Touati, "The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid," Rocky Mountain Institute, August 2015.
- Eto, Joseph, H., John Undrill, Ciaran Roberts, Peter Mackin, and Jeffrey Ellis, "Frequency Control Requirements for Reliable Interconnection Frequency Response," prepared for the Office of Electric Reliability Federal Energy Regulatory Commission, February 2018.
- Goldenberg, Cara, Mark Dyson, and Harry Masters, "Demand Flexibility – The key to enabling a low-cost, low-carbon grid," Rocky Mountain Institute, February 2018.
- Lopes, Rui Amaral, Adriana Chambel, João Neves, Daniel Aelenei, João Martins, "A literature review of methodologies used to assess the energy flexibility of buildings," Energy Procedia, 91, 1053-1058, 2016.
- O'Connell, Sarah, and Stefano Riverso, "Flexibility Analysis for Smart Grid Demand Response," 2017.
- Olsen, D. J., N. Matson, M. D. Sohn, C. Rose, J. Dudley, S. Coli, S. Kiliccote, M. Hummon, D. Palchak, J. Jorgenson, P. Denholm, O. Ma., "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.
- Potter, Jennifer and Peter Cappers, "Demand Response Advanced Controls Framework and Assessment of Enabling Technology Costs," prepared for the Office of Energy Efficiency and Renewable Energy U.S. Department of Energy, August 2017.
- Starke, Michael, Nasr Alkadi, and Ookie Ma, "Assessment of Industrial Load for Demand Response across U.S. Regions of the Western Interconnect," prepared for the Energy Efficiency and Renewable Energy U.S. Department of Energy, ORNL/TM-2013/407, September 2013.
- Stoll, Brady, Elizabeth Buechler, and Elaine Hale, "The Value of Demand Response in Florida," The Electricity Journal, 30, 57-64, 2017.

Appendix

Illustrating the potential for load flexibility

Electric water heating is a compelling example of load flexibility

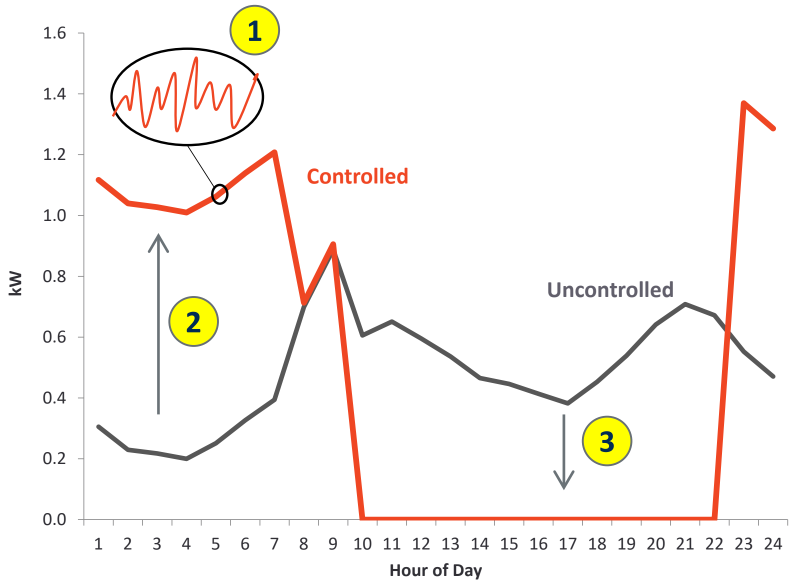
Electric resistance water heating load can be controlled to provide several grid services. The thermal energy storage properties of the water tank work similar to a battery

While water heaters have been used to reduce peak capacity for decades, recent technological developments now allow for more flexibility in load control, including the provision of frequency regulation

In the past few years, “grid-connected water heating” programs have been introduced in Arizona, California, Hawaii, Minnesota, Oregon, Vermont, and across PJM

In recognition of the potential renewables integration benefits, 2015 federal legislation made grid-connected water heaters exempt from prohibitive energy efficiency standards

Water Heating Load Profile

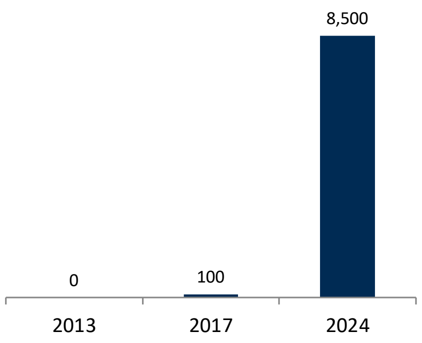


1. Heating element controlled with near-instantaneous response to provide **balancing services**
2. Off-peak **load building** to reduce wind curtailments or reduce ramping of thermal generation
3. **Peak demand reduction** to reduce need for generation capacity and/or T&D capacity, and to avoid peak energy prices

Consumer technologies drive the DR transition

Adoption of behind-the-meter (BTM) energy technology is accelerating; these technologies are enabling the provision of load flexibility

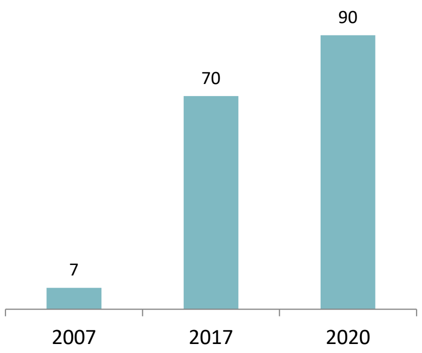
BTM Storage
(U.S. capacity, MW)



Source: Estimated from Wood Mackenzie and Energy Storage Association, 2019

CAGR: 89% (2017-24)
85x total growth in 7 yrs

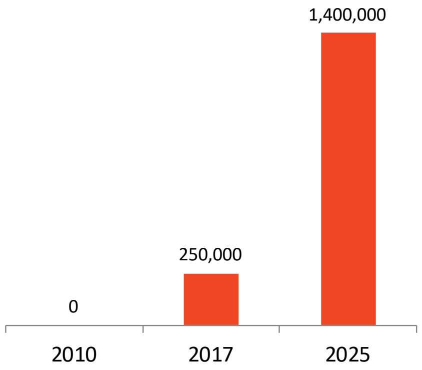
Smart Meters
(U.S. meters, millions)



Source: Institute for Energy Innovation (IEI), 2017

CAGR: 22% (2007-20)
13x total growth in 13 yrs

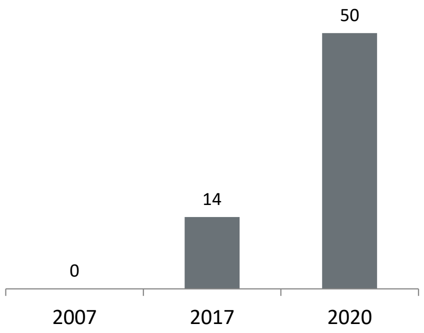
Electric Vehicles
(U.S. annual sales)



Source: Edison Electric Institute and IEI, 2018

CAGR: 24% (2017-25)
6x total growth in 8 yrs

Smart Appliances
(U.S. homes, millions)



Source: Brattle estimate based on review of various sources

CAGR: 53% (2017-20)
4x total growth in 3 yrs

The national potential for load flexibility

Three factors drive the national potential estimate of 198 GW

1 Expanded conventional programs

- Existing conventional programs often have untapped potential that can be harnessed through revamped customer marketing and outreach, modified program rules, and redesigned incentive structures
- These programs generally only provide peak capacity value, but often can do so cost-effectively by leveraging existing program infrastructure
- *Potential increase over existing DR capability: 16 GW (27% increase)*

2 New load flexibility programs

- Relative to existing conventional programs, new load flexibility programs capture additional value streams and leverage emerging load control technologies and sources of load
- Under current national average market conditions, the most significant cost-effective potential is in smart thermostat programs (residential) and dynamic pricing (all customer segments)
- *Potential increase over existing DR capability: 40 GW (67% increase)*

3 Market transition impacts (2019 – 2030)

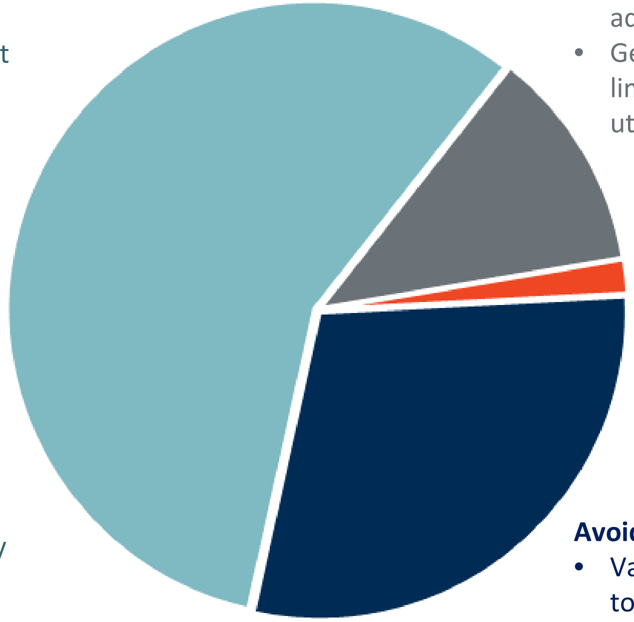
- Growth in adoption of AMI, EVs, smart thermostats and other smart appliances over the forecast horizon enables expanded participation in load flexibility programs
- Increased renewable generation development introduces more energy price variability and a greater need for ancillary services, increasing the value of load flexibility programs with fast-response capability
- Continued expansion and modernization of the T&D system introduces a growing opportunity for non-wires alternatives
- These market developments justify greater incentive payments for customer participation in load flexibility programs and also justify the introduction of robust smart water heating and Auto-DR programs, among others
- *Potential increase over existing DR capability: 83 GW (140% increase)*

Load flexibility value

Avoided generation costs are the largest source of load flexibility value under national average conditions. There is significant regional variation in this finding.

2030 Annual Benefits of National Load Flexibility Portfolio

Avoided Generation Capacity, *$9.4 billion/yr (57%)*
- Value based on avoided cost of gas-fired combustion turbine, assuming no near-term peaking capacity need in some regions
- Capacity remains the dominant source of load flexibility value through at least 2030
- Capacity value will vary significantly by region; load flexibility poised to provide most capacity value in regions with pending capacity retirements, supply needs in transmission-constrained locations, or unexpected supply shortages



Avoided Transmission & Distribution Capacity, *$1.9 billion/yr (12%)*
- Value includes system-wide benefits of peak demand reduction, plus added benefit of geographically targeted T&D investment deferral
- Geo-targeted T&D deferral opportunities are typically high value but limited in quantity of near-term need; this value is likely to grow as utility T&D data collection and planning processes improve

Ancillary Services, *$0.3 billion/yr (2%)*
- Value accounts only for frequency regulation and assumes a need equal to 0.5% of system peak demand; additional value may exist if considering other ancillary services products
- Frequency regulation provides very high value to a small amount of capacity; in our analysis, the full need for frequency regulation can be served through a robust smart water heating program

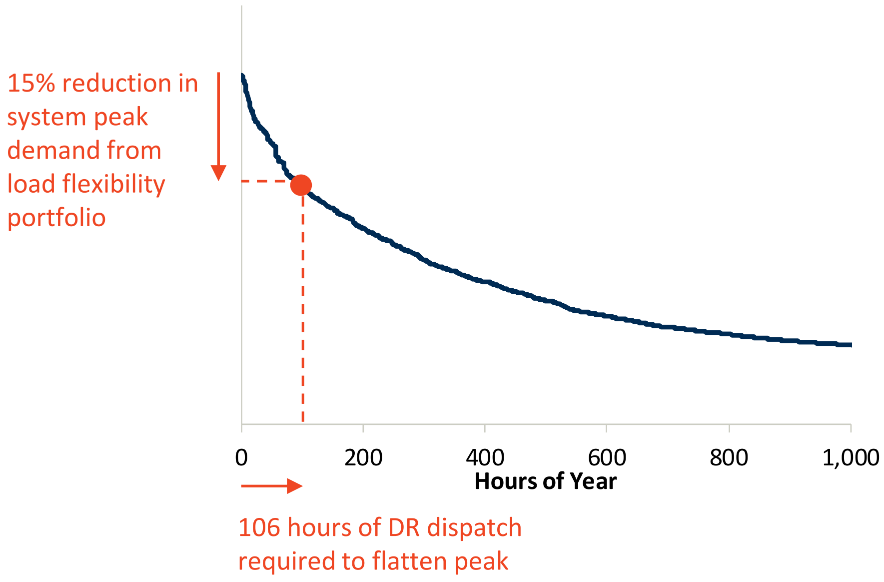
Avoided Energy Costs, *$4.8 billion/yr (29%)*
- Value accounts for reduced resource costs associated with shifting load to hours with lower cost to serve; does not include consumer benefits from reductions in wholesale price of electricity
- Energy value is best captured through programs that provide daily flexibility year-round, such as Auto-DR for C&I customers, TOU rates, EV charging load control, and smart water heating

Notes: Values shown in 2030 dollars. Values are gross benefits, before netting out costs of the load flexibility programs.

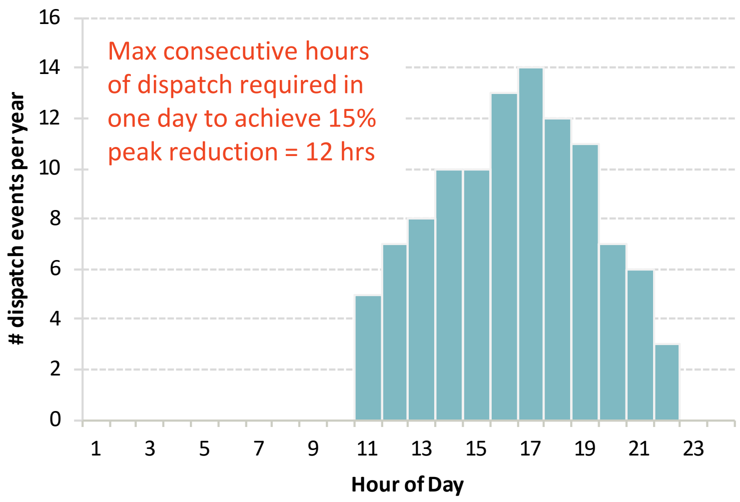
Operational implications

Deep load reductions will require significant changes to the way DR programs have been utilized historically

Utility Load Duration Curve (Top 1,000 Hours)



Required # Hours of Dispatch Over Year



Implications: Load flexibility programs will need to be dispatched much more frequently and during a broader window of hours of the day. This requires new customer engagement initiatives and advanced portfolio dispatch strategies.

Notes: Based on actual load data for a large Midwestern utility during a year with a hotter-than-normal summer.

Policy & market developments

The constantly evolving policy and market landscape will define new load flexibility opportunities and challenges

Wholesale Market Design

- ↑ Policies are increasingly opening wholesale markets to demand-side participation (e.g., FERC Order 745)
- ↓ Existing market rules still undervalue load flexibility (e.g., year-round, 10-hour performance requirement for capacity credit)

Emerging Technologies

- ↑ Cost declines for smart home technologies and EVs could accelerate load flexibility adoption
- ↓ Batteries and solar PV could soon become the technology that load flexibility competes with, rather than combustion turbines

Deep Decarbonization Policies

- ↑ The transition to a fully decarbonized and electrified economy will create massive fluctuations in power supply and load, emphasizing the value of load flexibility
- ↓ Seasonal mismatches between supply and demand will be difficult to mitigate through load flexibility alone

Codes and Standards

- ↑ Standards such as CTA-2045 can significantly reduce load flexibility technology costs for consumers
- ↓ Policies prohibiting programs that promote electrification, such as the Three Prong Test in California, will inhibit adoption of load flexibility technologies

Regulatory Incentives

- ↑ Performance incentive mechanisms will provide utilities with a financial incentive to pursue load flexibility as an alternative to capital investment in grid infrastructure
- ↓ Without accompanying incentives, traditional cost-of-service regulation discourages utility investment in demand-side resource options

Resource Planning

- ↑ Some utilities are using increasingly sophisticated modeling techniques to account for the unique value of load flexibility, putting it on a level playing field with conventional generation resources in planning activities
- ↓ Most traditional off-the-shelf resource planning approaches de-emphasize load flexibility

The role of retail pricing

There are two competing views on how to incentivize load flexibility

	Method 1: Dynamic retail rates ("Prices-to-Devices")	Method 2: Participation incentives ("Flexibility Payments")
Example of load flexibility incentive	Sub-hourly real-time pricing with locational price variation	Fixed monthly incentive payment to participate in smart thermostat program
Role of retail rates	Rates are the primary driver of customer investment in various load flexibility technologies and/or arrangements with third-party load flexibility service providers, in order to capture electricity bill savings	Simple dynamic pricing rates are offered as complementary, voluntary alternatives to various incentive-based programs
Advantages	**Equitable:** All load flexibility is treated equal; no need to develop program-specific incentive payments **Efficient:** Once the necessary infrastructure is in place (a big hurdle), ongoing implementation cost is relatively low **Dynamic:** Real-time prices could provide a financial incentive that is more closely aligned with the value of load flexibility to the system	**Simple:** Fixed payments are predictable and easy for customers to understand **Tailored:** Each program can be designed to optimize the characteristics of the specific end-use it targets **Practical:** Does not involve massive IT investments or political complexity of implementing highly granular retail pricing

Implications: Both methods can be used to achieve the potential identified in this study. Utilities & regulators must determine their preferred position on the spectrum of options.

