The National Potential for Load Flexibility

VALUE AND MARKET POTENTIAL THROUGH 2030

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Overview

“Load flexibility” will address new challenges of an evolving power system

- Demand response historically provided value through peak demand reductions
- But system needs are evolving: renewables integration, grid modernization
- Load now can be managed to provide additional high value services, such as geographically-targeted demand reductions, load building, and system balancing
- This is facilitated by rapid adoption of emerging consumer technologies

New methods for quantifying load flexibility value & market potential are needed

- Assessing likely performance of nascent programs and technologies
- Determining location-specific value of distributed energy resources
- Estimating plausible value of providing multiple services from a single resource
- Quantifying value streams not previously provided by demand-side options

This presentation provides an assessment of the value and market potential of load flexibility opportunities in the U.S.

Key Findings

Nearly 200 GW of cost-effective load flexibility potential in U.S. by 2030

- This is 20% of the 2030 US peak (though not all will be used to reduce peak demand)
- Under existing market conditions, current DR capability could double (to 120 GW)
- Market transformation through 2030 enables a further increase of roughly 80 GW

National benefits of load flexibility could exceed $15 billion/year by 2030

- Avoided generation capacity investment remains the dominant source of value over the next decade, with energy benefits increasing in value during that time
- T&D deferral and ancillary services are the "cherry on top of the sundae;" highly valuable niche applications with limited need
- Findings based on national average conditions; will vary significantly on a regional basis

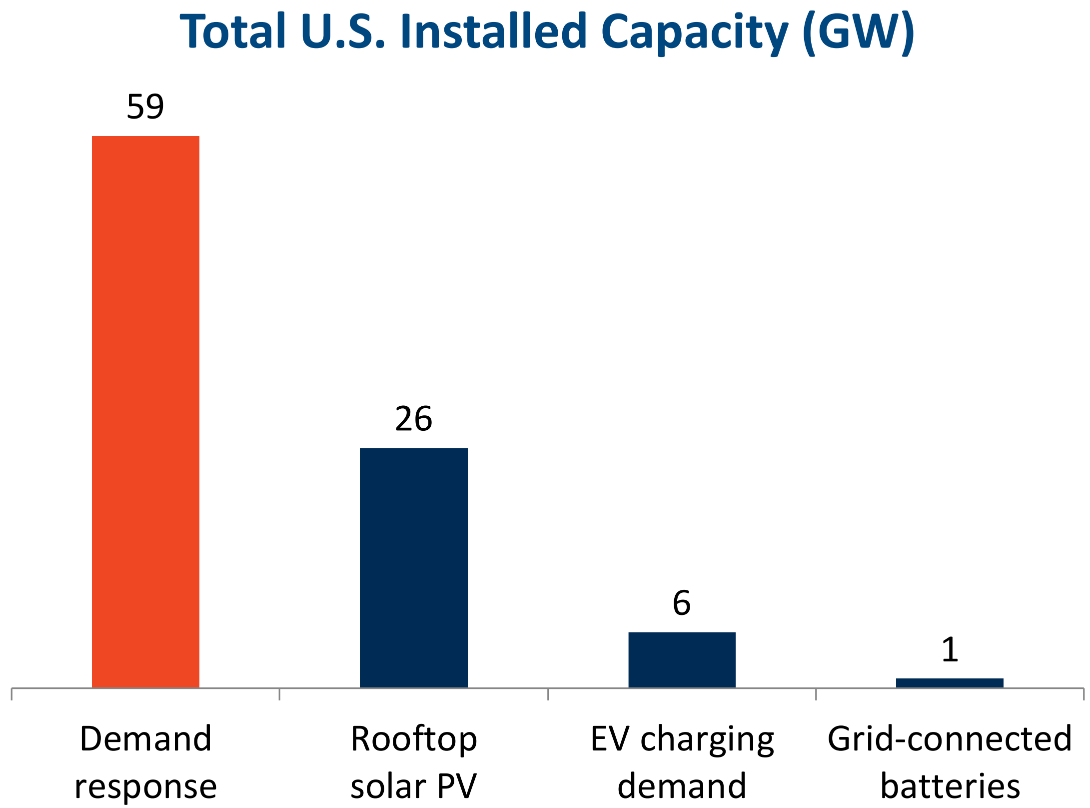
Load flexibility benefits will be unlocked through creative planning and policies

