Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency

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March 2017

Report U1703

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Acknowledgments

This report was made possible through the generous support of the Energy Foundation, Commonwealth Edison, and The JPB Foundation. The author gratefully acknowledges external reviewers, internal reviewers, colleagues, and sponsors who supported this report. External expert reviewers included Douglas Jester from 5 Lakes Energy, Dan Cross-Call from Rocky Mountain Institute, Jim Lazar from Regulatory Assistance Project, Peter Cappers from Lawrence Berkeley National Laboratory, Casimir Bielski and Rick Tempchin from Edison Electric Institute, and John Howat from National Consumer Law Center. External review and support does not imply affiliation or endorsement. Internal reviewers included Neal Elliot, Maggie Molina, Steve Nadel, Jen Amann, Marty Kushler, Reuven Sussman, and Annie Gilleo. Last, I would like to thank Fred Grossberg for developmental editing and managing the editorial process; Keri Schreiner, Sean O'Brien, and Roxanna Usher for copy editing; Eric Schwass for graphics support; and Patrick Kiker, Wendy Koch, and Maxine Chikumbo for their help in launching the report.

Executive Summary

Rapid changes in the electric utility industry are driving utilities to propose new ways of collecting revenues from residential customers. Among these changes are flat or declining electric sales, increased penetration of advanced metering infrastructure, and growing numbers of residential customers with rooftop solar. Many of the industry's proposed changes to residential rate structures are a stark departure from previous billing approaches. Instead of collecting revenues through small customer charges and a flat or inclining volumetric energy rate, many utilities are now proposing higher customer charges, volumetric rates that vary based on the time of day or season, and, in some cases, demand charges.

These proposed changes alter the price signal to customers to conserve electricity and invest in energy efficiency. In this report, we explore the relationship between changes in residential rate design and energy efficiency, focusing on how recently proposed rate structures alter customer behavior through a review of recent pricing studies. We find that some recently proposed rate designs—specifically, higher customer charges and demand charges—could increase overall consumption and discourage investments in energy efficiency technologies.[1] Time-of-use (TOU) rates, potentially combined with other time-varying rate elements such as peak-time rebates (PTR) or critical-peak pricing (CPP), encourage investments in energy efficiency technologies and reduce peak demand. Our review of recent pricing pilots and studies shows that these rates also generally reduce overall consumption, meaning that customers are not using higher levels of electricity from shifting usage outside of peak hours.

ACEEE PRINCIPLES OF RATE DESIGN

There are many competing policy objectives in designing residential rates. The primary function of regulation is to impose on monopoly providers the pricing discipline that markets impose on competitive providers. There are many other subordinate policy objectives, including revenue stability for the utility, affordability for all customers, encouraging conservation, minimizing cross subsidies between rate classes and customers within rate classes, and general clarity and simplicity. Table ES1 summarizes three rate design principles we believe are particularly important.

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[1] Demand charges and time-varying rates are not mutually exclusive and can be offered jointly as one rate option. However, as we discuss later in this report, most of the pricing pilots and studies we reviewed do not evaluate these options jointly.

Table ES1. ACEEE principles of rate design

Principle	Definition
Rate simplicity	Rates should be easy for customers to understand and respond to.
Utility revenue stability	Rates should allow utilities the ability to earn commission-authorized revenues to maintain financial health.
Promotion of conservation and energy efficiency	Rates should send price signals to customers to discourage wasteful use of electricity.

Fairness is an additional objective often discussed in the context of rate cases. It has different meanings to different parties. From our perspective, fairness in rate design requires the regulator to balance the interests of the utility and its customers, and also the interests of customer classes and groups within classes. Rates should strive to be cost based and should avoid undue discrimination.

These three principles balance the interests and objectives of customers, utilities, and society at large. Rate simplicity is important because customers need to understand rates to effectively respond to price signals. Utility revenue stability reduces risk in revenue recovery, thereby improving the financial health of electric utilities, which should reduce customer costs through lower cost of debt and equity. Promoting conservation and energy efficiency is critical; discouraging wasteful consumption reduces the need for unnecessary utility infrastructure, such as new power plants, and thereby reduces costs for all customers. This also reduces power plant air emissions associated with energy production, including greenhouse gases.

CUSTOMER RESPONSE AND RATE DESIGN

We reviewed recent pricing pilot studies and other literature to better understand the empirical evidence related to how customers respond to changes in electric prices. Numerous recent pricing pilot studies focus on time-varying rates such as TOU rates, CPP, variable-peak pricing, PTR, and real-time pricing. These studies provide overwhelming evidence that customers respond to changes in volumetric energy rates. Many of the studies document significant peak demand reductions, especially when customers are equipped with technology such as programmable or learning thermostats. Our review of these studies also shows small reductions in overall consumption. Not all estimates were statistically significant at the 90% level, but the results for each treatment group show a consistent trend in reduced overall consumption, with very few showing increased consumption. Table ES2 shows the reduction in overall consumption and peak demand for 50 pricing pilot treatments under various time-varying rates.

Table ES2. Reduction in overall consumption and peak demand for 50 treatment groups in various pricing studies

Rate treatment	Number of observations	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Of the 50 observations, 19 involve annual changes in overall consumption; the remaining 31 are seasonal. Appendix C provides detailed information for each treatment and associated pricing pilot.
CPP = Critical-peak pricing. PTR = Peak-time rebate. TOU = Time-of-use rate.

Many pricing studies are available for time-varying rates, but little evidence exists on how customers respond to three-part rates that include demand charges. A demand charge bills a customer based on maximum demand for any 15- to 60-minute interval period over the course of a month. The charge can be based on maximum demand at any time over the month or assessed during a predefined peak period. Early evidence suggests some reduction in peak demand under three-part rates that include demand charges; however the reduction is less than that of time-varying rates alone. Glasgow, Kentucky, was an early adopter of mandatory demand charges for residential customers but experienced customer dissatisfaction and confusion with the rate, ultimately abandoning the rate as mandatory.[2] Fewer than 20 utilities currently have demand charge rates in place for residential customers, with many targeting customers with large controllable loads, such as central air-conditioning or swimming pools. Most of these rates are voluntary and not much evidence exists on how a mandatory or default residential demand charge rate affects overall consumption and peak demand reductions.

Utility proposals to increase residential customer charges are also very common.[3] As with demand charges, little real-world evidence exists to help us understand how customers respond to higher charges. However, since utilities that increase customer charges must correspondingly reduce the revenues recovered in volumetric energy rates, this approach diminishes the price signal to encourage conservation.

RATE DESIGN'S EFFECT ON ENERGY EFFICIENCY INVESTMENTS

A review of recent literature shows that bill savings are the primary reason customers engage in energy-efficient behaviors and participate in utility-sector energy efficiency

[2] To learn more about the experience in Glasgow, see bgdailynews.com/news/state-ag-steps-into-glasgow-epb-rate-controversy/article_67b746ee-6af4-11e6-974a-c7c55e838b5e.html.

[3] The customer charge is also known as the service charge, standing charge, connection fee, or fixed charge.

programs. Bill savings result when customers avoid energy charges by reducing consumption through behavior changes or the use of efficient technologies. Various rate design structures alter the energy charges. This affects both the bill savings and the payback period (the number of years it will take a customer to break even on an energy efficiency investment). Longer payback periods make it less likely for a customer to invest in energy efficiency measures.

To understand how changes in rate design alter payback periods, we analyzed energy efficiency data from the Arizona Public Service's *Technical Resource Manual* and load research data from a nearby Arizona utility. Our analysis showed that changes in rate design alter payback periods associated with energy efficiency investments. Figure ES1 shows the payback period differences, in years, for attic insulation under 20 different rate design scenarios. The scenarios tested differences in customer charges, TOU rates, tiered rates, and demand charges.

