

A walk on the frontier of rate design

PRESENTED TO

Western Farmers Electric Cooperative's Residential Demand
Workshop
Oklahoma City, Oklahoma

PRESENTED BY

Ahmad Faruqui
Cody Warner

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THE **Brattle** GROUP

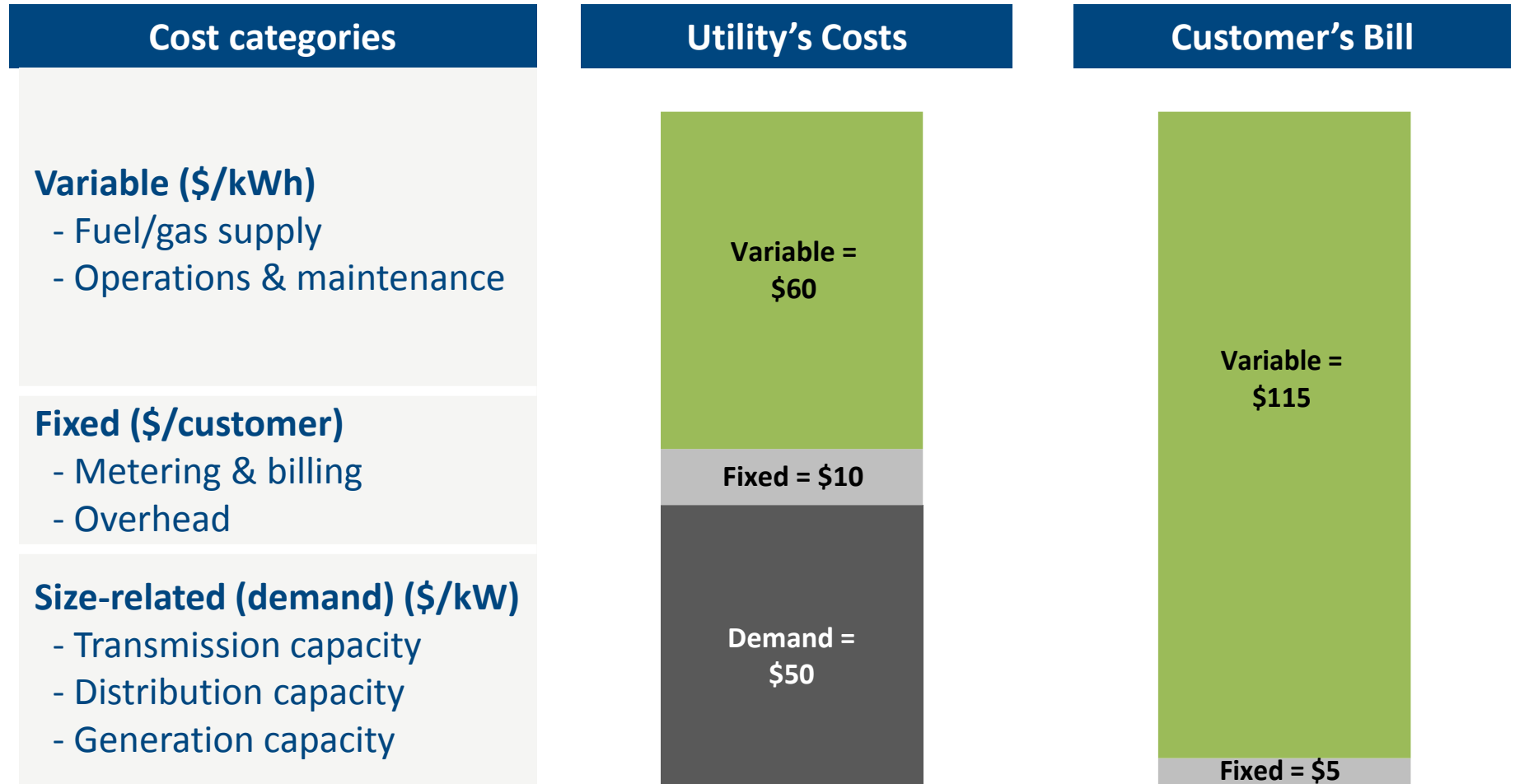
It is the 2nd decade of the 21st century

Most customers have Amazon, Google, smart phones, Netflix and Wi-Fi in their homes

- Many customers have video cameras for home security, smart thermostats, and smart appliances
 - Some customers have PV panels on the roof and many more are giving PVs much thought
 - A few customers have EVs in the driveway and several others are considering EVs the next time they buy a car
 - A handful of customers are toying with the idea of putting batteries in the garage

All customers, especially the Millennials, want greater control over their lives

But just about all these customers face electricity rates that are “so last century”