- Nearly 40% of the 2030 potential can be achieved simply by modernizing existing conventional programs through revamped program design and customer engagement
- The majority of potential is in new emerging load flexibility programs, which will be enabled primarily by smart thermostats and Auto-DR - gateways to accessing electrified building load
- Supporting policies, technology standards, regulatory incentives and analytical methods are needed to facilitate this transition

Introduction

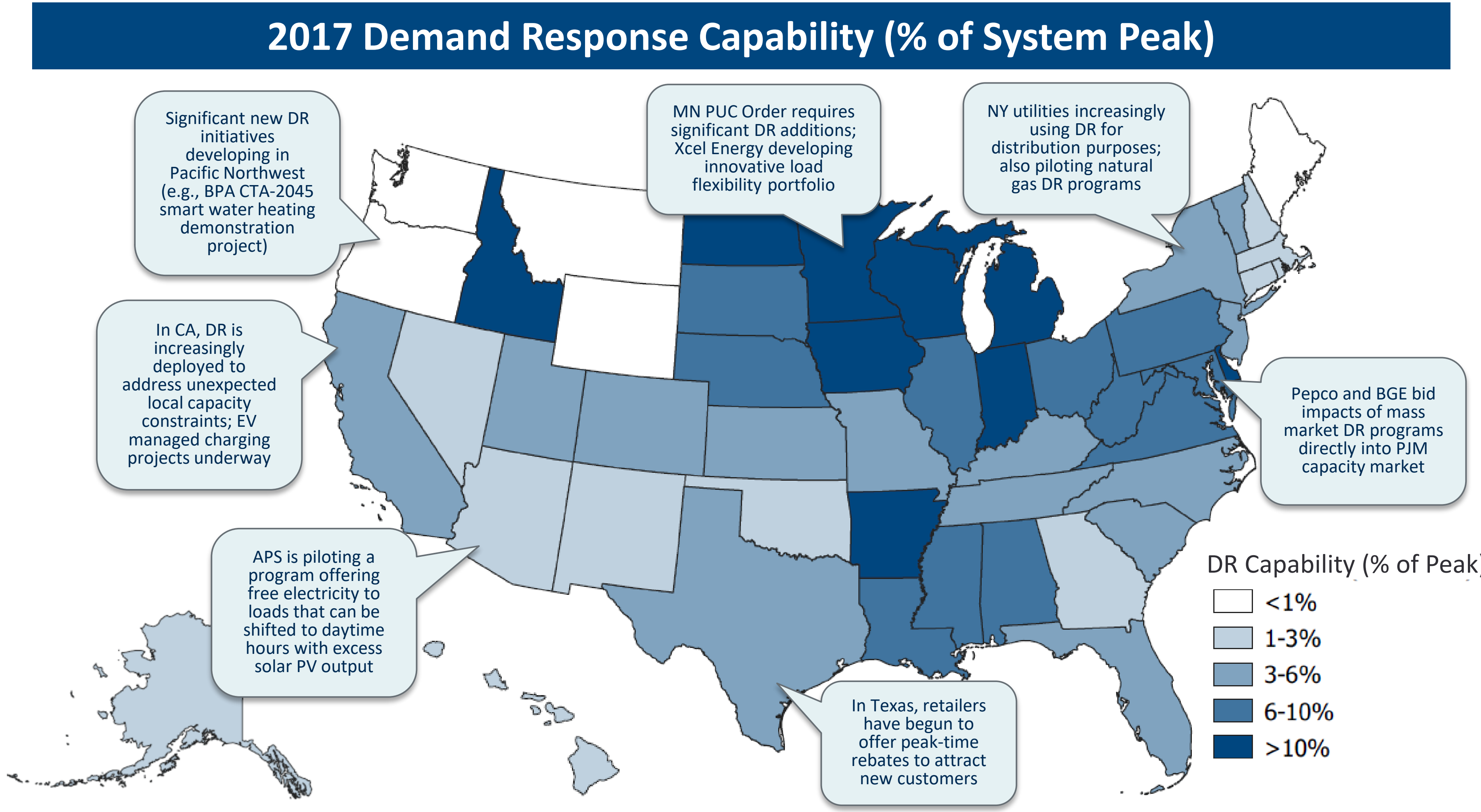
You can’t spell “DER” without “DR”