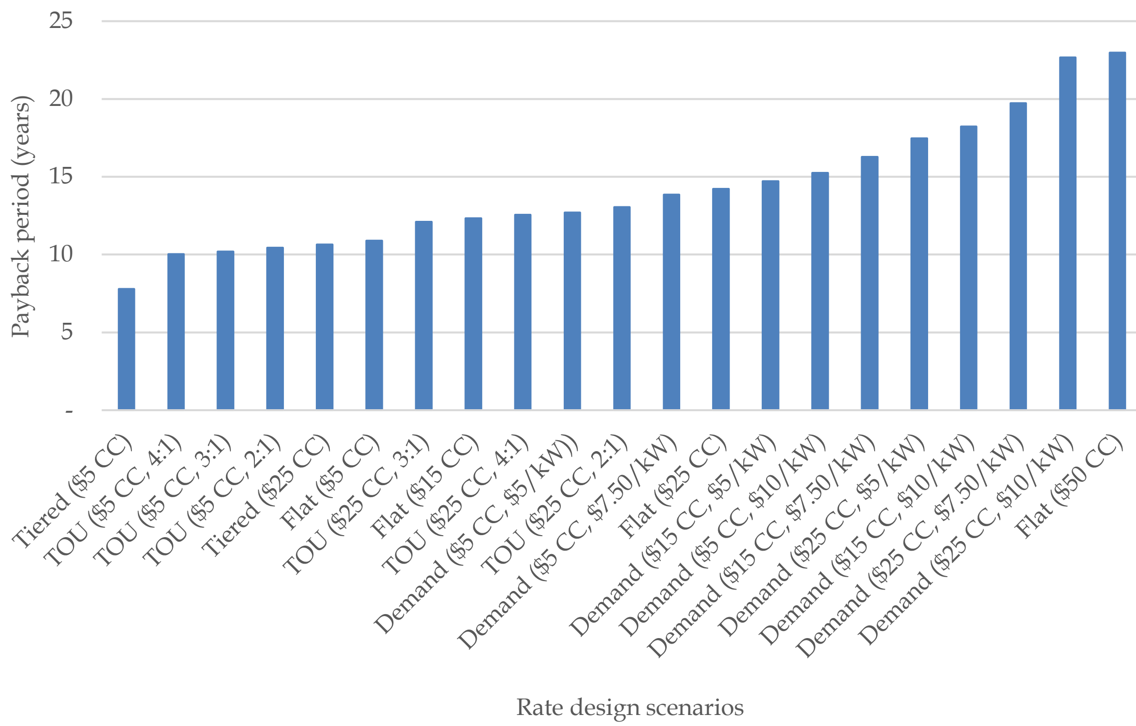

Figure ES1. Payback periods in years under 20 rate design scenarios. CC = Customer charge. TOU = Time-of-use rate. The ratios shown are the on- to off-peak ratios for time-of-use volumetric energy rates.

Scenarios with the longest payback periods are those with higher customer charges (more than $25 per month) and demand charges. The scenarios with the lowest payback periods have lower customer charges, tiered or flat rates, and TOU rates. Moving from a TOU or flat rate with a $5 customer charge to a demand rate with a $25 customer charge and demand charge of $7.50 or $10 per kW nearly doubled the payback period. Moving from an inclining tiered rate with three tiers and a $5 customer charge to a flat rate with a $50 customer charge tripled the payback period.

Rate design scenarios utilizing demand charges show large increases in payback periods for all measures—often more than 30% when compared with flat or TOU rates. Tiered rate scenarios show the shortest payback periods, even when combined with a higher monthly customer charge. Scenarios with higher customer charges often increased payback periods, especially when combined with demand charges.

RATE DESIGN IMPACT ON LOW-INCOME CUSTOMERS

Regulators should consider the impact on low-income customers with any change in rate design. Financially, these customers are often the least able to absorb rate increases and respond to rate changes. Further, because lower-income customers often have a flatter load profile and use less electricity on average than other customers, they may be disproportionately affected by utility proposals—such as a higher customer charges or demand charges—that seek to recover greater levels of costs from low-usage customers. In pricing studies we reviewed, low-income customers were able to respond to changes in volumetric energy prices, but at a lower level than other customers. A flatter load profile also means that, on average, low-income customers might be financially better off than other customers under a TOU rate. Utilities should focus on targeting and recognizing the customers that will be negatively impacted by rate changes to protect vulnerable populations from large rate increases or to assist them with these increases if they occur.

CONCLUSIONS AND RECOMMENDATIONS

Our review of existing studies shows that customers do respond to changes in electric prices. Time-varying rates reduce peak demand and overall consumption. The limited evidence on residential customer response to demand charges shows a smaller reduction in peak demand than with time-varying rates, as well as some difficulty for customers in understanding how the rate is billed. Rate structures recovering more revenue in customer charges must recover less revenue in volumetric rates, reducing the price signal for efficient consumption. Research shows this could lead to increases in overall consumption and higher utility infrastructure costs. All of these changes in rate design also alter payback periods for energy efficiency investments—and some dramatically reduce annual bill savings. Such changes may therefore discourage customers from making energy efficiency investments.

Based on our research on residential rate design, ACEEE finds that confining customer charges to include only customer-specific costs (such as bill and collection) and adopting time-varying rates (specifically, a TOU rate with a CPP or PTR element) comes closest to meeting our three principles of rate design: price signals that encourage conservation and energy efficiency, simplicity, and utility revenue stability. Utilities can reduce costs without sacrificing customer satisfaction by automatically enrolling customers in these rates, while still allowing a return to a standard rate. Utilities should pay special attention to potential financial impacts on low-income customers and ensure that they have the programs, tools, and knowledge necessary to respond to rate changes. Regulators should also support full revenue decoupling for utilities to ensure full recovery of costs, especially for utilities that are risk adverse to new rate designs that could reduce consumption. Finally, regulators should be cautious in adopting demand charges for residential customers; such charges require additional study—possibly in the form of new pilot studies—to understand effects on residential customer usage and peak reduction.

Introduction

Electric utility proposals to modify or alter residential rate design have increased significantly in recent years. Several key factors are driving these proposals, including an increase in customers installing rooftop solar, declining or flattening electric sales, increased penetration of electric vehicles, and proliferation of advanced metering technologies.

In this paper, we explore the relationship between recently proposed changes in residential electric rate design and energy efficiency. We focus primarily on the relationship between rate design and customer response, but we also consider how rate design changes could affect energy efficiency investment decisions. To better understand this relationship, we attempt to answer three questions:

- What effect do various rate structures have on overall consumption of electricity?
- What effect will recently proposed changes in rate design have on payback of various energy efficiency measures?
- What are the implications of various rate design options for low-income customers?

To answer these questions, we first consider rate design goals from various perspectives and outline ACEEE's rate design principles. We then briefly discuss the drivers influencing changes in residential rate design. Following this discussion, we outline recent trends in utility-proposed changes to residential rates. Next, we present a review of pricing pilot studies and literature for several rate design variations, focusing on changes in overall consumption. We then analyze how changes in rate design alter energy efficiency measure payback periods using data from Arizona Public Service. Following this, we review the implications of rate design changes for low-income customers, who are often the least able to respond to utility rate changes. Finally, we offer conclusions from our research, along with recommendations on residential rate design.

Brief Primer on Volumetric Rates

Residential rate design for electric customers has historically relied on a two-part rate: a customer charge and a volumetric price (cents per kilowatt-hour). The customer charge, which is fixed per month regardless of usage, generally includes customer-specific costs for meters, customer service, meter reading, and the line drop from the distribution system into a customer's home. The volumetric rate, which is the price per kilowatt-hour consumed, recovers the remaining distribution network and power supply costs to provide electric service.

The volumetric rate can be billed in several ways. Initially, this rate was often a flat charge. Over time, utilities began charging tiered (or block) rates to offer customers incentives to use more or less electricity. Inclining tiered rates charge a higher rate for increased levels of consumption, sending a price signal to customers to reduce usage. The inclining block rate can be a useful tool for utilities to promote reduced consumption, especially when used as the default rate. According to one study, the implementation of inclining block rates might reduce consumption by 6% in the first few years and potentially more in the long run (Faruqui 2008).

Declining tiered rates offer customers discounts for higher usage levels, promoting increased consumption. These rates are much less common than inclining tiered rates. Declining rates were used historically to stimulate consumption and promote load growth, but have been discouraged more recently through public policy such as the Public Utility Regulatory Policies Act (PURPA) of 1978. Some utilities still offer declining tiered rates in winter months to increase consumption when capacity is underutilized.

