Appendix A:
Participation Assumptions

Estimating Maximum Achievable Enrollment in DR Programs for PGE

PRESENTED TO

Portland General Electric

PRESENTED BY

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THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind estimates of enrollment in potential new DR programs in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Participation rates shown in this presentation are "steady state" enrollment rates once full achievable participation has been reached; they are expressed as a % of eligible customers

Pricing Programs

We developed enrollment estimates based on an extensive review of pricing participation studies

The enrollment estimates are derived from a review of 6 primary market research studies and 14 full scale deployments:

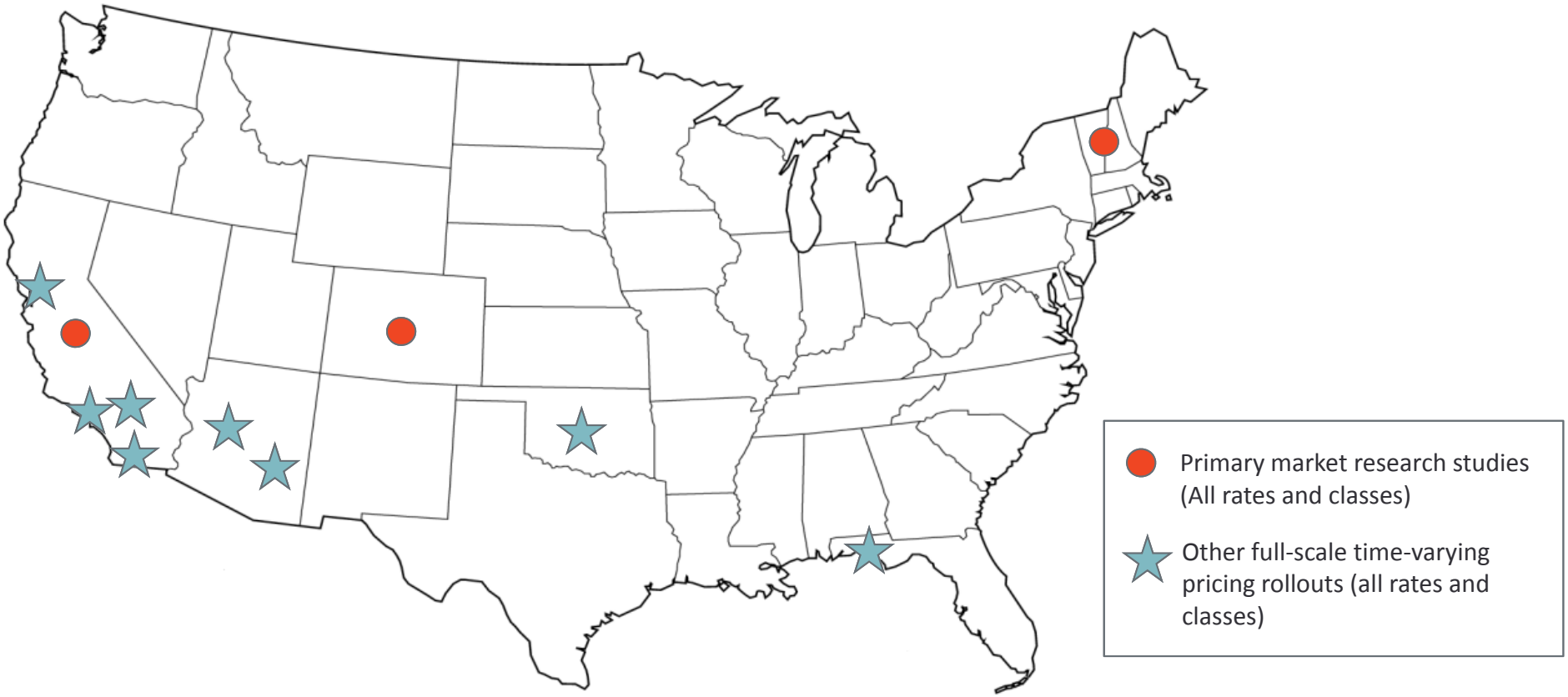
Primary market research studies

- A survey-based approach designed to gauge customer interest
- Adjustments were made to account for natural tendency of respondents to overstate interest in survey responses
- Respondents were randomly selected from utility customer base and confirmed to be representative of entire class
- Samples were large enough to ensure statistical validity of findings

Full-scale deployments

- Based on enrollment levels reported by utilities and competitive retail suppliers to FERC and other sources
- Restricted to programs with significant enrollment
- Focus on well marketed deployments

The market research studies and full-scale rate deployments span many regions of the U.S.



Additionally, our analysis includes the Ontario, Canada TOU rollout and three non-public market research studies in the Upper Midwest, Central Midwest, and Asia

Full-scale rate offerings have mostly been for residential and large C&I customers

Utility/Market	State/Region	Applicable class	Rates	Offering type	Approx. years offered
Arizona Public Service (APS)	Arizona	Residential	TOU	Opt-in	30+
Ontario Power Authority (OPA)	Ontario, CA	Residential	TOU	Opt-out	2
Salt River Project (SRP)	Arizona	Residential	TOU	Opt-in	30+
Gulf Power	Florida	Residential	CPP	Opt-in	14
Oklahoma Gas & Electric (OGE)	Oklahoma	Residential	CPP	Opt-in	2
Pacific Gas & Electric (PG&E)	California	Residential	CPP	Opt-in	3
Oklahoma Gas & Electric (OGE)	Oklahoma	Large C&I	TOU	Opt-in	?
Pacific Gas & Electric (PG&E)	California	Large C&I	CPP	Opt-out	3
San Diego Gas & Electric (SDG&E)	California	Large C&I	CPP	Opt-out	3
Southern California Edison (SCE)	California	Large C&I	CPP	Opt-out	3
Los Angeles DWP (LADWP)	California	All C&I	TOU	Opt-in	?
Progress Energy Carolinas	North/South Carolina	All C&I	TOU	Opt-in	15+

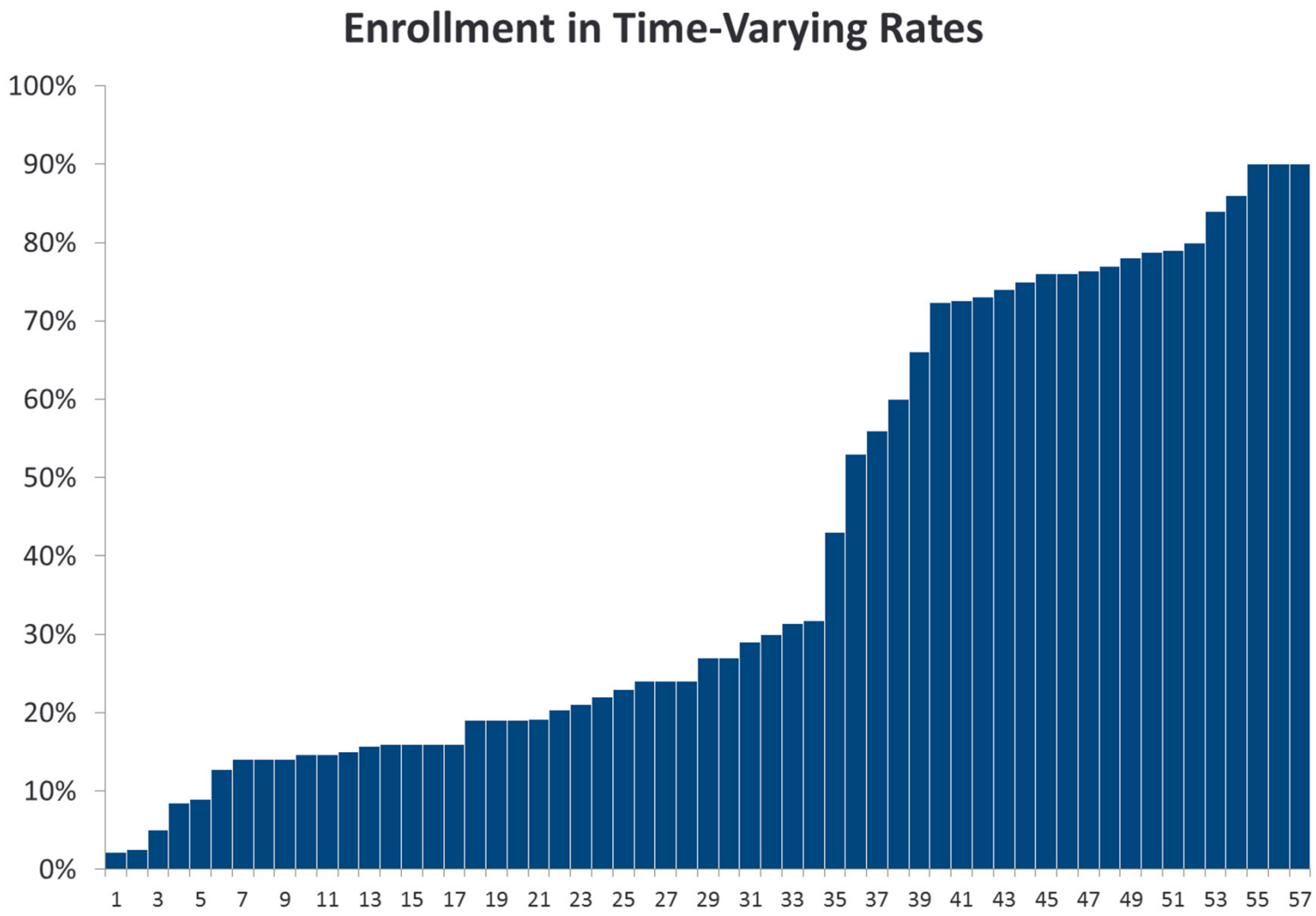
Notes:
BGE, Pepco, SDG&E and SCE have rolled out default PTR to their residential customers, but enrollment data is not available. Results are forthcoming.
The OPA TOU deployment is considered opt-out rather than mandatory because customers can switch to a competitive retail supplier.

The six market research studies primarily surveyed residential and small/medium C&I customers

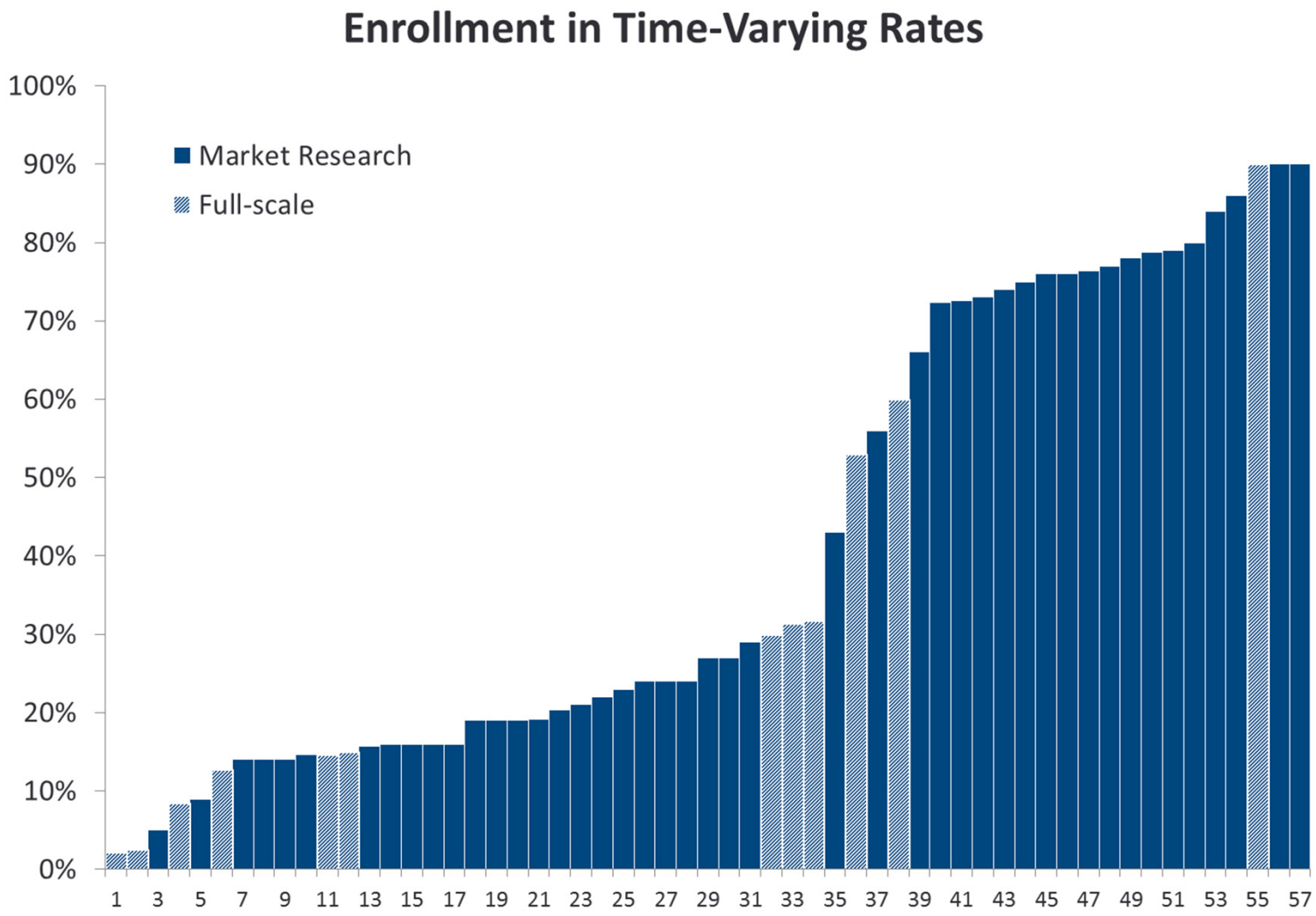
Utility/Market	Year of Study	Applicable classes			Rates	Deployment type	
		Res.	Small/Med	Large C&I		Opt-in	Opt-out
California IOUs	2003	X	X		TOU, CPP	X	X
ISO New England	2010	X	X		TOU, CPP, PTR, RTP	X	
Asian Utility	2013	X			TOU, PTR	X	
Large Midwestern IOU	2013	X	X	X	TOU, CPP	X	X
Mid-sized Midwestern Utility	2013	X	X		TOU, CPP	X	
Xcel Energy (Colorado)	2013	X	X	X	TOU, CPP, PTR	X	X

- These market research studies were conducted in order to form the basis for utility AMI business cases or DSM potential studies
- They were led by Dr. David Lineweber and a team of market researchers who are now with Applied Energy Group (AEG)

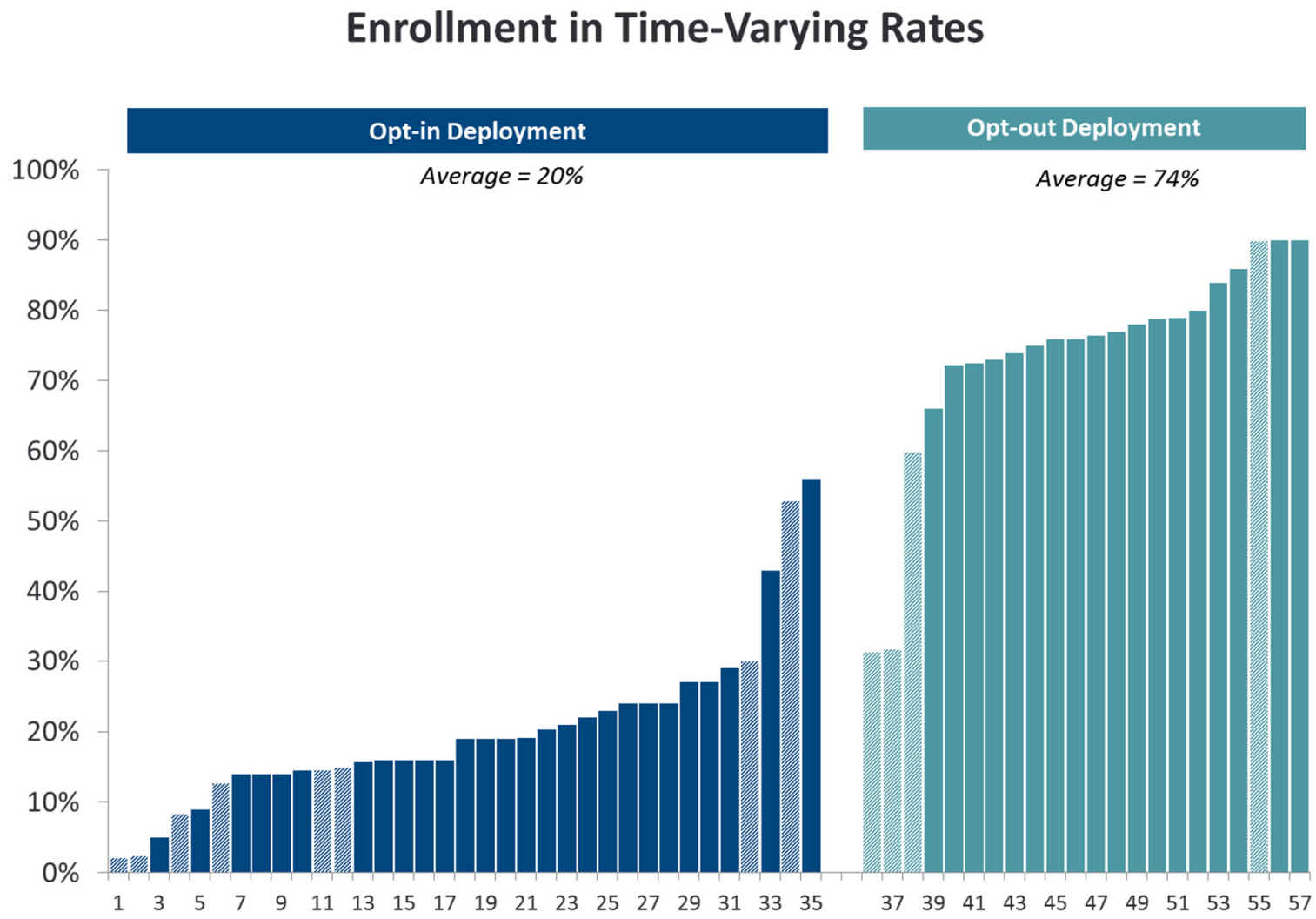
There are 57 enrollment observations across all of the studies (sorted low to high)



