Retail Pricing: A Low Cost Approach to Load Flexibility

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Primary Mission of Retail Pricing

First and foremost function of retail rates is to recover utility's revenue requirement in the most economically efficient and equitable fashion

At the same time, rates should reflect the structure of the costs incurred to serve them and lead to **efficient price signals** to:

- Encourage optimal consumption decisions;
- Lead to bill stability for customers and revenue stability for utilities; and
- Be easily understandable by customers

When the rate construct is laden with other objectives, such as incentivizing new technologies and subsidizing certain customer groups, they start to **fall short of delivering on their primary mission**, may lead to inter- and intra-class cost shifts, and convey inefficient price signals that lead to over- or under-consumption of electricity

Cost-reflectivity is not be compromised for efficient price signals

There are various alternatives to standard volumetric rates, many of which are time-varying rates and are enabled by AMI

Rate	Definition
1- Time-of-Use *(TOU)*	The day is divided into peak and off-peak time periods. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period
2- Critical Peak Pricing *(CPP)*	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed
3- Peak Time Rebates *(PTR)*	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their “baseline”)
4- Variable Peak Pricing *(VPP)*	During alternative peak days, customers pay a rate that varies by day to reflect dynamic variations in the cost of electricity
5- Real-Time Pricing *(RTP)*	Customers pay prices that vary by the hour to reflect the actual cost of electricity
6- Two-part Real-Time Pricing *(2-part RTP)*	Customer’s current rate applies to a baseline level of consumption. A second, marginal cost based, price applies to deviations from the baseline consumption
7- Three-part Rates *(3-part Rates)*	In addition to volumetric energy charge and fixed charge, customers are also charged based on peak demand, typically measured over a span of 15, 30, or 60 minutes
8- Fixed Bill with Incentives	Customers pay a fixed monthly bill accompanied with tools for lowering the bill (such as incentives for lowering peak usage)

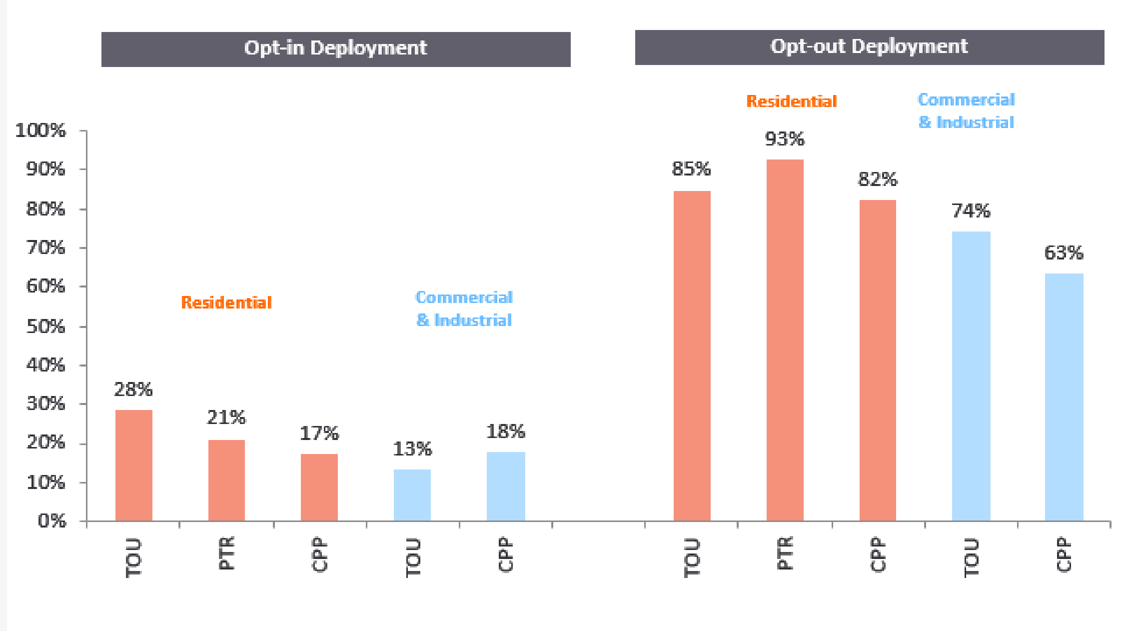
Residential TVRs have been deployed around North America and the rest of the world