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

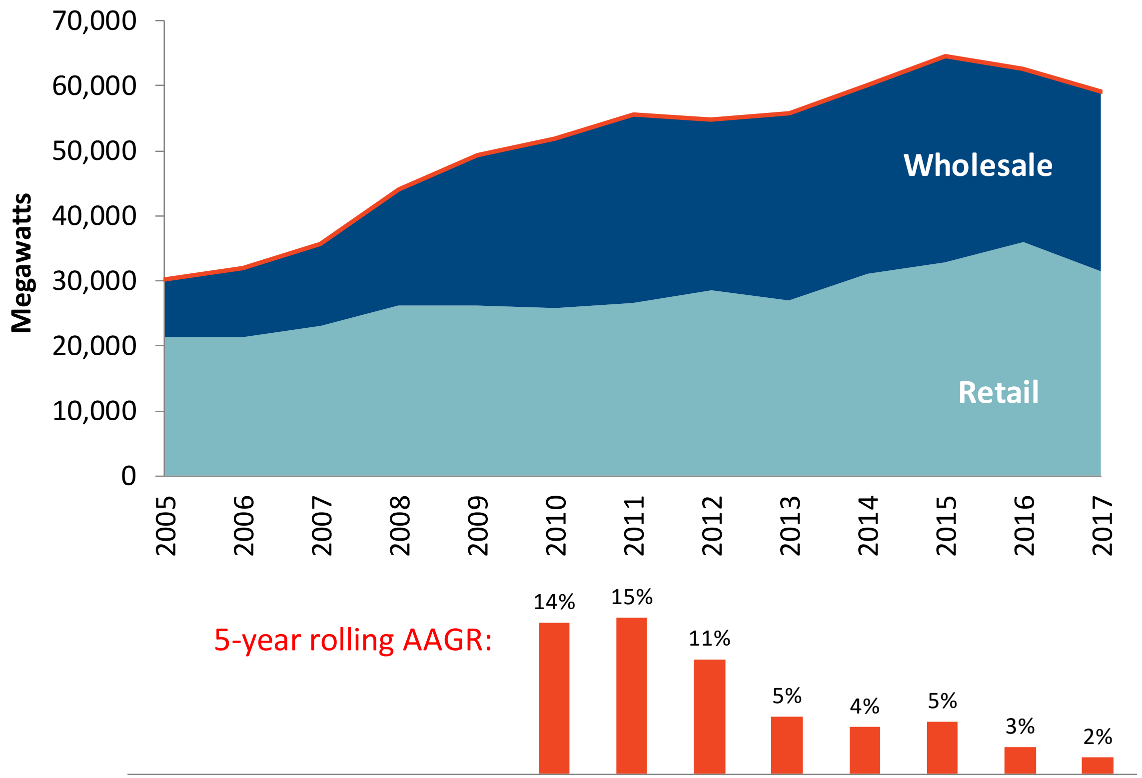


Notes and sources: Brattle analysis of data from 2018 FERC Assessment of Demand Response and Advanced Metering and 2017 EIA-861. Wholesale DR capability from FERC Assessment allocated to states proportional to estimated state share of ISO peak demand (according to 2015-2017 EIA-861 data). Values are 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