There is no obvious bias in market research results relative to full-scale deployments



Opt-out offerings result in significantly higher enrollment on average



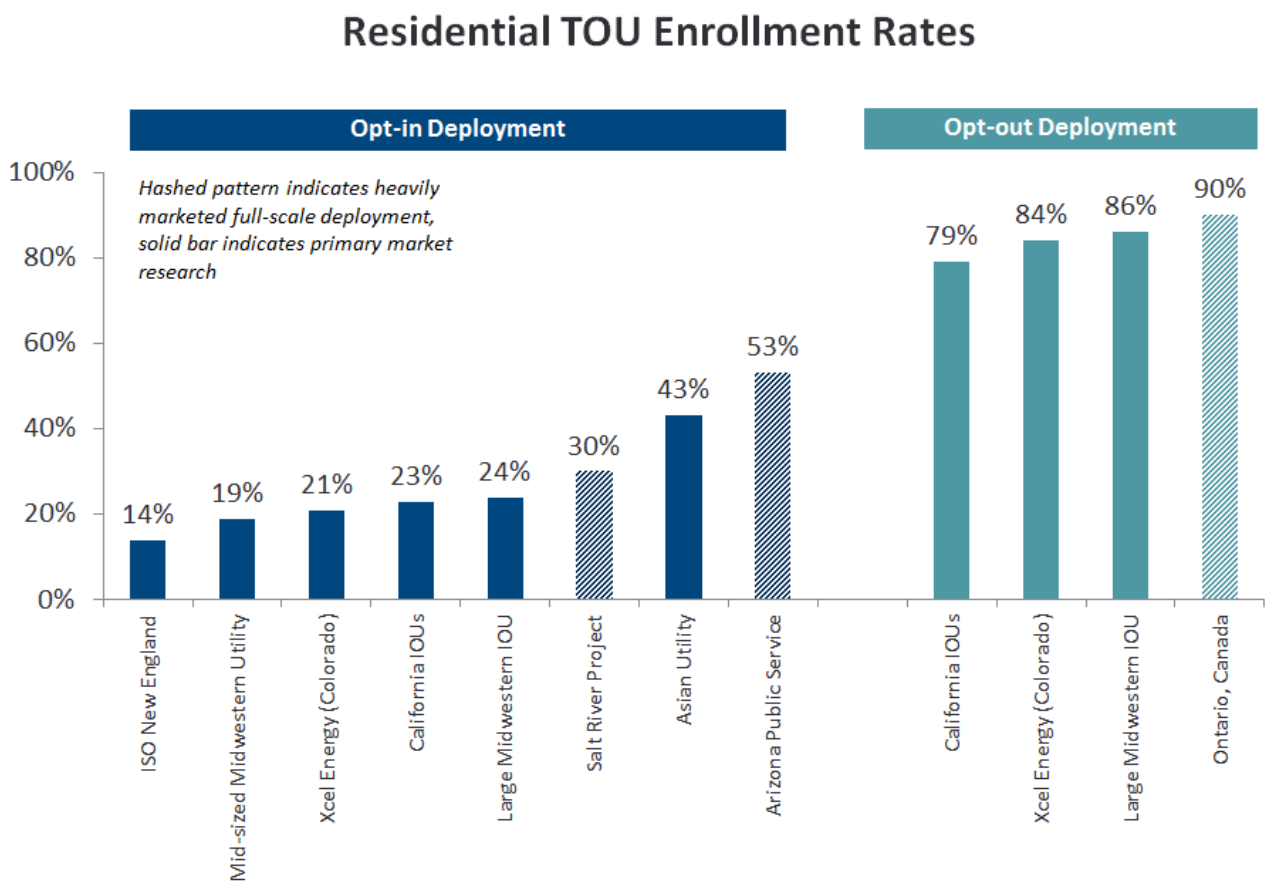
The enrollment data can be further organized with additional granularity

We have organized the data across the following elements

- Customer class (residential vs non-residential)
- Rate (TOU, CPP)
- Offering (opt-in vs opt-out)

We summarize the key findings of this comparison in the slides that follow

The results of our residential TOU analysis are summarized below

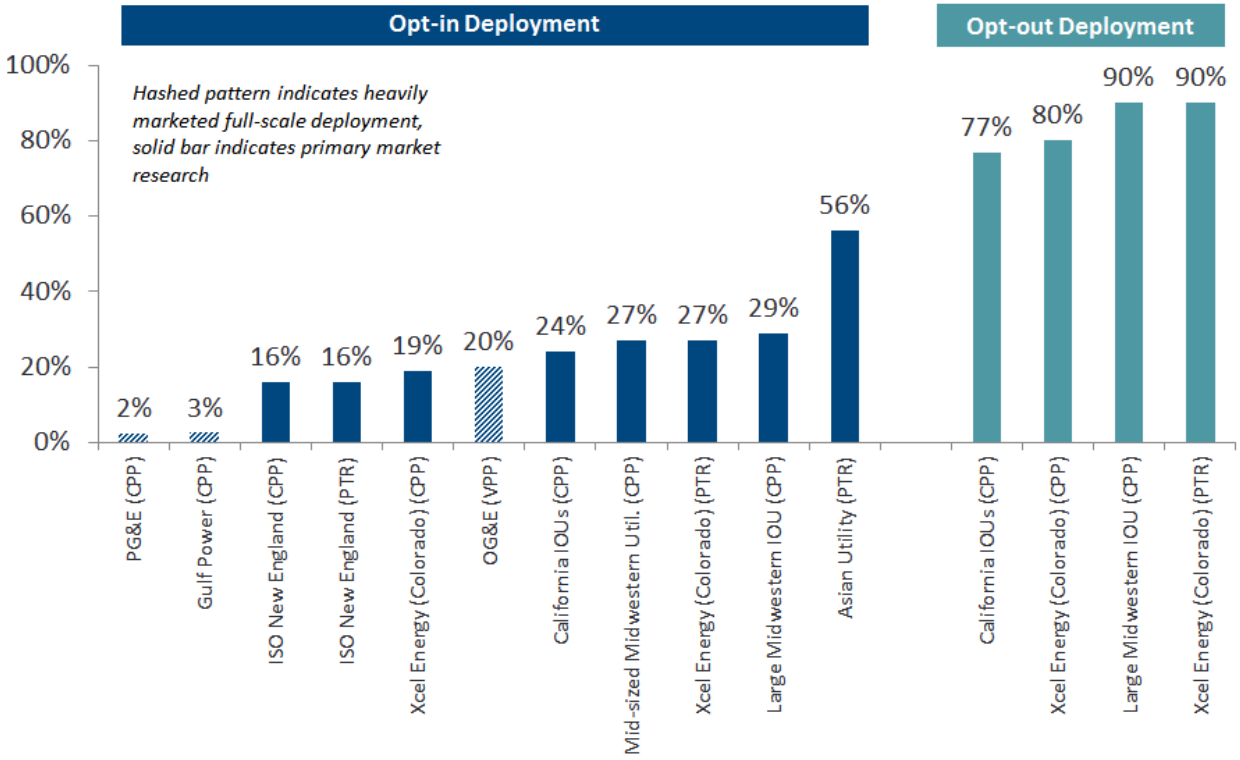


Comments

- Opt-in average = 28%
- Opt-out average = 85%
- Opt-out rate offerings are likely to lead to enrollments that are 3x to 5x higher than opt-in offerings
- Arizona's high opt-in TOU participation is attributable to heavy marketing as well as large users' ability to avoid higher priced tiers of the inclining block rate
- In Ontario, the 10% opt-out rate includes some customers who switched to a competitive retail provider even before the TOU rate was deployed

Residential dynamic pricing enrollment observations are similar to those of TOU

Residential Dynamic Pricing Enrollment Rates



Note: Pepco and BGE have deployed a default residential PTR. Results forthcoming.

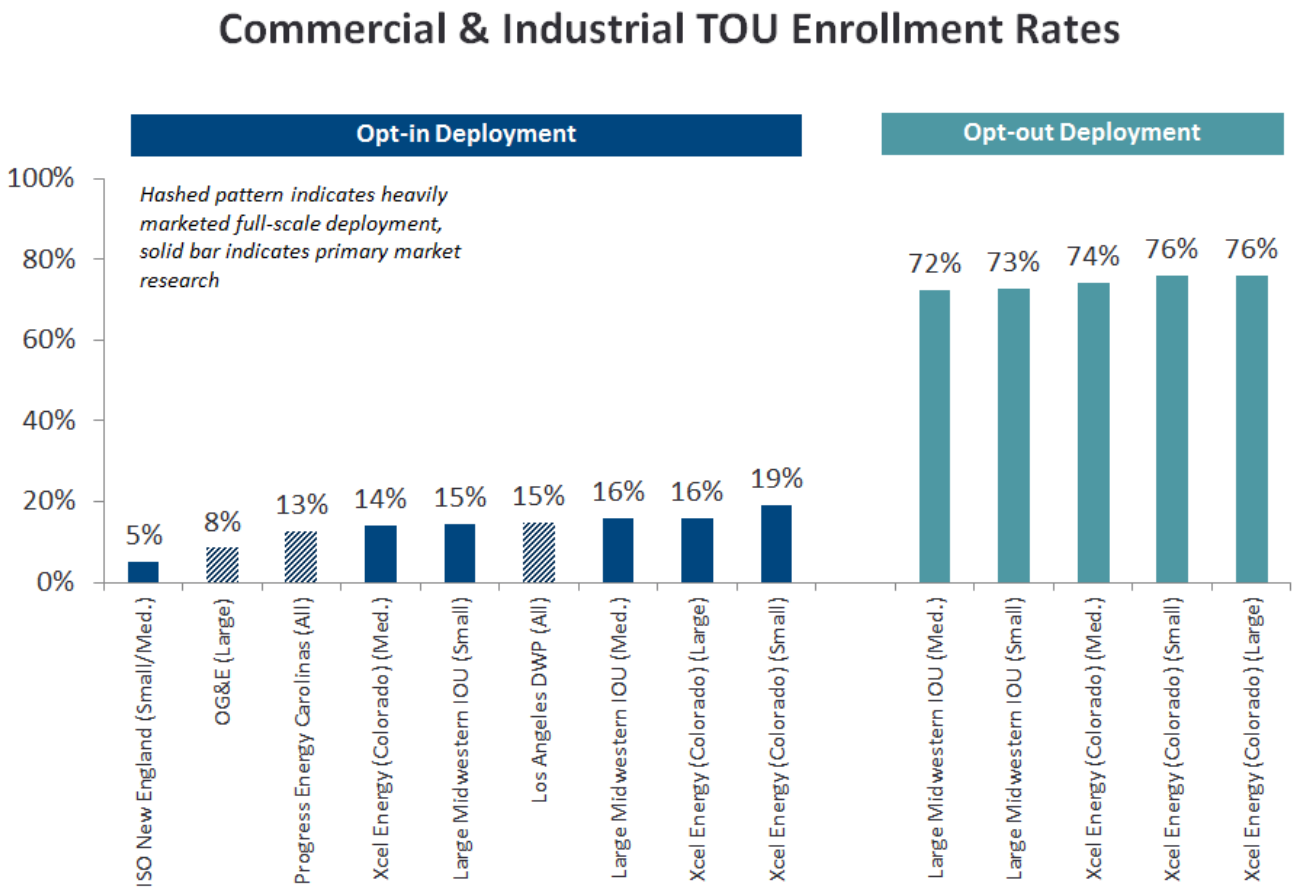
Comments

- Dynamic pricing options considered include CPP, variable peak pricing (VPP), and peak time rebates (PTR)
- PTR enrollment is roughly 20% higher than CPP enrollment
- OG&E's VPP rate was rolled out on a full scale basis in 2012 and has reached its target enrollment rate of 20% a year ahead of schedule
- Availability of Gulf Power's CPP rate is limited
- Additionally, Pepco, BGE, SCE, and SDG&E have deployed a default residential PTR; results are forthcoming

Why are the full scale residential dynamic pricing enrollment levels slightly lower than the market research results?

- The primary market research identifies all “likely participants” in the dynamic pricing rate, some of whom are very proactive and eager to sign up, while others would sign up but require more education, clear explanation, and additional outreach
- Most utility marketing budgets for dynamic pricing programs have been relatively low and are not designed to provide the type of outreach necessary to enroll customers falling in the latter category
- These customers represent untapped potential in the program and could likely be signed up with a more intensive marketing effort
- For example, heavily marketed utility energy efficiency programs with similar bill savings opportunities reach enrollment rates of 60%

C&I TOU enrollment levels are slightly lower than those of the residential class

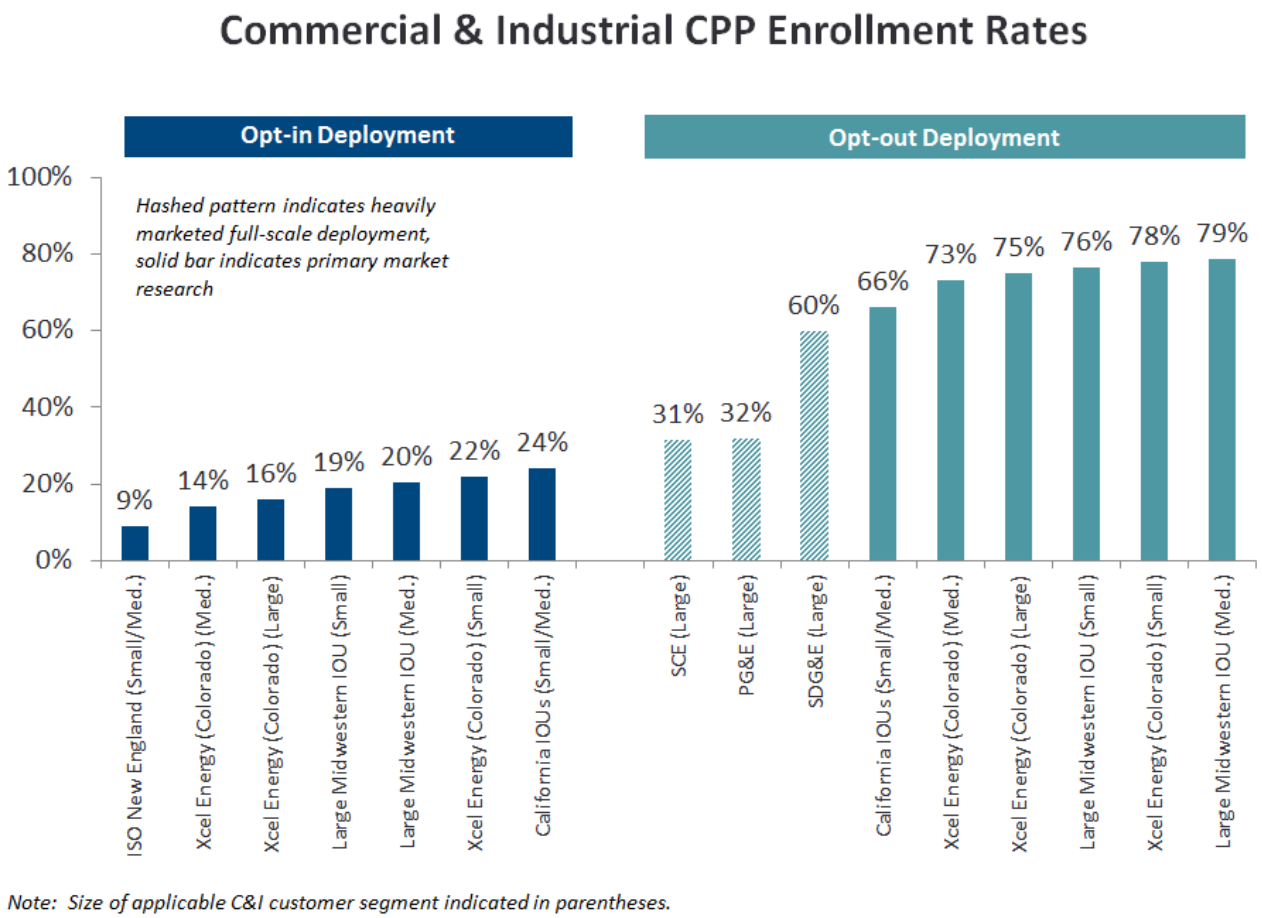


Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 13%
- Opt-out average = 74%
- Estimates are reported separately for Small, Medium, and Large C&I customers (as designated by the utility) where possible
- Full-scale opt-in deployment estimates were derived from FERC data, with a focus on the highest enrolled programs
- TOU rates are often offered on a mandatory basis to Large C&I customers; these are excluded from our assessment