	Type of Rate	Applicability	Participating Customers
Oklahoma *(OGE)*	Variable Peak Pricing (VPP)	Opt-in	20% (130,000)
Maryland *(BGE, Pepco, Delmarva)*	Peak Time Rebate (PTR)	Default	80%
Ontario, Canada	Time-of-Use (TOU)	Default	90% (3.6 million)
Great Britain	Time-of-Use (TOU)	Opt-in	13% (3.5 million)
Hong Kong *(CLP Power Limited)*	Peak Time Rebate (PTR)	Opt-in	27,000
Arizona *(APS, SRP)*	Time-of-Use (TOU)	Opt-in	APS: 57%, SRP: 36%
California *(PG&E, SCE, SDG&E)*	Time-of-Use (TOU)	Default (2020)	TBD – 75-90%*
California *(SMUD)*	Time-of-Use (TOU)	Default	75-90%*
Colorado *(Fort Collins)*	Time-of-Use (TOU)	Mandatory	100%
Illinois *(ComEd, Ameren IL)*	Real Time Pricing (RTP)	Opt-in	50,000
Michigan *(Consumers Energy)*	Time-of-Use (TOU)	Default (2020)	TBD – 75-90%*
France	Time-of-Use (TOU)	Opt-in	50%
Spain	Real Time Pricing (RTP)	Default	40%
Italy	Time-of-Use (TOU)	Default	75-90%*

While there are a handful of states offering default TVRs on a mandatory or default basis, TVRs are most commonly offered as opt-in rates at this time

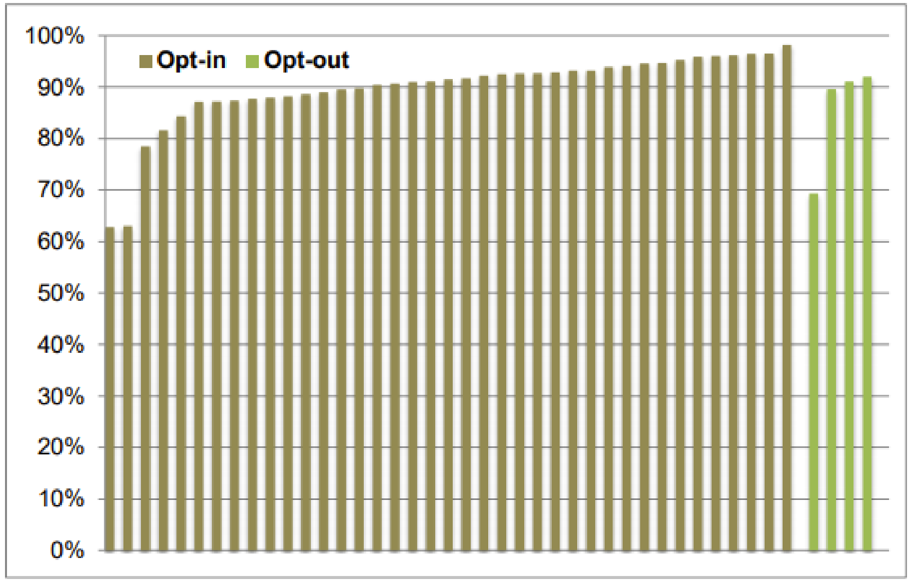
Enrollment in Time-Varying Rates

(Average Across 6 Market Research Studies and 14 Full Scale Deployments)



- **TVR opt-in rates** are around 20% for residential and 15% for C&I customers
- **TVR opt-out rates** are around 85% for residential and 70% for C&I customers

Retention Rates by Treatment Type: Opt-in vs. Opt-out



- A DOE Meta Study (*) on 10 TVR pilots found that, while adoption and enrollment rates are lower under opt-in deployment compared to opt-out, retention is slightly higher

(*)DOE LBNL, "Final Report on Customer Acceptance, Retention, and Response to Time Based Rates from the Consumer Behavior Studies , November 2016

https://www.energy.gov/sites/prod/files/2017/01/f34/CBS_Final_Program_Impact_Report_20161107.pdf

U.S. Benchmark for the Residential and Commercial TVRs

According to 2022 EIA Form-861, **380 U.S. utilities offer at least one form of time-varying rate** to residential customers

- 347 offer Time-of-Use (TOU)
- 28 offer Critical Peak Pricing (CPP)
- 14 offer Peak Time Rebate (PTR)
- 7 offer Variable Peak Pricing (VPP)
- 33 offer Real-Time Pricing (RTP)