Description of load flexibility programs

Direct load control (DLC): Participant's central air-conditioner is remotely cycled using a switch on the compressor.

Smart thermostats: An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. Customers could provide their own thermostat, or purchase one from the utility.

Interruptible rates: Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

Demand bidding: Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty.

Time-of-use (TOU) rate: Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled for all customers as well as for EV charging.

Critical peak pricing (CPP) rate: Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year.

Behavioral DR: Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

Description of load flexibility programs (cont'd)

EV managed charging: Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in at home from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive.

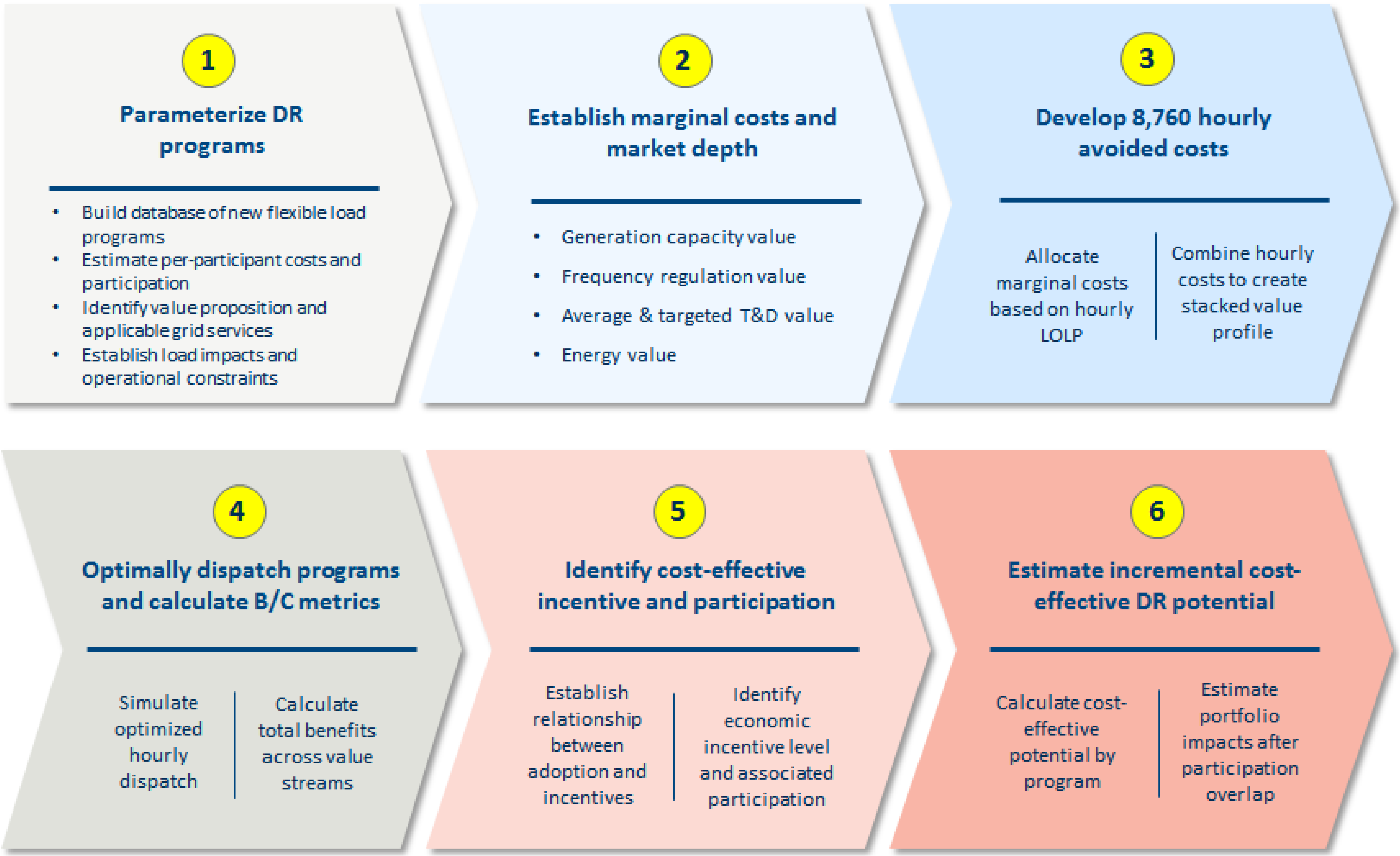
Timed water heating: The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

Smart water heating: Offers improved flexibility and functionality in the control of the heating element in the water heater. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

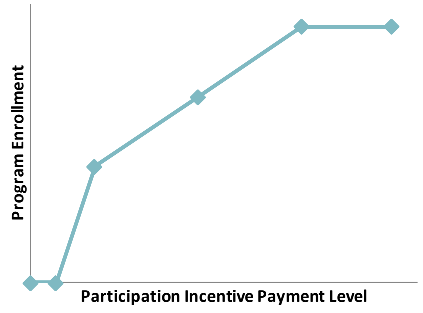
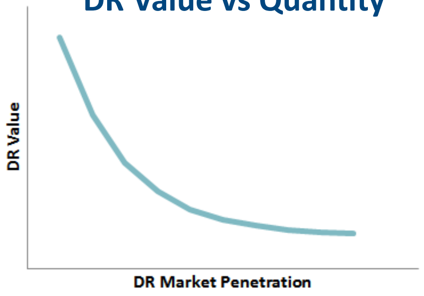
Ice-based thermal storage: Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

C&I Auto-DR: Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

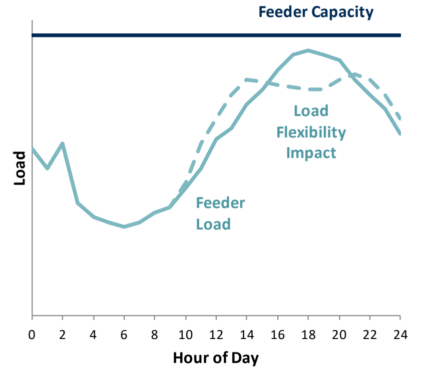
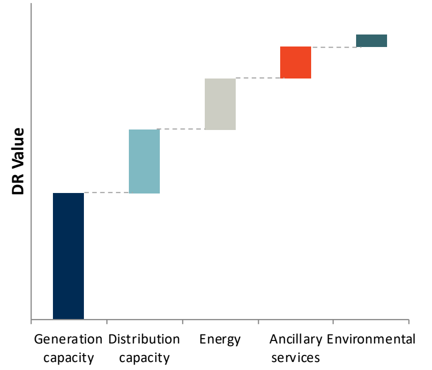
The Load*FLEX* modeling framework



Load flexibility analytical challenges & solutions

Load Flexibility Analytical Challenge	Load*FLEX* Approach	Illustration
Reliably estimating impacts of nascent programs & technologies	• Brattle maintains a database of load flexibility programs and their associated costs, impacts, and adoption rates • Supplementary interviews are conducted to fill in gaps where publicly available data is limited • Primary market research can establish tailored estimates of customer adoption • Participation is modeled as a function of the cost-effective participation incentive payment level • Probabilistic analysis (i.e., Monte Carlo simulation) can account for uncertainty	DR Enrollment vs Incentive Payment 
Accounting for "depth" of resource need	• Some of the new load flexibility value streams are sensitive to the quantity of the DR resource that is participating; for instance, frequency regulation is valuable but has very limited need on most systems • Modeling establishes the "depth" of each value opportunity and quantifies the relationship between incremental value and DR resource additions	DR Value vs Quantity 

Load flexibility analytical challenges & solutions

Load Flexibility Analytical Challenge	Load*FLEX* Approach	Illustration
Quantifying deferred distribution capacity value	• Distribution capacity deferral is a highly system-specific calculation, requiring locational assessment of utility distribution system data • Initial screening identifies grid locations at risk of capacity constraints • The performance profile of the load flexibility resource is compared to the load profile of the distribution system component • Capacity deferral value is assigned based on the probability that constraints can be relieved through deployment of the load flexibility resource	**DR Impact on Distribution System** 
Accounting for "stacked value"	• Load flexibility can provide multiple sources of value, but analysis must account for realistic operational constraints associated with capturing this value • Each value stream is converted to an hourly price series based on assessment of appropriate cost drivers • Load flexibility resource is "dispatched" against the price series based on realistic utilization algorithms	**DR Stacked Value (Illustrative)** 

Key modeling assumptions

To illustrate the national potential for load flexibility, we modeled the potential for a utility with characteristics that are roughly representative of the national average. Results were then scaled up to the national level.

	2019	2030
Power Supply Mix	74% fossil, 15% nuclear, 9% renewable, 2% hydro	54% fossil, 29% renewable, 12% nuclear, 2% hydro, 3% EE
Henry Hub Gas Price	\$3/MMBtu	\$8/MMBtu
U.S. System Peak Demand	881 GW	987 GW
Marginal Generation Capacity Cost	\$45/kW-yr Allocated across top 100 hours of hourly system load shape	\$74/kW-yr Allocated across top 100 hours of hourly system load shape
Marginal Energy Cost	Forecasted hourly prices Average: \$25/MWh	Forecasted hourly prices Average: \$41/MWh
Avoided System-wide T&D Cost	\$10/kW-yr	Same as 2019
Geo-targeted Distribution Investment Deferral Value	\$35/kW-yr average, limited to 8,800 MW	\$45/kW-yr average, limited to 29,600 MW (2019 – 2030)
Frequency Regulation Value	\$11/MWh average, limited to 2,400 MW	\$14/MWh average, limited to 5,300 MW
DR Technology Costs	Varies by technology	30% reduction from current levels

Key modeling assumptions (cont'd)

- **Eligibility:** Determined based on a review of appliance saturation data and independent forecasts.
  - E.g., 19 million EVs on the road by 2030, 64% of households with central A/C, 75% of households with AMI

- **Participation:** Based on a review of market research studies, actual participation in existing DR programs, and assumptions from various DR potential studies. Participation is calibrated to the maximum incentive payment level that allows the program to pass the benefit-cost screen. At the portfolio level, participation is reduced to account for overlap that would otherwise exist in competing programs.
  - E.g., Approximately 70% of eligible customers participating in smart thermostat program (i.e., those with smart thermostat and central A/C), 14% of eligible customers participating in opt-in CPP (i.e., those with AMI)

- **Program performance:** Operational parameters (hourly load impacts, allowed timing and frequency of dispatch events) based on review of pilot studies and full-scale utility programs
  - E.g., 0.34 kW avg peak impact from residential CPP, based on simulation using Brattle's Arcturus database, with up to 75 hours of dispatch per summer

- **Program costs:** Include startup costs, marketing and customer recruitment, utility share of equipment and installation, program administration and overhead, churn, and participation incentives. Based on review of utility programs, demonstration projects, and conversations with vendors.
  - E.g., Smart thermostat program/equipment cost of $27/participant-year and incentive cost of $25/participant-year

- **Dispatch:** Simulated using Brattle's LoadFLEX model. Load flexibility programs are dispatched against the "stacked" marginal hourly cost series to maximize benefits, subject to each program's unique operational constraints.

For additional information about the Load*FLEX* modeling methodology, see The Brattle Group, "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, June 2019.

Three commonly used approaches to pilot design

Possible Pilot Design Approaches	Description and Pros/Cons
Randomized Controlled Trial ("RCT")	Involves a random assignment of the recruited customers into the treatment and control groups. While this is the most rigorous approach from a measurement perspective, it is rarely used by electric utilities due to a potentially adverse impact on customer satisfaction (as it would involve either "recruit-and-deny" or "recruit-and-delay" approaches for some portion of the recruited customers).
Randomized Encouragement Design ("RED")	Allows the researcher to construct a valid control group, maintaining the benefits of an RCT design by not negatively affecting the customer experience. However, it requires much larger sample sizes, relative to the RCT approach, in order to be able to detect a statistically significant impact. Large sample sizes increase pilot implementation costs.
Random Sampling with Matched Control Group	Involves recruiting treated customers from a randomly selected sample, and using regression analysis to identify and match customers from the rest of the population that are most similar to the treatment customers. This matched control group approach strikes a good balance between achieving statistically valid results and requiring a manageable level of pilot participants.

Source: Sergici et al., "Evaluation, Measurement and Verification Plan for the PC44 TOU Pilots," prepared for PC44 Rate Design Work Group, June 2018.

Five steps to full-scale deployment

1	**Designing the rates**	• Rates should be cost-reflective to promote economic efficiency and equity. However, they should also be **customer focused** • Unless new rates have **savings opportunities**, customers will either not join or not alter their usage habits to respond. Savings opportunities can be maximized by discounting off-peak prices substantially compared to the existing rate
2	**Marketing the rates**	• Most utilities offer time-varying rates but only a handful of customers are on them. Often, customers don't even know the rates exist due to limited **customer outreach** and **advertising** on traditional and social media • Customers who know the rates exist have questions, but customer service staff are untrained to answer them while information on websites is poorly presented and couched in utility-speak that eludes customers • This can be remedied by studying customer service practices of utilities like APS and OGE, which have large numbers of customers on time-varying rates • Utilities can also conduct **focus groups** with customers to get insights on which design features appeal to customers and which ones turn them off. For further insights, **conjoint analysis** can be carried out with data gathered via online customer surveys

Five steps to full-scale deployment

3	**Inclusion of enabling technologies**	• Customer responses to time-varying rates can be facilitated and often magnified by including new **digital thermostats** rapidly being acquired by customers. For example, OGE has successfully used smart thermostats to boost response and take the pain out of demand management • Other enabling technologies include **digitally-enabled appliances** and **home-energy controllers**
4	**Inclusion of behavioral messaging**	• Research has shown that **behavioral messaging** or **social norming** can boost response • This can be done through mailers, emails and text messages, which inform customers of how their change in usage compares with the response of peers on the same rate
5	**Transitioning to new rates**	• Many rollouts are abruptly handled, such that customers are not prepared for the arrival of the new rates, and customer service staff are not trained to answer customer questions • This can be avoided through **proper planning**

Presenter Information

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Ryan Hledik specializes in regulatory and planning matters related to the emergence of distributed energy technologies.

Mr. Hledik has consulted for more than 50 clients across 30 states and eight countries. He has supported his clients in matters related to energy storage, load flexibility, distributed generation, electrification, retail tariff design, energy efficiency, and grid modernization.

Mr. Hledik's work has been cited in regulatory decisions establishing procurement targets for energy storage and demand response, authorizing billions of dollars in smart metering investments, and approving the introduction of innovative rate designs. He is a recognized voice in debates on how to price electricity for customers with distributed generation. He co-authored Saudi Arabia's first Demand Side Management (DSM) plan, and the Federal Energy Regulatory Commission's landmark study, A National Assessment of Demand Response Potential.

Mr. Hledik has published more than 25 articles on retail electricity issues and has presented at industry events throughout the United States as well as in Brazil, Belgium, Canada, Germany, Poland, South Korea, Saudi Arabia, the United Kingdom, and Vietnam. His research on the "grid edge" has been cited in *The New York Times* and *The Washington Post*, and in trade press such as *GreenTech Media*, *Utility Dive*, and *Vox*. He was named to *Public Utilities Fortnightly's* Under Forty 2019 list, recognizing rising stars in the industry.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, where he concentrated in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining Brattle, Mr. Hledik was a research assistant with Stanford's Energy Modeling Forum and a research analyst in Charles River Associates' Energy Practice.

Presenter Information

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Ahmad Faruqui is an internationally recognized authority on the design, evaluation and benchmarking of tariffs. He has analyzed the efficacy of tariffs featuring fixed charges, demand charges, time-varying rates, inclining block structures, and guaranteed bills. He has also designed experiments to model the impact of these tariffs and organized focus groups to study customer acceptance. Besides tariffs, his areas of expertise include demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents, including electric and gas utilities, state and federal commissions, governments, independent system operators, trade associations, research institutes, and manufacturers.

Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, Saudi Arabia, and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand, New Zealand and the United Kingdom and given seminars on all 6 continents. He has also given lectures at Carnegie Mellon University, Harvard, Northwestern, Stanford, University of California at Berkeley, and University of California at Davis and taught economics at San Jose State, the University of California at Davis, and the University of Karachi.

His research been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He is a member of the editorial board of The Electricity Journal. He holds BA and MA degrees from the University of Karachi, both with the highest honors, and an MA in agricultural economics and a PhD in economics from The University of California at Davis, where he was a research fellow.