Behavioral economics tells us that customers have diverse preferences

Some want the lowest price

- They are willing to be flexible in the manner in which they use electricity

Some want to lock in a guaranteed bill

- They are willing to pay a premium for peace-of-mind

Many others are in between these two bookends

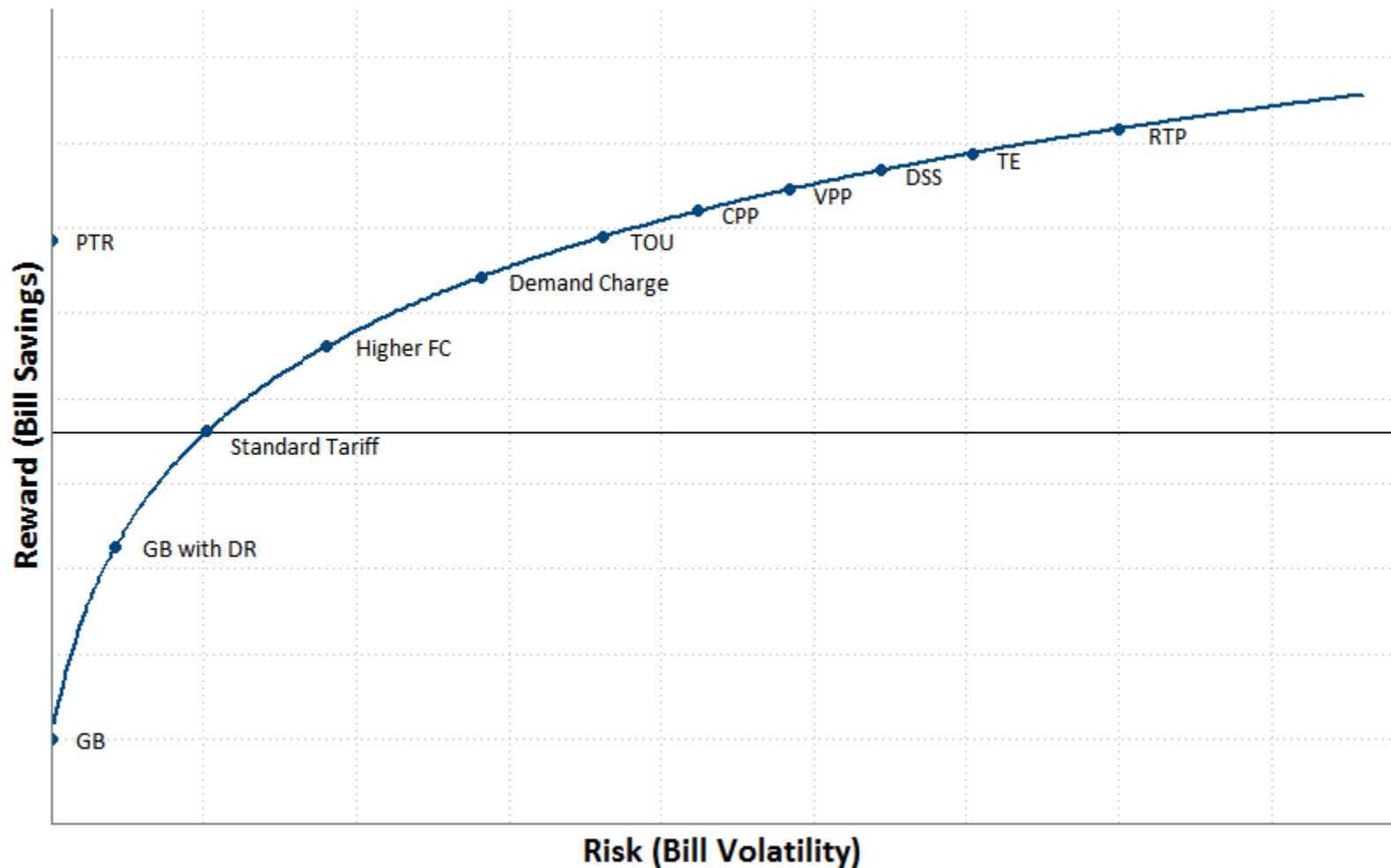
- Some might want a guaranteed bill but may be willing to lower it if rebates are offered for reducing demand during peak periods
- Others may wish to subscribe to a given level of demand

All customers want choice but *they only want what they want*

Using “design thinking,” a few utilities are beginning to offer innovative rate choices

- A Guaranteed bill (GB)
- B GB with discounts for demand response (DR)
- C Standard tariff
- D Increased fixed charge(| FC)
- E Demand charge
- F Time-of-Use (TOU)
- G Critical peak pricing (CPP)
- H Peak time rebates (PTR)
- I Variable peak pricing (VPP)
- J Demand subscription service (DSS)
- K Transactive energy (TE)
- L Real-time pricing (RTP)

These create an efficient pricing frontier, and customers can get what they want



Progress in Oklahoma

OGE rolled out a dynamic pricing rate coupled with a smart thermostat to its residential customers a few years ago

- “Smart Hours” features variable peak pricing, or five levels of peak pricing depending on what day type it happens to be

Some 130,000 customers are on that rate today; they control their thermostat setting, not OGE

- Average peak load has dropped by ~40%
- Average bill savings amount to ~20% of the customer's bill

Progress in Maryland

Both BGE and PHI offer dynamic pricing rebates of \$1.25/kWh to their customers in Maryland (~ 2 million households), and bid in the load reductions into the PJM market

At BGE, about 80% of its customers have taken advantage of the rebates and saved \$40 million in utility bills since the program began in 2013

In 2015, BGE's PTR customers showed an average demand reduction of 16.2%, up from 14.5% in 2014, and 13.7% in 2013

The Maryland Commission may authorize new pilots to be done with time-of-use rates

Progress in Ontario (Canada)

For the past five years, some 90% of Ontario's 4 million residential customers have been buying their energy through a regulated supply option, which features a three-period TOU rate

- They have reduced their peak demand by ~3%, based on a three-year analysis that we carried out for the IESO

Knowing the limitations of TOU rates, the Ontario Energy Board (OEB) has authorized dynamic pricing pilots that would allow those rates to be offered as supplements to the TOU rates

The OEB has ruled that distribution charges will be collected through a fixed charge

- The Texas PUC is watching the developments with interest

Progress in Australia

A distribution network in Victoria is offering significant rebates for dynamic demand curtailment during peak times (~ \$5/kWh curtailed)

- Avoiding costly upgrade on low load factor feeder
- Electricity rules say networks must consult alternative resources before building

Progress in the United Kingdom

UK Power Networks (London) is piloting a peak time rebate targeted specifically at low income customers

A couple of pilots have tested time-varying rates

- One rate featured a “wind twinning” tariff, which was intended to encourage consumption increases/decreases at times of unexpectedly high/low output from wind generation
- Some of the rates tested were dynamic in nature

Ofgem, the regulator, is looking at new ways to increase the role of price responsive demand, including the possible introduction of firms like Amazon and Google into the marketplace

Progress in the United Kingdom (concluded)

13% of customers are on a TOU rate (Economy 7) designed for customers with thermal energy storage

- The rate that has been offered for many years, is based on old technology, and the number of participants is in decline

A start-up retailer has introduced a TOU tariff with a strong price signal

British Gas offers a FreeTime tariff, which allows customers to pick one weekend day during which their electricity is free

A pilot tested the “Sunshine Tariff,” which charged a lower price during mid-day hours in an attempt to alleviate local distribution system constraints due to net excess solar generation

Progress in Hong Kong

Pilot with ~2,000 customers on PTR was carried out a few years ago

- It showed a peak reduction in the 15-20% range attributable to the dynamic rebate