Time-of-use (TOU) rates charge a different fee based on the time of day or season. A higher price is charged during on-peak hours, when strain is highest on the electric system and costs are highest for utilities. Off-peak time periods have the lowest charges and occur when demand on the utility system and costs are lowest. Sometimes utilities also use *shoulder periods*, charging customers a lower rate than on-peak, but higher than off-peak. Some TOU rates also vary based on season, with summer rates higher than winter rates for utilities with higher summer demand.

As we describe later in this report, this two-part structure has many rate design variations, including variable-peak pricing (VPP), critical-peak pricing (CPP), TOU rates, and real-time pricing (RTP).[4]

Goals of Rate Design

Residential rate design has several competing policy objectives that regulators must reconcile. These objectives are often argued in specific rate cases, leaving public utility commissions the responsibility of carefully balancing the goals of utilities and the public interest. The most-often cited rate design objectives or goals are those featured in James Bonbright's *Principles of Public Utility Rates* (Bonbright 1961). Bonbright outlined eight criteria for a sound rate structure, but highlights three as primary: a revenue requirement objective (fair return for the utility), a fair cost apportionment objective (rate recovery is evenly distributed among classes and customers), and optimum use or customer rationing objective (rates are designed to discourage wasteful use of public utility services) (Bonbright 1961).

PURPA expanded on Bonbright's eight criteria. The landmark legislation focused on equitable customer rates, efficient use of facilities and resources by utilities, and conservation of energy by end users. Specifically, PURPA required utilities to implement time-of-day rates when cost effective and strongly discouraged the use of declining block (or tiered) rates for energy charges (PURPA 1978).[5] PURPA's overarching objective was to promote conservation and energy efficiency through price signals. The Energy Policy Act of 1992 further articulated these goals, but also expanded the inclusion of energy efficiency in integrated resource planning guidelines and encouraged utilities to consider revenue decoupling and performance incentives for energy efficiency (NRRI 1993).

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[4] To learn more about variations of time-varying rates, see Faruqui, Hledik, and Palmer 2012.

[5] Time-of-day rates bill customers a different price for electricity used at different times of the day. Declining tiered rates charge customers less money as they use more electricity.

Bonbright's eight criteria are still widely cited in rate cases today. However much has changed since the initial publication of *Principles of Public Utility Rates* in 1961, most notably the proliferation of distributed generation. Some organizations have therefore argued for an update to the Bonbright principles.

Rocky Mountain Institute (RMI) has advocated for more sophisticated rate design that will account for 21st century technologies and realities. RMI argues that rates should strive for social equity, simplicity of understanding, and resource efficiency (RMI 2015). RMI advocates for moving beyond the simple two-part rate with a flat energy charge, such as TOU, to more sophisticated rate structures that provide clear price signals to guide efficient investment in distributed energy resources (DERs) and utility-scale resources (Glick, Lehrman, and Smith 2014).

In *Smart Rate Design for a Smart Future* (Lazar and Gonzalez 2015), the Regulatory Assistance Project outlines a new vision for rate design based on three principles. First, a customer should be able to connect to the grid for no more than the cost of connecting to the grid. Second, customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume. Third, customers who supply power to the grid should be fairly compensated for the full value of the power they supply (Lazar and Gonzalez 2015).

Electric utilities have also stressed the need for rate design changes to address the increase in DERs. The Edison Electric Institute (EEI), an organization that represents interests of investor-owned electric utilities, states that shifting cost recovery of system assets from those who own onsite generation to those who are unable to participate is unacceptable (EEI 2012). EEI also stresses that customer equity requires that fixed costs be recovered through customer charges. EEI further elaborates on the need for increased customer charges, stating that utilities should "institute a monthly customer service charge to all tariffs in all states in order to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources"(Kind 2013). Utilities often focus on revenue stability and eliminating cross subsidies.[6]

ACEEE PRINCIPLES OF RATE DESIGN

ACEEE has identified three particularly important principles for rate design: simplicity, utility revenue stability, and price signals that encourage conservation and energy efficiency. Here we elaborate on each of these principles and why they are so important.

Promoting conservation and energy efficiency. Rate design should send price signals to customers to discourage wasteful electricity consumption. This objective is consistent with the principles outlined by Bonbright and enacted in PURPA and in the Energy Policy Act. Rates should be cost based and send price signals to customers related to the long-run marginal cost of service, communicating how usage affects future utility system costs. These

[6] Investor-owned utilities also have the objective of minimizing risk and maximizing return to shareholders, which can influence preference for a particular rate design.

signals also allow utilities to communicate to customers when the cost to serve is highest, letting customers reduce demand in these periods.

Rate simplicity. Electricity rates should be easy for customers to understand. Rate simplicity is critical because customers cannot respond to a price signal unless they understand it. Simplicity thus increases customers' ability to respond effectively. These effective responses in turn produce outcomes that are socially optimal, saving all customers money in the long run. Coordinated education efforts can also improve the effectiveness of a rate design.

Utility revenue stability. Rate design should allow utilities the ability to earn commission-authorized revenues. This ability is critical to a utility's financial health. While care should always be taken to ensure that rates are fair and do not facilitate excessive revenues, rate design should not compromise an electric utility's ability to earn authorized revenues. A utility's financial health is important because higher-risk utilities (those in poorer financial health) impose higher costs on customers through higher-cost debt and equity.

Drivers of Change in Residential Rate Design

Several recent developments in the electric utility industry are driving the new proposals in residential rate design. Three of the most important are described below.

FLAT AND DECLINING ELECTRICITY SALES

The first and perhaps most concerning factor for utility management is the fact that electric utility sales are flattening and declining in many regions. According to the US Department of Energy's Energy Information Administration (EIA) (2016), national electric sales have declined in five of the past eight years. Residential sales have remained flat, even as the number of residential customers continues to increase. Figure 1 shows retail electric sales by sector over the past 10 years.

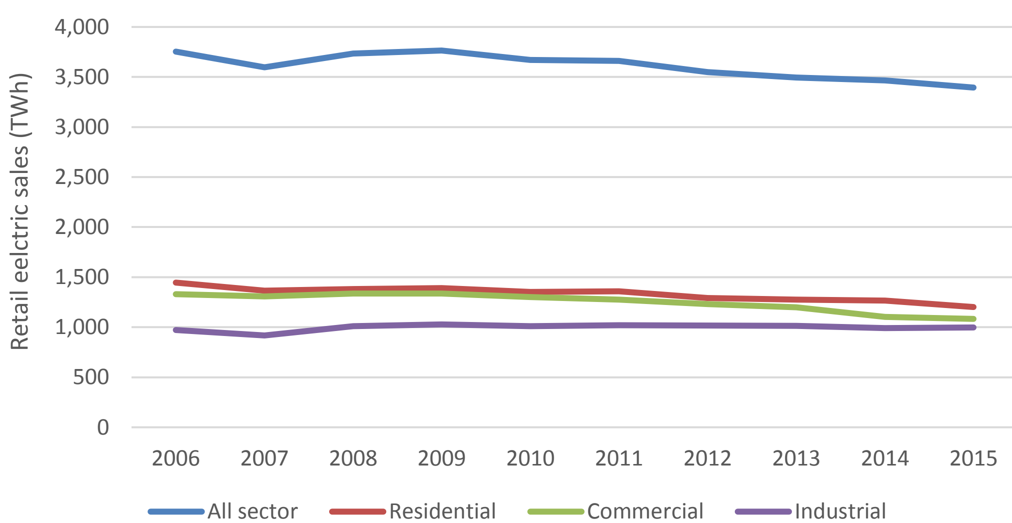

Figure 1. Retail electric sales by sector (in terawatt hours). ***Source:*** **EIA 2016.**

Flattening and declining sales are occurring simultaneously with increases in population and home size. According to the US Census Bureau, the population grew from 298 million in 2006 to 322 million in 2015, an increase of 8% (US Census Bureau 2016a). Further, median single-family home sizes grew from 2,248 square feet in 2006 to 2,467 square feet in 2015, an increase of nearly 10% (US Census Bureau 2016b).