Demand Response Insights for the Northwest

June 8, 2020

Juliet Homer; Josh Butzbaugh; Dhruv Bhatnagar
Pacific Northwest National Laboratory

PNNL is operated by Battelle for the U.S. Department of Energy

Outline

1. Load Shifting in Residential Buildings: Grid-connected Heat Pump Water Heaters (HPWH) in the Pacific Northwest (PNW)
   – Josh Butzbaugh
2. Olympic Peninsula GridWise Demo, Portland General Electric Demand Response Testbed, and Other Considerations for the PNW
   – Juliet Homer
3. Demand Response in Hawaii and Massachusetts
   – Dhruv Bhatnagar

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Load Shifting in Residential Buildings: Grid-Connected Heat Pump Water Heaters in the Pacific Northwest

June 8, 2020

Presenter: Josh Butzbaugh

Team: Cheryn Metzger, Josh Butzbaugh,
Walt Hunt, Travis Ashley, Ebony Mayhorn,
Sam Rosenberg,Jaime Kolln,
and Michael Baechler

U.S. DEPARTMENT OF ENERGY BATTELLE

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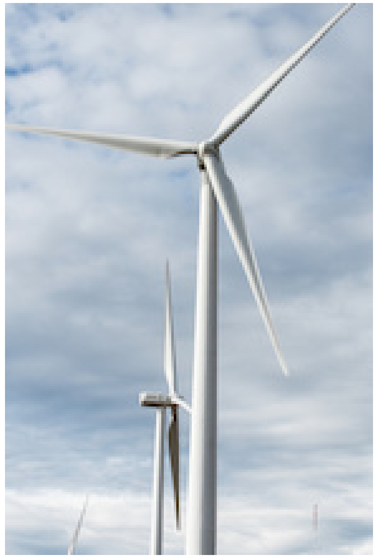
Project Goals: Grid-Connected HPWHs

- Determine the kW reduction (on-peak) between electric resistance (ERWHs) and connected heat pump water heaters (HPWHs)
- Demonstrate a 24x7 control paradigm for shifting load to align with renewable generation (e.g., loading up during solar bulge in late afternoon or high-wind-power periods in early morning)
- Evaluate customer acceptance/impact of 24x7 demand response operation of their water heater
- Compare data reported from the universal communication modules to sub-metered data to determine accuracy



Overview

- Water heating is the second largest energy use in U.S. residences
- Heat pump water heaters (HPWH) can save 60% of electric water heating energy
  - Only 70,000 shipments per year (1.5% market share of electric water heaters)
  - Market share has been flat since 2009 despite more than 180 models in the market
- Opportunity to demonstrate the viability of HPWH in providing load shifting
  - Pacific Northwest – region is active and committed to studying energy efficiency and load shifting strategies to integrate into existing utility programs
  - Southeast or Mid-Atlantic – regions with high potential for energy efficiency and load shifting, need technology demonstration to justify launching new programs and/or revising state policies
  - Transfer lessons learned and best practices from PNW study to a field study based in the Southeast

The Secret Sauce

CTA-2045

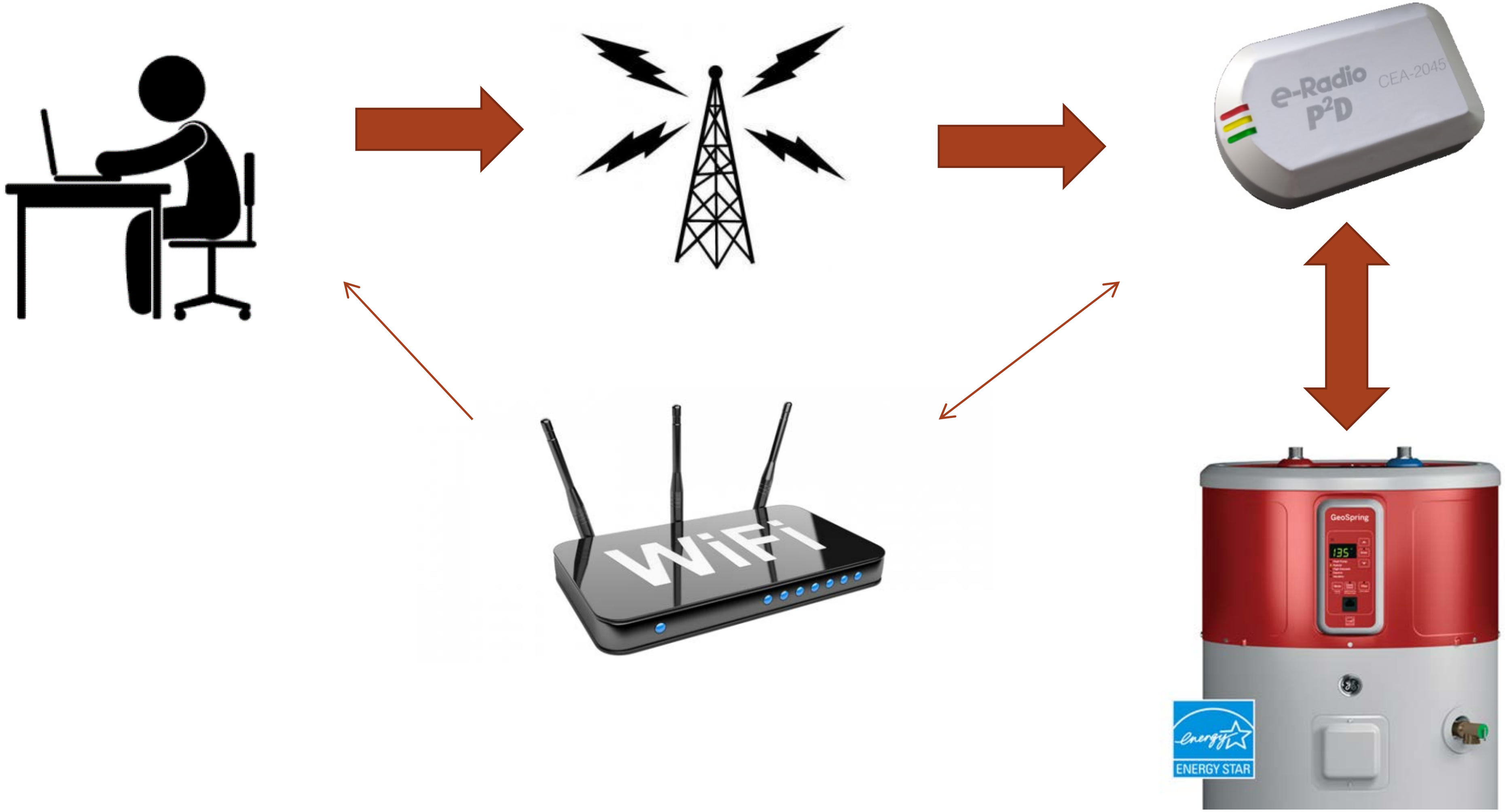
- Manufacturer only supplies standard port
- Others can pay additional costs to make devices “connected”
- Interface supports every type of communication method
  - Physical layer (e.g. Wi-Fi, 4G LTE, etc.)
  - Command layer (e.g. SEP, OpenADR, etc.)

Heat Pump Water Heaters

- 3-5 year payback
- Reduce peak loads
- Interactions with interior temperatures are minimal [1]
- NEEA Advanced Water Heater Spec
  - ✓ Cold-climate compressor cut-off temperature
  - ✓ Maximum decibel requirements
  - ✓ CTA-2045 or equivalent

[1]Widder et al. Interaction between HPWH or Other Internal Point Source Loads and a Central Heating System. NEEA/PNNL https://neea.org/img/uploads/interaction-between-heat-pump-water-heaters-and-heating-system.pdf

How It Really Works



Roles and Responsibilities

- Bonneville Power Administration: Initial funder of NW efforts
- Portland General Electric: Lead utility
- U.S. Department of Energy: Funder of PNNL work
- Northwest Energy Efficiency Alliance: Market analysis
- PNNL: Data analysis and reporting
- Other Utilities: Recruitment of homes for study
  - ✓Puget Sound Energy
  - ✓Tacoma Power
  - ✓Franklin PUD
  - ✓Emerald PUD
  - ✓Clark PUD

Northwest Field Validation

Project Scope

- 145 HPWH (~40 sub-metered)
- 86 Electric Resistance Water Heaters
- 10 weeks of data per season
- 2 load shifting events per day during peak hours
- Control group and event group flip-flop each week

Example Event Schedule for One Day

Date	Event Description	Duration	Start Time	End Time
Feb. 19th	Load Up	1 hr	5:00	5:59
Feb. 19th	Shed	3 hrs	6:00	9:00
Feb. 19th	Load Up	1 hr	16:00	16:59
Feb. 19th	Shed	3 hrs	17:00	20:00

Load Up Event = Command water heater to energize and reach set point

Shed Event = Command water heater to turn off as long as customer still has hot water (exact definition of "hot water" is determined by manufacturer/algorithm)

Average Peak kW Reduction during Shed Events per Water Heater

Many ways to determine the average kW reduction

- Baseline 1: Event Group vs. Control Group during same week
- Baseline 2: Event Group compared to its previous week as the Control Group
- Baseline 3: Full Season Average of all Event and Control power data

Full Season Average Watts Reduced per Hour of Shed Event (per Water Heater)

	ERWH (Baseline)	Connected ERWH	HPWH	Connected HPWH	% Load Reduced Connected HPWH
Winter Morning	616	-374	-310	-533	87%
Winter Evening	668	-321	-437	-602	90%
Summer Evening	474	-347	-365	-448	95%

What About the Consumer?

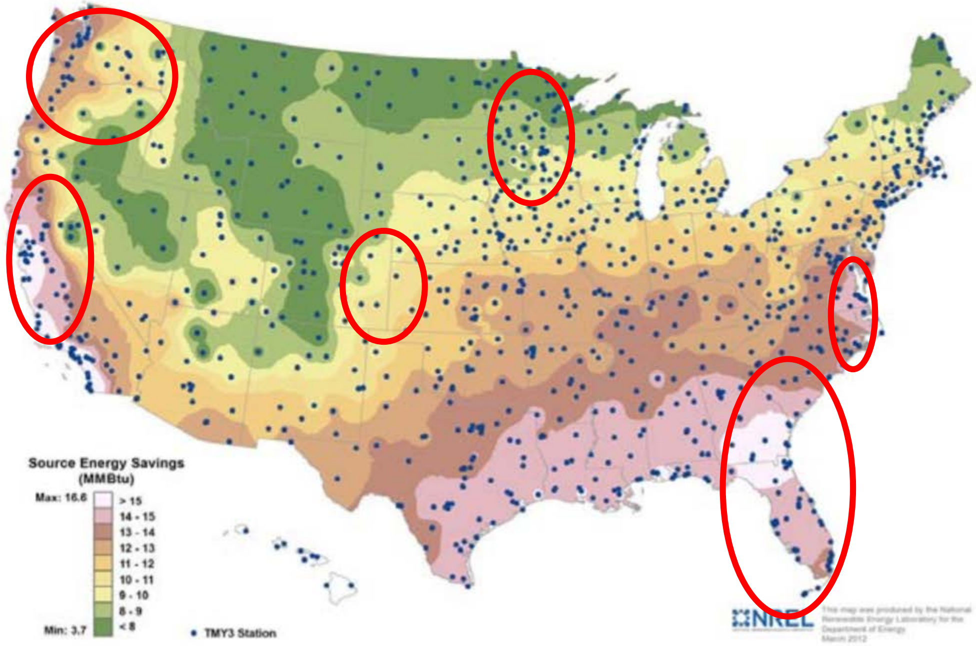
- Opt-Outs allowed two ways:
  - Button on the water heater (address run out in progress)
  - Through the web portal (planned high demand period)

- 1,634 opt-out hours during the winter season
- Out of 40,000 opportunities to opt-out (145 customers, about 28 event-hours per week)
- Results in 4% opt-outs (relatively low!)
- Most customers seem largely unaffected by the demand response program

What’s Next?

Load Shifting with Heat Pump Water Heaters

- Field Validation in the Northwest
  - o Machine learning to optimize load shifting with occupant schedules
  - o Support for transferring knowledge to other regions
- Field Validation in the Southeast
  - o Recruiting, installing connection devices, collecting data



Load Shifting With Ductless Mini-Splits

- Taking advantage of CTA-2045 enabled devices that are already in the field
- First field validation study of HVAC/heat pump load management using CTA-2045

Published Reports

- BPA (Bonneville Power Administration). 2018. *CTA-2045 Water Heater Demonstration Report Including A Business Case for CTA-2045 Market Transformation.* https://www.bpa.gov/EE/Technology/demand-response/Documents/Demand%20Response%20-%20FINAL%20REPORT%20110918.pdf
- Metzger, CE, Ashley T, Bender, S, Morris, S, Kelsven P, Urbatsch E, Kelly N, Eustis, C. 2018. *Large Scale Demand Response with Heat Pump Water Heaters.* ACEEE (American Council for an Energy Efficient Economy). http://iframes.aceee.org/confpanel.cfm?&ConferencePanelID=291
- Metzger, CE, Kelsven P, Ashley T, Bender, S, Kelly N, Eustis, C. 2019. *Not Your Father's Water Heater Demand Response Program: Measuring Impacts from an Innovative Load Shifting Pilot.* International Energy Program Evaluation Conference. August 2019. https://www.iepec.org/2019_proceedings/#/paper/event-data/055-pdf
- Widder, S, Metzger CE, Petersen, J, McIntosh, J. 2017. *Interaction between Heat Pump Water Heaters or Other Internal Point Source Loads and a Central Heating System.* NEEA, August 2017. https://neea.org/img/uploads/interaction-between-heat-pump-water-heaters-and-heating-system.pdf

Other Opportunities

- Building on this work with BPA, combining technologies: space conditioning, water heating, pool pumps, spas/hot tubs, other equipment?
- Building on Fault Detection and Diagnostics for residential
- Previous Lab Homes work:
  - Electric vehicle/appliance interaction under Rick Pratt
  - Cyber Security of Connected Devices under Penny McKenzie

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Olympic Peninsula GridWise Demo, Portland General Electric Demand Response Testbed, and Other Considerations for the PNW