The rollout of PTR is being expanded to some 27,000 customers

Modernizing rate design

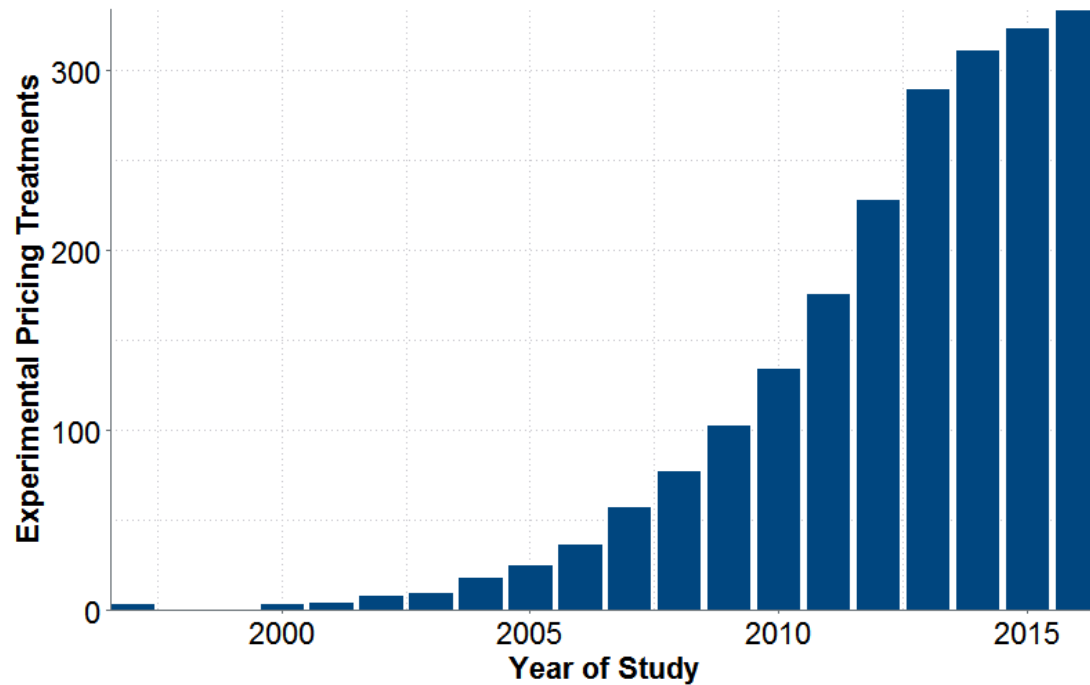
Any improvement in rate designs to make them more cost-reflective will instantly benefit some customers and instantly cost other customers

There is a special concern among policy makers about the impact on low income customers and customers with disabilities

Bill protection has often been offered to such customers and it has also been suggested as a mechanism to protect all customers in the near term

New cost-based rate designs have been tested across the globe

At least nine countries spanning four continents have tested more than 300 time-varying rates in 62 pilots



Source: Ahmad Faruqui , Sanem Sergici, and Cody Warner, "Arcturus 2.0: International Evidence on Time-Varying Rates," *The Electricity Journal*, 2017, forthcoming.

The magnitude of demand response varies by price ratio and rate design

Pilots feature a combination of rate designs

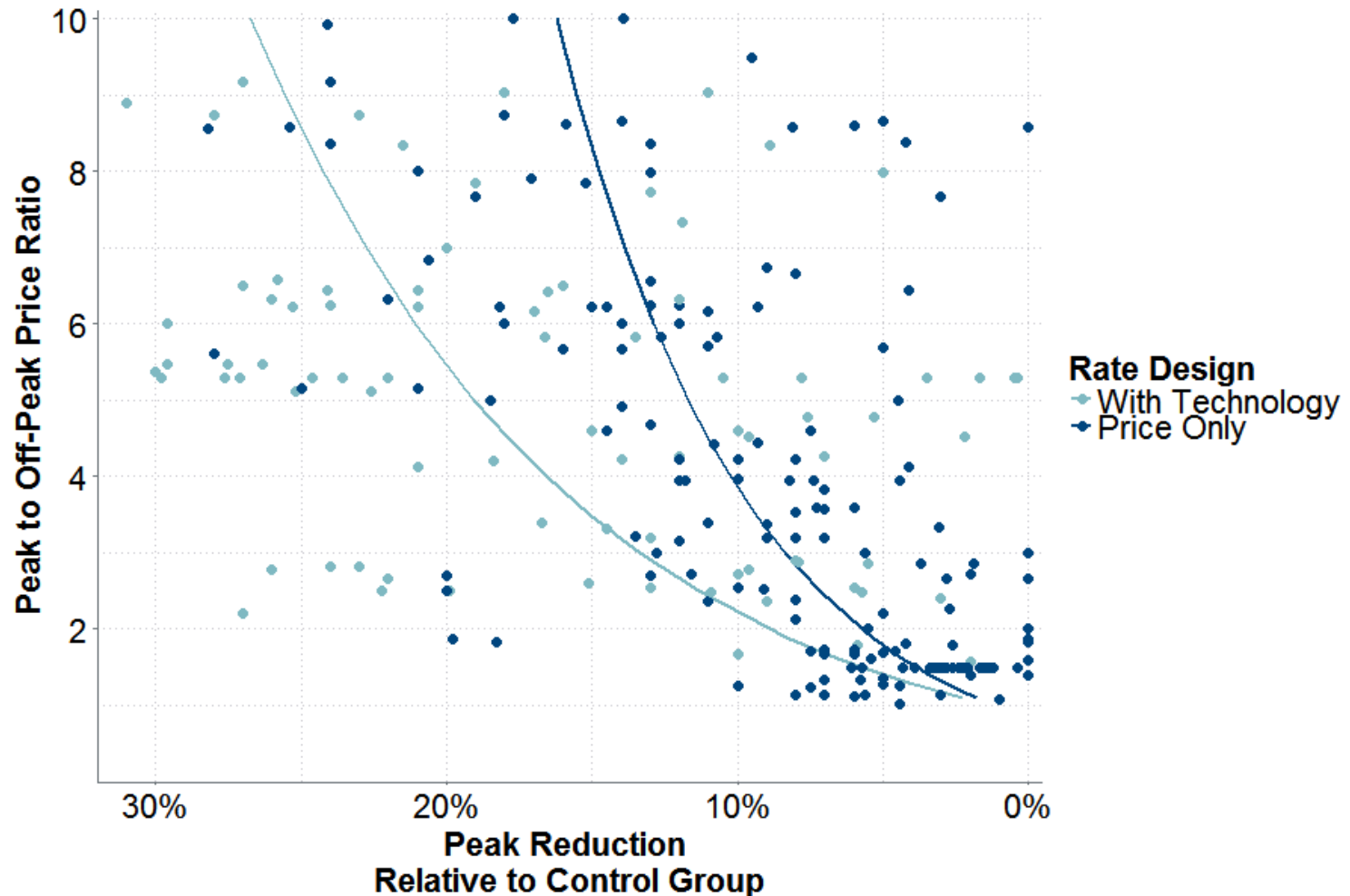
- Time-of-use, critical-peak pricing, peak-time rebates, and variable-peak pricing