Illustrating the potential for load flexibility

Electric water heating is a compelling example of load flexibility

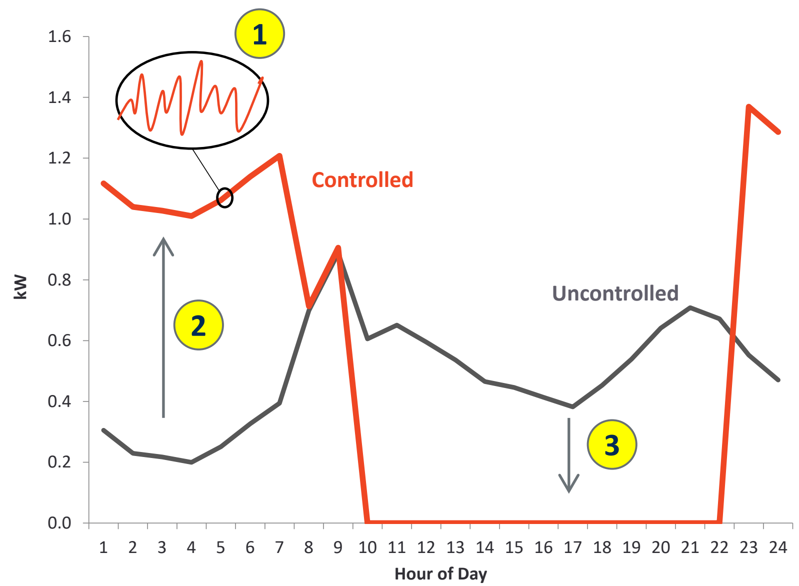
Electric resistance water heating load can be controlled to provide several grid services. The thermal energy storage properties of the water tank work similar to a battery

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

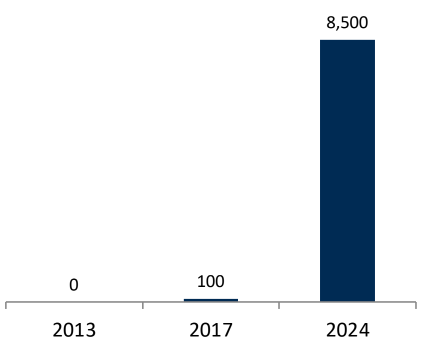


1. Heating element controlled with near-instantaneous response to provide **balancing services**
2. Off-peak **load building** to reduce wind curtailments or reduce ramping of thermal generation
3. **Peak demand reduction** to reduce need for generation capacity and/or T&D capacity, and to avoid peak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

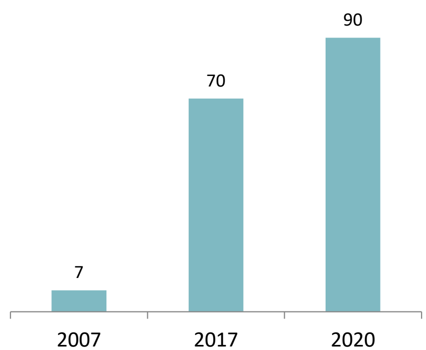
BTM Storage
(U.S. capacity, MW)



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

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

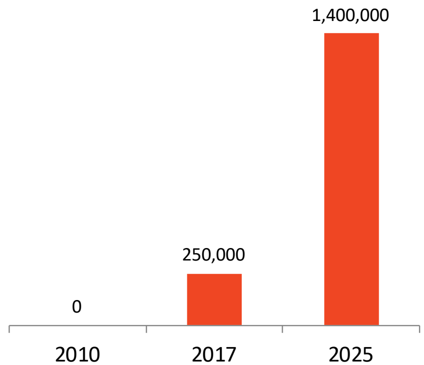
Smart Meters
(U.S. meters, millions)



Source: Institute for Energy Innovation (IEI), 2017

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

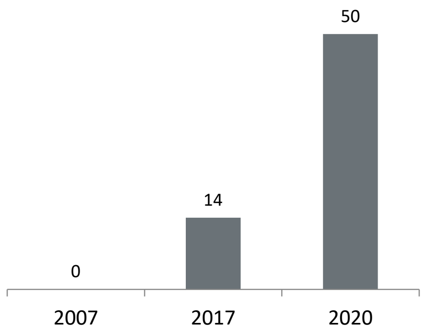
Electric Vehicles
(U.S. annual sales)



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

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.