June 8, 2020

Juliet Homer
Pacific Northwest National Laboratory

U.S. DEPARTMENT OF ENERGY BATTELLE
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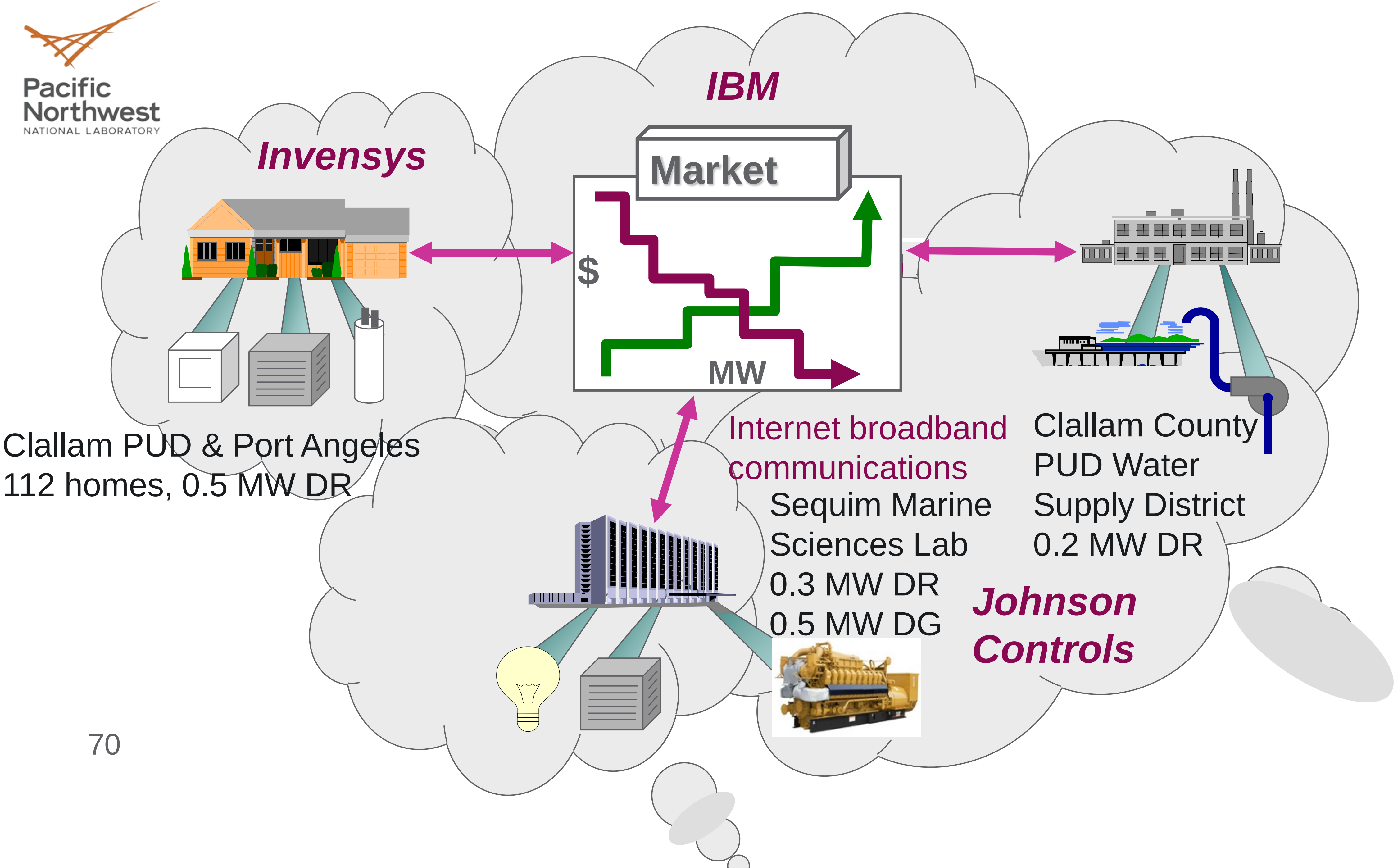
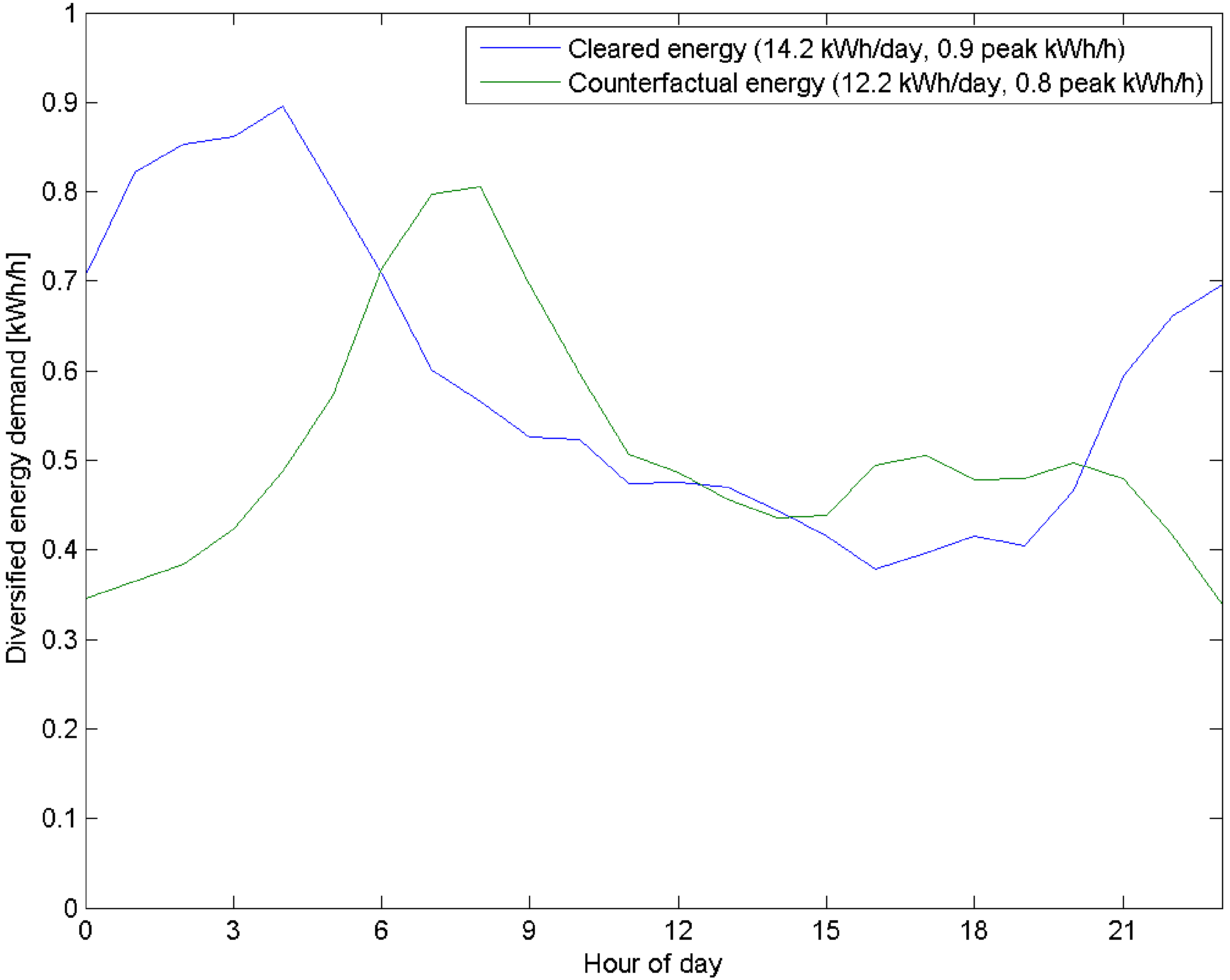
Olympic Peninsula GridWise Demo Project

- Established viability of transactive decision-making to achieve multiple objectives
  - Peak load, distribution constraints, wholesale prices
  - Residential, commercial, & municipal water pumping loads, distributed generation
- Conducted in 2006-2007

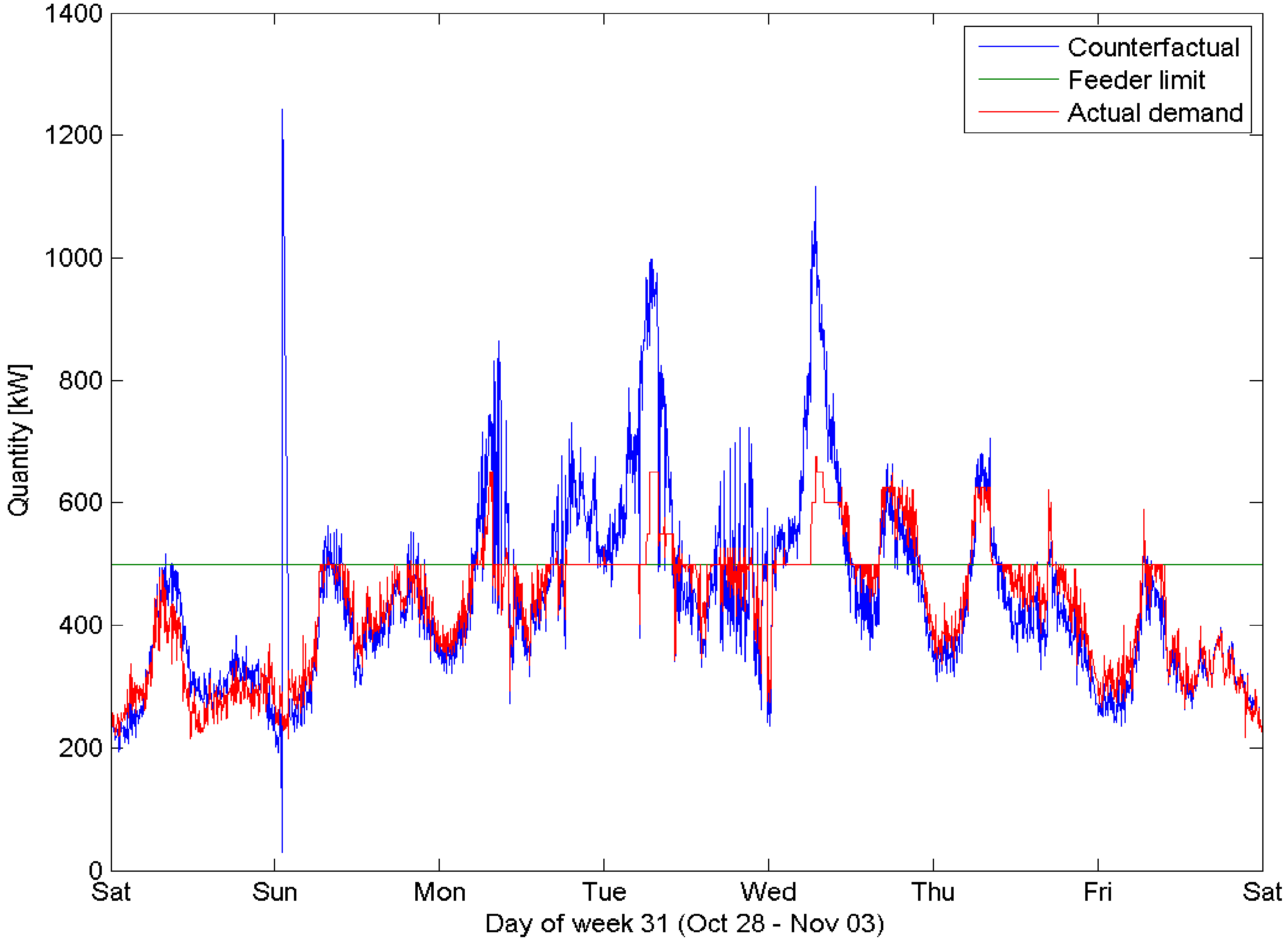

IBM
Market
$
MW
Invensys
Clallam PUD & Port Angeles
112 homes, 0.5 MW DR
Internet broadband
communications
Sequim Marine
Sciences Lab
0.3 MW DR
0.5 MW DG
Clallam County
PUD Water
Supply District
0.2 MW DR
Johnson
Controls

Winter Load Shifting Results for Real-Time Pricing Customers



- Winter peak load shifted by pre-heating
- Resulting new peak load at 3 AM is non-coincident with system peak at 7 AM
- Illustrates key finding that a portfolio of contract types may be optimal – i.e., don't want to just create a new peak

Flexible Loads to Manage Feeder Loading



Olympic Peninsula Demo: Key Findings

- Significant demand response was obtained:
  - 15% reduction of peak load
  - Up to 50% reduction in total load for several days in a row during shoulder periods
- Response to wholesale prices + transmission congestion + distribution congestion
- Able to cap net demand at an arbitrary level to manage local distribution constraint
- Short-term response capability could provide regulation, other ancillary services add significant value at very low impact and low cost
- Same signals integrated commercial & institutional loads, distributed resources (backup generators)

Portland General Electric (PGE) Demand Response Testbed

- Grew from PGE's 2016 IRP
- PGE hired a consultant to conduct a demand response potential study
- Oregon Public Utility Commission (OPUC) Staff were concerned PGE's DR targets in IRP were too far below potential study targets
- OPUC required PGE to develop a DR review committee and select potential areas for a DR testbed
- Objective of testbed was to inform DR planning, accelerate DR implementation, and drive market maturity

From PGE 2019 Smart Grid Report Update to Oregon PUC July 2019

DR Testbed Hypotheses to Test

- Can customers be recruited in sufficient numbers to achieve more significant peak demand offsets and renewable integration cost benefits?
- Forecast ultimate penetration and time periods to achieve them?
- Will customers who sign up for DLC programs accept it being dispatched with the frequency and duration needed to achieve substantial reductions in peak loads for the system as a whole or local T&D systems?
- Do pricing-based programs mitigate mandatory dispatch issues for consumers?
- Do portfolios of DR offerings increase recruiting?
- How much more cost effective is DR, and what level of increased penetration rate can be achieved, by programs targeting new buildings?
- Replacement programs, working with supply chain partners.
- Regional branding program.
- Joint EE/DR programs.
- Determine the level of customer service staff and program operating staff needed?

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Testbed Substations

Customer Engagement & Empowerment

Delaware

- Planned for reconstruction by end of 2019
- Modern SCADA and DA scheme in development
- University of Portland Solar + Storage
- Kaiser Interstate Campus

Roseway

- New Construction
- Planned for future reconstruction
  - Communication
  - Visualization
  - Remote operation
- Customer mix includes residential subsets

Island

- Multifamily and high concentration of commercial business
- High number of electrically heated homes
- Challenging recruitment
- High profile site for the City

From PGE 2019 Smart Grid Report Update to Oregon PUC July 2019

Portland General Electric DR Test Bed

- 2.5 year pilot; $5.9 million; funded through deferral and R&D funds
- Program is evolving from behavioral demand response of Peak Time Rebate (PTR) to direct load control (DLC)
- Opt-Out Peak-Time Rebate – 16,000 participants; ~3% unenrollments
- Optional Direct Load Control offerings
  - Heat pump water heater control research, testing customer-hosted Wi-Fi, cellular LTE, and radio frequency mesh network;
  - Ductless mini-split controls, in collaboration with the Energy Trust to better understand how energy efficiency and demand response can be "stacked"
  - A solar smart inverter for flexible grid services
  - EV chargers
  - A "whole house" bring your own device pilot where customers may enroll and manage multiple appliances with one platform.
- Testing recruitment messaging:
  - Monetary, giving back, carbon, renewable energy

Other Considerations for the NW

- Peak concerns in the Northwest aren't the same as peak issues in other systems because of the hydro system
- Northwest peaks may last 3-5 consecutive days and occur every five years; not typical hot or cold weather annual "needle peaks"
- Northwest peaks stem from extreme weather/demand during a low water year at a time when reservoirs are filling slowly (can be summer or winter)

Library of Congress/Corbis/VCG via Getty Images

Other Considerations for the NW, cont.

- What does this mean for demand response potential studies and programs?
- Each utility is unique; Understanding the exact nature of a utility's peak problem will help define the type of DR that can help solve it
- Individual utilities need to look at nature of their particular peak(s) of concern
- Key question for utilities to ask: **What is the specific problem I am trying to solve with my DR?**
  - Identify where peak problems are and how long they last
  - Identify exactly why are they short? (hydro, forced outages, natural gas storage)
- To identify peak issues, need models that run hourly and chronologically
- In modeling, need to evaluate water and weather stochastically
- Deterministic models will not reveal the need and potential value of DR
- Typical consultant studies may not pick up the nuance of NW peak needs and opportunities if methodology used elsewhere is simply replicated

Insurance Perspective

- In the Northwest Power and Conservation Council's 7th Power Plan, models selected DR almost as an **insurance product;** DR was deployed as if it were operating reserves in the model
- The big risk in the NW is the **hydro risk**; in a bad hydro year, DR can help
- The second worst hydro year on record was 2001, the year of the CA Energy Crisis; lack of available hydro was a major contributor to the crisis
- In a bad hydro year with a forced outage and high load event, DR would be very valuable
  - This type of value is revealed through stochastics
- Utilities and the WUTC could develop a consistent methodology that each utility could incorporate into their own models
- For smaller utilities, a simplified approach could be established

DR and Markets

- Some utilities don't need capacity now – hard to justify spending $$ on DR
- Explore opportunities for DR to be offered in a market between IOUs
- What about using DR to free up generation that could be bid into the EIM?
- What about DR opportunities in resilience hubs and ecodistricts?
- **Meanwhile, you have that DR resource that one day you really need!**
- While DR is relatively new in the Northwest, that's not the case everywhere.
  - Large DR programs bid into PJM and New England ISO forward capacity markets
  - At times, upwards of 70% of market is being met by DR
  - Verification requirements exist
- Day-ahead notification products are cheaper than 15-minute, hour-ahead or real-time products; in planning and procurement, utilities should consider the right product to get the job done at least cost

Other Value Streams to Consider

- Savings to distribution, transmission, and generations systems, including avoided losses or non-wires alternatives
- Temporal and locational aspects of value
- Value associated with interactions with other grid resources and other DERs
- Account for benefits across full effective useful life of the resource
- Insurance/risk reduction value
- Emissions avoidance value
- Opportunities related to increased technology or service-based customer engagement
- Recent Tom Eckman and LBNL report: Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings

Resources

In 2019 Regional Technical Forum Demand Response Subcommittee looked at demand response equipment and technical feasibility for:

- Commercial lighting controls
- Residential water heaters
- Connected thermostats
- EV battery chargers
- Irrigation pump controls
- Refrigeration controls

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Demand Response in Hawaii and Massachusetts

Dhruv Bhatnagar

June 8, 2019

Washington Utilities and Transportation Commission

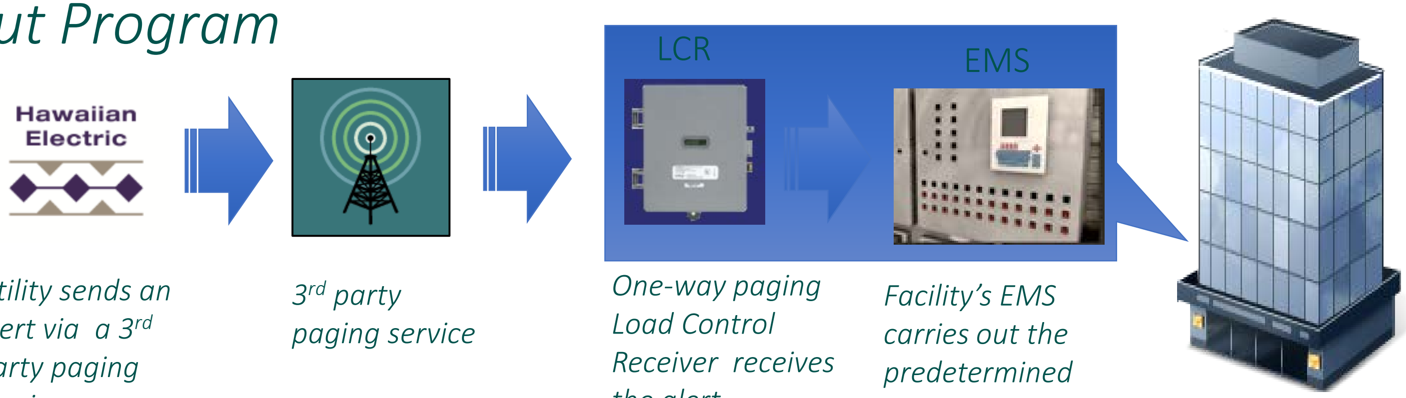
Stakeholder Meeting on Demand Response

U.S. DEPARTMENT OF ENERGY BATTELLE

PNNL is operated by Battelle for the U.S. Department of Energy

Existing Demand Response: EnergyScout

EnergyScout Program



Utility sends an alert via a 3rd party paging service

3rd party paging service

One-way paging Load Control Receiver receives the alert

Facility's EMS carries out the predetermined directives

Programs are dispatched by system operations on a frequent basis, ~ 1-4 dispatch events per month