Flattening and declining sales are leading many utilities to reconsider rate design options due to revenue recovery concerns. This is especially true for utilities operating in states that require the use of a historic test year for rate case purposes—that is, a utility must base cost-of-service assumptions and electricity sales on a previous year. If sales are declining, the use of a historic test year can make revenue recovery challenging.

ADVANCED METERING CAPABILITY

A second major factor is the development and adoption of advanced metering infrastructure (AMI) technology. AMI allows utilities access to hourly (or more frequent) customer usage data at relatively low incremental costs. These data allow utilities to utilize time-variant pricing or demand charges for residential customers. Although time-variant pricing existed prior to AMI's spread, the cost of metering until recently prohibited its widespread use.

The number of utility customers with these advanced meters has increased markedly in recent years. In 2007, 2.2 million customers had AMI. By 2016, this number had grown to nearly 58.5 million—a penetration level of approximately 40.6% (FERC 2016). Residential customers have a higher penetration of AMI meters than other customer classes, although not by much.

AMI technology creates an opportunity to use pricing to shape load in desirable ways, and utilities often face regulatory pressure to document the benefits of AMI infrastructure investments. Rate design is important for capturing those benefits. Increased penetration of AMI meters also increases data availability to customers.

GROWTH IN DISTRIBUTED SOLAR PV

The proliferation of residential rooftop solar is also a significant driver of rate design changes. Figure 2 shows the annual installed capacity of rooftop solar installations from 2010 to 2016 for residential and nonresidential customers. Residential rooftop solar capacity grew from almost zero in 2010 to more than 2,500 megawatts in 2016.

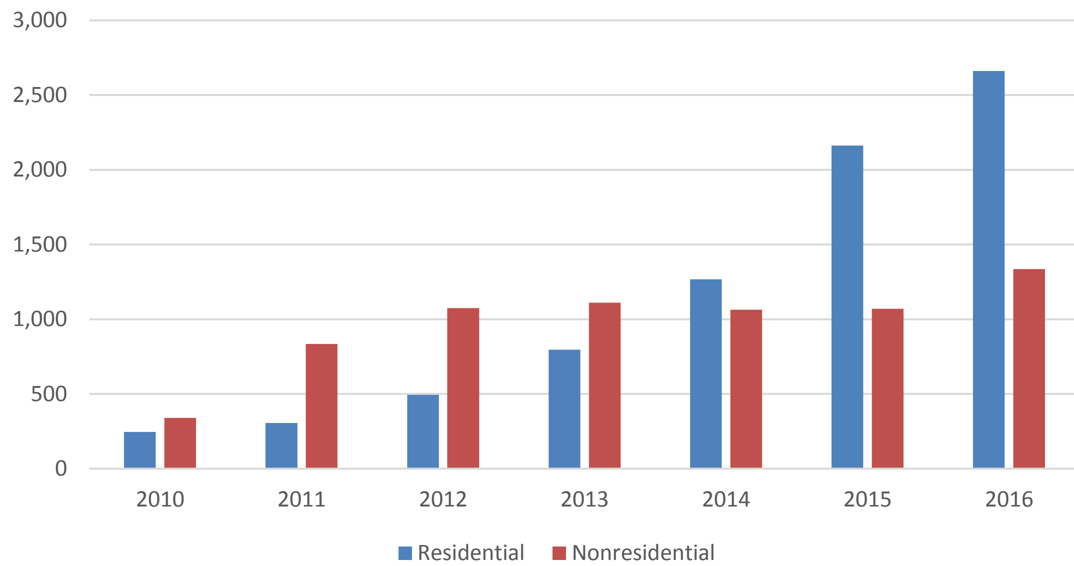

Figure 2. Yearly US solar photovoltaic installations. *Source:* SEIA 2017.

Some utilities argue that the higher numbers of customers with rooftop solar require non-solar customers to subsidize the cost of maintaining the distribution system because the rooftop solar customers avoid significant volumetric charges.[7] In an effort to reduce cross subsidization, some utilities are proposing a number of potential solutions, including higher customer charges and mandatory demand charges. Utilities have also proposed segmenting solar (and other self-generation) customers into rate classes that are separate from other residential customers. The stated intention of these changes is to recover greater costs from rooftop solar customers.

Recent Trends in Residential Rate Design

Here we highlight a few recent trends in residential rate design. These trends are not related to increased revenues for utilities, but are focused on changes to rate structures. New proposals vary by jurisdiction but often include the following changes.

Default TOU rates. Some utilities are moving to default TOU rates instead of the traditional two-part rate structure (a customer charge and flat or inclining energy rate). The California Public Utilities Commission (CPUC), following a three-year examination of rate reform alternatives, ordered the state's investor-owned utilities to begin a transition to default TOU rates for all residential customers starting in 2019 (CPUC 2015). The Massachusetts Department of Public Utilities (DPU), as part of a comprehensive suite of dockets and orders related to grid modernization, ordered the state's electric distribution companies to use a TOU rate with a CPP overlay as the default for basic service customers following the deployment of advanced metering functionality (Massachusetts DPU 2014). The Arizona

[7] Utilities have made this argument in several recent rate cases, including Tucson Electric Power (Docket No. E-01933A-15-0322), UNS Electric Company (Docket No. E-04204A-15-0142), NV Energy (Docket Nos. 15-07041/15-07042), and Madison Gas and Electric (Docket No. 3270-UR-120).

Corporate Commission also required UNS Electric to implement default TOU rates for new customers (ACC 2016).

Introduction of demand charges. Some utilities have also proposed both voluntary and mandatory demand charges for residential customers. Demand charges have a long history of use in billing large commercial and industrial customers, but very little history for residential customers. Only 19 utilities offer demand charges for residential customers, and only two—Arizona Public Service and Black Hills—have subscription rates higher than 1% (Faruqui 2017). Most residential three-part rate options are optional, but in the past year, three small electric cooperative utilities have adopted mandatory demand charge rates for residential customers.[8] Glasgow, Kentucky, instituted mandatory demand charges for residential and small commercial customers in January 2016. The Glasgow electric plant board was forced to reinstate a two-part rate because of strong public dissatisfaction with the mandatory demand charge rate (Tomich 2016).

Recent utility proposals to implement demand charges for residential customers have been met with sweeping opposition. A recent legislative proposal in Illinois included mandatory demand charges for all residential customers in the Ameren Illinois and ComEd service territories. The demand charge proposal was withdrawn from the bill's final version following strong opposition from consumers and Governor Rauner's office (Daniels 2016).

Higher customer charge proposals. Utility proposals to increase customer charges have increased substantially since 2010. Instead of collecting only costs associated with metering, billing, and customer service, utilities are now proposing to collect distribution infrastructure costs in customer charges. As of October 2016, higher customer charge proposal cases were ongoing in 25 states. A review of 87 investor-owned utility rate cases from 2014 through January 2017 show an average proposed increase of 61% (from $9.09 to $14.64), but an average approved increase of only 15%. Appendix A shows the results of these cases in greater detail.

Value of solar and other distributed-generation ratemaking. Several states are now examining the resource value of distributed resources as an alternative to full retail net metering. These states include Arizona, Minnesota, Oregon, Georgia, and New York.[9] Some states have also approved a separate residential self-generation customer class (Nevada). Others have rejected a separate rate class (New Mexico).

Customer Response and Rate Design

Numerous pricing studies in recent decades demonstrate that customers adjust usage in response to changes in electric prices (EPRI 2008). In this section, we review the results of several recent studies testing customer response to various rate designs and discuss other relevant literature. We also outline basic definitions and variations of specific rates. Our

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[8] These utilities include Mid-Carolina Electric Cooperative and Butler Rural Electric Cooperative. Some utilities have also instituted mandatory demand charges for all customers owning distributed generation.

[9] Associated docket numbers are Arizona (Docket No. E-00000J-14-0023), Minnesota (Docket No. 14-65), Oregon (Docket No. UM 1716), Georgia (Docket No. 40161), and New York (Docket Nos. 15-02703/15-E-0751).

review highlights key findings from each pricing study, but we focus on two primary metrics: percentage reduction in peak demand and percentage change in overall consumption.