On average, residential customers reduce their on-peak usage by 6.5% for every 10% increase in the peak-to-off-peak price ratio

In the presence of enabling technology, such as smart thermostats, the effect is stronger

- On average, customers enrolled on time-varying rates that offer enabling technologies reduce peak usage by 11.1% for every 10% increase in the price ratio

Price responsiveness follows a downward-sloping demand curve



Source: Ahmad Faruqui, Sanem Sergici and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," The Electricity Journal, 2017, forthcoming, 2017.

Demand charges

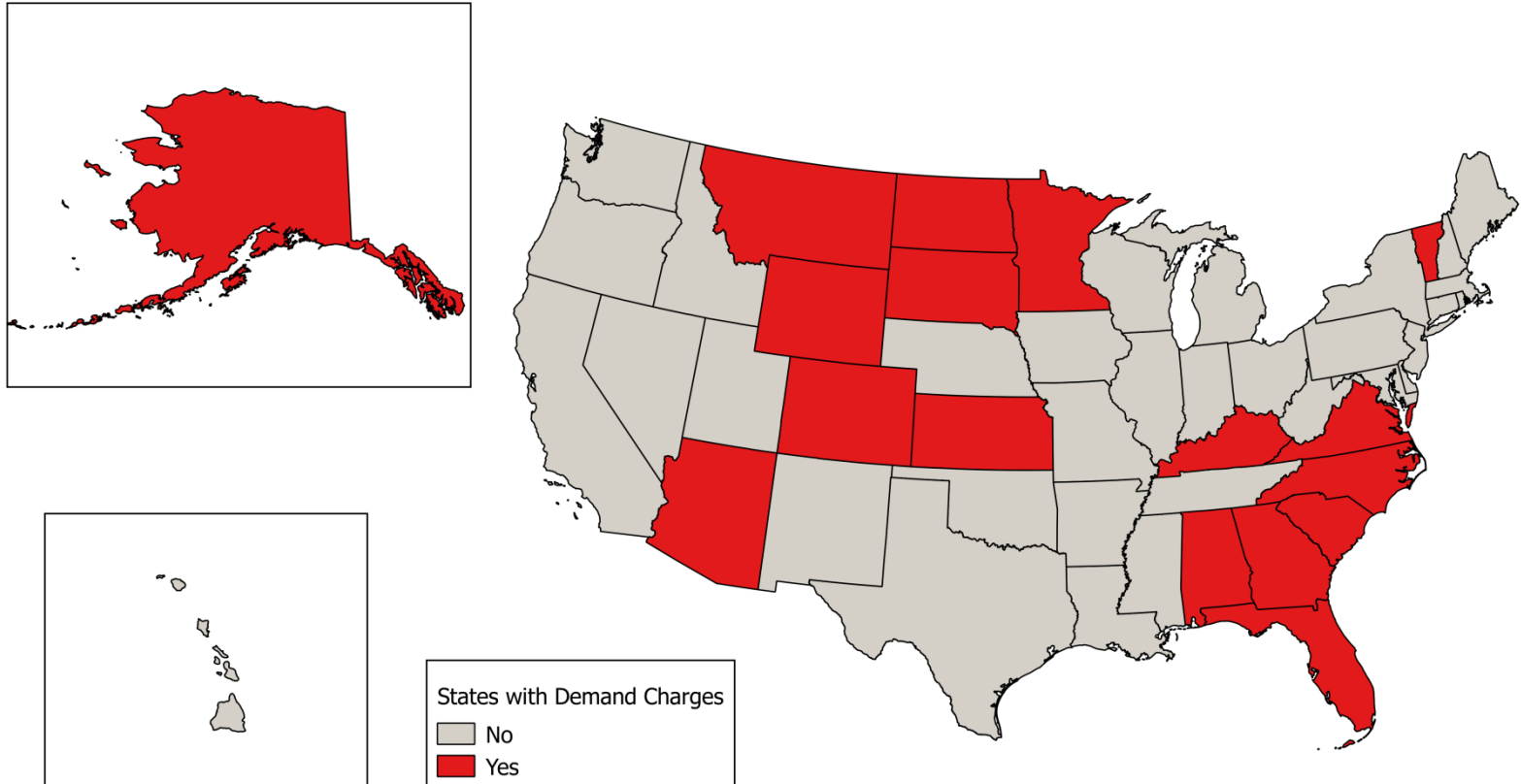
Capacity charges based on the size of the connection are mandatory for residential customers in France, Italy, and Spain

Demand charges are being offered by more than 30 utilities in the United States, including a few rural cooperatives

Utilities such as Arizona Public Service, NV Energy, and Westar Energy have filed applications to make them a mandatory tariff for customers with PVs on their roof

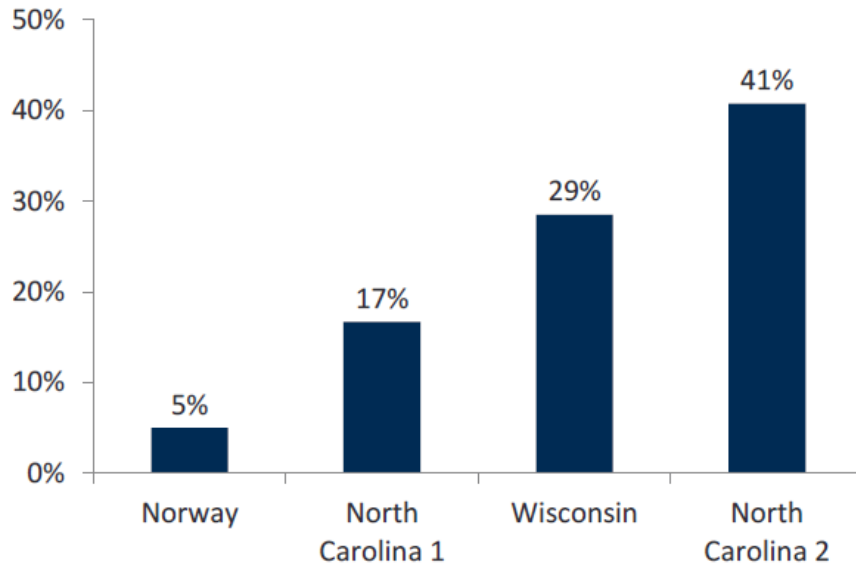
- Salt River Project in Arizona, a municipally owned system, has instituted a mandatory tariff for DG customers
- The Kansas Corporation Commission has ordered that DG customers be considered a separate class and be offered three-part rates, among other options