Large Customers

- 42 customers, ~12 MW
- Technology: diesel generators, HVAC
- Dispatch, 1 hr. notification, underfrequency load shed at 59.5 Hz

Small & Medium Business

- 200 customers, ~1 MW
- Technology: HVAC
- Dispatch, 1 hr. notification, and underfrequency load shed at 59.7 Hz

Residential

- 30,000 customers, ~8 MW
- Technology: electric water heaters
- Dispatch, notification at time of event, and underfrequency load shed at 59.7 Hz

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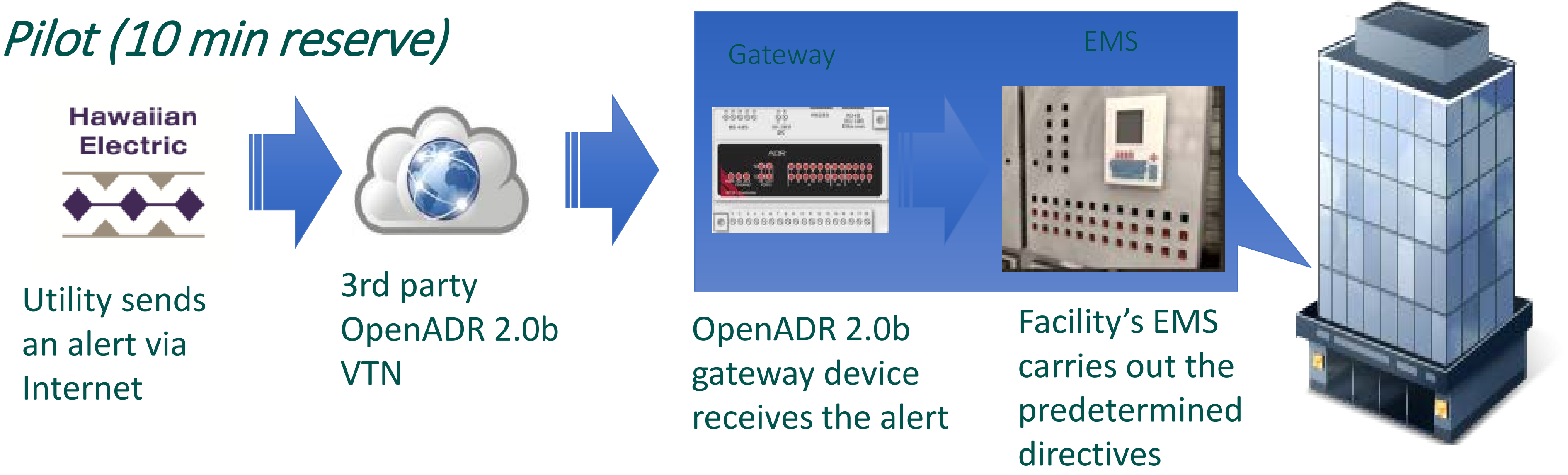
Existing Demand Response: FastDR

Fast DR "Pilot"

- ~7 MW, 38 customers subscribed
- Technology: largely backup generation, 2 energy storage participants, some customers are *just* HVAC response
- Responsive to
  - ✓ Under-frequency load shed (59.7Hz)
  - ✓ 10 minute utility dispatch

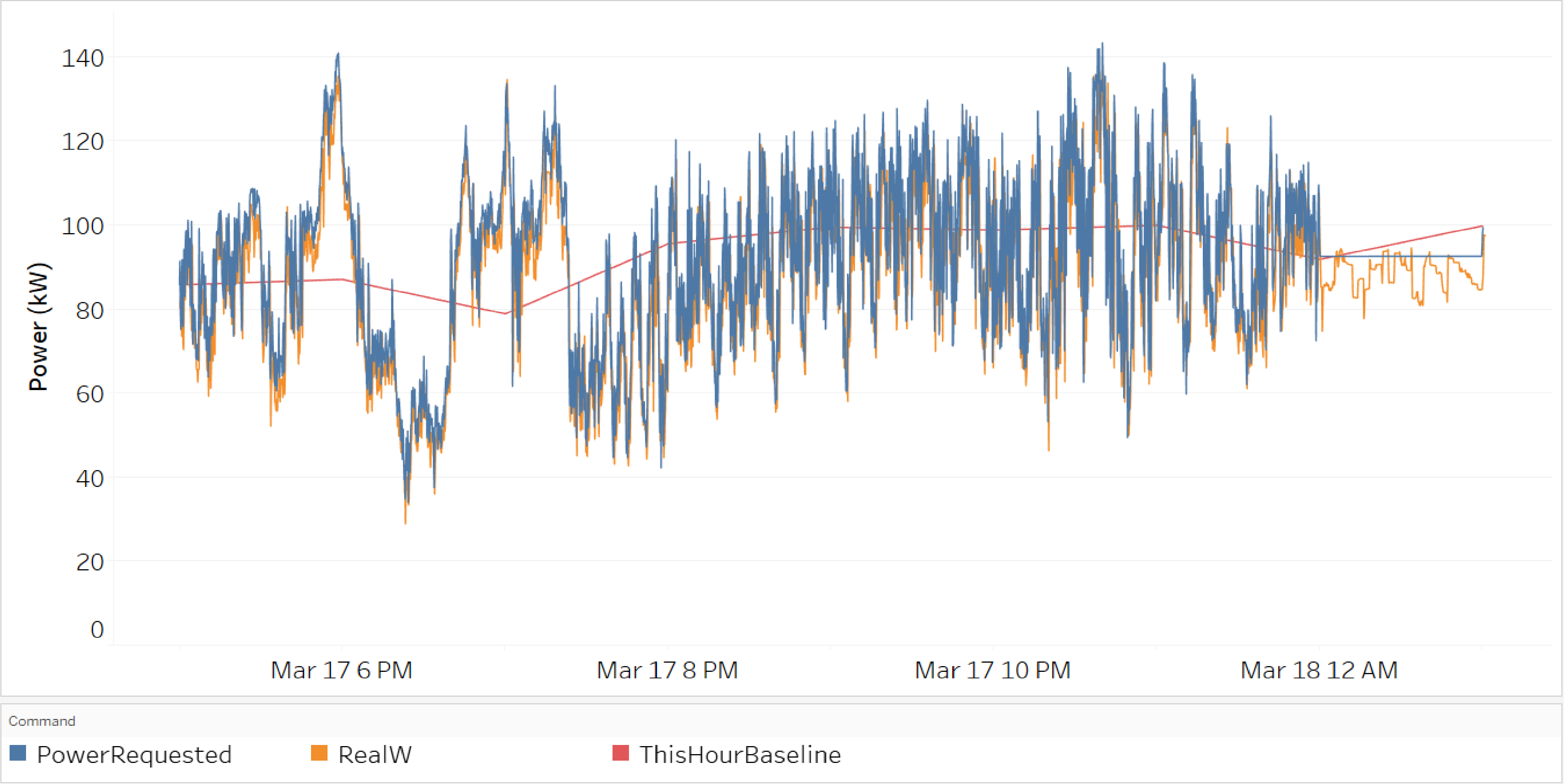
Fast DR Pilot (10 min reserve)



Grid-Interactive Water Heater

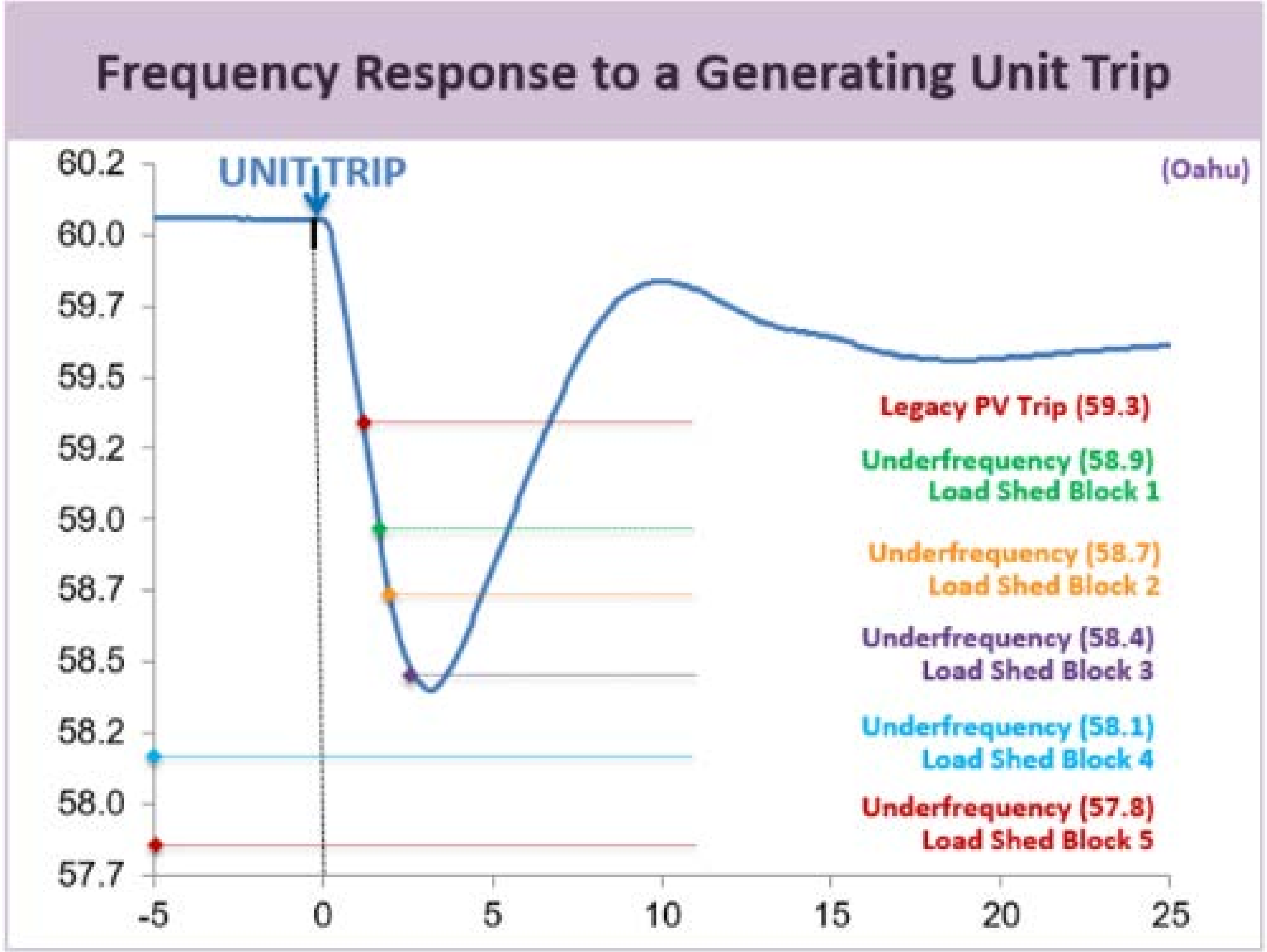
Grid-Interactive Water Heater (GIWH): is a “thermal battery” for storing energy, having the ability to follow locational marginal pricing, providing fast regulation service and better integrating renewable energy, thereby effectively reducing the carbon footprint of the appliance. (Source: PLMA GIWH Interest Group)

GIWH Regulation: Test 18: 8 hours (“Bad” day)



Under Frequency Response (UFR) Laboratory Testing for Water Heater Controllers

- The under-frequency response (UFR) test is designed to determine how accurately a load controller turns off a load in response to an under-frequency event.
- The controller must monitor the frequency locally at the device-level and respond autonomously without connection to the internet
- UFR Testing Conducted by EPRI



Controller Testing Results

Steffes (GIWH):

- Performed as intended, average frequency of past 10 cycles was exactly 59.700 Hz.
- The controller ramped the load back up to full output over the course of 1-2 minutes once the frequency returned to 60 Hz

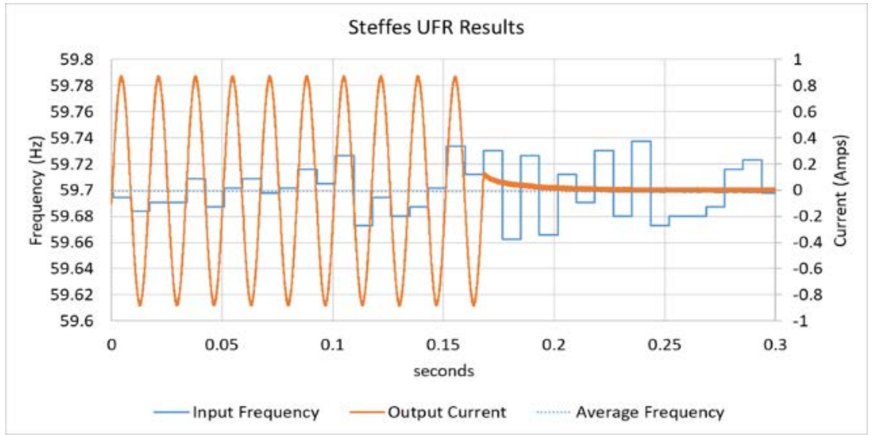
Mosaic Power (controller):

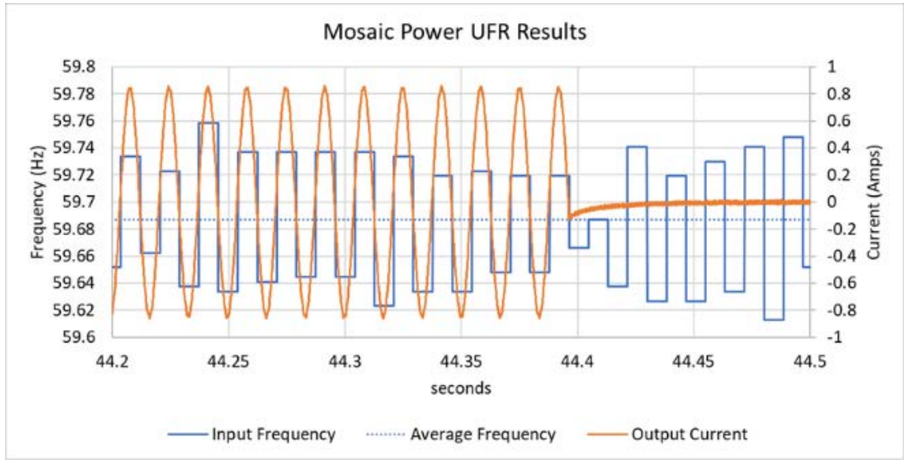
- Performed as intended, average frequency of past 12 cycles from shutoff was 59.687 Hz
- The controller turned the load back on after 30 minutes
- 14,000 water heaters providing frequency regulation in PJM

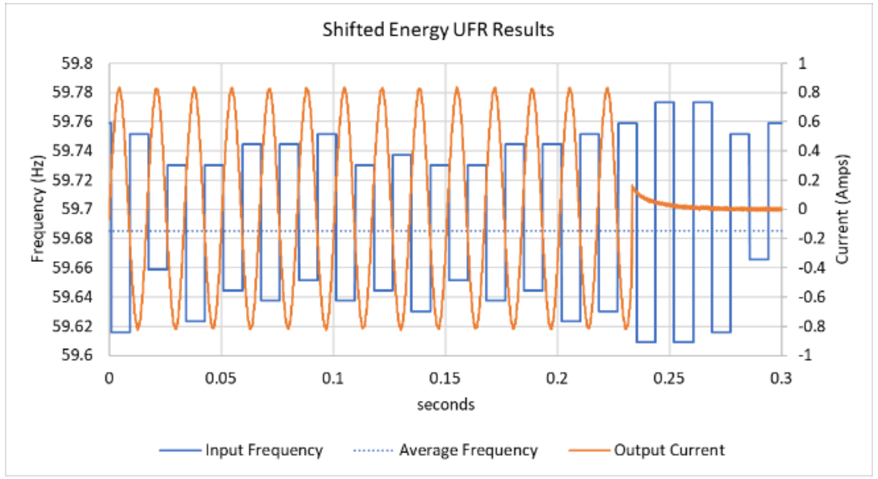
Shifted Energy (controller):

- Performed as intended, average frequency of past 12 cycles from shutoff was 59.685 Hz
- The controller turned the load back on after a set amount of time once the frequency returned 60.0 Hz

Source: Angela Cheung, EPRI







New Integrated DR Portfolio: Hawaiian Electric Grid Services

- Capacity (Load Reduction and Load build)
  - Load Build: 10:00AM – 2:00PM, 8 hr. notification
  - Load Reduction: 5:00PM – 9:00PM, 10 min. notification
- Fast Frequency Response (FFR)
  - Autonomously triggered due to an under frequency excursion
  - Trigger: 59.7Hz, 12 cycle response
- Regulating Reserve/Regulation (secondary frequency regulation)
  - Response to a set-point regulation signal (AGC: automatic generation control)
- Replacement Reserve
  - 10-30 minute response after notification, 1-2 hour duration

Grid Service Participation Paths

Options Now

Aggregators (third-party)

Contract directly with aggregators. Third Party recruits and contracts with customers to operate customer loads in a “Portfolio”

Customer wanting turn-key services as part of larger group in portfolio

Self-Aggregators

Contract directly with Hawaiian Electric.
Utility negotiate directly with customer for delivery of services at large or multiple site facilities

For professionally managed customers providing more control and greater total financial incentive

Future Additions

Hawaiian Electric Companies’ Programs

Programs offered directly to customers through a Utility Tariff

Alternate contracting path to directly participate in a Utility Tariff

Initial Targets for Grid Services

Grid Service Type	Oahu ~1,200 MW Peak	Maui ~200 MW Peak
Fast Frequency Response	36 MW	0
Capacity (Load Reduction)	44 MW	9.8 MW
Capacity (Load Build)	44 MW	8.9 MW

- Aggregators will be utilized to achieve the target levels starting 2019 and contract committed until 2023 under a standard form **Grid Services Purchase Agreement**
- Self-aggregators will also be utilized to achieve these target levels
- As necessary, utilities will deploy their own programs
- All programs are intended to be technology neutral: water heaters, HVAC, building controls, pumps, batteries, existing distributed generation, electric vehicles etc.