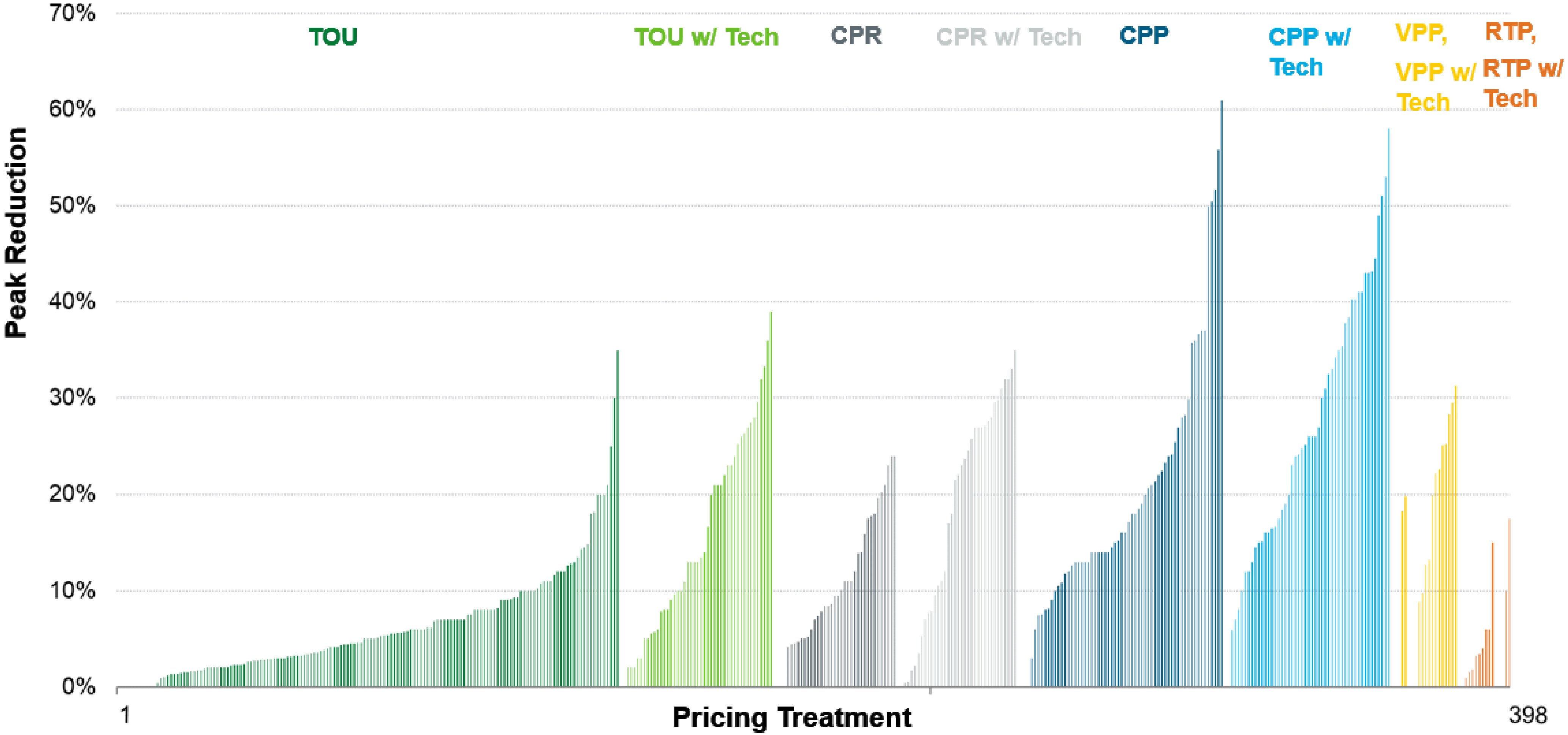
Altogether, **13.1 million customers** (or 9% of all residential customers) are enrolled on one of these time-varying rates

According to 2022 EIA Form-861, **580 U.S. utilities offer at least one TVP to their** commercial customers

- 420 offer Time-of-Use (TOU)
- 42 offer Critical Peak Pricing (CPP)
- 12 offer Peak Time Rebate (PTR)
- 14 offer Variable Peak Pricing (VPP)
- 125 offer Real Time Pricing (RTP)