Over 30 utilities in 17 states offer residential demand charges



Three experiments have detected significant response to demand charges

Average Reduction in Max Demand



Note: North Carolina was analyzed through two separate studies using different methodologies; both results are presented here

However...

- Two of the pilots are old and the third is from a unique climate
- The impact estimates vary widely
- Findings are based on small sample sizes
- New research is needed

The PRISM software can simulate customer response to demand charges

PRISM is based on a widely accepted methodological framework that captures two key effects

- **Load shifting** in response to a change in rate structure
- **Conservation (or the opposite)** in response to a change in average rate level

The model draws on an extensive library of customer price elasticity estimates found in pricing pilots over the past decade

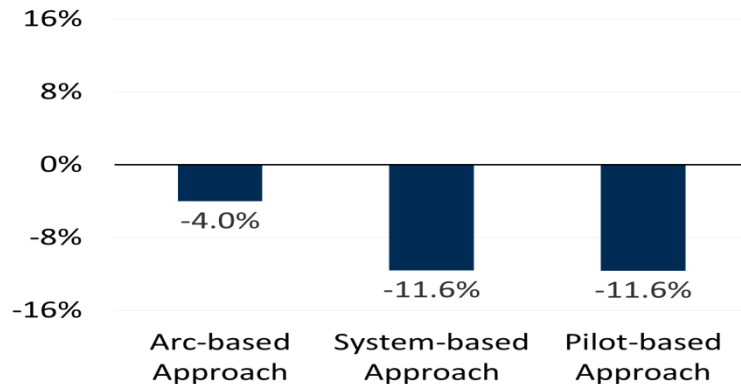
It was used to predict impacts in Xcel Energy's grid modernization filing in Colorado last year (details in appendix)

Simulating demand response from demand charges for Xcel Energy (Colorado)

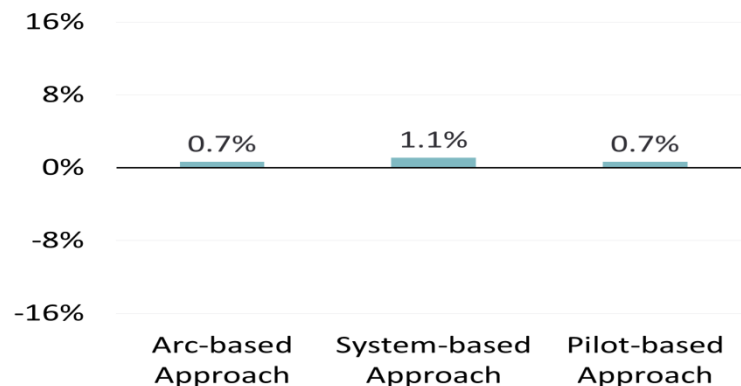
- 1) Arc-based approach. Demand response is based on the magnitude of the peak-to-off-peak price ratio and its relationship to price response as estimated in more than 60 residential pricing pilots.
- 2) PRISM-based approach. Like the Arc-based approach, customers are assumed to respond to the new rate as if it were a time-varying rate and the PRISM software is used to project response. It has been used in California, Connecticut, Florida, Maryland, Michigan, and abroad.
- 3) Pilot-based approach. Peak demand reductions are based directly on the average results of three residential demand charge pilots. One of the pilots found specifically that customers respond similarly to demand charges and equivalent TOU rates.

The simulated impact on peak demand

Change in Avg Peak Period Demand (Summer)



Change in Annual Electricity Consumption



Comments

- Average peak demand reductions during summer months range from 4.0% to 11.6% across all customers
- Average annual energy consumption increases slightly; this is driven by a number of factors, including (1) that the average price of electricity decreases for most hours of the year for all customers and (2) the average daily rate decreases for large customers

In some jurisdictions, cost-based tariffs are already the default tariff

Spain offers real-time pricing as the default regulated supply option and about half of all customers have elected to stay on it

Ontario (Canada) has made TOU tariffs the default supply option

- The rates vary seasonally and feature three periods
- Some 90% of customers are on that tariff

California is planning to roll out TOU tariffs to all residential customers by 2019

- A pilot to test default deployment will be implemented next year

Conclusions

Rate design has evolved through 5 waves during the past 5 decades

300+ pricing tests in 60+ pilots have shown that customers respond to time-varying energy-based rates and the PRISM software can be used to simulate the impact of such rates

More than 30 utilities offer demand charges but not much has been published on how much demand response is brought about by these charges

There is a need to design and rollout new pilots featuring three-part rates with demand charges and time-varying energy rates

It would also be useful to design pilots designed to test customer acceptance and response to transactive energy

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Presenter Information



AHMAD FARUQUI, PH.D.

Principal | San Francisco, CA

Ahmad.Faruqui@brattle.com

+1.415.217.1026

Ahmad Faruqui's consulting practice is focused on the efficient use of energy. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents. His research has been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He holds BA and MA degrees from the University of Karachi, an MA in agricultural economics and Ph. D. in economics from The University of California at Davis.

The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group.

Presenter Information



CODY WARNER

Senior Research Analyst | San Francisco, CA

Cody.Warner@brattle.com

+1.415.217.1000

Cody Warner is a Senior Research Analyst at The Brattle Group. While at Brattle, Cody has worked on a variety of high-profile energy and resources cases, including an interstate water dispute of original jurisdiction between Florida and Georgia. Cody has also provided analyses in rate design proceedings for residential solar customers in Arizona, Nevada, and Oklahoma. Most recently, Cody developed econometric models that quantify natural resources damages as a result of perfluorinated chemicals (PFC) contamination. Cody's current research focuses on the impact of time-varying rates on residential customers' peak demand. Prior to joining Brattle, Cody interned with Pacific Gas & Electric in San Francisco. At PG&E, Cody developed protocol for monitoring fluctuations in local natural gas prices. He also had the opportunity to attend market training seminars at CAISO, tour wind farms and natural gas peaker plants, and shadow natural gas traders. Cody graduated from Northwestern University with a degree in Economics and Environmental Policy.