Massachusetts DR: ISO

ISO-NE Active Demand Resource Program

Resources that are actively dispatched by the ISO when needed. Example: powering down an energy-intensive machine to comply with a dispatch instruction.

- These resources are fully integrated into the ISO-NE energy, capacity, and reserve markets.
- Load reduction is offered in the day-ahead market and dispatched in real-time

Parameter	Value
Minimum Size	100 kW
Participation Months	Summer (Jun-Nov) & Winter (Dec-Mar)
Required Availability	24/7 during applicable months + two 1-hour performance tests each year
Incentive	• $/kW monthly incentive for availability based on Forward Capacity Market • $/kWh for actual performance at real-time energy market prices.
Eligible Participants	Distributed dispatchable generation or load curtailment

ISO-NE Passive Demand Resource Programs

Non-dispatchable resources that provide energy efficiency and save electricity over time. Example: Solar array generating electricity for a facility.

1. On-Peak Resources: Incentivized for energy saved during summer and winter peak load hours (1-5 p.m. Summer and 5-7 p.m. Winter)
2. Seasonal-Peak resources: Incentivized for energy saved during summer and winter weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent system peak 50/50 load forecast for the applicable season.

Parameter	Value
Minimum Size	100 kW load reduction
Participation Months	Summer (Jun-Nov, April-May) & Winter (Dec-Mar)
Incentive	$/kW monthly payment based on Forward Capacity Market and demonstrated load reduction.
Eligible Participants	Energy efficiency projects and distributed generation that contributes to load reduction

https://cpowerenergymanagement.com/wp-content/uploads/2019/02/ISONE_Snapshots_22719.pdf

MA: Mass Save and ConnectedSolutions

- Integration of MA energy efficiency (Mass Save) program with demand response
  - Residential and small business: existing EE program administrator sales teams
  - C&I: EE program administrator sales teams and third-party curtailment service providers (C&I) to sign customers up for DR
- Funding: energy efficiency surcharge (bill surcharge)
- Energy efficiency measures installed as a function of Mass Save are eligible for DR participation (previously installed and co-marketing to new participants)
  - Smart thermostats can receive enrollment ($25) and annual participation ($20) incentives to allow program administrators (the distribution utilities) control during peak hours
  - Higher incentives for energy storage participation (can be partially funded through the EE HEAT loan) *Summer and winter*

Massachusetts DR (cont.)

- Energy suppliers in MA (National Grid, Eversource, Unitil, and Cape Light Compact) offer Connected Solutions to their customers - a collection of residential and commercial DR programs.

Residential Programs:

EV Charger Program (Eversource only)

Performance Incentive	$150 instant, $50/annual for 3 year commitment

Thermostat Program

Performance Incentive	$25 instant, $20 annual
Events per Summer	15 on average, 3 hours each
Months Events can Occur	June through September
Time Discharge Events Can Occur	2 p.m. to 7 p.m.

Battery Program

	Summer	Winter
Performance Incentive	$225 per kW-summer	$50 per kW-winter
Discharge Events per Season	30 to 60	5 - 15
Months Discharge Events Can Occur	June through September	December through March
Time Discharge Events Can Occur	2 p.m. to 7 p.m.	2 p.m. to 7 p.m.
5-year incentive lock	Yes	Yes

- Participating in both the Summer and Winter programs can count towards the Solar Massachusetts Renewable Target (SMART) program's full cycle equivalent dispatch requirement in order to obtain additional battery adder incentives within the SMART program.

https://www.nationalgridus.com/MA-Home/Connected-Solutions/ConnectedSolutions
https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-ciprogrammaterials.pdf

Commercial & Industrial Programs

Cape Light Compact, National Grid, and Unitil	*Summer*		*Winter*
Option	Targeted Dispatch Summer[1]	Daily Dispatch Demonstration Summer[2]	Targeted Dispatch Winter[3]
Number of Events per Season	2 to 8 per Summer	30 to 60 per Summer	Up to 5 per Winter
Incentive	$35/kW-Summer +10/kW-Summer Weekend Bonus	$200/kW-Summer	$25/kW-Winter
Incentive Lock	None	5 Years	None
Length of Events	3 Hours	2 to 3 Hours	3 Hours
Time of Day	Between 2pm and 7pm	Between 2pm and 7pm	TBD
Weekend/Weekday	Mon. – Friday Only With a Weekend Bonus	Any Day	Mon. – Friday Only
Events on Holidays	No	Yes	No
Day-Ahead Notification	Yes	Yes	Yes
Months	June – September	June – September	December – March

For Cape Light Compact customers there is an additional $65/kw-summer to the Targeted Dispatch Summer incentive and $25/kW-winter for Targeted Dispatch Winter Incentive for using battery storage.

Eversource	*Summer (June – Sept.)*						*Winter (Dec.- Mar.)*	
Option	Targeted Dispatch			Daily Dispatch Demonstration[4]		Weekend Bonus	Targeted Dispatch	
Technology	Agnostic	Batteries[5]	Thermal Storage[6]	Batteries[5]	Thermal Storage[6]	All	Neutral	Batteries[5] & Thermal[6]
Max number of Events per Season	8	8	8	60	60	2	5	5
Incentive	$35/kW-Summer	$100/kW-Summer	$75/kW-Summer	$200/kW-Summer	$100/kW-Summer	$10/kW-Events	$25/kW-Winter	$50/kW-Winter
Length of Events	3 Hours	3 Hours	3Hours	2 – 3 Hours	2 – 3 Hours	3 Hours	3 Hours	3 Hours
Time of Day	2:00 PM and 7:00 PM	2:00 PM and 7:00 PM		2:00 PM and 7:00 PM		2:00 PM and 7:00 PM	TBD	TBD
Weekend/Weekday	Weekdays, Non-Holiday					Weekend & Holidays	Weekdays, Non-Holiday	
Metering Assistance	$1,500					No		

Customers will be notified the day before the event.

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Baltimore Gas & Electric: Peak Time Rebate

- Smart Energy Rewards Program (peak time rebate)
  - Automatic enrollment, customers receive a notification (day before) an event to reduce load
  - Rewarded with an incentive of $1.25/kWh
  - Savings are monetized in the PJM Energy and Capacity markets

SER Program Summary to Date

Year	# of Energy Savings Days	Eligible Customers	Average Bill Credit	Peak Demand Reduction (MW)	Total Bill Credits to Customers	% Participation
2013	4	315,000	$9.03	96	$7 M	82%
2014	2	860,000	$6.55	209	$5.6 M	76%
2015	4	1,020,000	$6.67	309	$15.5 M	81%
2016	3	1,074,000	$6.73	336	$11 M	71%
2017	2	1,095,000	$6.13	330	$6.1 M	74%

SER Wholesale Market Benefits to Customers, 2013 to 2015[6]

	Benefits from Peak Demand Reductions			Benefits from Energy Reductions			Total
	Wholesale Capacity Revenue	Avoided Capacity Cost	Capacity Price Mitigation	Wholesale Energy Revenue	Avoided Energy Cost	Wholesale Energy Price Sup-pression	
Benefits	$46 M	$87 M	$234 M	$25 M	$9 M	$5 M	$406 M
Share of Total	11%	21%	58%	6%	2%	1%	100%

BGE estimated $93M of avoided transmission capital expenditures and $72M of avoided distribution capital expenditures as a result of the SER program from 2013 to 2015

Source: AEE Institute
https://info.aee.net/hubfs/MD%20DR%20Final.pdf

Thank You

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Demand Response

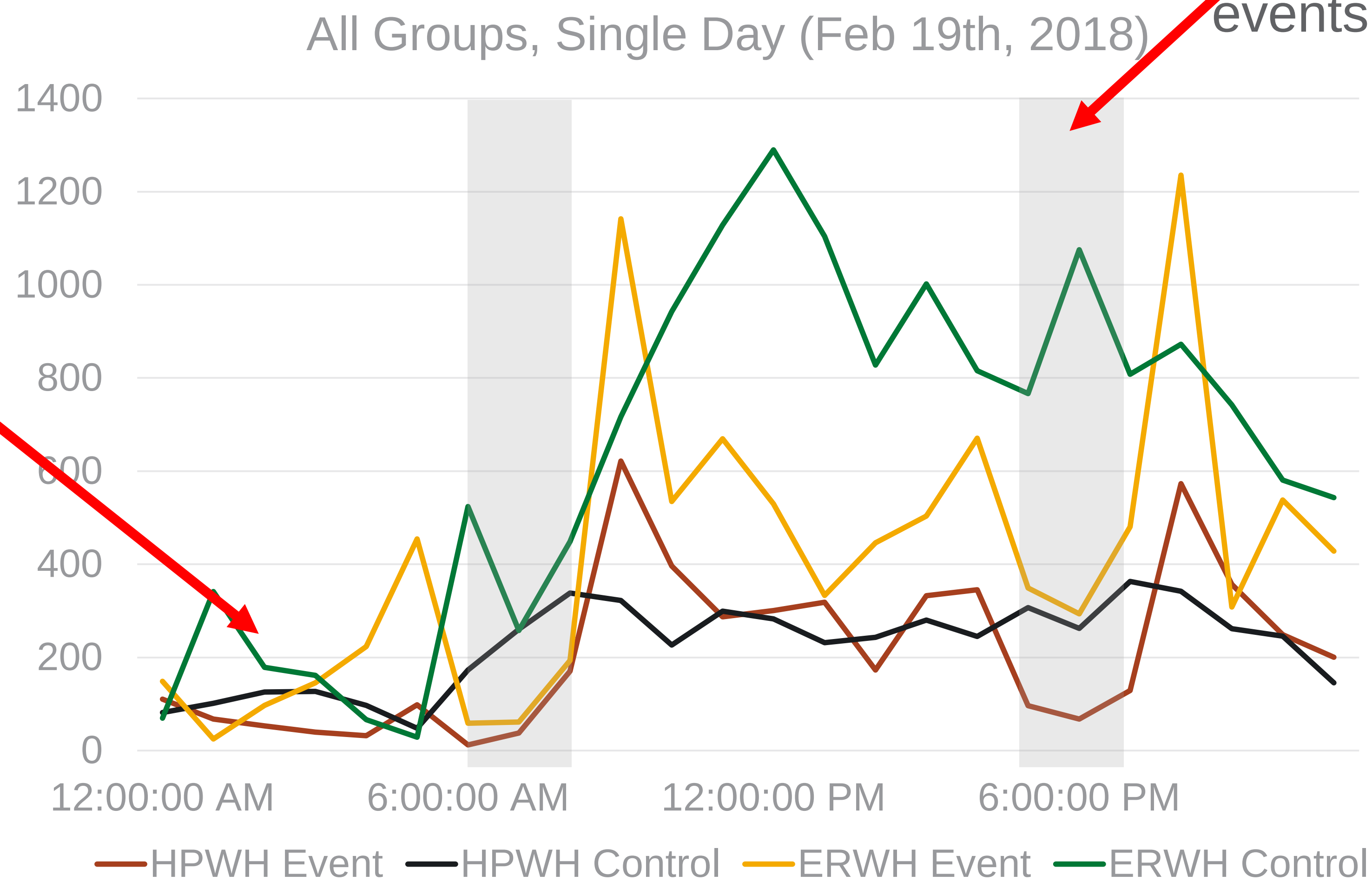
- The Smart Electric Power Alliance has adopted the following working definition for demand response:
    - *Changes in the electric load—such as reductions, increases, or shifts—by end-use customers from their normal consumption patterns in response to specific market or system conditions. Such conditions could include time-varying changes in the cost of producing energy, shortages of distribution, transmission, or generation capacity, or unusually high or low voltage or frequency.*
    - *This could also be customer generation (export beyond a customer's load)*

- *Utility DR Offerings in the United States (2017 SEPA/Navigant Survey):*
    - 41% of utilities offer AC switch programs
    - 16% offer water heater programs
    - 24% of utility respondents offer thermostat programs
    - 9% offer behavioral programs to their residential customers