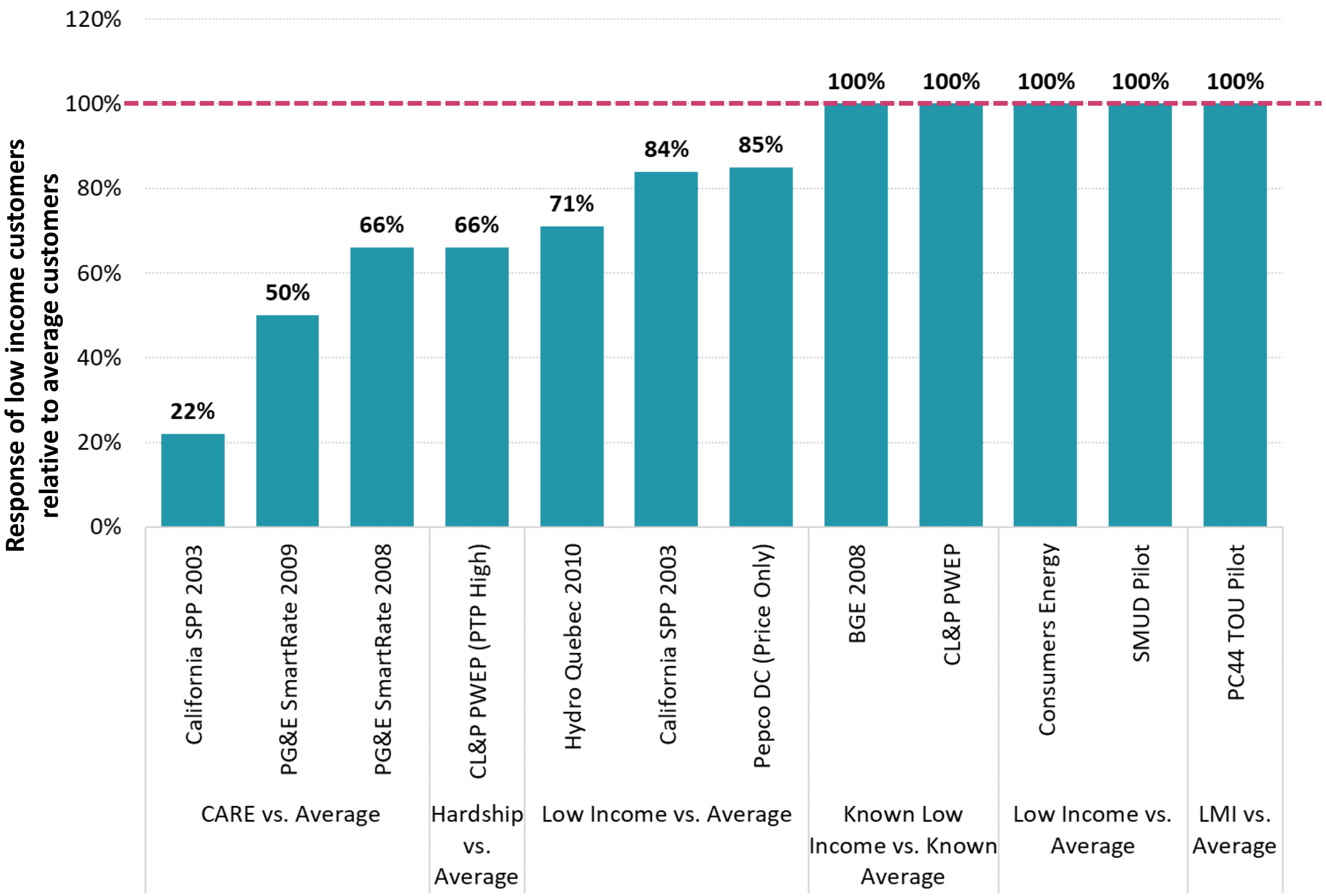
Altogether, **approximately 2 million customers** (12% of commercial customers served by these utilities) are enrolled on one of these commercial TVPs

There is compelling evidence from ~400 treatments that residential customers respond to TVRs



Source: Results from 79 pricing pilots and programs and 398 individual treatments in the Arcturus database.

Low income customers respond to TVRs, in many cases as much as average customers



Notes: For the Pepco DC pilot, the average residential response excludes low income customers from RAD program. The average population for Hydro Quebec and Consumers Energy refers to specifically residential customers.