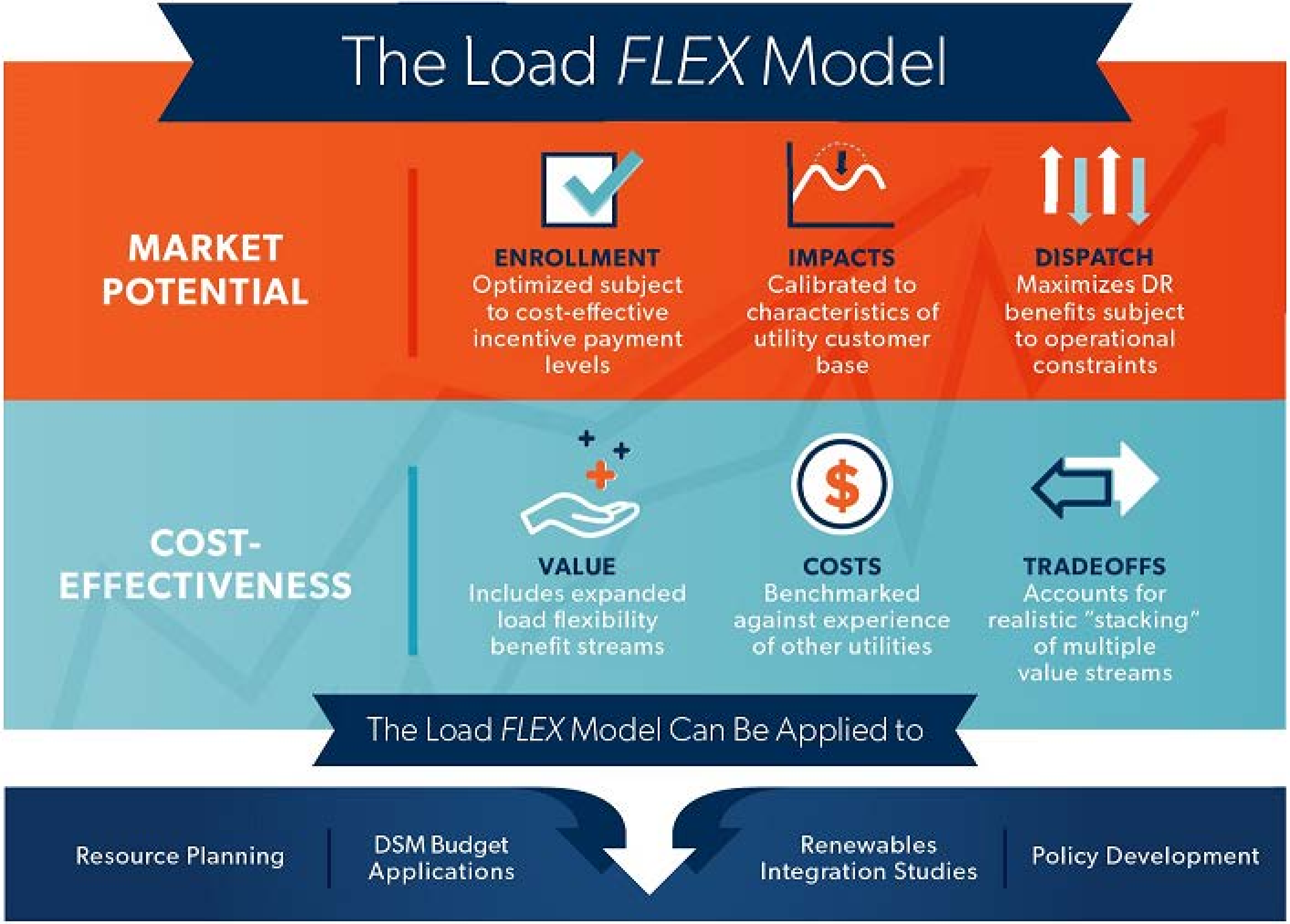
1 Extend DR value streams

2 Broaden definition of DR

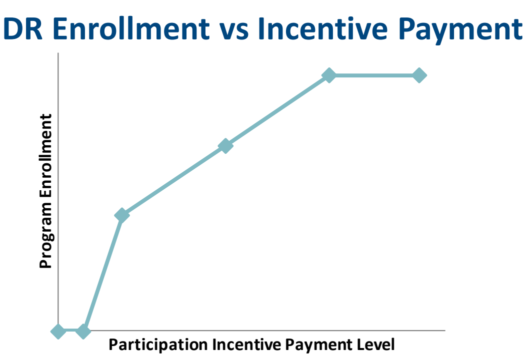
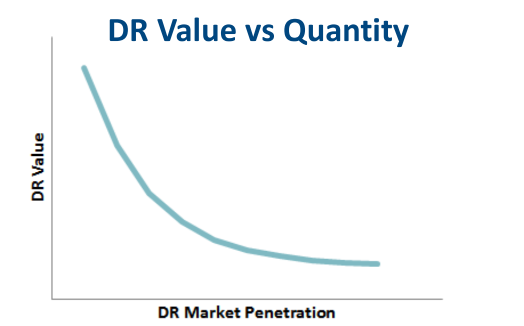
	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted T&D capacity deferral	Load shifting/ building	Ancillary services
Direct load control	X	X	X	X		
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X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