There is limited full-scale CPP deployment experience for C&I customers



Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 18%
- Opt-out average = 63%
- C&I preferences for CPP rates tend to be slightly higher than for TOU rates – the opposite of the relationship observed among residential customers
- The California IOU default CPP offering began in 2011 and has experienced significant opt-outs - it may not have been effectively marketed. The rate is being deployed to smaller customers and further results are forthcoming

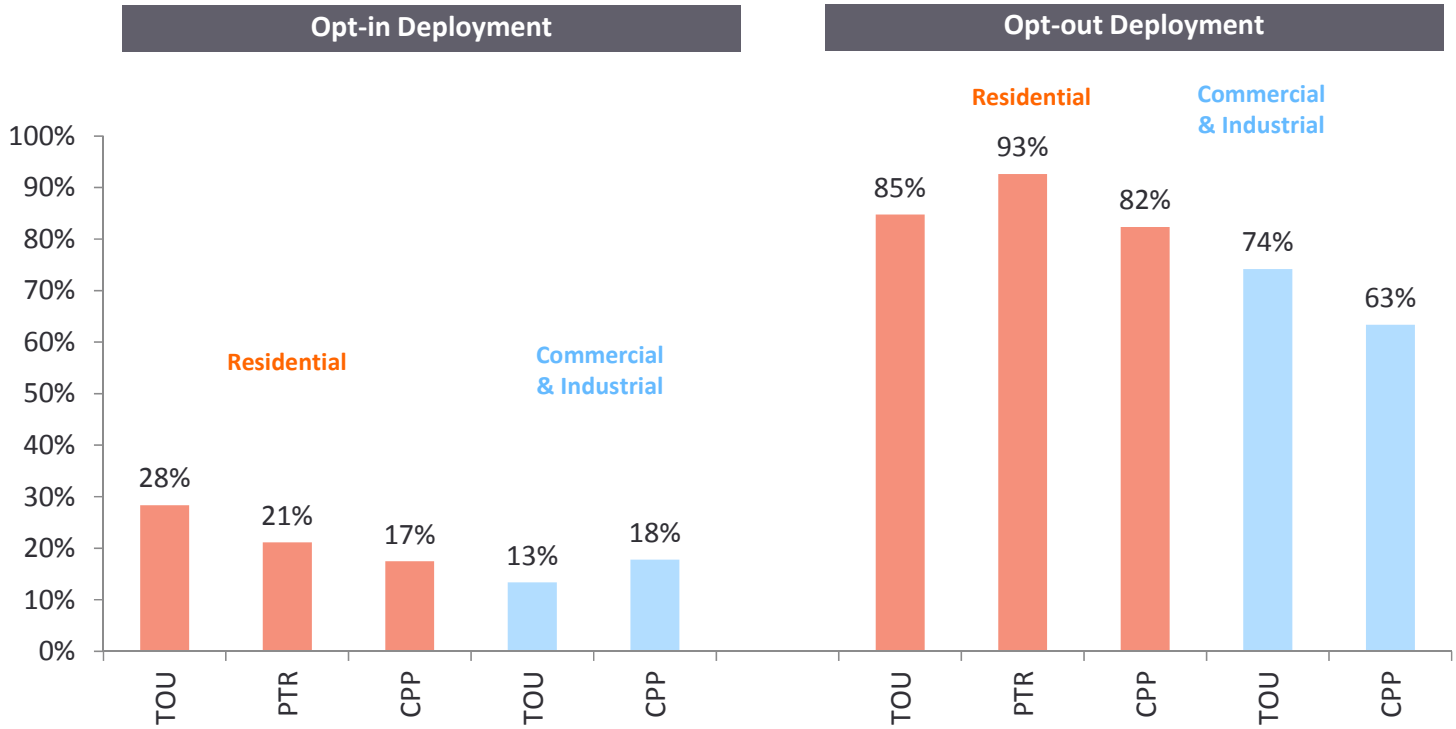
Preliminary conclusions can be drawn from our assessment, although further research and experience are needed

- Opt-out rate offerings produce enrollment levels that are between 3x and 5x higher than opt-in rate offerings
- Residential customers express a slightly higher likelihood to enroll in time-varying rates than small/medium C&I customers, both through market research and in full-scale deployments
- When offered in isolation, residential customers appear to have a slight preference for TOU over CPP; when offered as two competing rate options, more customers choose CPP
- Customers appear more likely to enroll in PTR than CPP
- Market research and full scale deployment results generally align well; in cases where full deployments produces lower enrollment estimates, it is likely that additional enrollment could be achieved through more focused marketing efforts

The results of our assessment can be averaged across the studies for each customer class and rate option

Time-Varying Pricing Enrollment Rates

Average Across 6 Market Research Studies and 14 Full Scale Deployments



Offering enabling technology is likely to slightly increase participation among eligible customers

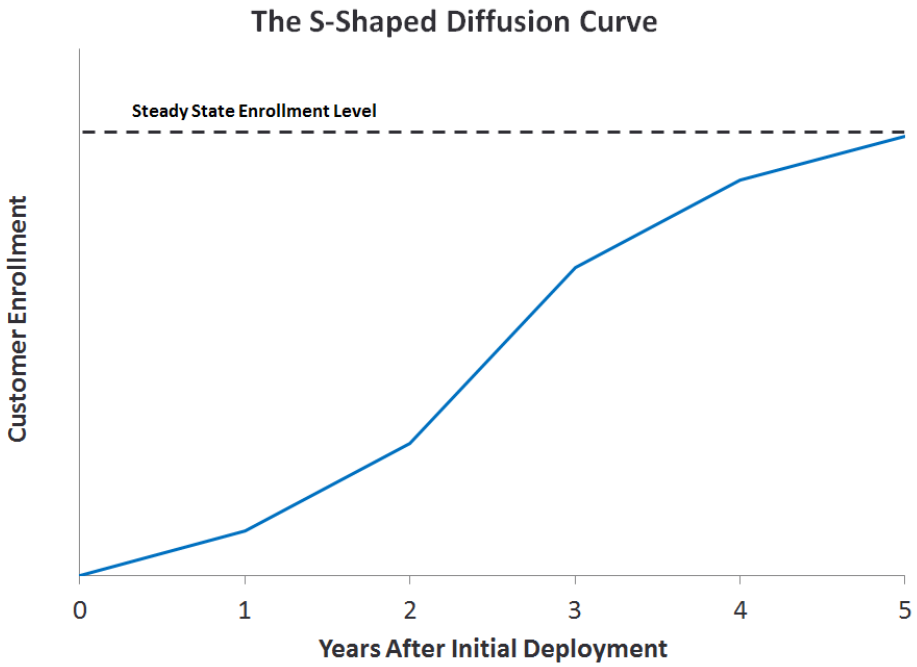
- For residential and small C&I customers, programmable communicating thermostats (PCTs) would automate reductions in air-conditioning load during critical peak periods
- For medium and large C&I customers, Auto-DR technology could be integrated with a facility's energy management system to automate load reductions during high priced periods of the CPP rates
- Market researchers have estimated that enrollment among tech-eligible customers will increase if they are also offered these technologies as part of the rate deployment
- **Opt-in enrollment among eligible customers is likely to increase by around 25% if offered enabling technology** (i.e., an enrollment rate of 20% would become 25% among tech-eligible customers)
- **For an opt-out rate offering, enrollment would likely increase by roughly 10%** (i.e. an enrollment rate of 80% would become 88% among tech-eligible customers)
- Large C&I customers are assumed to have more interest in Auto-DR than medium C&I customers due to a higher degree of sophistication in energy management capability

The proposed "steady state" enrollment rates

Class	Option	Opt-in	Opt-out
Residential	TOU - No Tech	28%	85%
Residential	CPP - No Tech	17%	82%
Residential	CPP - With Tech	22%	91%
Residential	PTR - No Tech	21%	93%
Residential	PTR - With Tech	26%	95%
Small C&I	TOU - No Tech	13%	74%
Small C&I	CPP - No Tech	18%	63%
Small C&I	CPP - With Tech	20%	69%
Small C&I	PTR - No Tech	22%	71%
Small C&I	PTR - With Tech	27%	78%
Medium C&I	CPP - No Tech	18%	63%
Medium C&I	CPP - With Tech	20%	69%
Large C&I	CPP - No Tech	18%	63%
Large C&I	CPP - With Tech	25%	69%

We account for a multi-year transition to the steady state enrollment levels

- Changes in participation are assumed to happen over a 5-year timeframe once the new rates are offered
- The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half
- A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options



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- FERC, "Assessment of Demand Response and Advanced Metering," December 2012
- FERC, Form 1 Database, 2012
- Lineweber, David, "Understanding Residential Customer Opinions of Time-Based Pricing Options in New England," prepared for ISO New England, May 2010
- Lineweber, David, "Understanding Business Customer Opinions of Time-Based Pricing Options in New England," prepared for ISO New England, May 2010
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Small/Medium Commercial & Industrial Customers in California," July 2004
- PG&E, "PG&E's SmartRate Program Tops 100,000 Participants," PG&E Currents, May 28, 2013
- Various utility tariff sheets, as of January 2014

Non-Pricing Programs Included in Prior PGE Studies

Participation in non-pricing programs was updated using the most recent FERC data

FERC conducts a bi-annual survey of utility DR programs, including information on program impacts and enrollment

The 2012 PGE DR potential study enrollment estimates were based on data in the 2010 FERC survey, which was the most current information available at the time

FERC has since released the 2012 survey results and has discontinued the survey; information is now collected through EIA form 861, but with much less granularity

We have updated the enrollment estimates using the 2012 FERC survey

The 75th percentile of achieved enrollment is used as a "best practices" estimate

The FERC data provides a national distribution of actual enrollment in DR programs

To establish a "best practices" estimate of what could eventually be achieved through a new program, we use the 75th percentile of the distribution for each program type

The recent PacifiCorp DR potential study used the 50th percentile

However, since the purpose of our study is to estimate maximum achievable potential rather than the average participation rate, we recommend using the 75th percentile

We will acknowledge throughout the final report that the figures presented are estimates of maximum achievable potential rather than what is necessarily likely to occur, particularly in the short run given the relatively limited experience with DR in the Pacific Northwest

Updated estimates are fairly similar to those of the 2012 PGE potential study

Class	Option	PGE (2012)	PacifiCorp (2014)	PGE (2015)
Residential	DLC - Central A/C	20%	15%	**20%**
Residential	DLC - Space Heat	20%	15%	**20%**
Residential	DLC - Water Heating			**25%**
Small C&I	DLC - Central A/C	20%	3%	**14%**
Small C&I	DLC - Space Heat	20%	3%	**14%**
Small C&I	DLC - Water Heating			**2%**
Medium C&I	DLC - AutoDR	18%		**15%**
Medium C&I	Curtailable Tariff		24%	**20%**
Large C&I	DLC - AutoDR	18%		**25%**
Large C&I	Curtailable Tariff	17%	24%	**40%**

Note:
An average curtailable tariff participation rate of 30% for C&I customers was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's ISOC program)

In a couple of instances, we deviated from the 75th percentile assumption

Space heating DLC participation is assumed to be the same as air-conditioning DLC due to lack of better data

The 75th percentile participation rate of 30% for C&I customers in a curtailable tariff was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's highly subscribed "ISOC" program)

There is limited data available on Auto-DR adoption rates when deployed at scale; we have assumed that adoption would be similar to that of technology-enabled CPP for C&I customers, since it offers a similar financial incentive to manage load

New Non-Pricing Programs
Not Included in Prior PGE Studies

We estimated participation rates for three new programs; two more are in development

Draft participation rates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Participation rates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- All assumptions for these two programs are being developed in parallel and in coordination with PGE staff

Enrollment in BYOD programs will be driven partly by the market penetration of smart thermostats

We have based our estimates of the eligible population for BYOD programs on projections of market deployment for communication-enabled thermostats

Research by Berg Insight projects that over 25% of homes in North America will be equipped with a 'smart system' by 2020, relative to 6% currently

CMO, and Adobe Company, reports that smart thermostats are expected to have over 40% adoption by 2020

Acquity Group's 2014 Internet of Things (IoT) survey reports that approximately 30% of consumers will adopt smart thermostats in the next 5 years

To be conservative, we use an assumption at the low end of this range

Source	Year	Market Penetration (%)
Berg Insight – N. America	2020	25%
CMO	2020	40%
Acquity Group – N. America	2020	30%

- We assume that smart thermostat market penetration in PGE's service territory will reach 25% of all homes by 2020
- The Energy Trust's interest in promoting smart thermostats could drive this estimate upward
- Additionally, rapid growth in central air-conditioning adoption in the Pacific Northwest relative to other parts of the country could lead to a future scenario that exceeds this estimate, as new A/C systems are installed with smart thermostats
- Note: Estimate could be refined further upon receiving the Navigant Research report on smart thermostats

Participation among eligible customers is likely similar to participation in conventional DLC programs

The BYOD program is assumed to be offered on an opt-in basis only

With a similar participation incentive as in the conventional DLC program, we assume that participation in the BYOD program would be similar to but slightly higher than that of the conventional DLC program

The intuitive reasoning for this is that customers who purchase a smart thermostat are more likely to be conscious about their energy usage and keen on using the features of their new device

To capture this, we estimate that participation in BYOD programs to be 25%, which is 5% higher than in DLC programs

We have modeled Behavioral DR both on an opt-in and an opt-out basis, similar to pricing programs

Behavioral Demand Response is essentially a peak time rebate (PTR) program without the accompanying financial incentive to reduce consumption during event hours

The no-incentive, no-risk nature of BDR programs could make customers slightly less likely to opt-in and slightly more likely to opt-out

To establish the BDR participation rates, we start with the PTR participation rates discussed previously in this presentation, and make adjustments to the share of customers that opt-in and opt-out

Three sources suggest that BDR participation could resemble that of a PTR program

OPower estimates that customer adoption of their opt-out BDR programs is upwards of 90%

Green Mountain Power (2012-2013)

- Recruitment strategies used a combination of mail, web and phone
- Participation in the opt-in, notification-only program achieved a 34% participation rate

MyMeter Program (four electric co-ops in Minnesota)

- Opt-in participation rates range from 9% to 16% per co-op, with more weight toward the high end of the range

Research supports a 20% opt-in and a 80% opt-out participation rate

Utility/Program	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
OPower BDR program adoption rate		90%
Green Mountain Power	34%	
MN electric co-ops (MyMeter Program)	9-16%	

- In both the opt-in and opt-out deployment scenarios, we choose fairly conservative participation rates relative to the data that is available on BDR enrollment
- This is in recognition of the long-term uncertainty in enrollment in these programs and the fairly small scale at which the existing pilots were conducted

Irrigation Load Control Programs typically target large irrigation & drainage pumping systems

Many utilities, such as SCE, Entergy Arkansas, and Idaho Power focus on large customers

The 2014 PacifiCorp potential study sets the eligibility threshold at customers with pumps 25 HP and higher, representing 78% of total agricultural load

We propose that the eligible population be limited to customers on Schedule 49

- Comprises Irrigation & Drainage Pumping customers with loads >30 kW
- These customers represents about 75% of total Irrigation and Drainage load (based on PGE's February 2015 Rate Case Filing)

There are a few data points upon which to base PGE's irrigation DLC participation estimate

EnerNOC's 2013 Irrigation Load Control Report provides enrollment estimates for Rocky Mountain Power

- The Utah service territory had a participation rate of about 20% of eligible load, whereas the Idaho service territory had participation of 48% of eligible load
- All irrigation customers were eligible to participate
- Customers with loads <50 kW required to pay an enablement fee

Idaho Power has achieved significant enrollment

- Conversations with Idaho Power staff indicate that roughly 10% of irrigation customers are enrolled
- These participants are significantly larger than average, representing peak reduction capability of 39% of system peak coincident irrigation load

The recent PacifiCorp DSM potential study suggested a lower participation rate for Oregon

- Participation in California, Oregon, Washington, and Wyoming assumed to be 15% of eligible load, based on PacifiCorp program experience
- Assumed participation rates for Idaho and Utah were significantly higher, likely reflecting the different nature of the crops in those two states, leading farmers to be more likely to allow more regular curtailments to their irrigation cycle

There is support for a 15% participation rate assumption for Irrigation Load Control programs

Utility/Program	Opt-In Participation Rate (% eligible load)
PacifiCorp 2015 (CA, OR, WA, WY)	15%
RMP 2013 (Utah)	20%
Idaho Power	39%
RMP 2013 (Idaho)	48%

- The range of participation rates observed in existing programs is wide
- We have chosen an estimate on the low end of the range to avoid overstating participation that may be associated with hotter, drier climates like those of Idaho and Utah
- This assumption has the added benefit of being consistent with the Oregon assumption in the PacifiCorp potential study

Summary of Participation Assumptions for New Non-Pricing programs

Program	Eligible Population in 2020 (%)	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
BYOD	25% of Residential Customers	25%	N/A
Behavioral DR	100%	20%	80%
Irrigation Load Control	75% of Irrigation Customers	15%	N/A

Sources for new non-pricing participation assumptions

- Acquity Group, The Internet of Things: The Future of Consumer Adoption, 2014.
- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015.
- Berg Insight, Smart Homes and Home Automation, January 2015.
- CMO, 15 Mind-Blowing stats about the Internet of Things, April 17, 2015.
- Edison Institute, Innovations Across the Grid, Volume II, December 2014.
- EnerNOC, 2013 PacifiCorp Irrigation Load Control Program Report, March 3, 2014.
- Honeywell, Structuring a Residential Demand Response Program for the Future, June 2011.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- R. Kiselewich, The Future of Residential Demand Response: BGE's Integration of Demand Response and Behavioral, E Source Forum 2014, September 29 - October 2, 2014.
- S. Blumsack and P. Hines, Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013, March 5, 2015.