Whether the low income customers can respond to TVRs is a contentious question that come up in many stakeholder discussions

Several pilots included specific treatment groups for low and (sometimes low and moderate) income customers (i.e. Maryland PC44 TOU Pilot)

Evidence shows that low income customers do respond to the TVRs and in some cases as much as average customers on a percentage basis

Retail Rates as a Load Flexibility Resource

While it is typical to think of **cost-causation** as a backward-looking concept for cost allocation, it is equally **forward-looking**

- How costs are allocated also affects price signals, which in turn affects future demand and system costs

Given the overwhelming evidence on customer response to price signals, **time varying rates** (TVR) emerge as an important and cost-effective load flexibility resource (especially for jurisdictions with AMI)

- As customers respond to time-varying price signals and move their consumption from high-priced periods to low-priced periods, they help avoid future generation, transmission and distribution capacity costs, reduce energy costs, help with the integration of renewable resources by reducing curtailments

Different rate designs meet different objectives

Rate Design	Cost causation	Customer Orientation	Equity	Revenue Stability	Bill Stability	Load Flexibility
TOU	M	M	M	M	M	M
CPP	M	L	M	M	L	M
PTR	L	H	H	L	H	M
RTP	H	L	L	H	L	H
Three-part rate	H	L	L	H	L	L
Fixed bill with incentives	L	H	M	H	H	L

Winter-peaking utility experience with TVPs has been limited historically, but this is changing rapidly

	Study Years	Form(s) of TVP	Peak Price Ratio	Peak Impact	Notes
BC Hydro	2006-2008	TOU, TOU/CPP	*TOU:* 3-6 *CPP:* 7.9	2%-4% reduction in on-peak TOU period, 5% in critical peak period	Analysis of the second winter found that enabling tech (in-home display) doubled estimated TOU and CPP reductions
Hydro-Québec	2008-2010	TOU, TOU/CPP	*TOU:* 1.4-1.7 *CPP:* 3	Only significant in critical peak period under TOU/CPP rate (~6% reduction)	Hydro-Québec is now gradually offering opt-in PTR and CPP rates, detailed in a later slide
Portland General Electric	2016-2018	TOU, PTR, TOU/PTR	*TOU:* 1.8-2.6	*TOU:* Only statistically significant in summer *PTR:* 7%-12% winter demand savings for opt-in, 5% for opt-out PTR *TOU/PTR:* 1%-5%	Usage reductions were less significant in winter than summer, in part because approximately 60% of TOU participants have gas heating
Hydro-Québec	2019-2021	PTR, CPP	6.8 and 7.7	~22% reduction in peak during winter period per event	Offers both PTR and CPP options to accommodate the preferences of both risk-taking and risk-averse customers. Overall survey show that 60% + customers were satisfied with the rate offering.
Nova Scotia Power	2021-2023	TOU, CPP	1.96 and 10.76 (residential)	TOU: 10.1% (morning) and 8.8% (evening) CPP: 27% (morning) and 29% (evening)	Residential TOU and CPP participants achieved greater load reductions during peaks that coincided with the highest Adjusted Net Load (ANL) hours compared to all other peak periods. CPP participants achieved significant reductions in electricity usage levels on event days throughout winter and, to a lesser extent, in summer.

Winter price response is becoming exceedingly important

- **Building electrification** being the centerpiece of decarbonization plans, summer-peaking systems are starting to switch to winter-peaking systems
- As the **penetration of solar increases** in the generation portfolio, we need more "flexibility" in the system, especially in the winter months
- **Gas shortages** are exceedingly straining winter resource adequacy, especially during extreme weather events

Time varying rates are an important but an <u>underutilized</u> tool in our tool kit to manage the impact of energy transition and extreme weather events

*It takes time to build a robust portfolio of price responsive demand; time to start is **NOW** if the efforts are not already underway*