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	
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	

Load flexibility analytical challenges & solutions

<table>
<tr><th>Load Flexibility Analytical Challenge</th><th>LoadFLEX Approach</th><th>Illustration</th></tr>
<tr><td>Quantifying deferred distribution capacity value</td><td>

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

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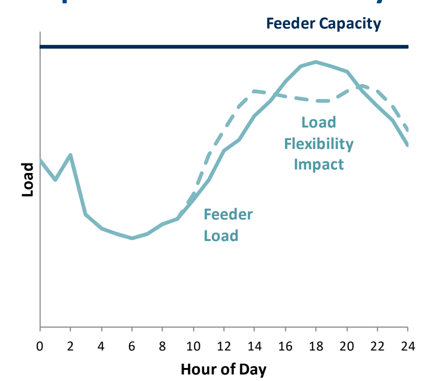
DR Impact on Distribution System



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<tr><td>Accounting for “stacked value”</td><td>

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

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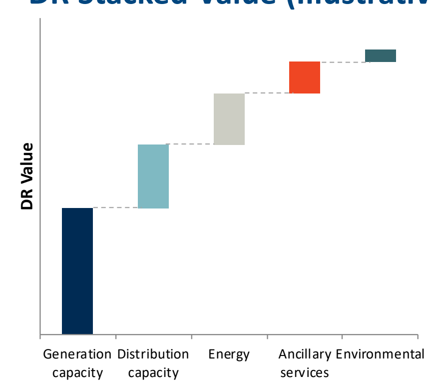
DR Stacked Value (Illustrative)



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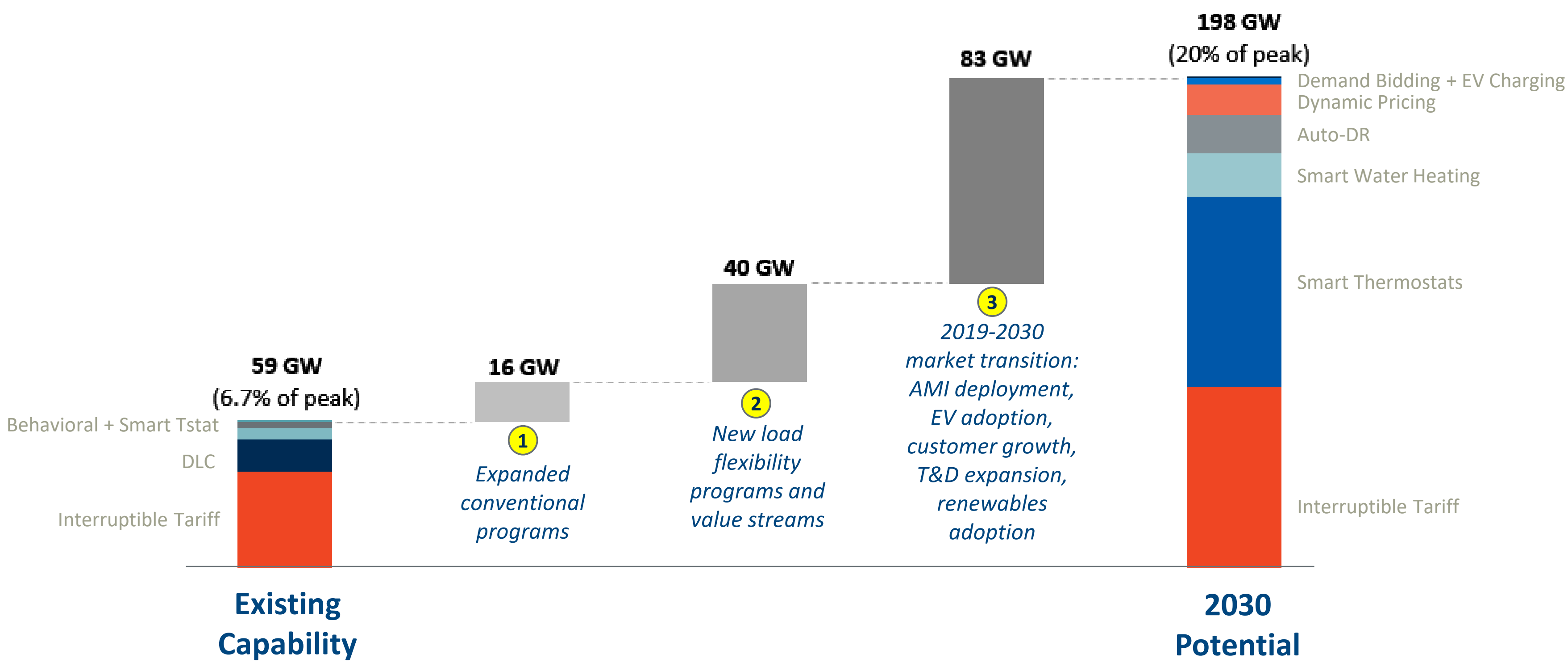
The National Potential for Load Flexibility