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APPENDIX

Simulating customer response to demand charges with PRISM: A case study of Xcel Energy (Colorado)

We use a hypothetical customer's June load profile when illustrating the three approaches

770 kWh of monthly electricity consumption

Time-differentiated consumption

- 70 kWh on peak (weekdays, 2 pm to 6 pm)
- 700 kWh off peak

IBR tier-differentiated consumption

- 500 kWh first tier
- 270 kWh second tier

3.5 kW of maximum demand

- Measured during peak hours
- Load factor of 30%

Converting the RD-TOU rate into an all-in TOU rate

As a first step in the Arc-based and System-based approaches, the RD-TOU rate is converted into an all-in TOU rate

Proposed Schedule RD-TOU

	Charge	Quantity	Bill
Service & facility charge (\$/month)	9.53	1	\$9.53
Grid use (\$/month)	14.56	1	\$14.56
Non-ECA riders (\$/kW)	3.78	3.5	\$13.23
ECA rider - peak (\$/kWh)	0.035698	350	\$12.49
ECA rider - off-peak (\$/kWh)	0.028109	420	\$11.81
Energy (\$/kWh)	0.004610	770	\$3.55
Demand (\$/kW)	7.880000	3.5	\$27.58
Total:			\$92.75

Notes:

Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

Levelized Prices

All-in Price	Peak	Off-Peak
Service & facility charge (\$/kWh)	0.0130	0.0130
Grid use (\$/kWh)	0.0199	0.0199
Non-ECA riders (\$/kWh)	0.1518	0
ECA rider (\$/kWh)	0.0357	0.0319
Energy (\$/kWh)	0.0046	0.0046
Demand (\$/kWh)	0.3165	0
Total (\$/kWh)	0.5415	0.0694
All-in peak-to-off peak price ratio	7.8	

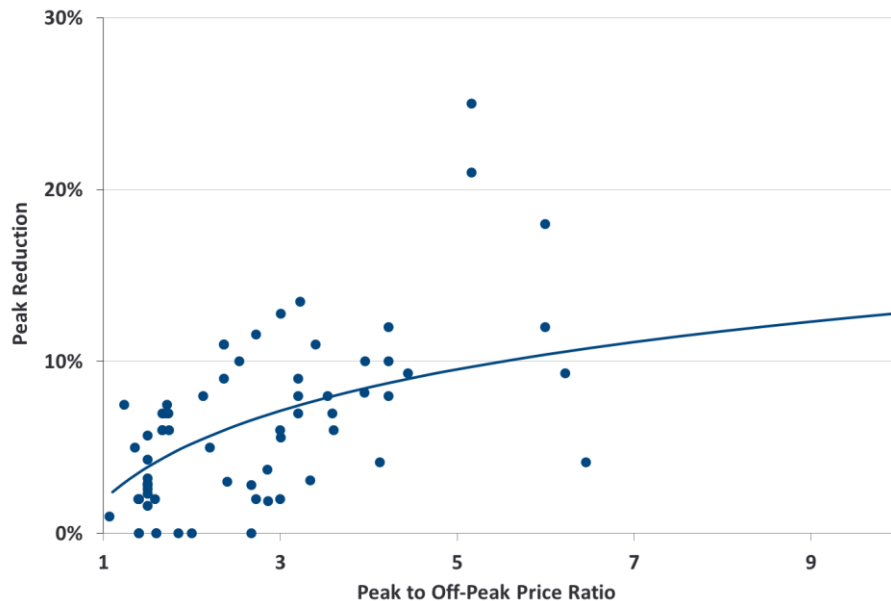
Notes:

Peak period is defined above as 2 pm to 6 pm, weekdays.
Due to a different peak definition in the ECA rider, the off-peak ECA rider price shown in the table is the load-weighted average of peak and off-peak ECA prices outside of the 2 pm to 6 pm window.

- Fixed charges are divided by the number of hours in the month and spread equally across all hours
- Demand charges are levelized and spread only across peak hours
- Volumetric charges remain unchanged

The Arc-based Approach

TOU Impacts Observed in Pricing Pilots



Note: Chart includes 67 data points from TOU pricing treatments without enabling technology.
The Arc was specified considering all 230 time-varying pricing treatments including CPP, VPP, PTR, and TOU.

Comments

- The results of 200+ pricing treatments across more than 40 pilots can be summarized according to the peak-to-off-peak price ratio of the rate and the associated measured peak reduction
- Focusing only on TOU pilots, we have fit a curve to these points to capture the relationship between price ratio and price response
- The drop in peak period usage can be read off the graph using the price ratio from the all-in TOU equivalent of the RD-TOU rate (as summarized on previous slide)
- For further discussion, see Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

The Arc-based Approach (cont'd)

Accounting for a Change in Average Price

Current Schedule R

	Charge	Quantity	Bill
Service & facility charge (\$/month)	6.75	1	\$6.75
Non-ECA riders (\$/kWh)	0.01156	770	\$8.90
ECA rider (\$/kWh)	0.03128	770	\$24.09
Energy - first 500 kWh (\$/kWh)	0.04604	500	\$23.02
Energy - 500+ kWh (\$/kWh)	0.09000	270	\$24.30
Total:			\$87.06