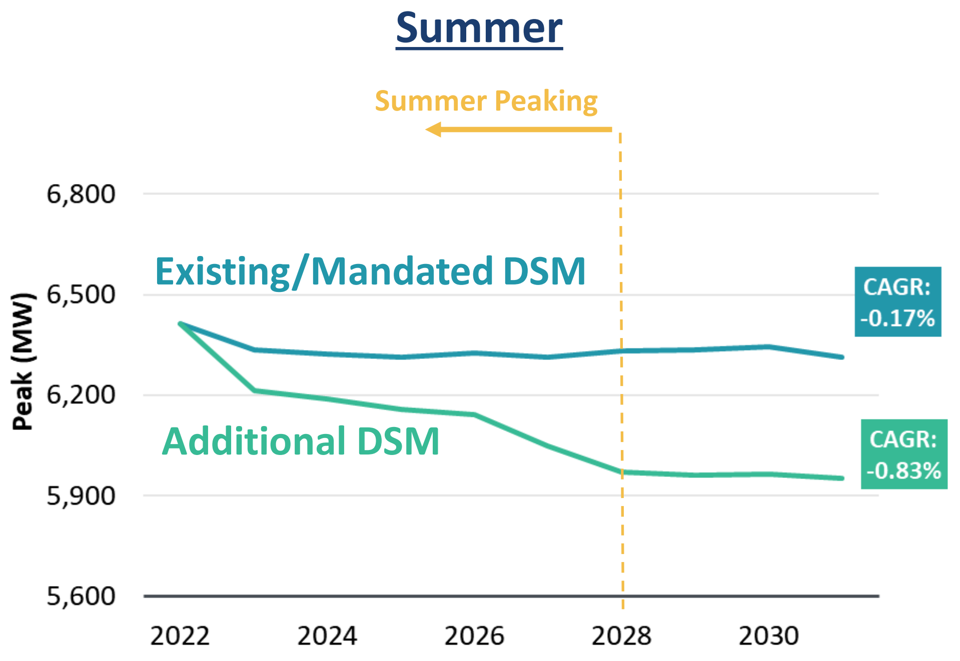
Advancing electrification rapidly may backfire, if we don't have reliable and affordable electricity to power heating and transportation systems

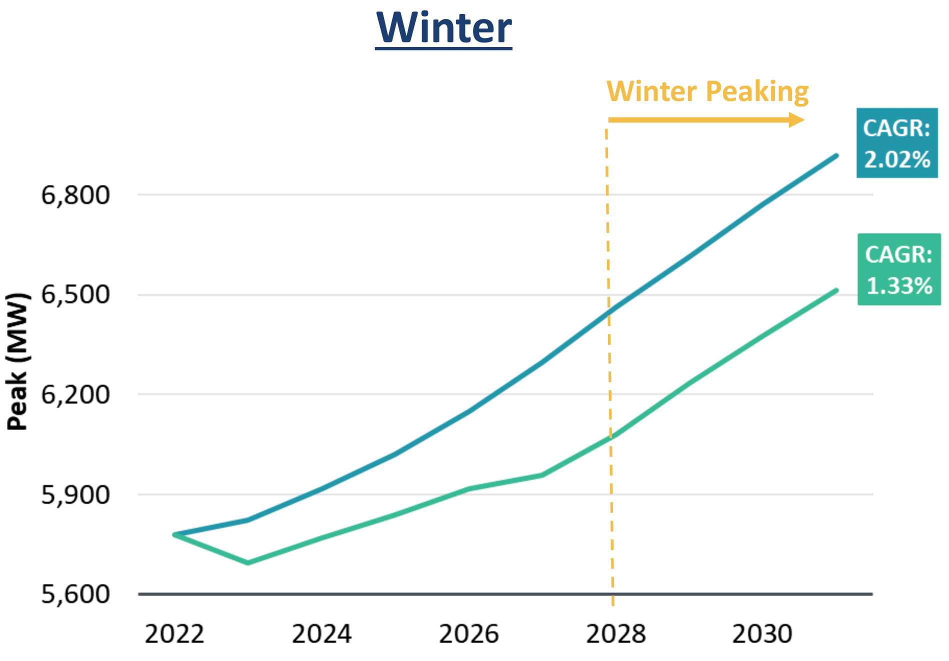
S.0 – Reference
S.1 – Low electrification
S.2A – Mid electrification
S.2B – High electrification w/ fossil backup
S.3A – High electrification w/ best-in-class tech
S.3B – High electrification w/ legacy tech

Impact of Load Flexibility in Managing Load Growth

BGE Summer and Winter Peak Loads with Existing/Mandated and Additional DSM

High Electrification with Best-in-Class Technologies Scenario (S.3A)





Source: "An Assessment of Electrification Impacts on the Maryland Electric Grid", Brattle Group, 2023, prepared for Maryland PSC.
https://www.psc.state.md.us/wp-content/uploads/Corrected-MDPSC-Electrification-Study-Report-2.pdf