Appendix B:

Per-Participant Load Impact Assumptions

Estimating Per-Participant DR Impacts for PGE

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In this presentation

This presentation summarizes the methodology and assumptions behind our estimates of per-participant peak demand reductions for DR programs that could be offered in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Note that the impacts in this presentation are per average participant; they are not multiplied into participation rates to arrive at estimates of system-level impacts

Pricing Programs

Pricing impact estimates have undergone a significant overhaul relative to the 2012 study

Incorporated new findings of 24 pilots and full-scale rollouts that have occurred since the 2012 study, including the DOE-funded consumer behavior studies

Modified the impact estimation methodology to take advantage of the greater number of data points that are now available

- Differentiation in price responsiveness between TOU, CPP, and PTR rates
- Accounting for difference in average response under opt-in versus opt-out deployment
- Improved differentiation between winter and summer impacts

The following slides provide a step-by-step description of our approach

First, we established a reasonable peak-to-off-peak price ratio for each rate option

The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates

A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result

Price ratios are based on rate designs that have recently been offered by PGE or are currently under consideration

- TOU: 2-to-1
- CPP: 4-to-1*
- PTR: 8-to-1*

* Rate designs were provided by PGE. It would alternatively be useful to explore CPP and PTR rates with consistent price ratios.

Impacts of time-varying rates were then simulated based on a comprehensive review of recent pilot results

PGE has recently conducted a CPP pilot and previously conducted a TOU pilot; the results are incorporated into our analysis, but have been supplemented with findings from dynamic pricing pilots across the globe to develop more robust estimates of price response

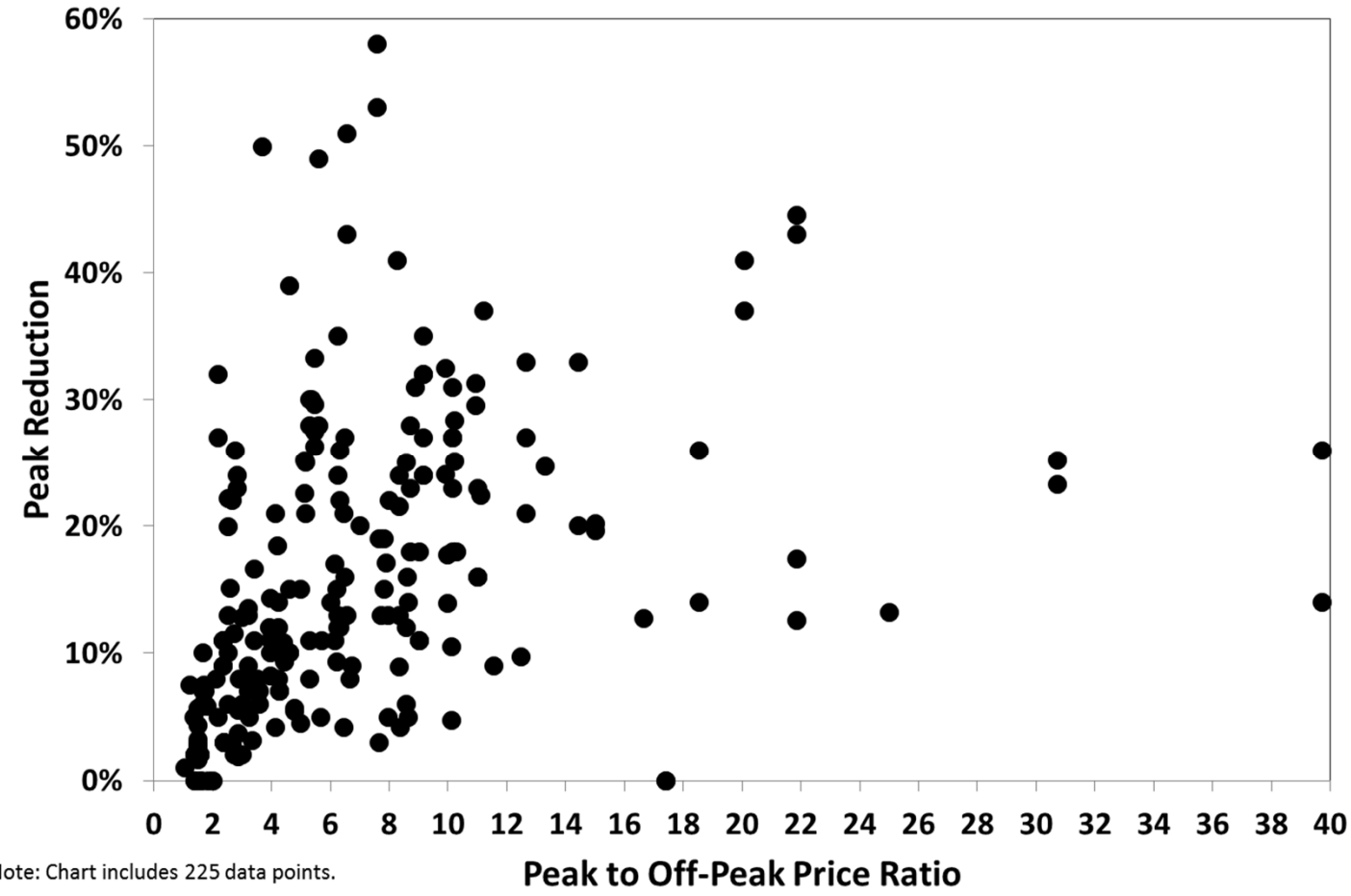
For residential customers, we rely on results from 225 pricing tests that have been conducted in a total of 42 pilots in the U.S. and internationally over roughly the past decade

Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California

Large C&I impacts are based on experience with full-scale programs in the Northeastern U.S.

To estimate residential impacts, we begin with a survey of impacts from recent pilots

Results of All Residential Time-Varying Pricing Tests



Note: Chart includes 225 data points.

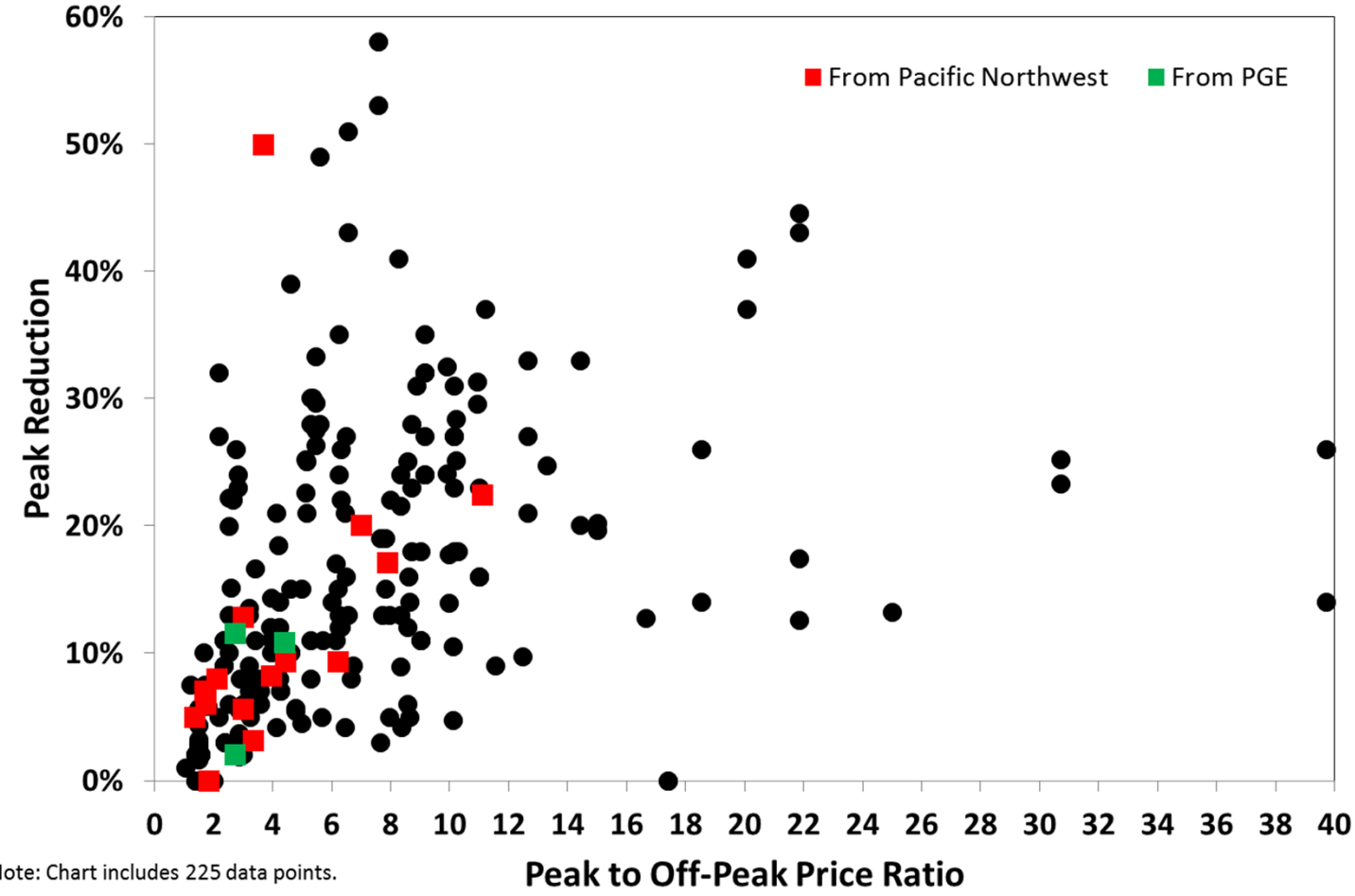
Our database of dynamic pricing pilots includes seven that have been conducted in the Pacific Northwest

Utility/Organization	State/Province	Name of Pilot	Year(s)	Rates Tested	Range of Price Ratios	Range of Peak Prices	Range of Impacts	Number of Pilot Participants	Season of System Peak
BC Hydro	British Columbia	Residential TOU/CPP Pilot	2007-2008	TOU CPP	TOU: 3.0-6.2 CPP: 7.9-11.1	TOU: 19-28¢ CPP: 50¢	TOU: 3-13%, CPP: 17-22%	TOU: 1,031 CPP: 273	Winter
Idaho Power	Idaho	Energy Watch (EW) and Time-of-Day (TOD) Pilot Programs	2005-2006	TOU CPP	TOU: 1.8 CPP: 3.7	TOU: 8¢ CPP: 20¢	TOU: 0% CPP: 50%	TOU: 85 CPP: 68	Summer
PacifiCorp	Oregon	TOU Rate Option	2002-2005	TOU	Summer: 1.7-2.1 Winter: 1.7	Summer: 11-14¢ Winter: 11¢	Summer: 6-8% Winter: 7%	~1200	Summer Winter
Portland General Electric (PGE)	Oregon	Residential TOU Option	2002-2003	TOU	2.7	8¢	8%	1,900	Winter
Portland General Electric (PGE)	Oregon	Critical Peak Pricing Pilot	2011-2013	CPP	4.4	44¢	11%	996	Winter
Puget Sound Energy	Washington	TOU Program	2001	TOU	1.4	See notes	5%	300,000	Winter
US DOE, PNNL, BPA, PacifiCorp, Portland General Electric, Public Utility District #1 of Clallam County, and City of Port Angeles	Washington/ Oregon	Olympic Peninsula Project	2006-2007	CPP	7.0	35¢	20%	112	Winter

Notes:
Could not find published estimates of TOU prices for Puget Sound Energy; only the price differential was available.
Price ratios are presented on an all-in basis.

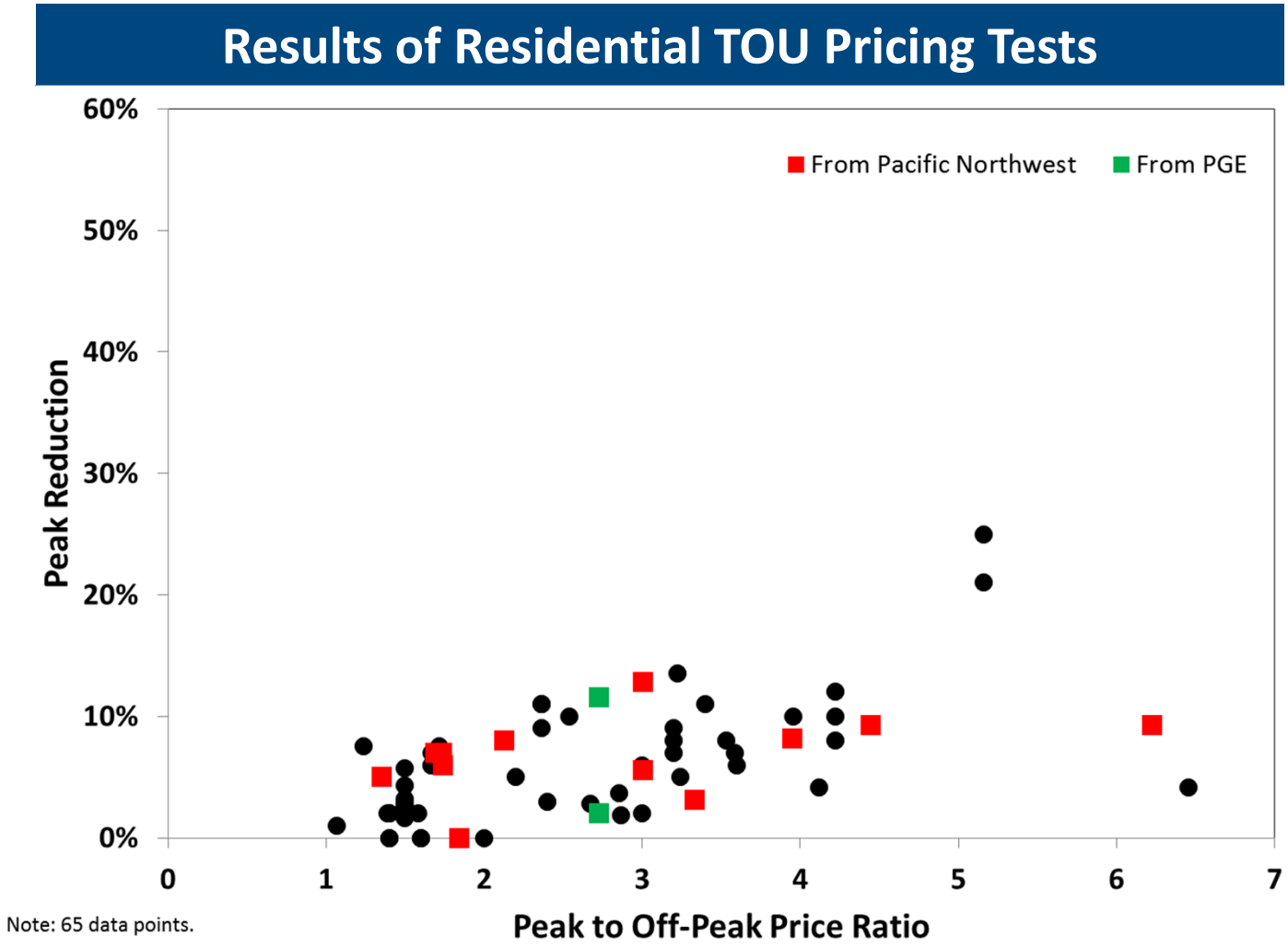
The Pacific Northwest price ratios and impacts are generally consistent with those of other pilots