Proposed Schedule RD-TOU

	Charge	Quantity	Bill
Service & facility charge (\$/month)	9.53	1	\$9.53
Grid use (\$/month)	14.56	1	\$14.56
Non-ECA riders (\$/kW)	3.78	3.5	\$13.23
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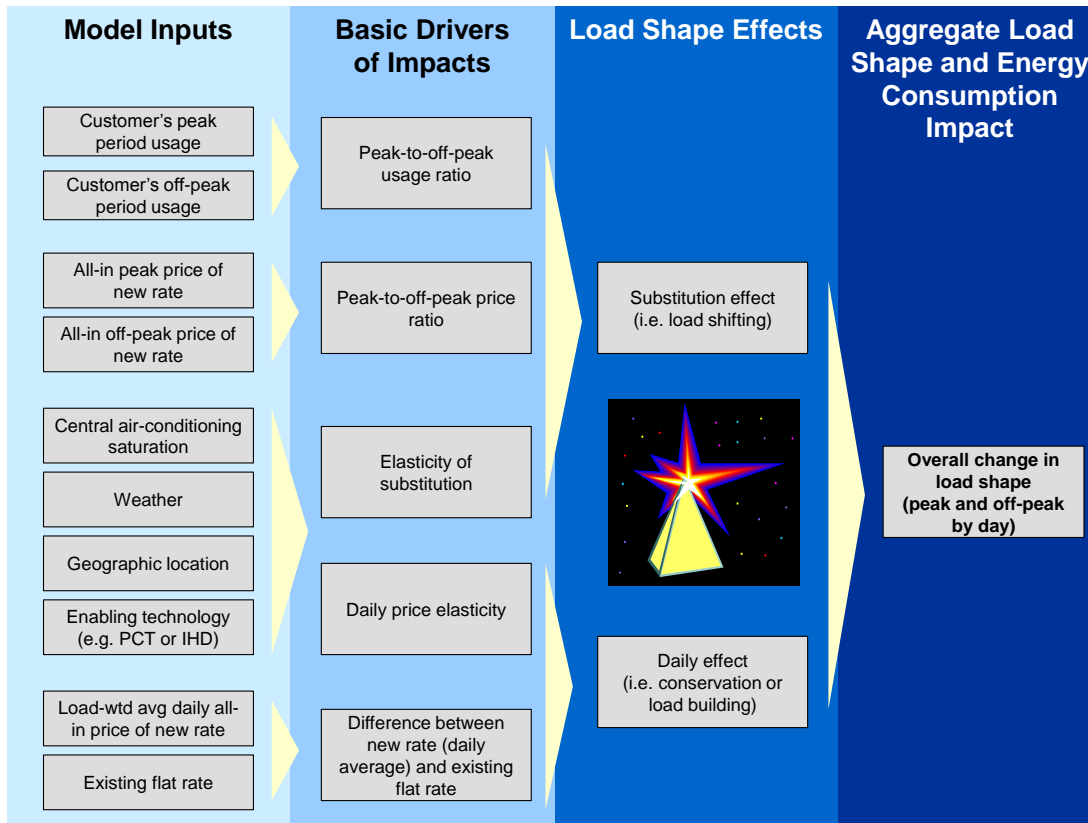
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

Comments

- The Arc-based Approach also accounts for customer response to a change in their average rate level
- For instance, if a customer's bill increases under the RD-TOU rate absent any change in consumption, that customer is likely to respond by reducing their overall energy use (including during the peak period)
- In this example, the hypothetical customer's total bill increases by 6.5% with the new rate
- Total electricity consumption would decrease as a result, based on an assumed price elasticity
- For example, with a price elasticity of -0.20, consumption would decrease by 1.3%
- We assume the same percentage change to consumption in all hours
- This effect is combined with the load shifting effect described on the previous slides to arrive at the composite change in load shape for each individual customer

The System-based Approach

Illustration of System-based Approach



Comments

- As an alternative to the two steps in the Arc-based Approach, the load shifting effect and the average price effect can be represented through a single system of two simultaneous demand equations
- The system of equations includes an “elasticity of substitution” and a “daily price elasticity” to account for these two effects
- There is support for this modeling framework in economic academic literature and it has been used to estimate customer response to time-varying rates in California, Connecticut, Florida, Maryland, and Michigan, among other jurisdictions
- In California and Maryland, the resulting estimates of peak demand reductions were used in utility AMI business cases that were ultimately approved by the respective state regulatory commissions

The Pilot-based Approach

In the Pilot-based Approach, the reduction in peak period demand is based on an average of the empirical results of the following three residential demand charge studies

Study	Location	Utility	Year(s)	# of participants	Monthly demand charge (\$/kW)	Energy charge (cents/kWh)	Fixed charge (\$/month)	Timing of demand measurement	Interval of demand measurement	Peak period	Estimated avg reduction in peak period consumption
1	Norway	Istad Nett AS	2006	443	10.28	3.4	12.10	Peak coincident	60 mins	7 am to 4 pm	5%
2	North Carolina	Duke Power	1978 - 1983	178	10.80	6.4	35.49	Peak coincident	30 mins	1 pm to 7 pm	17%
3	Wisconsin	Wisconsin Public Service	1977-1978	40	10.13	5.8	0.00	Peak coincident	15 mins	8 am to 5 pm	29%

Notes:

All prices shown have been inflated to 2014 dollars

In the Norwegian pilot, demand is determined in winter months (the utility is winter peaking) and then applied on a monthly basis throughout the year.

The Norwegian demand rate has been offered since 2000 and roughly 5 percent of customers have chosen to enroll in the rate.

In the Duke pilot, roughly 10% of those invited to participate in the pilot agreed to enroll in the demand rate.

The Duke rate was not revenue neutral - it included an additional cost for demand metering.

The Wisconsin demand charge is seasonal; the summer charge is presented here because the utility is summer peaking.

- Based on the results of these pilots, the average peak period demand reduction for each customer is assumed to be **14%** (impacts of the Norway and North Carolina pilots are derated when calculating this average, as described later)
- To estimate the change in total consumption, we account for the effect of the change in average price in the same way that it is accounted for in the Arc-based approach; this is combined with the peak impact described above

Price elasticities of demand

Price elasticities represent the extent to which customers change consumption in response to a change in price

We assume a price elasticity of -0.2 when estimating the average price effect, based on a review of price elasticities estimated by Xcel Energy and assumptions in prior Brattle work

The System-based Approach uses an elasticity of substitution of -0.14 and a daily price elasticity of -0.04

- The daily elasticity is based on California's "Zone 3" which we believe most closely represents the conditions of Xcel Energy's Colorado service territory. The elasticity of substitution is based on pilot results in Boulder.