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.

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)

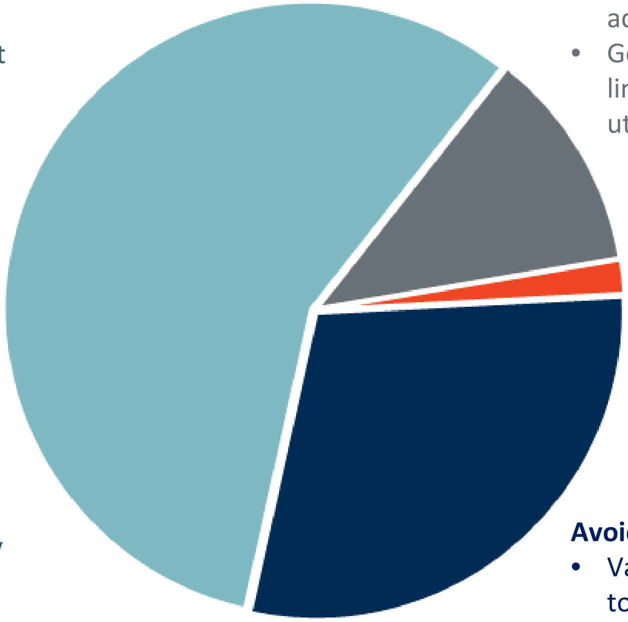
- Growth in adoption of AMI, EVs, smart thermostats and other smart appliances over the forecast horizon enables expanded participation in load flexibility programs
- Increased renewable generation development introduces more energy price variability and a greater need for ancillary services, increasing 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

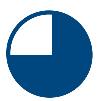
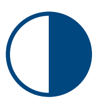
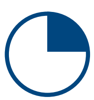
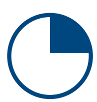
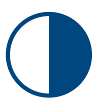
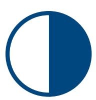
Avoided Energy Costs, *$4.8 billion/yr (29%)*
- Value accounts for reduced resource costs associated with shifting load to hours with lower cost to serve; does not include consumer benefits from reductions in wholesale price of electricity
- Energy value is best captured through programs that provide 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.