General Trends from HPWH Pilot

Results: Single Day Example

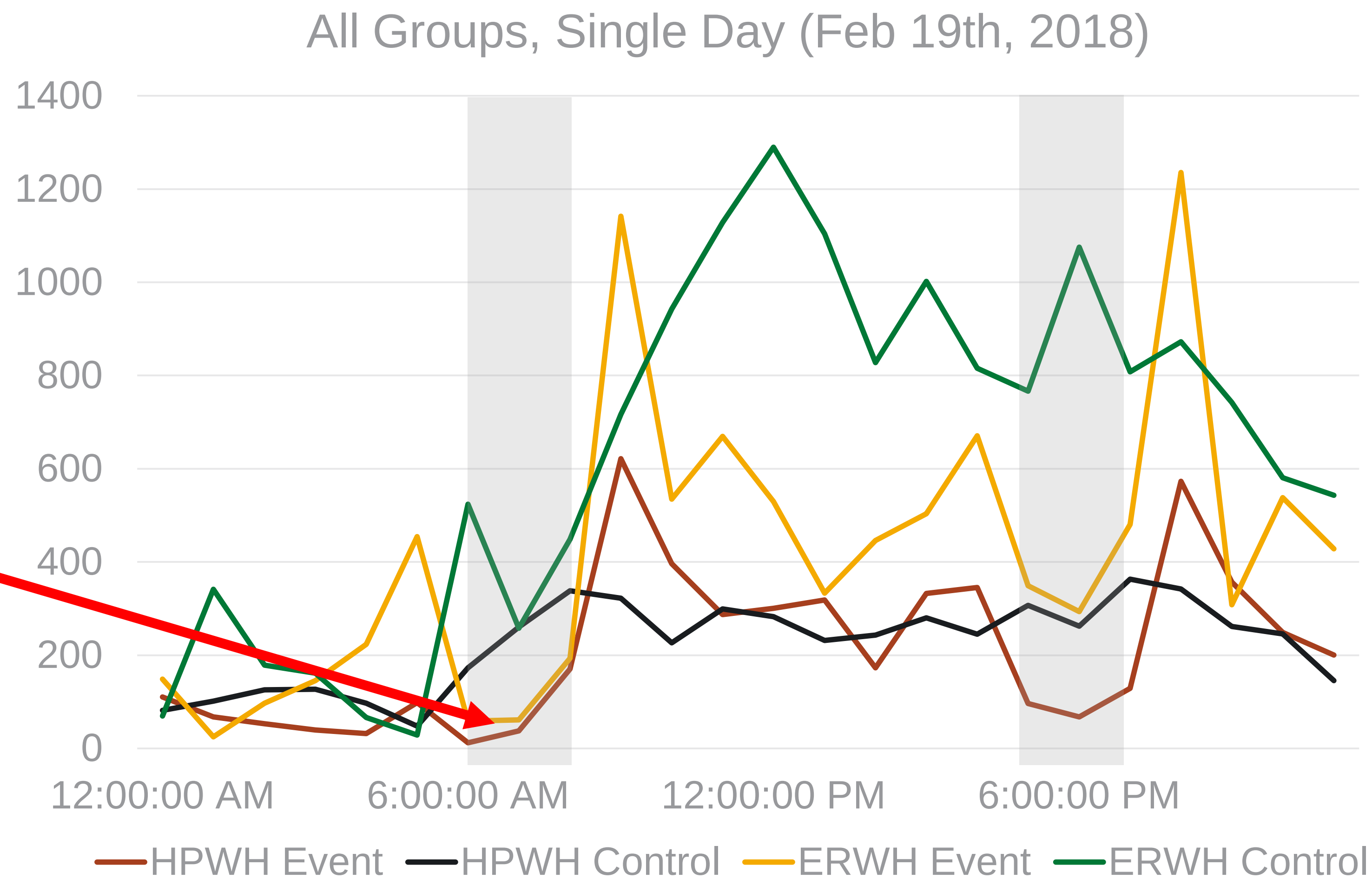
Low energy use by all groups at night



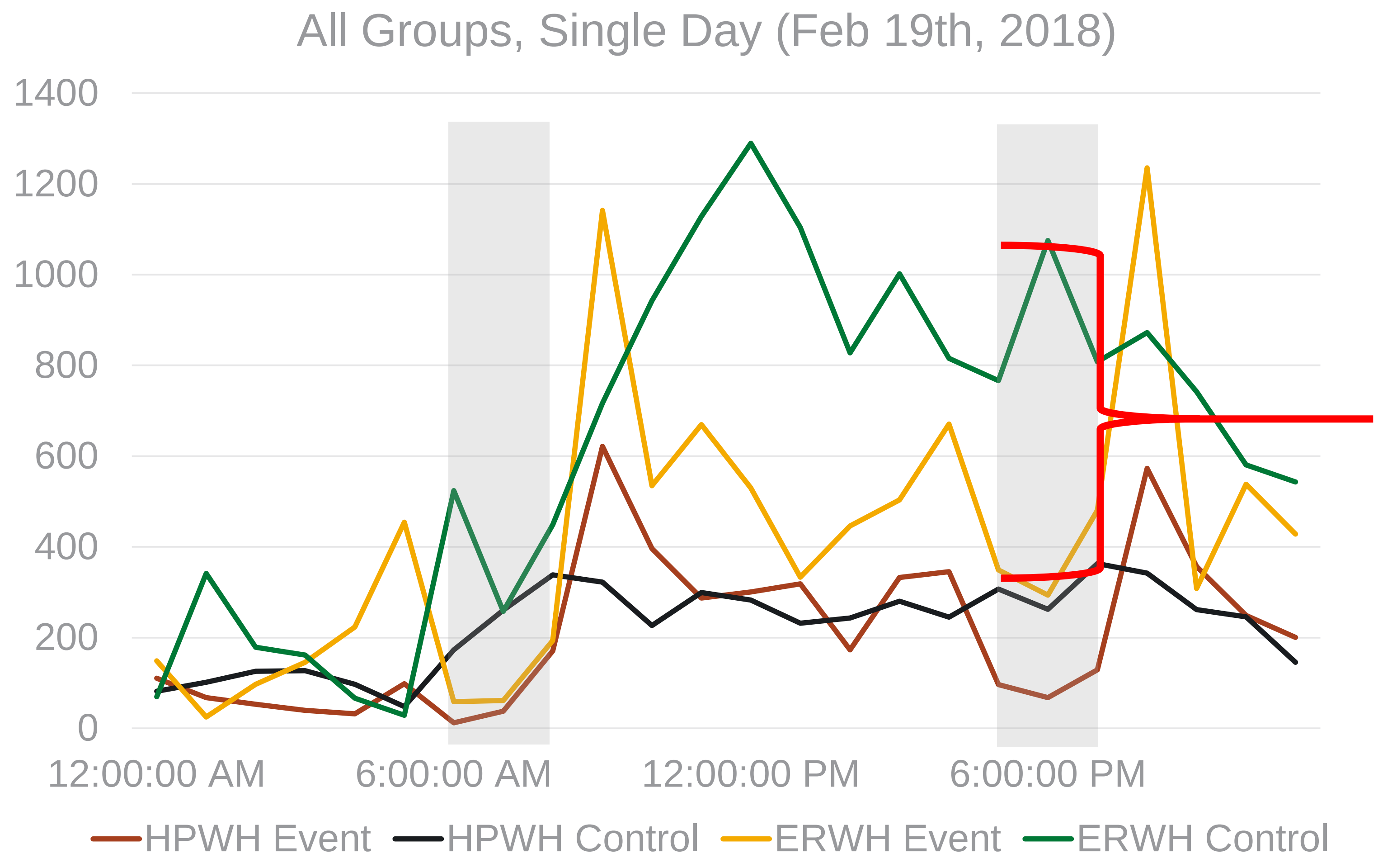
Grey bars = shed events

Single Day Example

Event groups use less energy during shed event

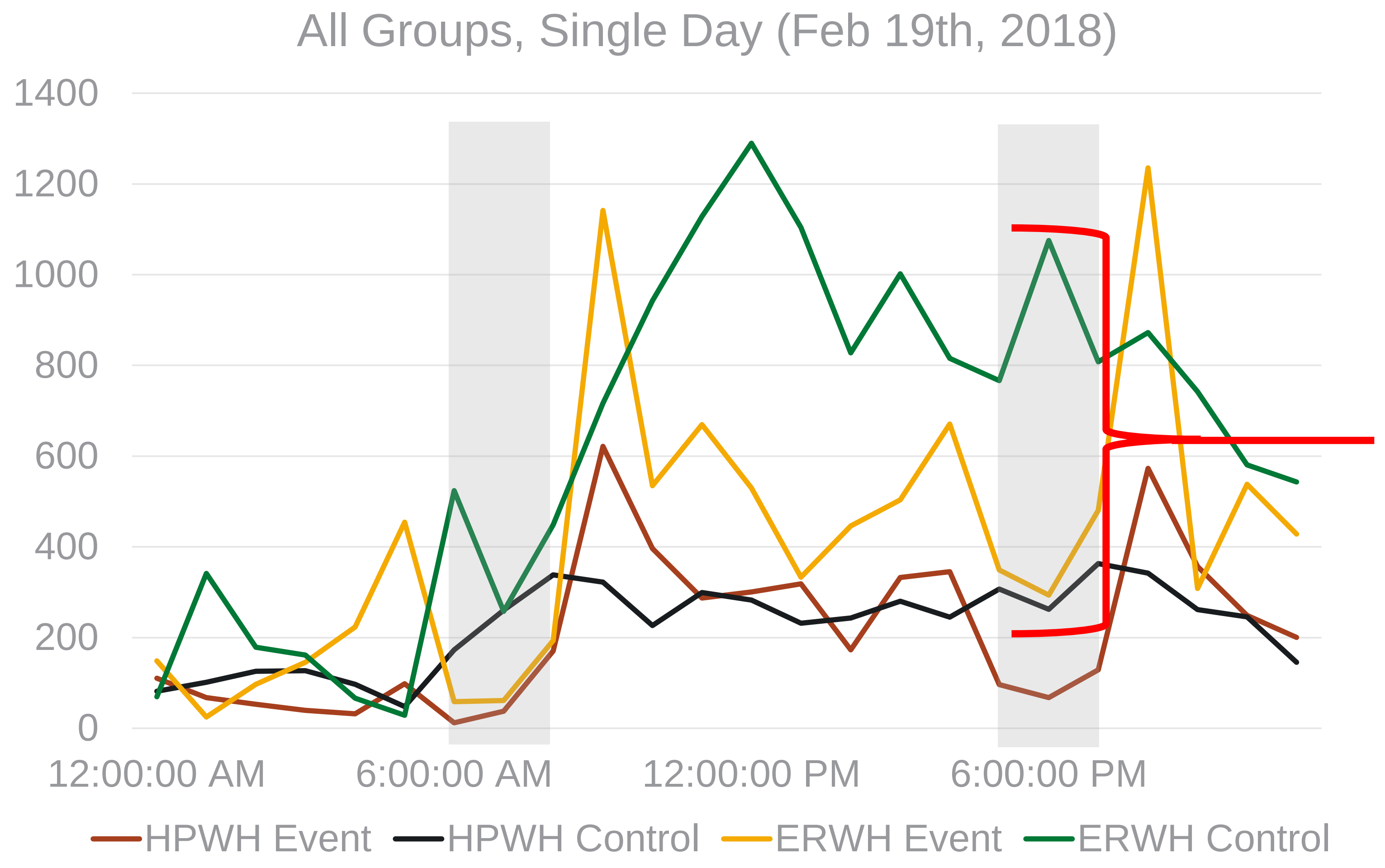


Single Day Example



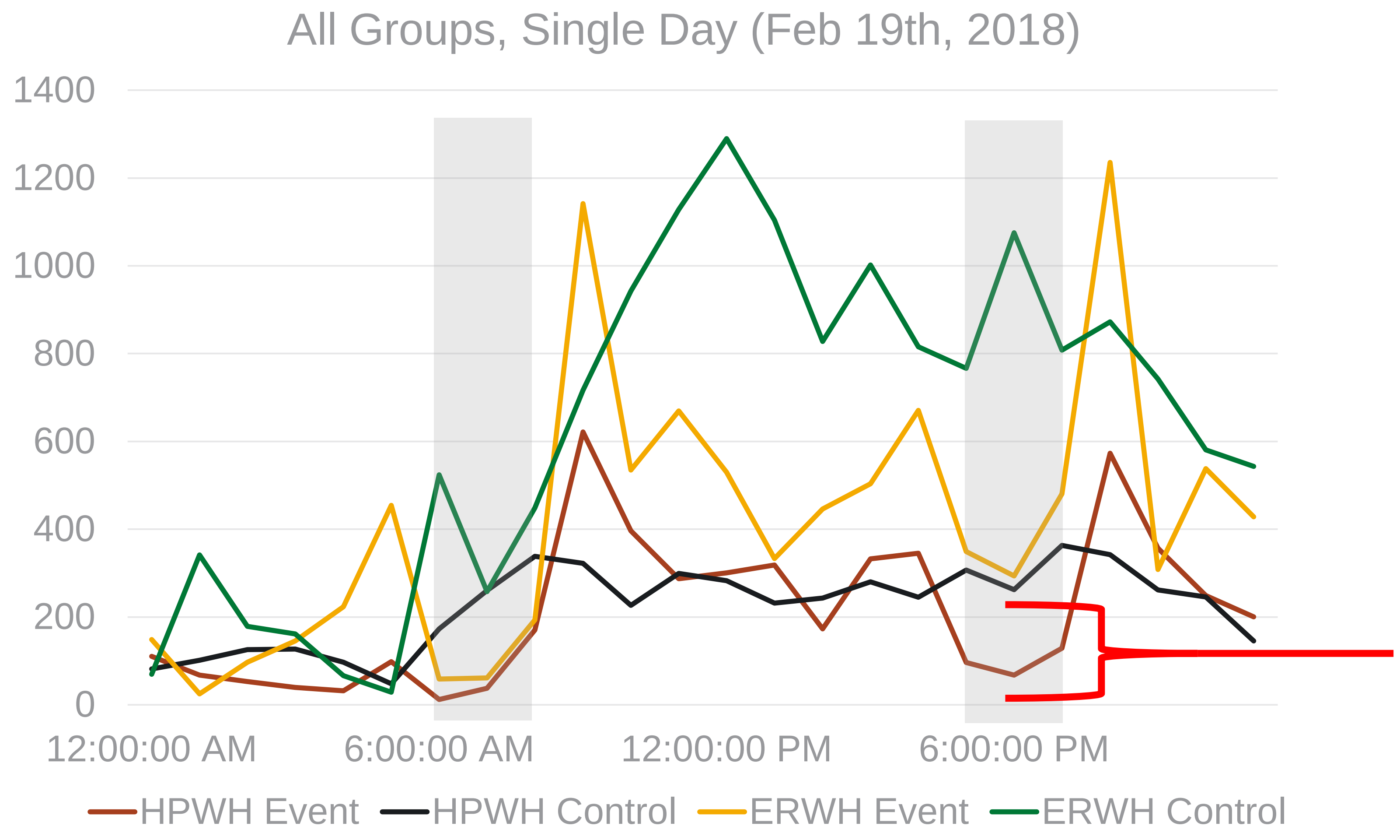
Large peak reduction with connected ERWH

Single Day Example



Larger peak reduction when switching to (“dumb”) HPWH

Single Day Example



Even greater peak load reduction with *connected* HPWH

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Full Season Results

- Average Hourly Peak (Watts) during Shed Events per Water Heater

	ERWH (Baseline)	Connected ERWH	HPWH	Connected HPWH
Winter Morning	616	242	306	83
Winter Evening	668	348	232	66
Summer Evening	474	127	109	26

- Average Peak Reduction from Baseline (Watts Reduced) during Shed Events Per Water Heater

	ERWH (Baseline)	Connected ERWH	HPWH	Connected HPWH	%Reduced Compared to Baseline
Winter Morning	616	374	310	533	87%
Winter Evening	668	321	437	602	90%
Summer Evening	474	347	365	448	95%

Total Energy Shifted

Approximate Energy Shifted During Peak Afternoon Hours (Average of Baselines, Rounded to the Nearest 50 W, Multiplied by the Average Number of Hours per Event for that Season)

Season	HPWH Energy Shifted Per Event (Wh)	Average Event Length (Hours)	ERWH Energy Shifted Per Event (Wh)	Average Event Length (Hours)
Winter	300	2	600	2
Spring	250	2	1050	2
Summer	350	4	1300	4

Reduced Risk for Utilities, Reduced Cost to Consumers

Winter Peak Load Reduction	ER BL (W/Hour of DR Event)	ER BL – ER with DR (W/Hour of DR Event)	ER BL – HPWH Control (W/Hour of DR Event)	ER BL – HPWH with DR (W/Hour of DR Event)	% Savings for Switching to HPWH with DR (W)
Morning Peak	616	374	310	533	87%
Evening Peak	668	321	437	602	90%

~90% of evening peak load power can be reduced by switching from uncontrolled ERWHs to Connected HPWHs

Acronyms: ER = electric resistance, BL= Baseline, W = watt, DR = demand response, CI = confidence interval, ERWH = electric resistance water heater, HPWH = heat pump water heater

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Reduced Risk for Utilities, Reduced Cost to Consumers

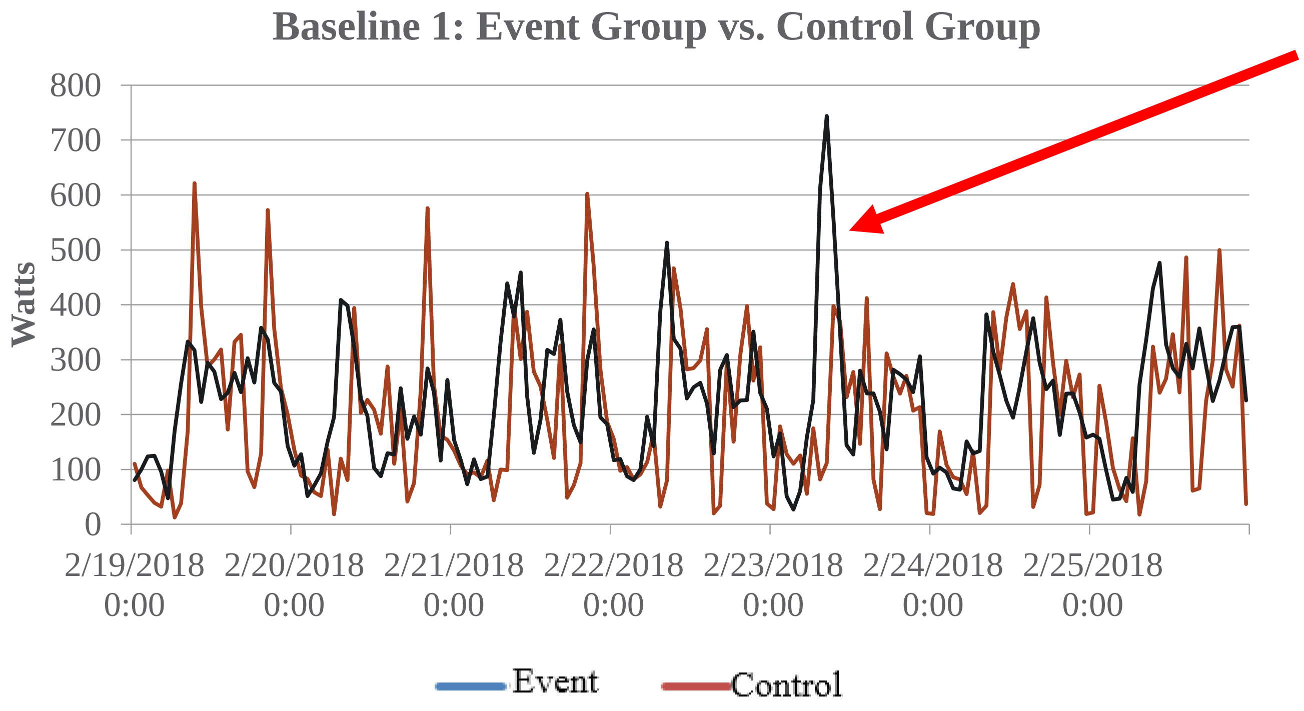
Winter Peak Load Reduction	ER BL (W/Hour of DR Event)	ER BL – ER with DR (W/Hour of DR Event)	ER BL – HPWH Control (W/Hour of DR Event)	ER BL – HPWH with DR (W/Hour of DR Event)	% Savings for Switching to HPWH with DR (W)
Morning Peak	616	374	310	533	87%
95% CI for Morning Peak	85	79	83	84	N/A
Evening Peak	668	321	437	602	90%
95% CI for Evening Peak	57	77	65	58	N/A

~90% of evening peak load power can be reduced by switching from uncontrolled ERWHs to Connected HPWHs

Acronyms: ER = electric resistance, BL= Baseline, W = watt, DR = demand response, CI = confidence interval, ERWH = electric resistance water heater, HPWH = heat pump water heater

Average kW Reduction During Shed Events (for each water heater type)

- Many ways to determine the average kW reduction
  - Baseline 1: Event Group vs. Control Group