Results of All Residential Time-Varying Pricing Tests



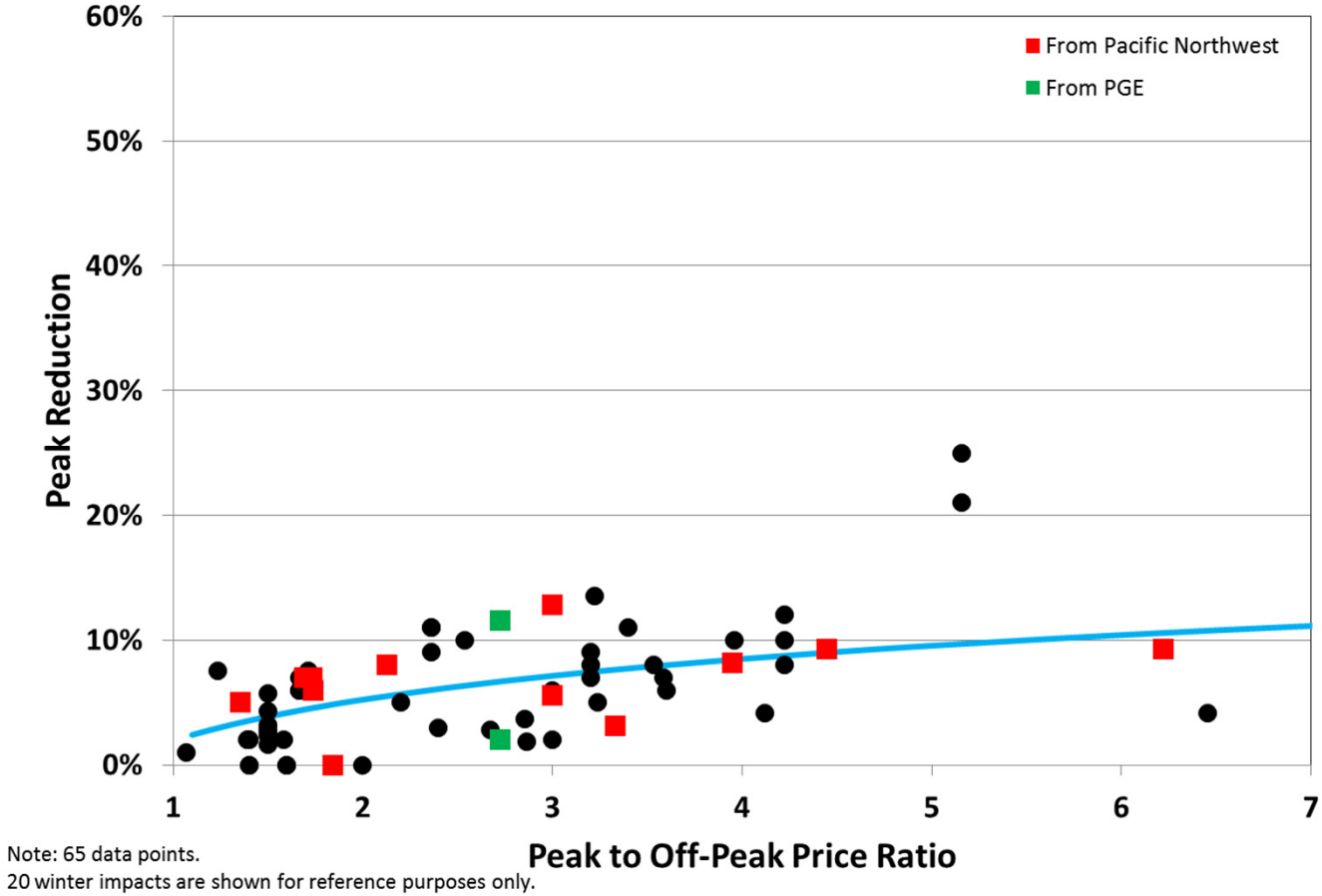
Note: Chart includes 225 data points.

To estimate TOU impacts, we focus only on those pilots which tested TOU rates



We then fit a curve to the summer data to capture the relationship between price ratio and impacts

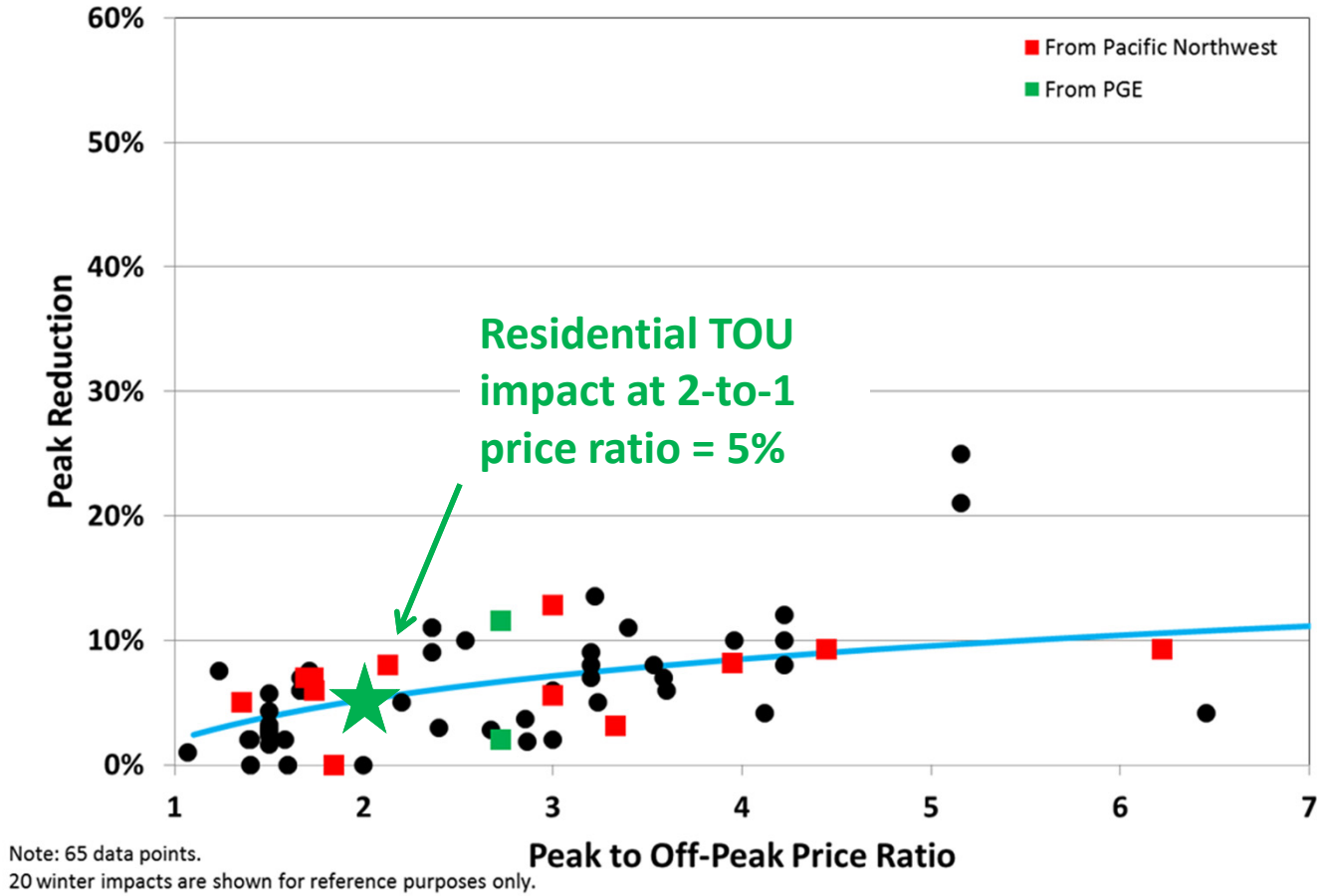
Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

We use the arc to simulate the impact of the residential TOU rate for our study

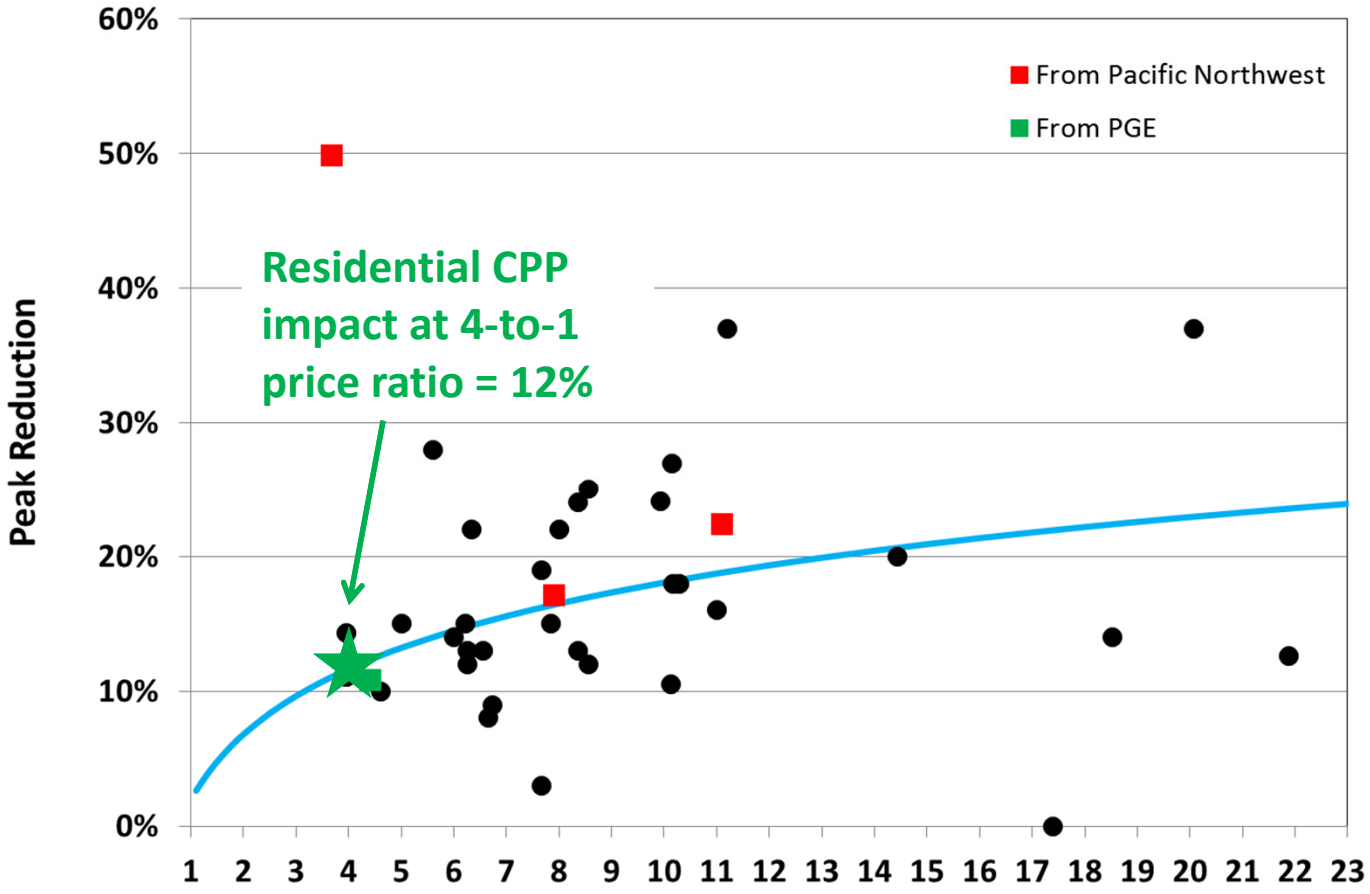
Results of Residential TOU Pricing Tests with Arc



Note: 65 data points.
20 winter impacts are shown for reference purposes only.

The same approach was used to estimate CPP impacts

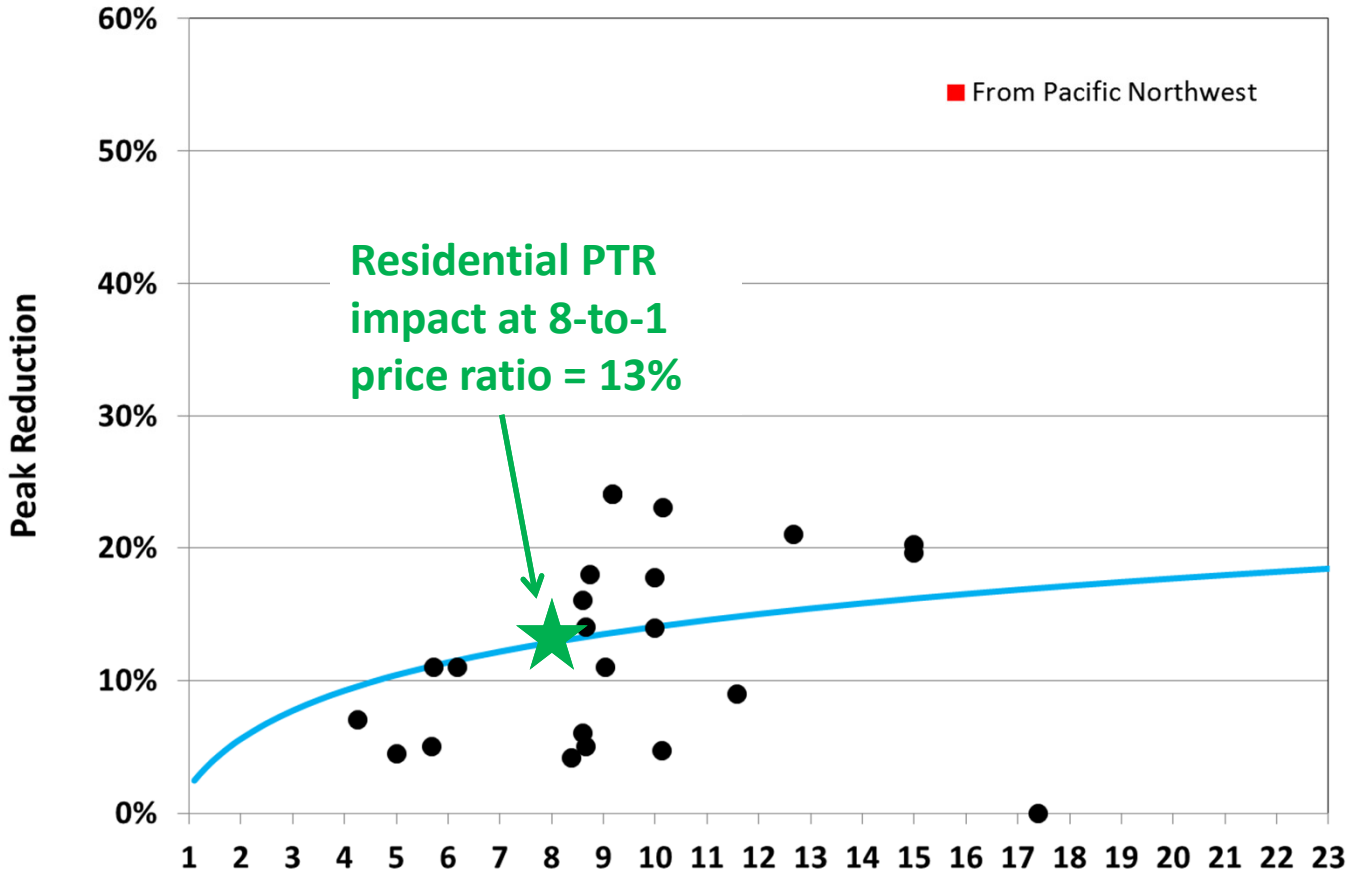
Results of Residential CPP Pricing Tests with Arc



Note: 40 data points, 2 not shown,
1 dropped as outlier in regression. 5 winter impacts are shown for reference purposes only.

PTR impacts were also estimated using the same approach

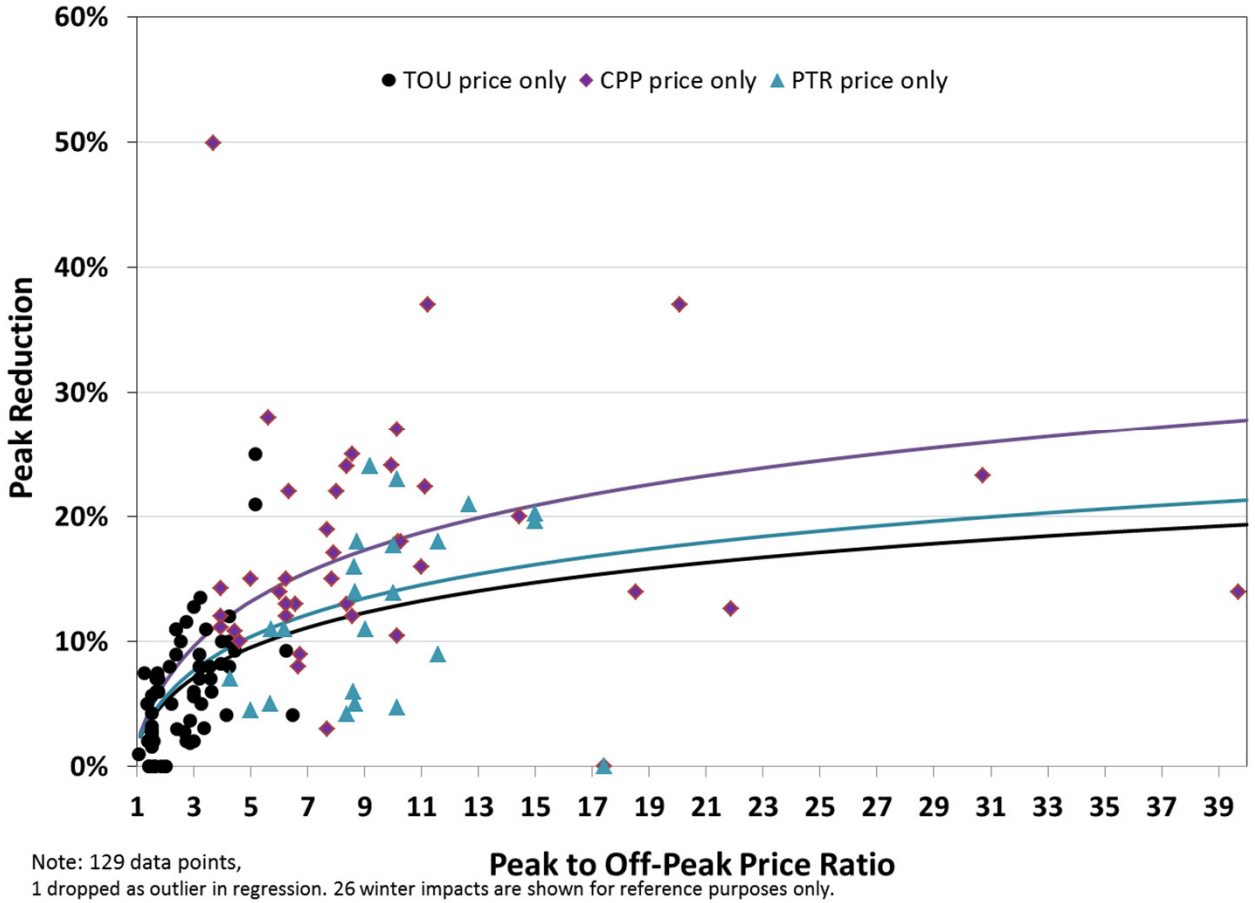
Results of Residential PTR Pricing Tests with Arc



Note: 24 data points.
2 winter impacts are shown for reference purposes only.