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*

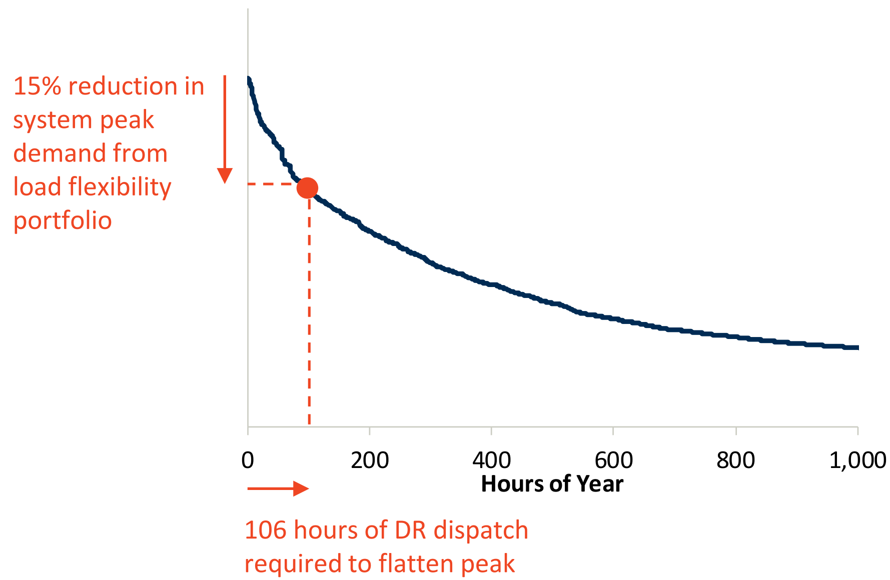
 *= Moderate source of value*

 *= Modest source of value*

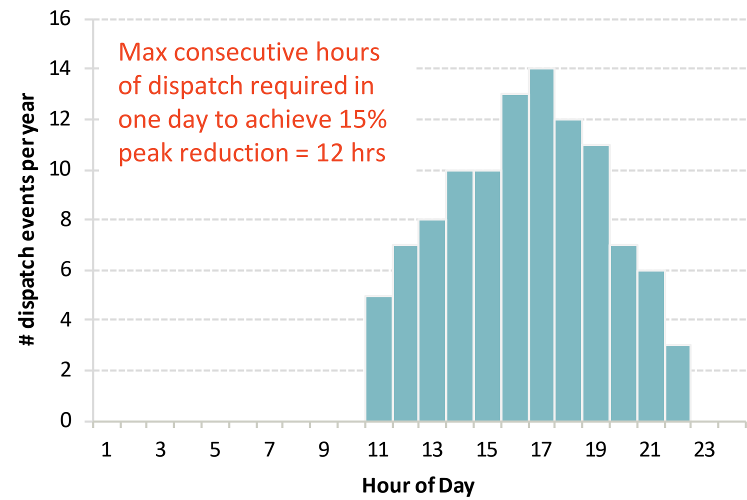
Operational implications

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.

Three predictions for the next decade

Prediction #1: Utility load flexibility programs will get smarter before they get bigger

- Many existing programs have been underutilized for decades. There is low-hanging fruit in simply modernizing these programs to serve the growing need for system flexibility
- For example, transitioning compressor switch-based DLC programs to smart thermostat-based programs. Or updating the rules, incentives, and operation of Interruptible Tariffs

Prediction #2: Residential load flexibility additions will exceed those of C&I

- For reasons entirely unrelated to demand response, customers are increasingly adopting technologies with load flexibility capabilities (e.g., electric vehicles, smart thermostats)
- At the same time, mass market smart metering deployments continue and customers are gradually being introduced to time-varying rates
- While the C&I sector has provided 70% of US retail DR up to this point, these factors will combine to (finally) capitalize on the untapped potential of the residential sector

Prediction #3: New regulatory incentives will drive growth in load flexibility

- There is a renewed industry-wide interest in regulatory models that provide utilities with incentives to pursue demand-side options rather than infrastructure investments
- Experience with these incentive mechanisms will ultimately instill industry stakeholders with the confidence that both consumers and utilities can benefit from load flexibility

Conclusion

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

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.

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Appendix

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

1

Parameterize DR programs

- Build database of new flexible load programs
- Estimate per-participant costs and participation
- Identify value proposition and applicable grid services
- Establish load impacts and operational constraints

2

Establish marginal costs and market depth

- Generation capacity value
- Frequency regulation value
- Average & targeted T&D value
- Energy value

3

Develop 8,760 hourly avoided costs

Allocate marginal costs based on hourly LOLP

Combine hourly costs to create stacked value profile

4

Optimally dispatch programs and calculate B/C metrics

Simulate optimized hourly dispatch

Calculate total benefits across value streams

5

Identify cost-effective incentive and participation

Establish relationship between adoption and incentives

Identify economic incentive level and associated participation

6

Estimate incremental cost-effective DR potential

Calculate cost-effective potential by program

Estimate portfolio impacts after participation overlap

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.

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