Derating peak impacts

A recent time-varying 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

The price elasticities in the Arc-based and System-based approaches are derived from pilots offered on an opt-in basis; since Xcel Energy is proposing to roll out the RD-TOU rate on a default or mandatory basis, we have derated the estimated impacts by 40% so that they are applicable to a full-scale default residential rate rollout

Similarly, in the Pilot-based Approach we derated the results of the Norway and North Carolina pilots by 40% since they both included opt-in participation. Results of the Wisconsin pilot were not derated, as we believe participation in that pilot was mandatory

Revenue neutrality

Several minor adjustments were made to the RD-TOU rate in order to make it revenue neutral to the current Schedule R rate for the load research sample

ECA rider

- Each customer's proposed ECA charge is multiplied by a constant so that revenue collected by the proposed ECA charge across all customers is equal to the revenue collected by the current ECA charge

Other riders (DSMCA, PCCA, CACJA, and TCA)

- Like the ECA rider, these charges in the RD-TOU rate are all scaled proportionally such that they produce in the aggregate the same revenue as the charges in the current rate

Production meter charge

- The production meter charge of \$3.65/month is excluded from the RD-TOU rate to avoid accounting for the effect of a rate increase associated with advanced metering

Demand charge

- The demand charge remains unchanged relative to the rates provided by Xcel Energy

Energy charge

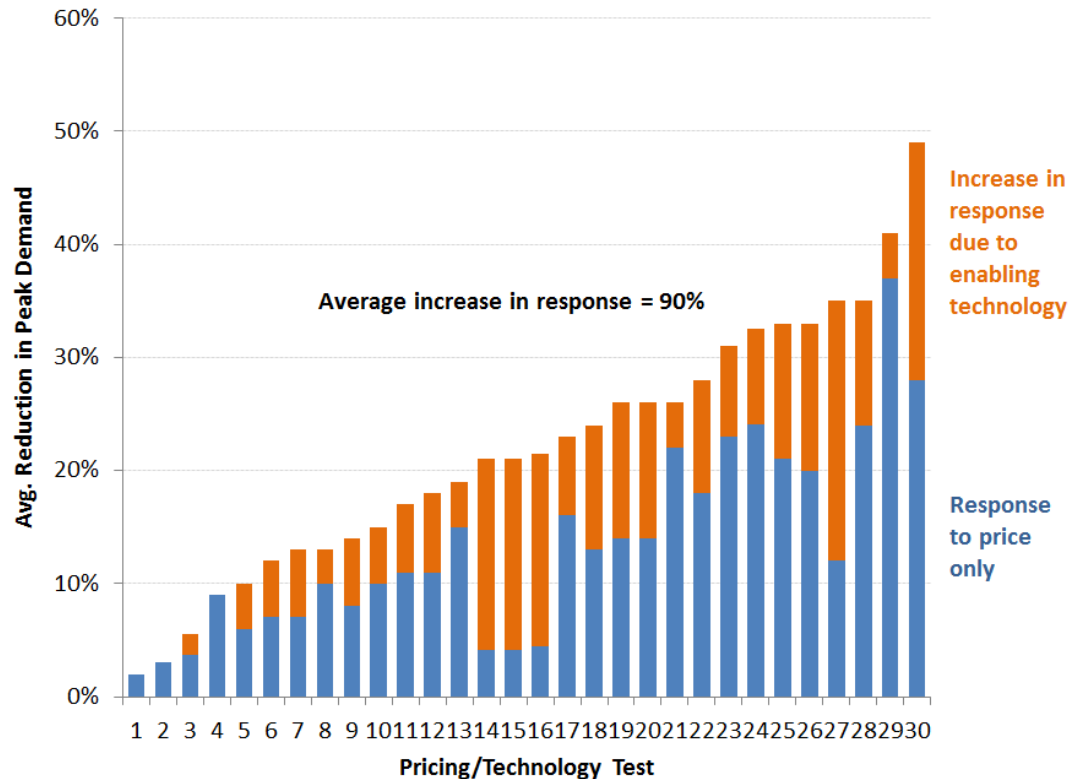
- The energy charge in the RD-TOU rate is adjusted to make up any remaining difference in revenue collected from the current rate and the proposed rate

Load research data

- Xcel Energy provided us with hourly load research data for 233 customers
- The hourly data covers the calendar year 2013
- In some cases, hourly observations were flagged in the dataset as meter reading errors – these were treated as “missing values” in our analysis.
- 15 customers were missing data for at least 5% of the hours in the year. These customers were removed from the sample.
- One customer had recorded usage of 0 kWh for over 60 consecutive days, but their usage was not flagged for errors. This customer was kept in the sample, and does not substantively impact the results.
- While the vast majority of customers had mean hourly usage of less than 5.8 kW, one customer had a mean hourly usage of 64 kW; this customer was flagged as an outlier and removed from the sample.
- After making all adjustments to the load research sample, we were left with 217 customers

The impact of technology

Price Response with and without Technology



Comments

- Note that our analysis accounts only for behavioral response to the new rate; it does not account for technology-enabled response
- The introduction of a demand charge will provide customers with an incentive to adopt technologies that will allow them to reduce their peak demand for bill savings; batteries, demand limiters, and smart thermostats are three such examples
- Technology has been shown to significantly boost price response (as shown at left) and could lead to larger peak demand reductions than we have estimated in this analysis

Results - Monthly Detail

Monthly change in class average peak period demand

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Peak Demand	-5.6%	-13.4%	-11.6%
January	-6.0%	-13.9%	-11.8%
February	-6.9%	-14.8%	-11.8%
March	-6.7%	-14.7%	-11.9%
April	-7.7%	-15.8%	-11.4%
May	-8.1%	-16.1%	-11.5%
June	-4.4%	-12.0%	-11.5%
July	-2.4%	-10.2%	-11.1%
August	-3.7%	-11.4%	-11.3%
September	-6.4%	-13.6%	-12.9%
October	-7.5%	-15.6%	-11.5%
November	-7.2%	-15.0%	-12.1%
December	-5.4%	-13.4%	-11.5%

Monthly change in class annual energy consumption

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Energy Use	0.7%	0.7%	1.1%
January	0.5%	0.5%	1.0%
February	-0.5%	-0.5%	0.7%
March	-0.3%	-0.3%	0.7%
April	-1.5%	-1.5%	0.6%
May	-1.9%	-1.9%	0.6%
June	2.2%	2.2%	1.6%
July	3.8%	3.8%	2.0%
August	2.8%	2.8%	1.8%
September	0.6%	0.6%	1.2%
October	-1.2%	-1.2%	0.6%
November	-0.5%	-0.5%	0.7%
December	1.0%	1.0%	1.1%