Price elasticity appears to be higher for CPP rates than PTR or TOU

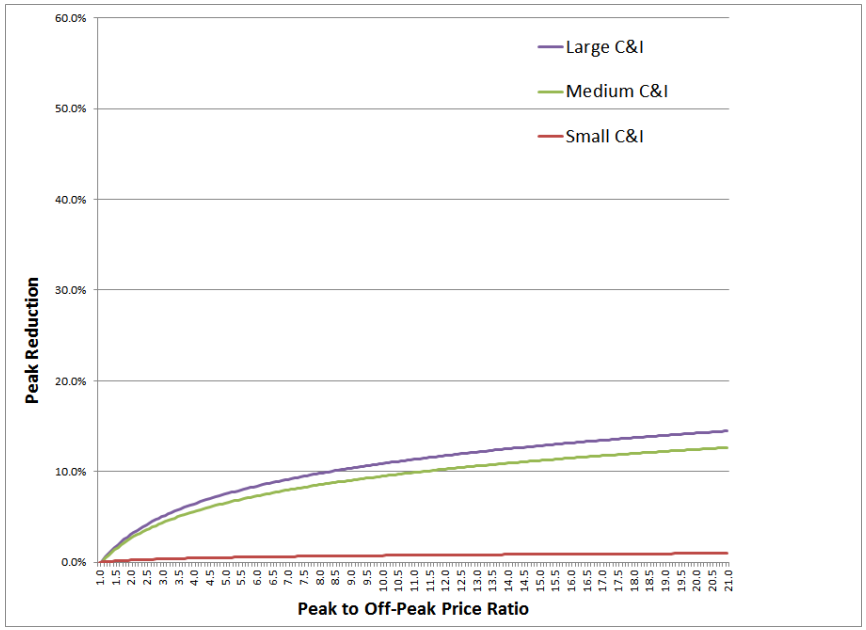
Results of All Residential Time-Varying Pricing Tests



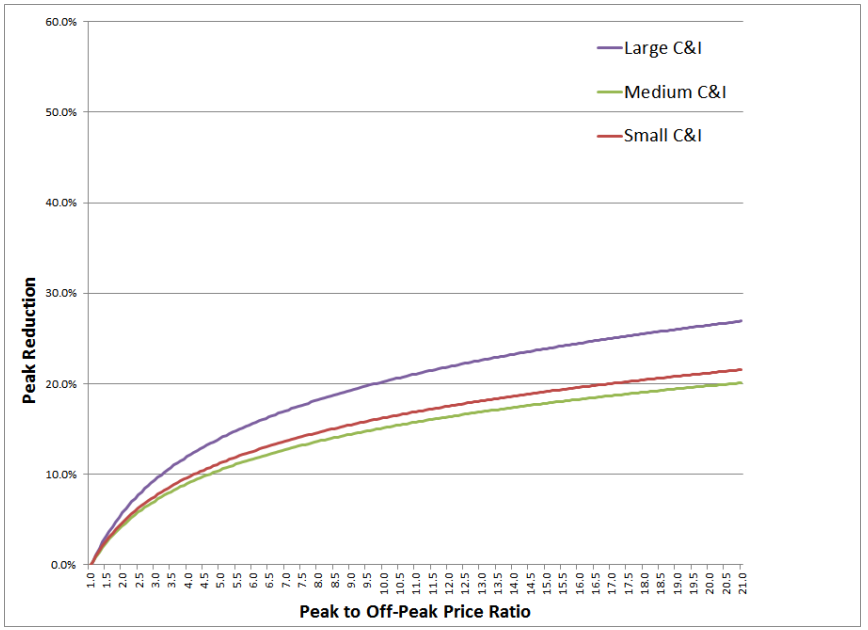
Note: 129 data points,
1 dropped as outlier in regression. 26 winter impacts are shown for reference purposes only.

C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers

C&I Arcs without Tech



C&I Arcs with Tech



Seasonal variation is based on the relationship observed in a limited number of pilots

To develop winter impact estimates, we created a scaling factor based on the relationship observed in pilots that tested both rates

The challenge is that there is not a consistent seasonal relationship across these pilots (see table)

Recognizing this uncertainty, but remaining consistent with the directional relationship in the PGE studies, we assumed a slightly higher degree of price responsiveness (10%) in the winter than in the summer

New primary research (e.g., the upcoming PTR pilot) is needed to refine this assumption

Pilot	Winter impact relative to summer
PGE TOU	Much larger (6x)
PGE CPP	Slightly larger*
PacifiCorp	Similar
Ontario TOU	Slightly smaller
Australian TOU	Much smaller (0.4x)
Xcel	Relationship varies

* Based on very limited summer data

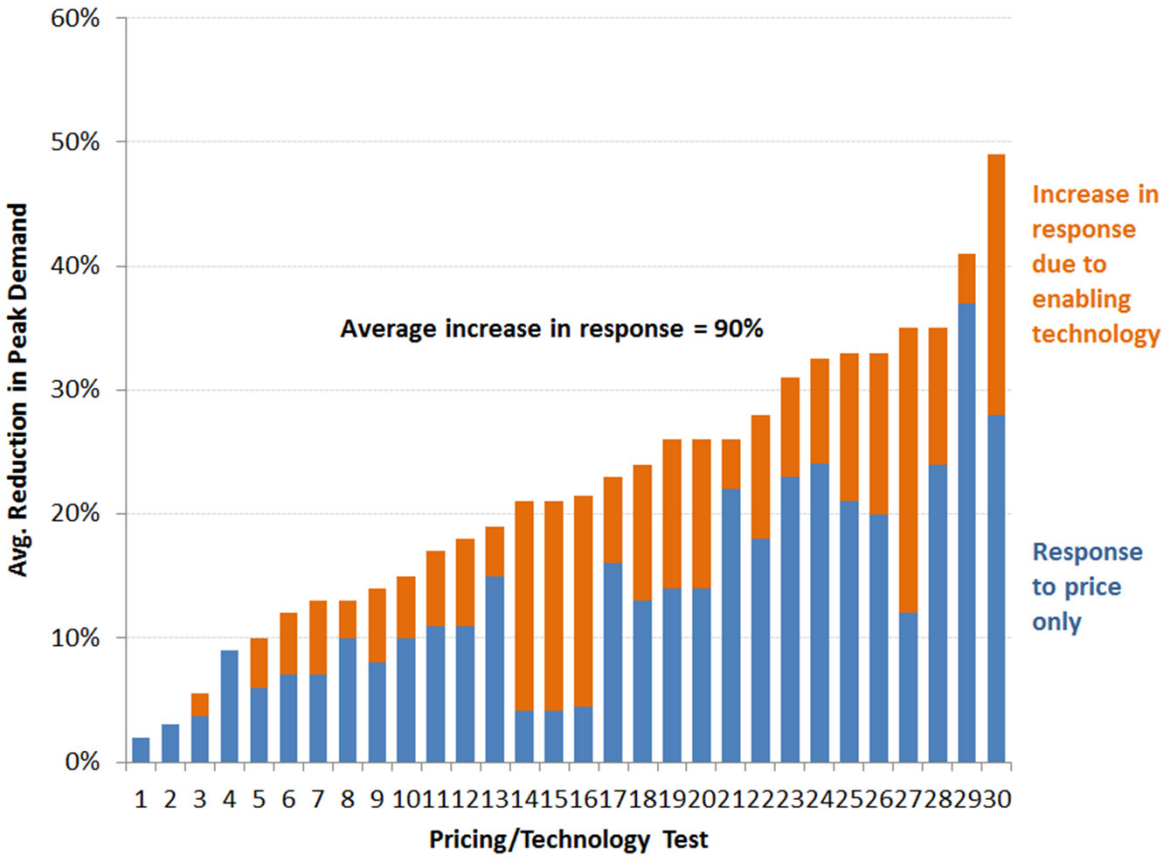
Impacts are scaled to account for enabling technology

Based on the relationship observed in other pilots, we assume a 90% increase in response attributable to technology (largely smart thermostats)

Winter technology impacts are assumed to be 80% of summer technology impacts based on the relationship observed in direct load control programs

TOU is not coupled with enabling technology because it does not have a dispatchable price signal

Price Response with and without Tech



Per-customer pricing impacts are scaled down in the opt-out deployment scenario

A new dynamic pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment

This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario; note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger

Per-customer TOU impacts were 40% lower when offered on an opt-out basis

Per-customer CPP impacts were roughly 50% lower

We have accounted for this relationship in our modeling of the residential impacts

We also simulated the impact of a TOU rate for irrigation customers

A 2001/2002 irrigation TOU pilot in Idaho found that customers produced, on average, a 9% reduction in peak for a TOU with a 3.5-to-1 price ratio

We used the Arc of Price Responsiveness to scale these impacts to the TOU price ratio we're analyzing in this study

The resulting peak reduction estimate is 4.7% for a TOU rate

Summary of draft results

		Without Tech			With Tech		
		TOU	CPP	PTR	TOU	CPP	PTR
Opt-in Deployment							
Residential	Summer	5.2%	11.7%	12.9%	N/A	31.0%	34.2%
	Winter	5.8%	12.8%	14.2%	N/A	24.8%	27.4%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A
Opt-out Deployment							
Residential	Summer	3.1%	5.8%	6.4%	N/A	15.5%	17.1%
	Winter	3.5%	6.4%	7.1%	N/A	12.4%	13.7%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A

Notes:

Impacts are average per eligible participant – individual participants could produce larger or smaller impacts

For ease of comparison, tech impacts are expressed as a % of the average customer even though they would only apply to customers with electric A/C or space heat, who have higher peak demand

Non-Pricing Programs Included in Prior PGE Studies

We estimate per-participant impacts for the following non-pricing programs from prior studies

	Residential	Small C&I	Medium C&I	Large C&I
DLC - A/C	X	X		
DLC - Space heat	X	X		
DLC - Water heating	X	X		
DLC - Auto-DR			X	X
Curtailable tariff			X	X

Updates to assumptions for conventional non-pricing programs were fairly minor

Impact assumptions remain stable for the conventional non-pricing programs analyzed in prior studies for PGE, since these programs are well established with a long history of performance

Where applicable, we revised the estimates to be more consistent with findings of studies in the Pacific Northwest

We also compared the 2012 assumptions to those of the more recent PacifiCorp potential study and resolved any discrepancies to ensure consistency

We relied on the following Pacific Northwest DR studies to refine our impact estimates

- Avista, “Idaho Load Management Pilot,” 2010
- Cadmus Group, “Kootenai DR Pilot Evaluation: Full Pilot Results,” 2011
- Cadmus Group, “OPALCO DR Pilot Evaluation”, 2013
- Itron, “Draft Phase I Report Portland General Electric Energy Partner Program Evaluation,” 2015
- Lawrence Berkeley National Lab, “Northwest Open Automated Demand Response Technology Demonstration Project,” 2009
- Michaels Energy, “Demand Response and Snapback Impact Study”, 2013
- Navigant and EMI, “2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program,” 2012
- Navigant, “Assessing Demand Response (DR) Program Potential for the Seventh Power Plan”, 2014
- Nexant, “SmartPricing Options Final Evaluation - The Final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study”, 2014
- Rocky Mountain Power, “Utah Energy Efficiency and Peak Reduction annual Report”, 2014

The following assumptions were updated for this study

Residential air-conditioning DLC

- Reduced slightly from 1.0 kW to 0.8 kW to reflect lower-than-average impacts observed in Pacific Northwest studies

Residential space heat DLC

- Increased from 0.6 kW to 1.0 kW
- Even higher impacts are observed in Pacific Northwest studies, but a 2004 PGE study found impacts in the 0.7 kW range
- Note that the relationship between space heat and air-conditioning has been reversed based on this revision

Assumption updates (cont'd)

Small C&I air-conditioning and space heat

- Scaled to be consistent with residential assumption (1.5x residential load reduction capability)

Medium and Large C&I Auto-DR

- Increased from 15-20% of peak load to 30% of peak load to establish appropriate relationship between curtailable tariff impacts and Auto-DR impacts
- Assumed to be offered in conjunction with curtailable tariff type of program and provides 50% incremental increase in load reduction relative to impact with no technology
- There is a significant range of uncertainty around this assumption; to be discussed further with PGE relative to the findings of its Auto-DR pilot, which referenced a fairly broad range of impacts

Summary of assumptions for non-pricing impacts from prior studies

Class	Program	Season	2012 Assumption	Updated 2015 Assumption
Residential	DLC - Central A/C	Summer	1.0 kW	0.8 kW
Residential	DLC - Space Heat	Winter	0.6 kW	1.0 kW
Residential	DLC - Water Heating	Summer	0.4 kW	0.4 kW
Residential	DLC - Water Heating	Winter	0.8 kW	0.8 kW
Small C&I	DLC - Central A/C	Summer	2.0 kW	1.2 kW
Small C&I	DLC - Space Heat	Winter	1.2 kW	1.5 kW
Small C&I	DLC - Water Heating	Summer	1.2 kW	1.2 kW
Small C&I	DLC - Water Heating	Winter	0.6 kW	0.6 kW
Medium C&I	DLC - Auto-DR	Year-round	15%	30%
Medium C&I	Curtailable tariff	Year-round	N/A	20%
Large C&I	DLC - Auto-DR	Year-round	20%	30%
Large C&I	Curtailable tariff	Year-round	20%	20%

New Non-Pricing Programs
Not Included in Prior PGE Studies

We estimated per-participant peak demand impacts for three new programs; two more are in development

Draft impact estimates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Impact estimates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- Developing assumptions for these programs requires ongoing interaction with PGE staff, which is already underway

We relied on the following data sources to develop our impact estimates for new non-pricing programs

- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015
- Austin Energy, PowerSaver Program website, Accessed May 1, 2015
- Con Ed of NY, Rider L – Direct Load Control Program filing, Case C14-E-0121, April 3, 2014
- Edison Foundation, Innovations Across the Grid, December 2013 and December 2014
- Hydro One website, Accessed May 1, 2015.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Nest Inc., White Paper: Rush Hour Rewards, Results from Summer 2013, May 2014.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- Rocky Mountain Power, Utah Energy Efficiency and Peak Reduction Annual Report, June 26, 2013 and May 16, 2014.
- S. Blumsack and P. Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013", March 5, 2015.
- Southern California Edison website, Accessed May 1, 2015.

We have identified key elements of "Bring Your Own Device" Type Programs

Bring Your Own Device/Thermostat ("BYOD" or "BYOT") programs provide an alternative to utility direct-install programs, reducing equipment and installation costs

The incentive structure for participating in BYOD programs is diverse

- One-time rebate/refund, with or without a minimum time commitment
- Fixed annual/monthly participation incentive in addition to a one-time rebate
- Variable monthly incentive based on kWh savings

Programs also include monetary incentives to thermostat vendors and annual compensation for portal/interface maintenance

Customers can opt out of individual events without penalty

Our assumptions are based on research of five different BYOD programs

We have identified five primary programs

- Hydro One
- Austin Energy
- Con Edison of NY
- Southern California Edison
- "Rush Hour Rewards (RHR)" program by Nest Inc.