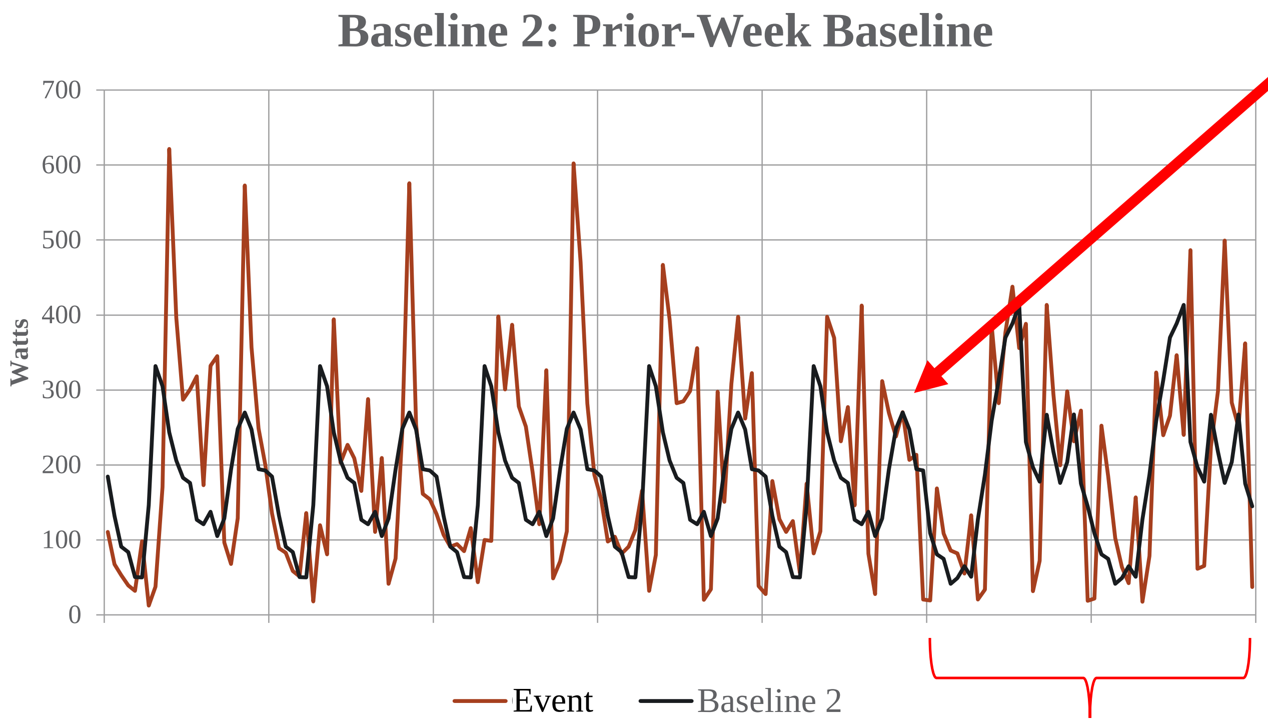
Unpredictable behavior is expected in this baseline

  - Baseline 2: Prior- Week Baseline
  - Baseline 3: Full Season Baseline

Average kW Reduction During Shed Events (for each water heater type)

Many ways to determine the average kW reduction

- Baseline 1: Event Group vs. Control Group
- Baseline 2: Prior- Week Baseline



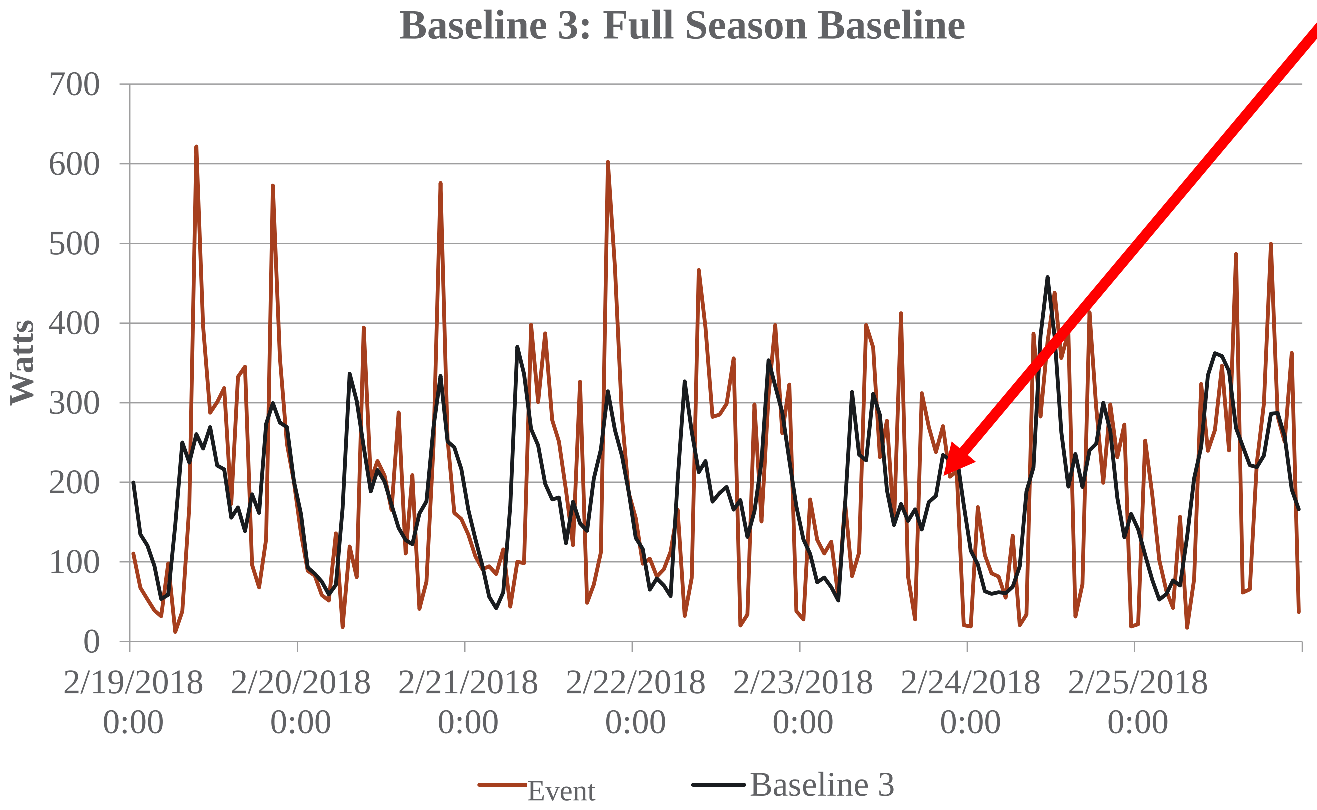
Unpredictable behavior is averaged out in this baseline

Weekend days

- Baseline 3: Full Season Baseline

Average kW Reduction During Shed Events (For each water heater type)

- Many ways to determine the average kW reduction
  - Baseline 1: Event Group vs. Control Group
  - Baseline 2: Prior- Week Baseline
  - Baseline 3: Full Season Baseline



Baseline 3 trends toward a typical hot water load profile

kW Reduction Using All Shed Events

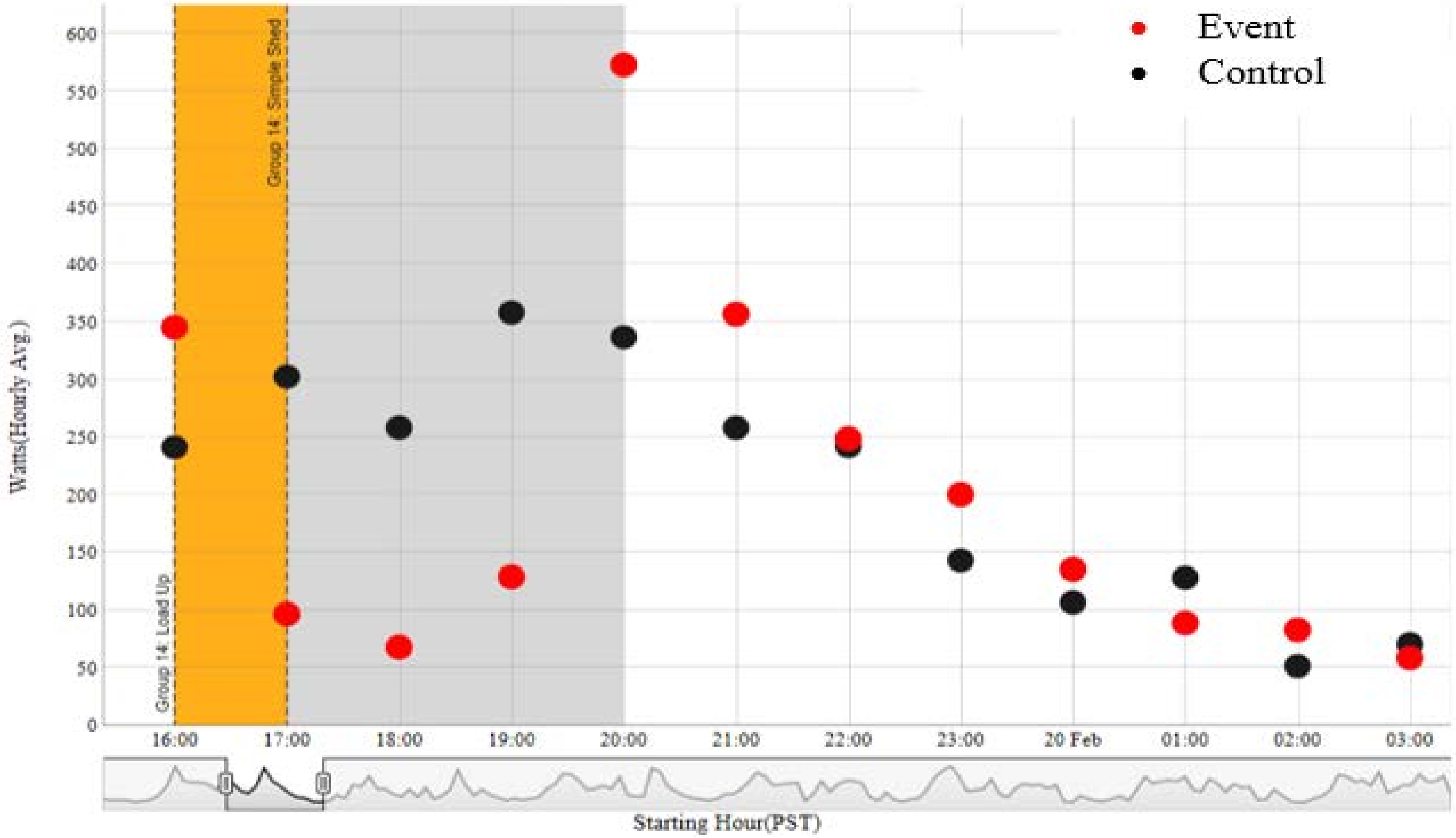
	Heat Pump Water Heaters (n=145)			Electric Resistance (n=86)		
Baseline #	Base 1	Base 2	Base 3	Base 1	Base 2	Base 3
Average Impact from 10pm to 5am	84	95	84	133	146	194
Std. Dev.[1] from 10pm to 5am	34	25	N/A[2]	81	59	N/A
Average Impact from 6am to 10am	201	196	232	337	318	444
Std. Dev. from 6am to 10am	45	45	N/A	67	121	N/A
Average Impact from 11am to 4pm	170	148	N/A[3]	322	329	N/A
Std. Dev. from 11am to 4pm	47	29	N/A	114	133	N/A
Average Impact from 5pm to 9pm	142	161	167	328	312	316
Std. Dev. from 5pm to 9pm	47	46	N/A	85	99	N/A

1. Standard deviation provides information about the variation of the average impact between the 10 weeks studied in the season
2.Only the last week of the season is part of this event group
3. No events occurred during this time for the week of March 26th

Recovery Time/Energy: HPWH

Challenges

- Unknown recovery energy associated with draws during shed period
- Unknown recovery energy associated with draws during recovery period

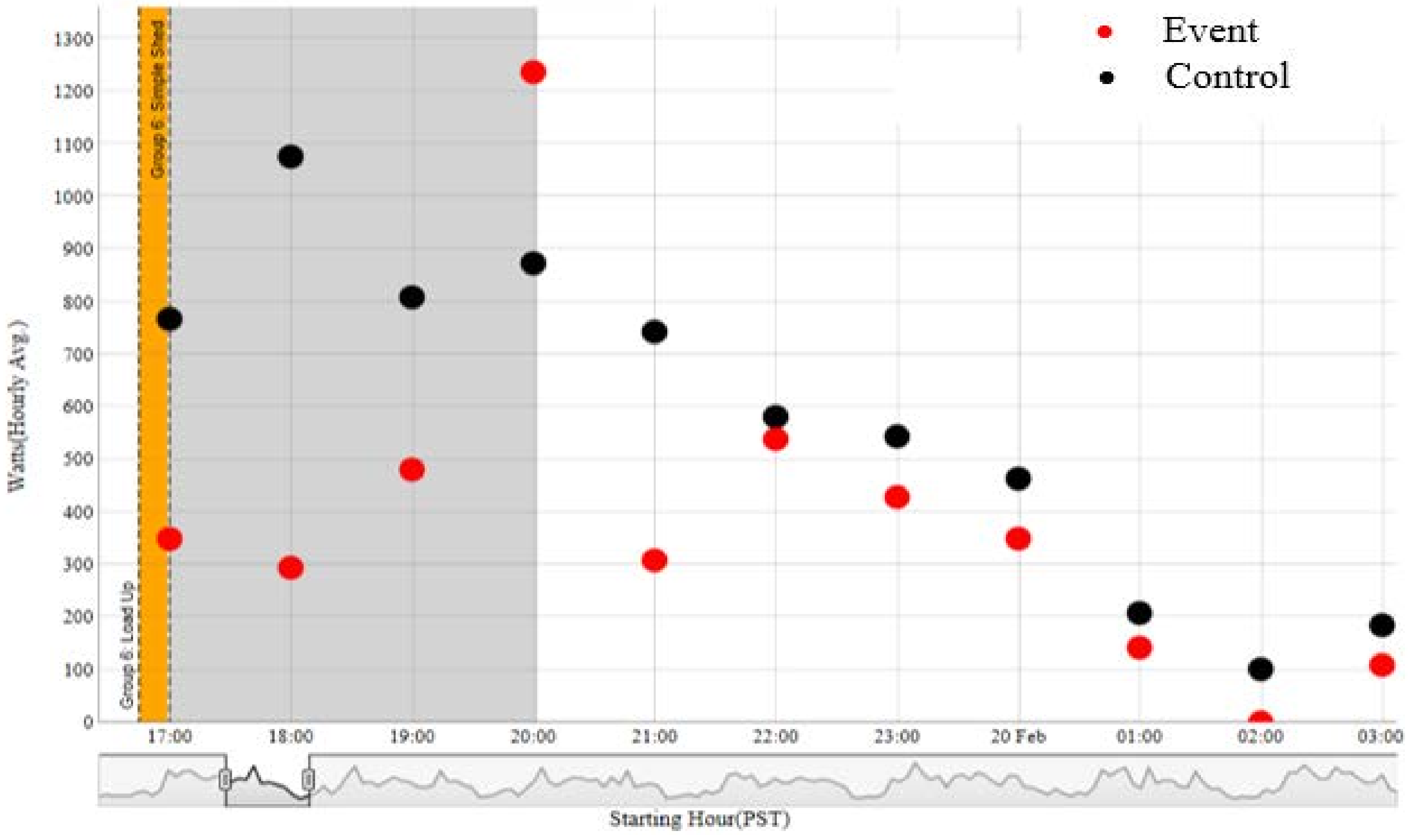


Orange Region = the Load Up Period, Grey Region = the Shed Period

Recovery Time/Energy: ERWH

Challenges

- Unknown recovery energy associated with draws during shed period
- Unknown recovery energy associated with draws during recovery period



Orange Region = the Load Up Period, Grey Region = the Shed Period

Stakeholder Discussion

For new topics: "Raise hand – Topic"

For responses to current topic: "Raise hand – Response"

Raise hand – Response

Raise hand – Topic

Raise hand – Topic

Raise hand – Response

Discussion Questions on DR Potential

Identify the potential cost-effective demand response and load management programs that may be acquired in the integrated resource plan.

1) Which values of demand response are utilities currently incorporating into the IRP to identify cost-effective demand response?
2) What additional values need to be included to ensure all utility system costs and symmetrical nonutility impacts are accounted for?
3) Which values can be identified directly within the IRP modeling process and which need to be included in the demand response potential assessment?
4) What type and level of guidance around demand response potential assessments would be useful?

Discussion Questions on DR Target Setting

Propose specific targets that pursue all cost-effective, reliable, and feasible demand response in the Clean Energy Implementation Plan.

1) Should DR targets in the CEIP be the same as the potential in the IRP? How should they be different?
2) How should DR pilots be treated in CEIP targets?
3) What type and level of guidance around setting demand response CEIP targets would be useful?

Next Steps

Staff will:

- Draft the next round of demand response rule language based on the information received during this workshop and in other written comments

Utilities will:

- Identify DR potential in current IRP
- Propose a DR target in the CEIP

Stakeholders will:

- Provide comments about DR in the next round of CEIP and IRP rule language

Thank You!

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