Note: BAU and High scenarios switch from Summer to Winter peaking in 2028

MD PSC Electrification Study Load Flexibility Participation Assumptions

Additional DSM Programs Case participation ramps up from current levels (low for most utility programs) to end state participation by 2031, following S-curve adoption

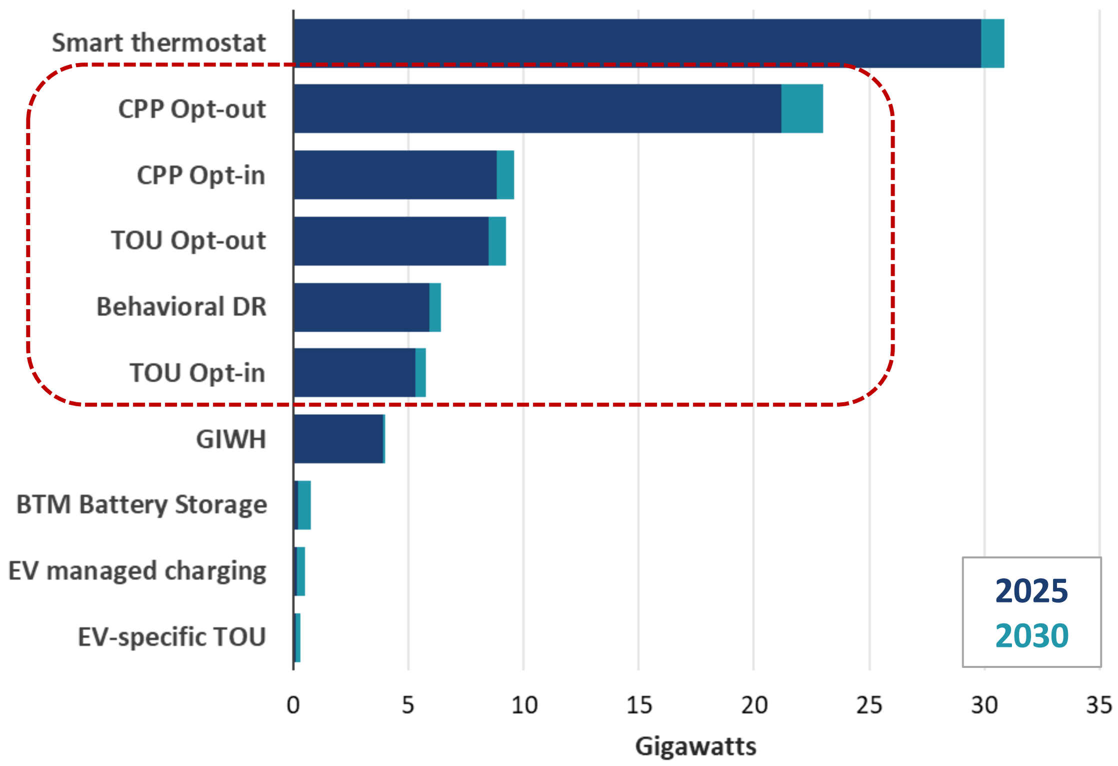
Program	Description	Existing Participation	Additional Case Participation
Residential			
Time-of-use (TOU)	Time varying pricing signals, consistent with proposed utility rates	0%	15%
Peak time rebate (PTR)	Residential customers reduce load during called event hours	BGE, Pepco, DPL: 90% (assume limited use of the program and that impacts are not reflected in utility forecasts) SMECO, Choptank, Potomac Edison: 0%	90%
Smart thermostat	Customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	Summer: BGE (28%, 342,000 customers); Pepco (38%, 206,012 customers); DPL (20%, 33,844 customers); SMECO, Choptank, Potomac Edison (0%) Winter: 0% for all utilities	Summer (~+25%pt from existing): BGE (55%); Pepco (65%); DPL (45%); SMECO, Choptank, Potomac Edison (25%) Winter: 25% for all utilities
Smart water heating	Customers shift heat water during off peak hours on a frequent (daily) basis	0%	30%
Commercial			
Smart thermostat	Small commercial customers reduce cooling or heating load by adjusting thermostats during utility called events (<20/yr)	0%*	25%
Automated demand response (DR) – HVAC	Automated control of customer heating and cooling demand. Only applicable to large (Covered) customers	0%	10%
Interruptible tariff	Large customers (Covered) reduce load during called events. Events are infrequent (<10/yr)	0%	15%
Additional Programs			
Managed electric vehicle charging	Customers are incentivized to charge in off peak hours and shift EV load out of daily peak periods	0%	30% (all vehicle classes)
Behind-the-meter battery storage	Utilities can call on batteries to charge and discharge during event hours (70 events/yr). Assume only a portion of BTM storage capacity from the PPRP study enrolls in utility programs	0%	30% of BTM storage capacity

*Note: Pepco and DPL have commercial smart thermostat programs, but participation is negligible. Participation expressed as % of eligible customers.