Considering these two metrics in percentage terms allows comparison across regions with different weather and building characteristics. Other metrics—such as participation approach (opt-in versus default), inclusion of technology (such as a programmable thermostat), and methodology—were secondary in our review, but are also important. Each study utilizes a different methodology to estimate peak reductions and changes in consumption. We do not provide a thorough review of these differences, but that information is available in the primary evaluations.

SCOPE OF REVIEW

We focus our review on studies conducted within the past 15 years. Appendix B offers detailed descriptions of the pricing studies and pilots we reviewed for this report. Although numerous studies were conducted in prior decades, we did not closely review these because they often rely on older technology and research methods. However two earlier studies of note summarized the results of TOU pricing pilots conducted in the 1970s and 1980s.

The first study compiled data from five residential TOU pilots conducted by Carolina Power and Light, Connecticut Light and Power, Los Angeles Department of Water and Power, Southern California Edison, and Wisconsin Public Service. All five of these pilots included some form of mandatory participation. This study concluded that the price differential between peak and off-peak periods is the primary driver in customer response and that TOU rates lead to a reduction in overall usage (Caves, Christensen, and Herriges 1984). The second study reviewed the results of 12 pricing pilots from the late 1970s. It concluded that TOU pricing generally reduces peak demand and daily energy consumption. Higher-use customers also were more responsive to TOU rates than low-use customers (Faruqui and Malko 1983).

We discuss different pricing designs separately in this report, but in reality these approaches are not mutually exclusive and can be offered jointly. For example, one utility might offer a pricing option that includes a high customer charge, flat energy rate, and time-based demand charge, while another offers a rate with a low customer charge, TOU energy rate, and a demand charge assessed during any hour of the month (that is, one not limited to a peak period).

TIME-VARYING RATES

Within time-varying rates, we include TOU rates, CPP, VPP, and peak-time rebates (PTR). CPP, PTR, and VPP are also referred to as *dynamic* because the rates are adjusted in real time based on system conditions. RTP is also a time-varying rate, but we review it in its own section below. The common characteristics of these rate structures are that prices vary by the season or time of day. Within these different rate types, however, several differences exist. Here we define each rate type and then discuss findings from pricing pilots and other relevant literature.

Time-of-use rates. TOU rates vary on a fixed schedule to recover higher revenue during times when utility demands (and costs) are higher and lower revenue at other times. The intention of a TOU rate is to send customers price signals to reduce usage during peak hours at times when utility costs are highest. TOU rates also send price signals to customers related to future investments: if a utility can reduce peak demand, costly investments in new infrastructure may be avoided or deferred.[10] TOU rates have existed for several decades but are increasingly popular where AMI technology penetration is high. Most TOU rates are opt in or voluntary. Recent industry experience shows that pursuing a voluntary approach to TOU rates typically means that less than 2% of residential customers participate, although enrollment for some utilities is much higher because of proactive marketing and education (FERC 2012). Table 1 shows an illustrative TOU rate structure with seasonal differences.

Table 1. TOU rate structure with seasonal differences

Season	Period	Hours	Price per kWh
Summer	On-peak	4–7 pm weekdays	$0.21
Summer	Off-peak	All other weekday hours; all weekend hours	$0.09
Winter	On-peak	6–9 am and 6–9 pm weekdays	$0.15
Winter	Off-peak	All other weekday hours; all weekend hours	$0.07

Critical-peak pricing. Under CPP, a higher energy rate is assessed during an announced event for a limited number of hours. The higher energy rate is the result of higher wholesale electricity prices and allocation of costs for capacity needed at peak load, and can exceed $1 per kWh (Faruqui and Sergici 2013). The announced events are often limited to a certain number of days or hours per year. Like many other rate design options, the increased prevalence of CPP programs is largely driven by AMI technology. Table 2 shows an illustrative CPP rate structure combined with a TOU element.

Table 2. CPP rate structure combined with TOU

Period	Hours	Price/kWh
On-peak	4–7 pm weekdays	$0.15
Off-peak	All other weekday hours; all weekends	$0.07
Critical-peak event	3–7 pm during event day	$0.75

[10] The utility infrastructure referenced here would include transmission, distribution, and generation assets.

Peak-time rebate. The PTR rate structure awards customers with a financial rebate for energy saved during announced peak events. Generally, a utility will notify customers in advance of the opportunity to reduce usage for a bill credit of a specified amount. PTR is a low-risk option for customers because they have nothing to lose financially. However CPP often reduces rates at non-event times, while PTR increases rates at non-event times to offset the revenue effects of the events. Some utilities, such as PEPCO Maryland, automatically enroll customers in PTR.

Variable-peak pricing. VPP is a pricing structure that charges customers a higher rate for a predefined peak period. The rate's on-peak price component can change day by day, and customers are often alerted about it by a specific time during the previous day. Table 3 shows an example of a VPP rate structure: the off-peak period is constant at seven cents per kWh but in the event of high or critical demand, a utility would alert customers of a higher price during a predetermined peak period, such as 3–7 pm.

Table 3. VPP rate structure

Price/kWh	Description
$0.07	Off-peak/low
$0.12	Standard
$0.25	High
$0.50	Critical

Peak Demand Reductions

A primary benefit of time-varying rates is a reduction in peak demand and associated generation, transmission, and distribution costs. A 2012 survey of 24 pilots conducted between 1997 and 2011 demonstrated significant peak-load reductions from time-varying rates (Faruqui, Hledik, and Palmer 2012). The most significant peak demand reductions came from CPP, especially those treatments using enabling technology such as a programmable thermostat. Figure 3 shows the average peak reductions from 109 rate treatments—that is, combinations of time-varying rates and enabling technologies—in the 24 pilots.

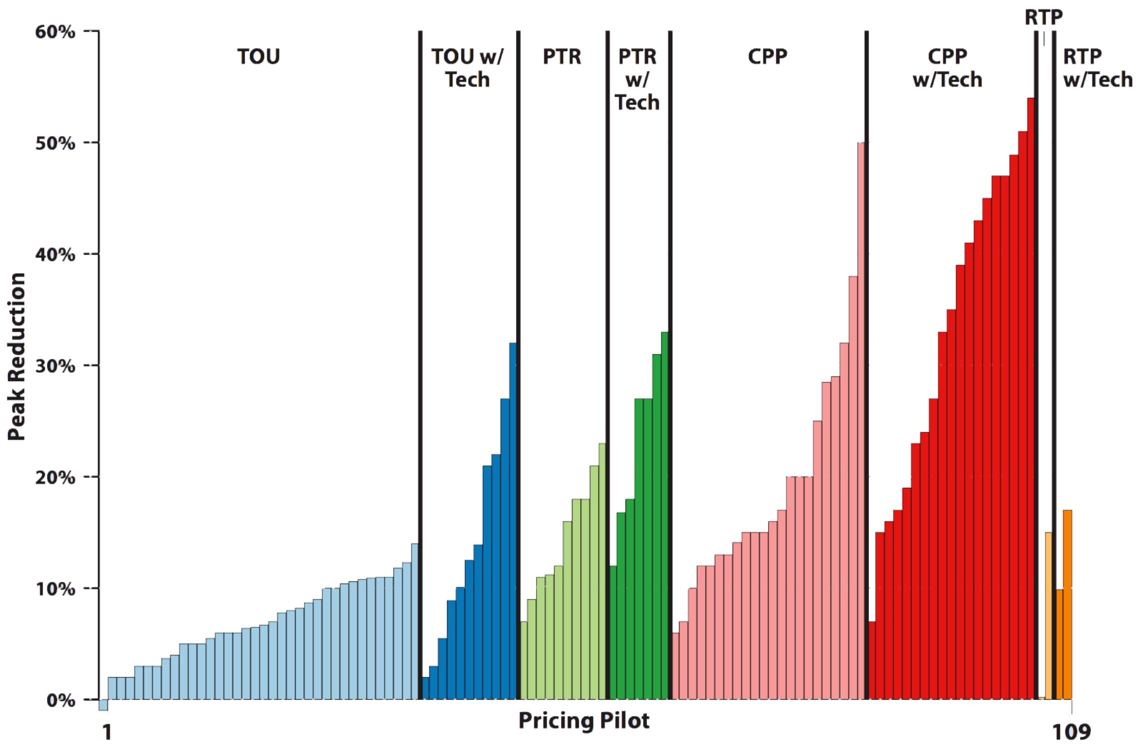

Figure 3. Average peak reduction from time-varying rate pilots. *Source:* Faruqui, Hledik, and Palmer 2012.