These programs have been able to successfully sign up new customers

- As of December 2014, Austin Energy had enrolled 7,000 thermostats (out of ~383,000 residential customers), with a planned expansion to 70,000 thermostats
- Con Edison enrolled 2,000 customers in its first year and believes that it can achieve 5,000 new sign-ups each year
  - Low enrollment may be explained by a relatively small number of eligible thermostats currently installed (~30,000)
- In 2013 Nest's Rush Hour Rewards program included over 2,000 customers from Austin Energy, Reliant, and Southern California Edison. Nest is currently expanding this program, and enrollment has likely increased since then

Our BYOD program impact estimates are similar to those of other Residential A/C DLC programs

Austin Energy's *Power Partner Thermostat* program has achieved a per device load shed of up to 33% during a peak event

Con Edison expects 1.0 kW of peak load reduction per thermostat based on its experience with other Residential DLC participants

Nest's "RHR" program studied the peak load impacts across three different utilities (Austin Energy, Reliant, and Southern California Edison)

- A total of 19 events were studied across the three utilities
- Each event reduced load by an average of 1.18 kW per device
- Only 14.5% of customers reduced their temperature during an event

Research suggests a per-customer peak reduction of around 1 kW

Utility/Program	Number of Participants	Customer Incentive	Peak Demand Impact (%/customer)	Peak Demand Impact (kW/customer)
Austin Energy	7,000	$85/one-time	33%	N/A
SCE	N/A	$1.25/kWh reduced	N/A	N/A
Con Ed of NY	2,000	$85/one-time; $25 annual for additional participation	N/A	1.0
Hydro One	2,000	$100-125/one-time	N/A	N/A
Nest Inc.'s "RHR"	2,000	N/A	55%	1.18

The available data suggests that per-customer impacts are similar to that of a utility-administered DLC program; we therefore assume the same summer and winter impacts that are being modeled in the conventional programs

Impacts of Behavioral DR programs were based primarily on programs conducted by OPower

Behavioral Demand Response aims to increase customer engagement

Achieved via a software-centered approach based on targeted and customized email, mobile, and interactive voice response (IVR) communications

Customers are notified of DR events ahead of time and receive post-event feedback on performance

Easy to deploy and scale relative to other DR programs that require hardware installations

No financial incentives are offered for load reductions

OPower reports significant summer peak savings from BDR programs

Deployed to 150k customers in Consumers Energy (MI), Green Mountain Power (VT), and Glendale Water & Power (CA)

- Achieved peak load reductions of 3% on average (max 5%)

BGE launched BDR in combination with a Peak Time Rebate Program

- 5% average reduction at peak across homes without a device (~0.2kW/home)

Added benefit of customer engagement and increased satisfaction, although it is possible that customers could find the notifications to be intrusive

Others are also exploring the potential of Behavioral DR

In Minnesota, four electric co-ops used MyMeter – a program that gives utility customers more detailed info about their energy use

- In 2013, demand reduction ranged between 1.8 – 2.8% per customer
- This program is different from those offered by Opower, as information is driven through an in-home display

In the fall of 2012 and summer of 2013, Green Mountain Power study tested a behavioral DR-like program

- GMP ran fourteen peak event tests for seven treatment groups with varying rate structures and informational treatments
- Customers who stayed on a flat rate, but were notified of peak events, reduced by peak demand by 3.4% and 8.2% in 2012 and 2013, respectively (0.030 - 0.073 kW)

We have heard that Silver Spring Networks may be developing BDR capability. However, we have not yet found any evidence and further research is needed

Research suggests a 3% reduction impact for Behavioral DR programs would be reasonable

Utility/Program	Summer Peak Demand Impact (%)
Consumers Energy, Green Mountain Power, and Glendale Water & Power	3.0%
BGE	5.0%
MN electric co-ops (MyMeter Program)	1.8-2.8%
Green Mountain Power	3.4-8.2%

- Since little is known about the persistence of BDR impacts over the long-term, we assume an impact from the lower end of this range, of 3%
- To establish a winter impact, we use the same assumption that is used in our dynamic pricing analysis, that winter impacts are 10% higher than summer impacts; this is because BDR similarly relies on behavioral response from customers rather than targeting a specific end-use

There is support for high per-customer impacts from Irrigation Load Control programs

Irrigation Load Control consists of scheduling or shutting off irrigation pumps above a certain size

The programs researched are available only during the summer and typically provide a fixed (per event) incentive payment

Customers can opt out of a maximum number of events per year

In the Pacific Northwest, PacifiCorp has experience with such programs in Idaho and Utah; Idaho Power and a number of electric cooperatives also offer irrigation load control programs

Southern California Edison and Entergy also offer irrigation load control programs, as do coops in other parts of the US

Estimates of irrigation peak load reductions are fairly large on a per-participant basis

Rocky Mountain Power (part of PacifiCorp) ran its irrigation load control program in 2009 and 2010 with customers in Idaho

- About 2,000 customers were enrolled between 2009 and 2010
- Aggregate reductions in 2009 was 206 MW out of 260 MW of irrigation load
- In 2010, reductions amounted to 156 MW out of 283 MW of load

RMP also ran a program in Utah that achieved reductions in the 62-73% range

FERC's DR Study reports peak demand reductions of about 60% for electric cooperatives

Southern California Edison and Entergy report impacts of 82% and 49%, respectively

In its 2014 DR potential study, PacifiCorp's assumed that 100% of agricultural irrigation load could be curtailed during an event

Our research suggests peak reductions in the 65%-75% range for Irrigation Load Control programs

Utility/Program	Peak Demand Impact (MW)	Baseline Demand (MW)	Peak Demand Impact (%)
PacifiCorp DR potential study	N/A	N/A	100%
Southern California Edison			89%
RMP 2009	205	260	79%
RMP 2010	156	283	55%
RMP 2012	35	48	73%
RMP 2013	16	26	62%
Various Coops (FERC 2013 Study)	N/A	N/A	60% (mean)
Entergy (Arkansas)			49%

Notes: Peak demand impact % calculated for RMP 2009-2012 as (peak demand impact) / (baseline demand).
RMP 2009-10 from The Cadmus Group, *Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program,* March 24, 2011, pp. 1-2.
RMP 2012 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* Revised June 26, 2013, p. 19.
RMP 2013 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* May 16, 2014, p. 19.

Summary of Impact Assumptions for New Non-Pricing programs

Program	Winter Peak Demand Impact (kW)	Winter Peak Demand Impact (%)	Summer Peak Demand Impact (kW)	Summer Peak Demand Impact (%)
BYOD	1.0 kW		0.8 kW	
Behavioral DR		3.3%		3%
Irrigation Load Control		N/A		70%

Appendix C:
Cost-Effectiveness Adjustments

Should the incentive payment be included as a cost in the TRC cost-effectiveness test?

If every participant valued their loss of comfort at an amount equal to the incentive payment (assume $90/year), then it would be correct to include the full incentive amount as a cost in the TRC test

However, every participant is unique and will therefore value the loss of comfort differently; consider four prototypical customers in a DLC program:

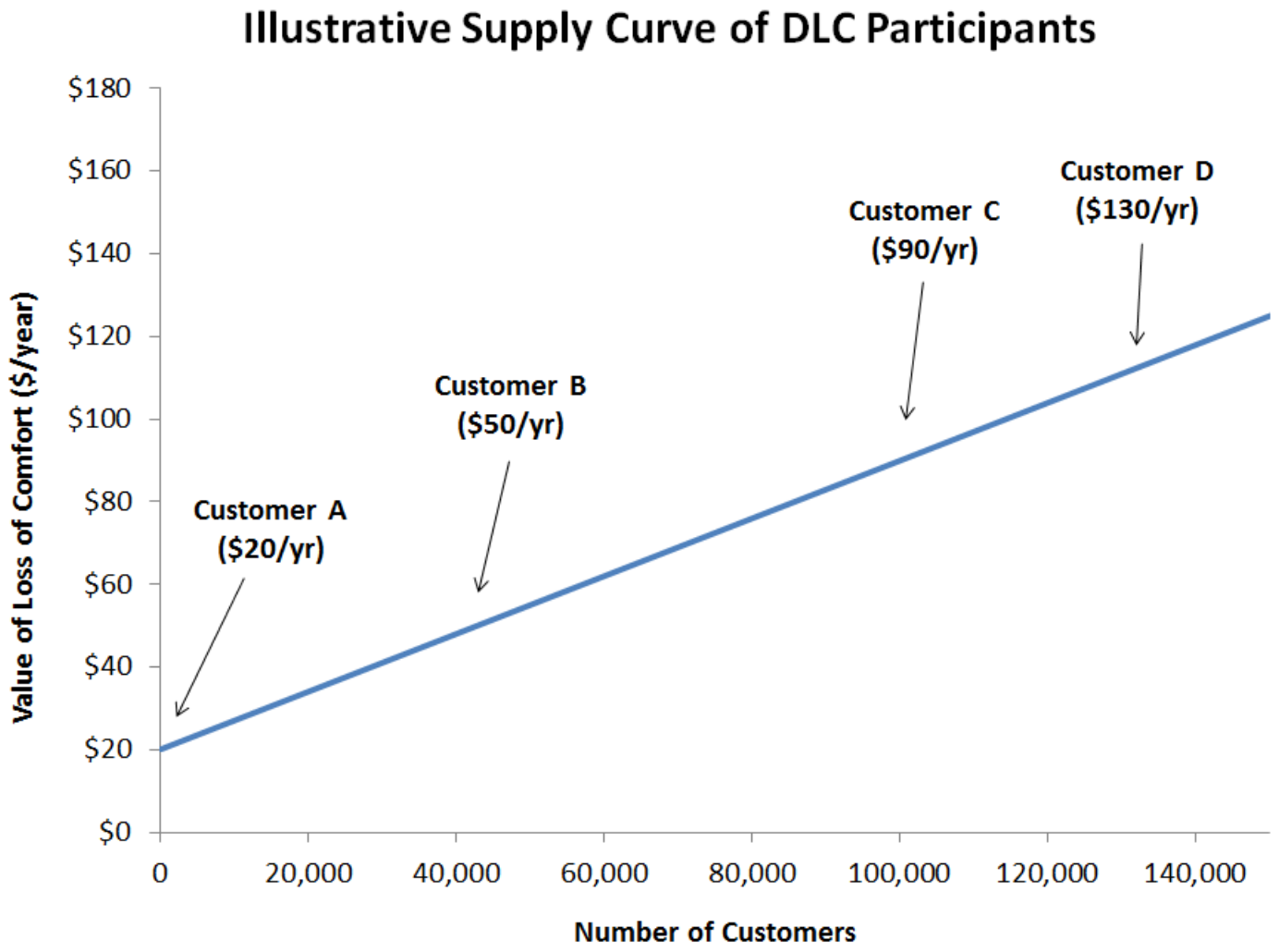
Customer A, for example, is rarely home and therefore only values his loss of comfort from participating in the DLC program at $20/year – his "profit" from participating in the program would be $70/year

Customer B is home more often, but does not particularly mind relinquishing control of his air-conditioner occasionally; he values the loss of comfort at $50/kW year

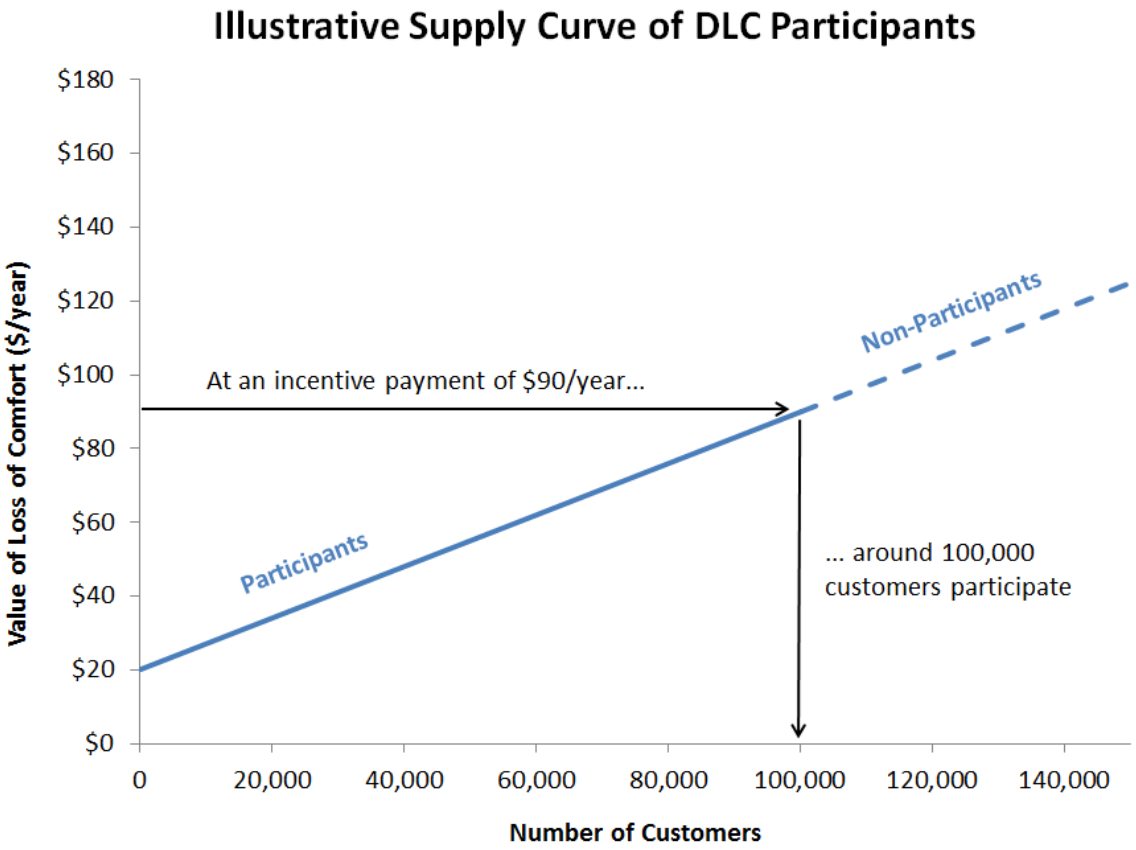
Customer C places higher value on comfort, and the cost of participating is roughly the same to him as the incentive payment that he receives; this is the "marginal" customer

Customer D is more temperature-sensitive and does not like the idea of curtailing use of his air-conditioner; his value of lost comfort is $130/year, or $40 more than the incentive payment that is being offered

The prototypical customers represent a "supply curve" of participants in the DLC program



The cost associated with "loss of comfort" should be the average across all participants



- Customers will only participate if their loss of comfort is less than the incentive payment
- In this purely illustrative example, the average loss of comfort among participants is $50 per year, which is 55% of the incentive payment
- The remaining 45% is simply a transfer payment and should not be considered a cost in the TRC test (which is consistent with treatment of energy efficiency programs)
- While that estimate would change depending on the slope of the supply curve, it is more realistic than assuming all customers incur a cost of $90/year
- We count 50% of the incentive as a cost in the base case of our analysis for this reason

We tested the sensitivity of our findings to the amount of incentive counted as a cost

Class	Program	Opt-in		
		Base Case (50%)	0%	100%
Residential	AC DLC	1.12	1.57	0.87
Residential	Space Heating DLC	1.31	1.78	1.03
Residential	Water Heating DLC	1.30	2.09	0.94
Residential	AC/Space Heating DLC	1.82	3.10	1.29
Residential	TOU	1.24	1.24	1.24
Residential	PTR	1.75	4.49	1.24
Residential	PTR w/Tech	1.32	2.26	0.98
Residential	CPP	1.62	1.62	1.62
Residential	CPP w/Tech	1.49	1.49	1.49
Residential	Behavioral DR	0.85	0.80	0.80
Residential	BYOT - AC	1.94	3.55	1.27
Residential	BYOT - Space Heating	1.98	3.30	1.41
Residential	BYOT - AC/Space Heating	2.43	5.39	1.57
Small C&I	AC DLC	1.00	1.51	0.75
Small C&I	Space Heating DLC	1.07	1.52	0.83
Small C&I	Water Heating DLC	0.79	1.14	0.60
Small C&I	AC/Space Heating DLC	1.40	2.41	0.98
Small C&I	TOU	0.06	0.06	0.06
Small C&I	PTR	0.17	0.18	0.16
Small C&I	PTR w/Tech	0.79	1.03	0.64
Small C&I	CPP	0.08	0.08	0.08
Small C&I	CPP w/Tech	0.55	0.55	0.55
Medium C&I	Third-Party DLC	1.59	2.09	1.23
Medium C&I	Curtailable Tariff	5.37	28.26	2.96
Medium C&I	CPP	1.94	1.94	1.94
Medium C&I	CPP w/Tech	1.38	1.38	1.38
Large C&I	Third-Party DLC	1.57	2.06	1.22
Large C&I	Curtailable Tariff	6.30	168.36	3.21
Large C&I	CPP	14.42	14.42	14.42
Large C&I	CPP w/Tech	6.70	6.70	6.70
Agricultural	Pumping Load Control	0.78	1.02	0.63
Agricultural	TOU	0.29	0.29	0.29

The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-in** program deployment

Cost-effectiveness sensitivity case results (cont'd)

Class	Program	Opt-out		
		Base Case (50%)	0%	100%
Residential	AC DLC	N/A	N/A	N/A
Residential	Space Heating DLC	N/A	N/A	N/A
Residential	Water Heating DLC	N/A	N/A	N/A
Residential	AC/Space Heating DLC	N/A	N/A	N/A
Residential	TOU	1.24	1.05	1.05
Residential	PTR	1.49	2.76	1.06
Residential	PTR w/Tech	0.86	1.16	0.69
Residential	CPP	1.15	1.04	1.04
Residential	CPP w/Tech	0.83	0.80	0.80
Residential	Behavioral DR	1.04	0.97	0.97
Residential	BYOT - AC	N/A	N/A	N/A
Residential	BYOT - Space Heating	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	N/A	N/A	N/A
Small C&I	AC DLC	N/A	N/A	N/A
Small C&I	Space Heating DLC	N/A	N/A	N/A
Small C&I	Water Heating DLC	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	N/A	N/A	N/A
Small C&I	TOU	0.11	0.09	0.09
Small C&I	PTR	0.30	0.30	0.26
Small C&I	PTR w/Tech	0.82	1.07	0.66
Small C&I	CPP	0.11	0.10	0.10
Small C&I	CPP w/Tech	0.60	0.58	0.58
Medium C&I	Third-Party DLC	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	N/A	N/A	N/A
Medium C&I	CPP	4.80	3.56	3.56
Medium C&I	CPP w/Tech	1.76	1.63	1.63
Large C&I	Third-Party DLC	N/A	N/A	N/A
Large C&I	Curtailable Tariff	N/A	N/A	N/A
Large C&I	CPP	42.10	34.79	34.79
Large C&I	CPP w/Tech	7.15	7.02	7.02
Agricultural	Pumping Load Control	N/A	N/A	N/A
Agricultural	TOU	0.83	0.63	0.63

The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-out** program deployment

Avoided costs derates are derived from the California cost-effectiveness protocols

The California PUC currently defines three factors that are used to adjust avoided capacity costs to better reflect the value of demand response:

(A) **Availability:** "The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted."