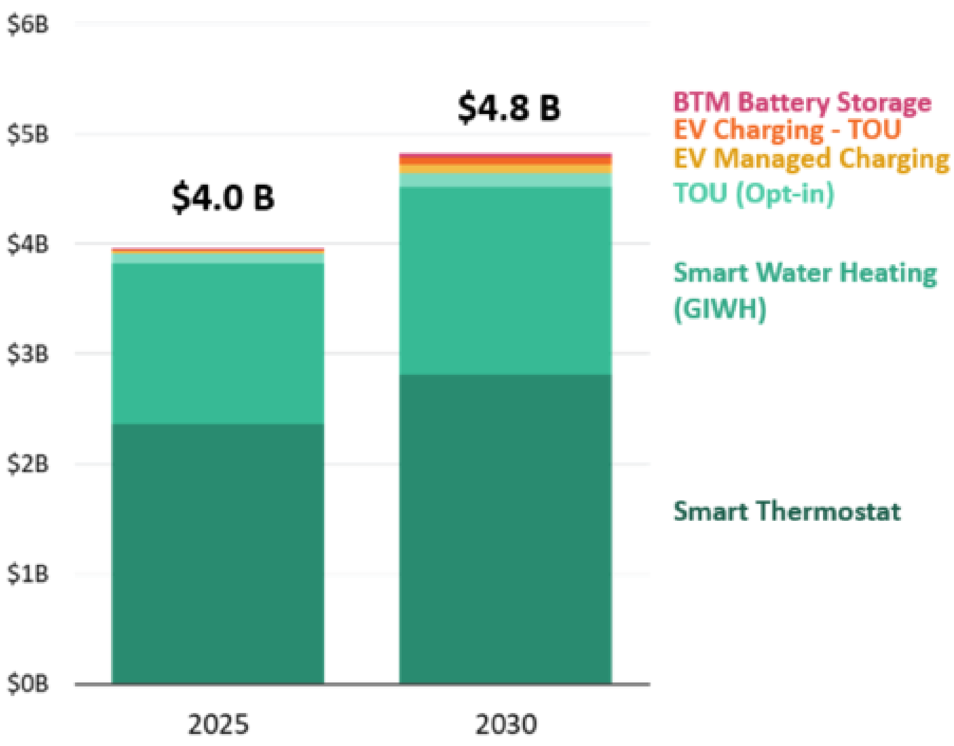
Residential Load Flexibility Potential

While smart thermostats and water heaters lead to the largest value, time varying rates may provide a significant value based on the rate type and deployment approach

System Peak Reduction Capability



Annual Value, by Program Type



The potential estimates are based on achievable levels of adoption, but do not account for the cost-effectiveness of the options. Load flexibility value in nominal dollars.
Source: Brattle LoadFlex Model

What comes next?

- We are rapidly nearing the important "**prices-to-devices**" breakthrough in which the devices respond to real-time prices based on the preprogrammed set-points reflecting customer preferences
  - Even then there will still be customers who prefer to self-manage their consumption, and not to rely on devices or aggregators. Providing many options/choices will be key
- In the meantime, **TOU plus CPP rate** might be most suitable for the needs of most systems with increasing renewable penetration
  - The TOU element would enable **daily load shifting** from high-priced to low-priced hours (or high net load to low net load hours), while CPP elements would be activated on a select number of extreme days when **system capacity is constrained**
  - CPP events can be called to manage system peak needs, but they can also be called on a more localized level (i.e., covering a few substations) to **manage distribution system constraints**
- Utilities should work on time-varying rate proposals while they complete AMI deployments to ensure they can offer TVRs soon after deployment
- Managing winter peak load through pricing signals will be paramount especially given ambitious goals for building and heating transportation
  - Material energy and peak savings can be achieved by small behavioral changes in response to price signals from many customers (such as a default TOU rate)

Clarity in the face of complexity

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