The 2012 study found that the on- to off-peak ratio of prices is a key driver in price response. Rate treatments with higher on- to off-peak ratios tended to produce larger peak demand reductions. A 2016 update to these findings expanded on the importance of the on- to off-peak ratio in increasing peak demand reductions, finding an "arc of price responsiveness," meaning that customer response increased, but then diminished at higher on- to off-peak ratios (Faruqui et al. 2016). Figure 4 shows the results from the updated study. The figure shows 204 pricing treatments, with price-only and price-plus technological intervention shown separately. The figure demonstrates a relationship between higher peak demand reduction and an increase in on- to off-peak ratio, especially in cases with technological intervention.

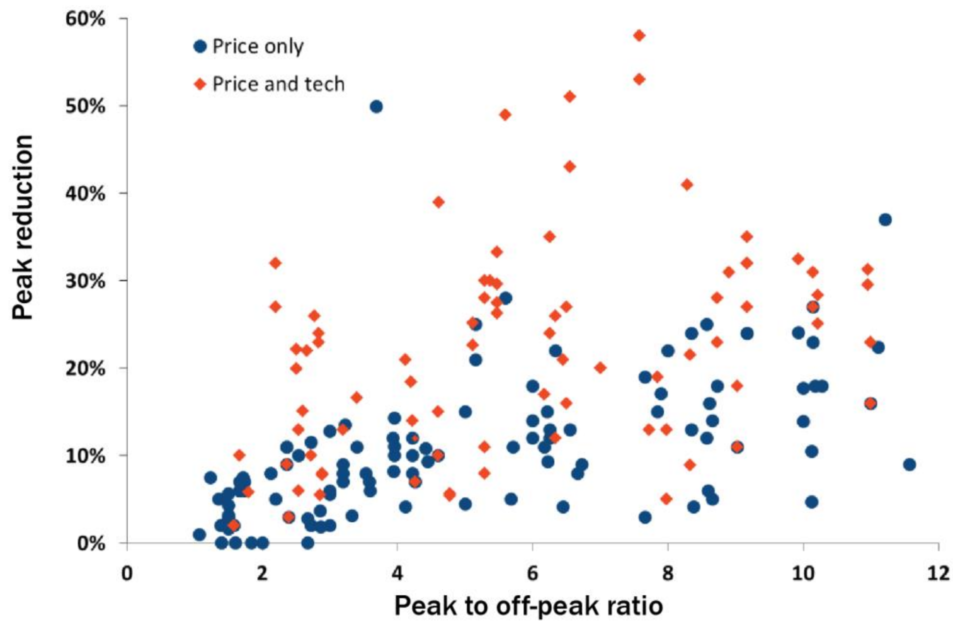

Figure 4. Peak period impacts for 204 time-varying rate treatments. Of the 204 treatments, 26 have ratios greater than 12:1. *Source:* Faruqui et al. 2016.

Change in Overall Consumption

The majority of the studies we reviewed clearly demonstrate peak demand reductions, which are a significant benefit. However time-varying rates may shift consumption from on- to off-peak periods. The magnitude of this shift varies based on several factors, including whether or not customers can actually shift usage from one hour to another. A lower price in an off-peak period also could potentially increase consumption in these periods. Our goal was to understand how time-varying rates affect overall consumption.

Six of the eight pricing pilots we reviewed for CPP, TOU, and PTR included estimates of total consumption changes due to pricing or technology treatments (for more details, see appendices B and C). We collected 50 observations within those six studies. An *observation* is a variation in technology or treatment in a specific year. For all 50 observations, the average peak demand reduction was 16% and the average reduction in consumption was 2.1%. Of the 50 observations, 19 were from year-long experiments, three were from fall/winter periods, and the remaining 28 were from summer experiments. Technology was involved in 16 of our 50 observations. The average peak demand reduction for those with technology was 23%, and the average reduction in overall consumption was 1.35%, relative to the control group. Table 4 shows descriptive statistics for each rate treatment group.

Table 4. Reduction in overall consumption and peak demand for 50 treatment groups in various pricing studies

Rate treatment	Number of observations	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Of the 50 observations, 19 involve annual changes in overall consumption; the remaining 31 are seasonal. Appendix C provides detailed information for each treatment and associated pricing pilot.

When reviewing the reductions in table 4 and figure 5, keep in mind that not all observations were statistically significant. However 46 of 50 observations showed a reduction in overall consumption. Only four observations showed an increase in consumption, with an average of 1%. All four of these observations involved a CPP rate.

Figure 5 shows the relationship between peak demand and overall consumption changes. This plot of all 50 observations indicates a very weak relationship between the two variables.

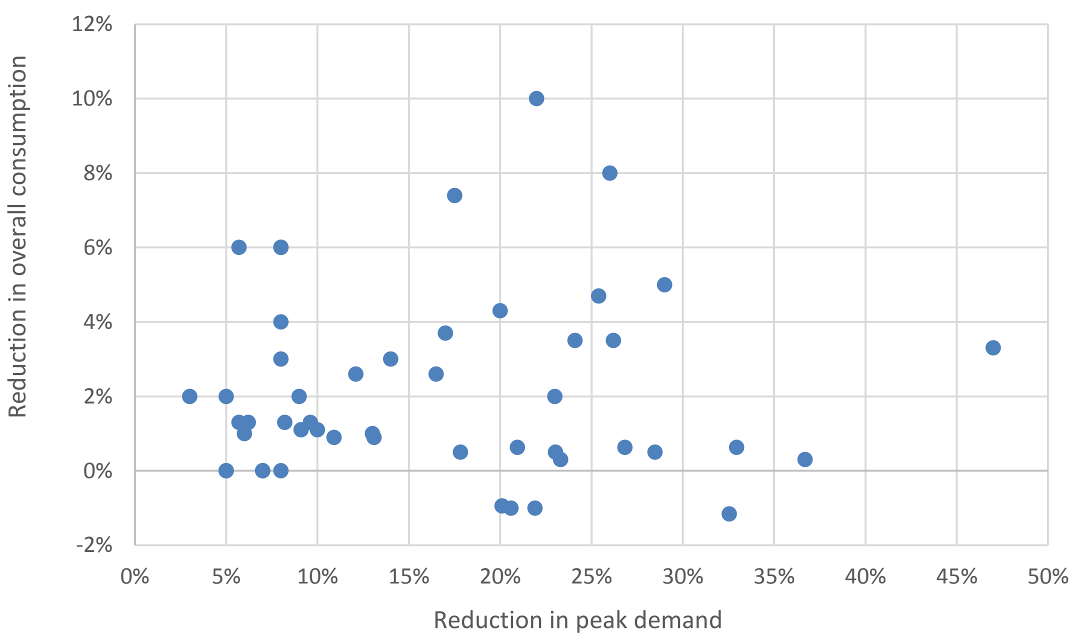

Figure 5. Reductions in peak demand and overall consumption for 50 observations in pricing pilots

Green Mountain Power Pricing Pilot and the Oklahoma Gas and Electric Consumer Behavior Study were not included in figure 5 because neither study explicitly included changes in overall consumption. However both demonstrated significant reductions in peak demand for nearly all treatments. The evaluation of the Oklahoma pilot included changes in off-peak consumption. For many treatment groups, the off-peak consumption increased, but did not offset the reductions in on-peak usage. The Green Mountain Power Pricing Pilot measured only the differences in overall usage for those with in-home display (IHD) devices and those without. Evaluation of the Green Mountain Power pilot showed the use of IHD technology reduced monthly consumption at a statistically significant level of between 2% and 5.3%.