(B) **Notification time:** "The B factor calculation should be done by examination of past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls… By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program."

(C) **Trigger:** "The C factor should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions.

Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE

For more information, see the 2010 California DR Cost Effectiveness Protocols report:
http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC

The CPUC is currently examining the possible modification and expansion of these factors

Avoided cost derates used in the PGE analysis

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

- Values at left represent the percent of the avoided cost that is attributed to the DR program
- Estimates are based on a survey of values developed by the California IOUs across a wide variety of DR programs
- Values are calibrated to capture appropriate relative relationships across the programs evaluated for PGE and intuitive estimates were developed for those programs for which there is not a clear example in the California data

Appendix D:

Annual Potential Estimates and Benefit-Cost Ratios

See the accompanying MS Excel file titled “PGE DR Potential Results - Annual Tables.xlsx”.

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0	42.0	43.2	44.6	45.7
Residential	PTR	Summer	0.0	94.3	97.2	100.3	102.9
Residential	PTR w/Tech	Summer	0.0	23.5	24.3	25.0	25.7
Residential	CPP	Summer	0.0	76.2	78.3	80.8	82.9
Residential	CPP w/Tech	Summer	0.0	20.4	21.0	21.6	22.2
Residential	Behavioral DR	Summer	45.2	38.1	39.3	40.6	41.7
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0	0.5	0.6	0.6	0.6
Small C&I	PTR	Summer	0.0	1.7	1.8	2.0	2.1
Small C&I	PTR w/Tech	Summer	0.0	3.7	4.0	4.3	4.6
Small C&I	CPP	Summer	0.0	0.9	1.0	1.0	1.1
Small C&I	CPP w/Tech	Summer	0.0	2.2	2.3	2.5	2.6
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0	21.9	23.3	25.2	26.8
Medium C&I	CPP w/Tech	Summer	0.0	38.5	41.1	44.4	47.3
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0	40.9	44.3	48.4	52.1
Large C&I	CPP w/Tech	Summer	0.0	83.9	90.9	99.4	106.9
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0	1.7	1.6	1.4	1.3

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	11.0	106.5	120.9	134.2	144.3
Residential	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Residential	Water Heating DLC	Summer	3.6	31.0	32.3	33.8	35.2
Residential	AC/Space Heating DLC	Summer	1.4	12.3	13.0	13.7	14.3
Residential	TOU	Summer	0.0	22.7	23.9	24.6	25.3
Residential	PTR	Summer	0.0	42.6	44.7	46.1	47.3
Residential	PTR w/Tech	Summer	0.0	12.9	13.5	13.9	14.3
Residential	CPP	Summer	0.0	31.9	33.5	34.6	35.5
Residential	CPP w/Tech	Summer	0.0	9.6	10.1	10.4	10.7
Residential	Behavioral DR	Summer	1.1	9.5	9.8	10.2	10.4
Residential	BYOT - AC	Summer	1.9	42.1	44.5	46.9	49.0
Residential	BYOT - Space Heating	Summer	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - AC/Space Heating	Summer	0.9	7.7	8.1	8.6	8.9
Residential	Smart Water Heater DLC	Summer	0.1	7.6	20.5	33.7	44.5
Residential	Electric Vehicle DLC	Summer	0.4	1.3	2.7	4.9	6.9
Small C&I	AC DLC	Summer	1.5	12.8	13.8	14.9	15.9
Small C&I	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Small C&I	Water Heating DLC	Summer	0.1	0.7	0.7	0.8	0.8
Small C&I	AC/Space Heating DLC	Summer	0.4	3.4	3.7	4.0	4.2
Small C&I	TOU	Summer	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Summer	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Summer	0.0	1.2	1.4	1.5	1.6
Small C&I	CPP	Summer	0.0	0.2	0.3	0.3	0.3
Small C&I	CPP w/Tech	Summer	0.0	0.6	0.7	0.7	0.8
Medium C&I	Third-Party DLC	Summer	5.2	46.1	49.6	53.6	57.1
Medium C&I	Curtailable Tariff	Summer	23.3	24.6	26.5	28.6	30.4
Medium C&I	CPP	Summer	0.0	6.1	6.7	7.2	7.7
Medium C&I	CPP w/Tech	Summer	0.0	10.9	11.9	12.9	13.7
Large C&I	Third-Party DLC	Summer	7.0	62.8	68.6	75.1	80.7
Large C&I	Curtailable Tariff	Summer	75.5	80.4	87.8	96.1	103.3
Large C&I	CPP	Summer	0.0	11.4	12.6	13.8	14.9
Large C&I	CPP w/Tech	Summer	0.0	29.6	32.9	36.0	38.7
Agricultural	Pumping Load Control	Summer	0.5	3.8	3.5	3.2	2.9
Agricultural	TOU	Summer	0.0	0.3	0.3	0.2	0.2

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0%	1.2%	1.1%	1.1%	1.1%
Residential	PTR	Summer	0.0%	2.6%	2.6%	2.5%	2.5%
Residential	PTR w/Tech	Summer	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Summer	0.0%	2.1%	2.1%	2.0%	2.0%
Residential	CPP w/Tech	Summer	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Summer	1.3%	1.1%	1.0%	1.0%	1.0%
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP w/Tech	Summer	0.0%	1.1%	1.1%	1.1%	1.1%
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0%	1.1%	1.2%	1.2%	1.2%
Large C&I	CPP w/Tech	Summer	0.0%	2.3%	2.4%	2.5%	2.5%
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	0.3%	3.0%	3.2%	3.3%	3.4%
Residential	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Water Heating DLC	Summer	0.1%	0.9%	0.9%	0.8%	0.8%
Residential	AC/Space Heating DLC	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	TOU	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Residential	PTR	Summer	0.0%	1.2%	1.2%	1.2%	1.1%
Residential	PTR w/Tech	Summer	0.0%	0.4%	0.4%	0.3%	0.3%
Residential	CPP	Summer	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Summer	0.0%	0.3%	0.3%	0.3%	0.2%
Residential	BYOT - AC	Summer	0.1%	1.2%	1.2%	1.2%	1.2%
Residential	BYOT - Space Heating	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - AC/Space Heating	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Residential	Smart Water Heater DLC	Summer	0.0%	0.2%	0.5%	0.8%	1.1%
Residential	Electric Vehicle DLC	Summer	0.0%	0.0%	0.1%	0.1%	0.2%
Small C&I	AC DLC	Summer	0.0%	0.4%	0.4%	0.4%	0.4%
Small C&I	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Water Heating DLC	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Summer	0.1%	1.3%	1.3%	1.3%	1.4%
Medium C&I	Curtailable Tariff	Summer	0.7%	0.7%	0.7%	0.7%	0.7%
Medium C&I	CPP	Summer	0.0%	0.2%	0.2%	0.2%	0.2%
Medium C&I	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Summer	0.2%	1.7%	1.8%	1.9%	1.9%
Large C&I	Curtailable Tariff	Summer	2.1%	2.2%	2.3%	2.4%	2.5%
Large C&I	CPP	Summer	0.0%	0.3%	0.3%	0.3%	0.4%
Large C&I	CPP w/Tech	Summer	0.0%	0.8%	0.9%	0.9%	0.9%
Agricultural	Pumping Load Control	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0	61.7	62.8	64.1	65.2
Residential	PTR	Winter	0.0	136.2	138.9	141.8	144.1
Residential	PTR w/Tech	Winter	0.0	24.6	25.0	25.6	26.0
Residential	CPP	Winter	0.0	109.4	111.3	113.6	115.5
Residential	CPP w/Tech	Winter	0.0	21.2	21.6	22.1	22.4
Residential	Behavioral DR	Winter	65.6	54.6	55.7	56.9	57.9
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0	0.5	0.5	0.5	0.6
Small C&I	PTR	Winter	0.0	1.7	1.8	1.9	2.0
Small C&I	PTR w/Tech	Winter	0.0	2.7	2.9	3.1	3.3
Small C&I	CPP	Winter	0.0	0.8	0.9	0.9	1.0
Small C&I	CPP w/Tech	Winter	0.0	1.6	1.7	1.8	1.9
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0	18.1	19.2	20.7	22.0
Medium C&I	CPP w/Tech	Winter	0.0	31.8	33.9	36.5	38.8
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0	35.4	38.2	41.6	44.7
Large C&I	CPP w/Tech	Winter	0.0	72.5	78.4	85.5	91.7
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	Space Heating DLC	Winter	2.3	20.1	21.2	22.4	23.3
Residential	Water Heating DLC	Winter	7.2	61.9	64.5	67.6	70.4
Residential	AC/Space Heating DLC	Winter	1.7	15.4	16.2	17.1	17.9
Residential	TOU	Winter	0.0	33.0	34.3	35.0	35.6
Residential	PTR	Winter	0.0	61.0	63.4	64.7	65.8
Residential	PTR w/Tech	Winter	0.0	13.4	13.9	14.2	14.5
Residential	CPP	Winter	0.0	45.4	47.2	48.2	49.0
Residential	CPP w/Tech	Winter	0.0	10.0	10.4	10.6	10.8
Residential	Behavioral DR	Winter	1.6	13.6	13.9	14.2	14.5
Residential	BYOT - AC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - Space Heating	Winter	1.4	12.6	13.2	14.0	14.6
Residential	BYOT - AC/Space Heating	Winter	1.1	9.6	10.1	10.7	11.2
Residential	Smart Water Heater DLC	Winter	0.2	15.1	41.1	67.5	88.9
Residential	Electric Vehicle DLC	Winter	0.3	0.9	2.0	3.5	5.0
Small C&I	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Small C&I	Space Heating DLC	Winter	0.7	6.0	6.5	7.1	7.5
Small C&I	Water Heating DLC	Winter	0.2	1.3	1.4	1.5	1.6
Small C&I	AC/Space Heating DLC	Winter	0.5	4.3	4.6	5.0	5.3
Small C&I	TOU	Winter	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Winter	0.0	0.5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Winter	0.0	0.9	1.0	1.1	1.1
Small C&I	CPP	Winter	0.0	0.3	0.3	0.3	0.4
Small C&I	CPP w/Tech	Winter	0.0	0.4	0.5	0.5	0.6
Medium C&I	Third-Party DLC	Winter	4.2	38.1	40.9	44.1	46.8
Medium C&I	Curtailable Tariff	Winter	19.0	20.3	21.8	23.5	25.0
Medium C&I	CPP	Winter	0.0	5.0	5.5	5.9	6.3
Medium C&I	CPP w/Tech	Winter	0.0	9.0	9.8	10.6	11.2
Large C&I	Third-Party DLC	Winter	6.0	54.3	59.2	64.5	69.2
Large C&I	Curtailable Tariff	Winter	64.3	69.5	75.7	82.6	88.6
Large C&I	CPP	Winter	0.0	9.8	10.9	11.9	12.8
Large C&I	CPP w/Tech	Winter	0.0	25.6	28.4	31.0	33.2
Agricultural	Pumping Load Control	Winter	0.0	0.0	0.0	0.0	0.0
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR	Winter	0.0%	3.7%	3.6%	3.5%	3.4%
Residential	PTR w/Tech	Winter	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Winter	0.0%	3.0%	2.9%	2.8%	2.7%
Residential	CPP w/Tech	Winter	0.0%	0.6%	0.6%	0.5%	0.5%
Residential	Behavioral DR	Winter	1.8%	1.5%	1.4%	1.4%	1.4%
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0%	0.5%	0.5%	0.5%	0.5%
Medium C&I	CPP w/Tech	Winter	0.0%	0.9%	0.9%	0.9%	0.9%
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0%	1.0%	1.0%	1.0%	1.1%
Large C&I	CPP w/Tech	Winter	0.0%	2.0%	2.0%	2.1%	2.2%
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Space Heating DLC	Winter	0.1%	0.5%	0.5%	0.6%	0.6%
Residential	Water Heating DLC	Winter	0.2%	1.7%	1.7%	1.7%	1.7%
Residential	AC/Space Heating DLC	Winter	0.0%	0.4%	0.4%	0.4%	0.4%
Residential	TOU	Winter	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	PTR	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR w/Tech	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	CPP	Winter	0.0%	1.2%	1.2%	1.2%	1.2%
Residential	CPP w/Tech	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	BYOT - AC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	BYOT - AC/Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Smart Water Heater DLC	Winter	0.0%	0.4%	1.1%	1.7%	2.1%
Residential	Electric Vehicle DLC	Winter	0.0%	0.0%	0.1%	0.1%	0.1%
Small C&I	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Space Heating DLC	Winter	0.0%	0.2%	0.2%	0.2%	0.2%
Small C&I	Water Heating DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	0.1%	1.0%	1.1%	1.1%	1.1%
Medium C&I	Curtailable Tariff	Winter	0.5%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	CPP w/Tech	Winter	0.0%	0.2%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Winter	0.2%	1.5%	1.5%	1.6%	1.6%
Large C&I	Curtailable Tariff	Winter	1.8%	1.9%	2.0%	2.0%	2.1%
Large C&I	CPP	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	CPP w/Tech	Winter	0.0%	0.7%	0.7%	0.8%	0.8%
Agricultural	Pumping Load Control	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Benefit-Cost Ratios

Opt-out Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	N/A
Residential	Space Heating DLC	N/A
Residential	Water Heating DLC	N/A
Residential	AC/Space Heating DLC	N/A
Residential	TOU	1.24
Residential	PTR	1.49
Residential	PTR w/Tech	0.86
Residential	CPP	1.15
Residential	CPP w/Tech	0.83
Residential	Behavioral DR	1.04
Residential	BYOT - AC	N/A
Residential	BYOT - Space Heating	N/A
Residential	BYOT - AC/Space Heating	N/A
Residential	Smart Water Heater DLC	N/A
Residential	Electric Vehicle DLC	N/A
Small C&I	AC DLC	N/A
Small C&I	Space Heating DLC	N/A
Small C&I	Water Heating DLC	N/A
Small C&I	AC/Space Heating DLC	N/A
Small C&I	TOU	0.11
Small C&I	PTR	0.30
Small C&I	PTR w/Tech	0.82
Small C&I	CPP	0.11
Small C&I	CPP w/Tech	0.60
Medium C&I	Third-Party DLC	N/A
Medium C&I	Curtailable Tariff	N/A
Medium C&I	CPP	4.80
Medium C&I	CPP w/Tech	1.76
Large C&I	Third-Party DLC	N/A
Large C&I	Curtailable Tariff	N/A
Large C&I	CPP	42.10
Large C&I	CPP w/Tech	7.15
Agricultural	Pumping Load Control	N/A
Agricultural	TOU	0.83

Benefit-Cost Ratios

Opt-in Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	1.12
Residential	Space Heating DLC	1.31
Residential	Water Heating DLC	1.30
Residential	AC/Space Heating DLC	1.82
Residential	TOU	1.24
Residential	PTR	1.75
Residential	PTR w/Tech	1.32
Residential	CPP	1.62
Residential	CPP w/Tech	1.49
Residential	Behavioral DR	0.85
Residential	BYOT - AC	1.94
Residential	BYOT - Space Heating	1.98
Residential	BYOT - AC/Space Heating	2.43
Residential	Smart Water Heater DLC	2.22
Residential	Electric Vehicle DLC	0.14
Small C&I	AC DLC	1.00
Small C&I	Space Heating DLC	1.07
Small C&I	Water Heating DLC	0.79
Small C&I	AC/Space Heating DLC	1.40
Small C&I	TOU	0.06
Small C&I	PTR	0.17
Small C&I	PTR w/Tech	0.79
Small C&I	CPP	0.08
Small C&I	CPP w/Tech	0.55
Medium C&I	Third-Party DLC	1.59
Medium C&I	Curtailable Tariff	5.37
Medium C&I	CPP	1.94
Medium C&I	CPP w/Tech	1.38
Large C&I	Third-Party DLC	1.57
Large C&I	Curtailable Tariff	6.30
Large C&I	CPP	14.42
Large C&I	CPP w/Tech	6.70
Agricultural	Pumping Load Control	0.78
Agricultural	TOU	0.29