Cost Basis for Time-Varying Rates

The time-varying rates outlined in this section are structurally different and align to system costs in different ways. CPP, VPP, and PTR are designed to send price signals about specific system conditions to customers in near real time. TOU rates are set based on projected system peaks and do not always capture real-time changes in hour-to-hour prices. However TOU rates can be combined with PTR or CPP. Time-varying rates are more closely aligned with utility system costs than flat rates. When compared with noncoincident peak demand charges, TOU rates may be better at reflecting the cost structure for most demand-related costs (NARUC 2016).

Conclusions for Time-Varying Rates

Our review shows that time-varying rate structures such as CPP, TOU, or PTR generally reduce overall consumption. In fact, the observations we collected document reductions in overall consumption for all rate types. Although many of the observations were not statistically significant, we can also infer that increases in overall consumption are not a normal occurrence in the pricing studies we reviewed.

REAL-TIME PRICING

RTP provides customers hourly electricity prices in real time based on wholesale market prices. The real-time price reflects the actual short-run marginal cost to provide service during peak periods of the day. Therefore the customer has a price signal to reduce usage at times when it is most valuable. Real-time prices reflect current conditions and provide a price signal based on the current marginal cost of power at a specific location (Hogan 2014). Real-time prices, as implemented for residential customers thus far, focus on energy prices and do not capture costs associated with generation, transmission, or distribution capacity.

Pricing information can be sent to customers in various ways, including email, text, telephone, or an installed in-home device. However some consumer advocates have argued RTP exposes customers to a high level of risk because of wholesale electricity markets' inherent volatility. While some states have experience offering RTP to industrial and commercial customers, very few utilities in the United States offer RTP to residential customers.

Commonwealth Edison in Illinois offers one of the largest residential RTP programs. At 4:30 pm, customers are sent day-ahead energy prices for the next day, but are billed based on the actual real-time prices. Figure 6 shows the day-ahead and real-time prices for a 24-hour period during a summer weekday in 2015.

Figure 2. Day-ahead and real-time prices for ComEd hourly pricing customers on August 12, 2015. *Source:* ComEd 2016.

In total, we reviewed four RTP programs. Two of these programs are ongoing (Ameren Illinois and Commonwealth Edison) and two are completed pilot studies (PEPCO PowerCents DC and Community Energy Cooperative Energy-Smart Pricing Plan). A review of these programs shows that customers do respond to higher prices and reduce overall consumption. An evaluation of the Commonwealth Edson residential RTP program showed an annual reduction in overall consumption of 4% from 2007 through 2010. However all four of these programs included only customers choosing to participate, thereby introducing selection bias into these findings.

DEMAND CHARGES

Some utilities are now offering a three-part residential rate consisting of a customer charge, volumetric rate (which can be time based), and a demand charge. The demand charge collects revenue based on a customer's peak demand during a defined time period. Demand charges have a long history of use for commercial and industrial customers, but very little history with residential customers. Table 5 shows select utilities with residential demand charges; this list is not exhaustive.

Table 5. Residential three-part rates for select utilities

Utility	State	Name	Customer charge ($/month)	Demand charge ($/kW)	Demand charge billing period	Volumetric rate
Alabama Power	AL	Time Advantage-Demand	$14.50	$1.50	All hours, all days	Varies, TOU
Arizona Public Service	AZ	Combined Advantage	$16.68	$13.50 (summer) $9.30 (winter)	Weekdays, 12–7 pm	Varies, TOU
UNS Electric	AZ	Residential Service Demand	$15.00	$5.10 (up to 7 kW) $7.10 (more than 7 kW)	Weekdays, 3–7 pm (summer); 6–9 am and 6–9 pm (winter)	6.61¢/kWh
Black Hills Energy	SD	Demand Service	$13.00	$8.10	All hours, all days	2.26¢/kWh
Black Hills Energy	WY	Demand Service	$15.50	$8.25	All hours, all days	6.43¢/kWh
Xcel Energy	CO	Demand Service	$12.25	$8.57 (summer) $6.59 (winter)	All hours, all days	1.74¢/kWh
Intermountain Rural Electric Association	CO	Residential Demand Metered	$10.00	$14/kW	All hours, all days	6.59¢/kWh
Glasgow Electric Board	KY	Residential Rate RS	$29.16	$11.33 (summer) $10.37 (winter)	Weekdays excluding holidays, 1–7 pm (summer); 6–10 am (winter)	Varies, TOU

The design of a residential three-part rate with demand charges can vary significantly. While these rates include a customer charge and a volumetric rate, the structure of the demand charge varies. The most significant differences are the time period in which the demand charge is assessed (peak or all hours) and the length of time peak demand is measured (often 60 minutes, but can be 15 or 30 minutes). Demand charges are intended to collect demand- or capacity-related costs of distribution, generation, and/or transmission.[11]

Cost Basis for Demand Charges

The differences in how a demand charge might be designed raises questions about the cost causation of such a charge. For example, if a demand charge is billed based on noncoincident peak (the customer's individual highest demand for a month, regardless of when it occurs relative to the utility system peak), the charge may not align with costs driving system peak. Also, if the demand charge is based on noncoincident peak, it may not recognize the diversity of usage from residential customers. Distribution system

[11] For a more detailed explanation on how demand charges can be designed to recover different categories of cost, see RMI 2015 and Chernick et al. 2016.

transformers and other localized distribution infrastructure are designed to meet combined and diverse loads (Chernick et al. 2016). A noncoincident peak demand charge may over-recover costs associated with that specific investment because customers sharing the capacity likely have individual peak demands at different times of the day; as a result, the sum of their noncoincident demands might exceed actual total capacity.

A cost-based coincident peak demand charge is difficult to design. Utility system peaks vary by year, often based on weather. Therefore utilities do not know when the monthly system peak is until month's end. Utilities could design a coincident peak demand charge based on expected hours during the day, but then risk a rate design that does not actually align with costs when the system peak falls outside of predetermined time periods. Many demand charges are also based on a 15-, 30-, or 60-minute time period in a single month. This single hour (or less) is not the only driver—and might not be even the primary driver—of a customer's contribution to costs associated with generation, transmission, and distribution capacity (Bornstein 2016).

The National Association of Regulatory Utility Commissioners (NARUC) *1949 Cost Allocation Handbook* identified several criteria for evaluating the equity of capacity cost recovery in rates; these were expressed succinctly in *Public Utility Economics* (Garfield and Lovejoy 1964). Table 6 compares the three types of rate design and how each achieves the criteria summarized by Garfield and Lovejoy (Lazar 2016). The table shows that the TOU energy charge is superior to coincident peak and noncoincident peak demand charges in terms of capacity cost recovery.

Table 6. Garfield and Lovejoy criteria for capacity cost recovery

Garfield and Lovejoy criteria	Coincident peak demand charge	Noncoincident peak demand charge	TOU energy charge
All customers should contribute to the recovery of capacity costs	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant costs	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something	Y	N	Y

Evidence of Demand Charge Impacts on Customer Behavior

Little evidence exists on how demand charges impact annual consumption or peak demand reduction, and few pilot studies focus on residential demand charges. A review of three pilots—two from the late 1970s and one from Norway in 2009—provide evidence of demand reductions, but the reductions varied widely within the studies (Hledik 2014). Further, because the two US studies are very old, they do not include the potential impact of modern technology.

The Brattle Group developed a model to simulate customer response to a three-part rate using an extensive library of customer price elasticity estimates found in previous pricing pilots. The model includes results for both load shifting and conservation effects (Hledik 2015). It predicts reductions in demand for the individual customer, the class peak, and the system peak, but also shows an increase in annual consumption. Table 7 shows the results of this analysis.

Table 7. Simulated average change in residential load metrics due to price response to a three-part rate

Metric	Average change
Customer max demand	−5.3%
Class peak demand	−1.7%
System peak-coincident demand	−1.5%
Annual consumption	0.2%

Source: Hledik 2015

Arizona Public Service (APS) also recently published a review of customer price response to demand charges (Snook and Grabel 2016). APS has more than 117,000 customers subscribed to its TOU demand rate. The study reviews usage changes for 977 customers who opted to move from the traditional energy TOU to the demand TOU rate. It demonstrates that these customers reduced summer peak demand by 0.3 kW or 3.9% on average and that residential customers reduced summer consumption by 2.9%, likely because of higher summer energy prices. However the annual consumption impacts are unclear because the study does not include changes in winter consumption. It is also unclear what information or technology customers received on reducing consumption and how much influence education or technology had on the reductions. The demographic characteristics of the treatment group are unknown; further, the customers opted into this rate, increasing the potential for selection bias in the study. Finally, it is unclear if the customers are responding to the demand charge or the TOU energy rate. Therefore it is difficult to draw definitive conclusions from this study.

The introduction of demand charges for solar customers has negatively affected rooftop solar installations as well. Salt River Project in Arizona was among the first electric utilities to implement a mandatory demand charge for rooftop solar customers. Following the rate design's approval in 2015, applications for rooftop solar permits dropped more than 95% (Magill 2015). A study one year after the rate's implementation showed that only 14% of rooftop solar customers were saving money on electric bills (Randazzo 2016). The Intermountain Rural Electric Association also experienced a similar decline in rooftop solar installations following the introduction of demand charges for its customers (Jaffe 2015).

Conclusions for Demand Charges

Current utility experience with residential demand charges demonstrates a lack of data and information on how customers respond to these rates. In the studies we reviewed, demand charges demonstrated smaller reductions in peak demand compared to other rate options, including TOU, CPP, and PTR. The APS study and the Brattle simulated price response produced contradictory results in terms of changes in annual consumption. The Glasgow, Kentucky, experience—which was an early instance of mandatory demand charges for the entire residential customer class—indicated that some customers faced much higher bills and may have had difficulty responding to the new rate structure. Given the results of the studies we reviewed, more research is needed to fully understand customer response and understanding, as well as the impact on low-income customers. Research should also evaluate the effect of the demand charge relative to any energy rate included in the rate design.

HIGHER CUSTOMER CHARGES

In recent years, we have seen a considerable increase in the number of utility proposals to raise the monthly customer charge (also known as the service charge, standing charge, connection fee, or fixed charge). Historically, this charge was designed primarily to collect the customer-specific costs of metering, customer service, billing, and the service drop. Utilities are now proposing to recover more distribution infrastructure costs in this charge.

Assuming revenue neutral rates, increasing the customer charge decreases the volumetric energy rates. Lower volumetric rates reduce the price signal to customers to conserve electricity and engage in energy efficiency. Consider an example based on load research data in the most recent UNS Electric rate case. In this example, we assume a proposed increase in the customer charge of $10 per month (raising it from $10 to $20). As table 8 shows, the proposed increase in the customer charge reduces the revenue collected in the energy rate by 11%, reducing the energy rate in $/kWh by 14%.

Table 8. Changes in volumetric rate based on changes in customer charge

Customer charge ($/month)	Revenue requirement collected in customer charge	Revenue requirement remaining	% of revenue requirement collected in customer charge	Energy rate ($/kWh)
$0	$0	$2,508,500	0%	$0.1139
$5	$138,540	$2,369,960	6%	$0.1076
$10	$277,080	$2,231,420	11%	$0.1013
$15	$415,620	$2,092,880	17%	$0.0950
$20	$554,160	$1,954,340	22%	$0.0887
$25	$692,700	$1,815,800	28%	$0.0824
$30	$831,240	$1,677,260	33%	$0.0761
$35	$969,780	$1,538,720	39%	$0.0699
$40	$1,108,320	$1,400,180	44%	$0.0636
$45	$1,246,860	$1,261,640	50%	$0.0573
$50	$1,385,400	$1,123,100	55%	$0.0510

Values based on load research sample in UNS Electric 2015 rate case

As this example demonstrates, as a utility moves more revenue collection to customer charges, the volumetric rate must correspondingly decrease. In this case, transferring 11% of the revenue requirement from the volumetric energy rate to the customer charge means a reduction in the energy rate of approximately 1.5 cents per kWh.

According to a 2008 study on electric price elasticity, the Electric Power Research Institute (EPRI) found that customers do respond to changes in electric prices (EPRI 2008). Price elasticity is a measure of customer response to changes in prices. The study found that customer response varies based on the time period considered. Customers tend to respond to changes in electric prices at greater levels in the long term (greater than five years) than the short term (between one and five years). Table 9 shows the study's results.

Table 9. EPRI price elasticity estimates

Sector	Short run			Long run		
	Mean	Low	High	Mean	Low	High
Residential	−0.3	−0.2	−0.6	−0.9	−0.7	−1.4
Commercial	−0.3	−0.2	−0.7	−1.1	−0.8	−1.3
Industrial	−0.2	−0.1	−0.3	−1.2	−0.9	−1.4

Source: EPRI 2008

Using the example in table 8 and the elasticities in table 9, we can forecast changes in overall consumption. Assuming the residential sector price elasticity estimates, overall consumption will increase from between 2.8% and 8.5% in the short run, and 9.9% and 19.8% in the long run. Even a conservative estimate using the low short- and long-run elasticity estimates projects increased consumption in our example. Figure 7 shows the results of this analysis.

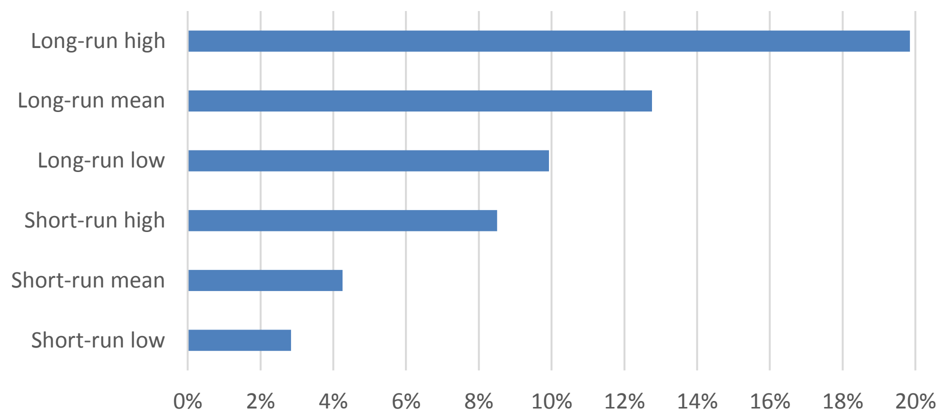

Figure 7. Overall change in consumption when moving from a $10 to a $20 customer charge under EPRI 2008 residential price elasticity estimates

We could not locate any existing pilot studies in which a utility implemented higher customer charges and corresponding lower volumetric rates. While such a study may not exist, research into customer response tells us that consumers will increase consumption of electricity when facing lower rates. Our example demonstrates the potential implications for overall consumption in rate designs with higher customer charges. Increased customer consumption will require additional utility infrastructure in the long term, as utilities will need to meet growing demand. High customer charges are undesirable as they will increase long-term costs for all utility customers.

Conclusions for Customer Charges

When they exceed basic customer costs such as metering, customer service, billing, and the service line drop, higher customer charges are not cost based. Further, high customer charges discourage energy efficiency investments by reducing the volumetric rate price signal. Some research also suggests that higher customer charges—when combined with lower volumetric rates—may increase overall consumption, which would lead to higher utility system costs.

Rate Design and Energy Efficiency Investments

Residential customers reduce electricity usage for a variety of reasons, including to save money on electric or gas bills, increase comfort, reduce environmental impacts, and improve aesthetics. Customers also engage in energy efficiency programs when replacing broken or failing equipment. While nonmonetary benefits are important, recent research indicates customers primarily reduce usage and participate in energy efficiency programs to reduce bills and save money.

For example, a 2010 Accenture survey found that 88% of respondents cited decreases in the amount of an electric bill as a factor that most encouraged the use of electricity management programs (Accenture 2010). Another study conducted in 2014 surveyed residential customers who had previously installed solar systems. When this survey asked customers about factors that motivated their energy efficiency upgrades, 71.8% ranked lower energy bills as most important (Langheim, Arreola, and Reese 2014).

Further, a 2013 focus group study also found that the overwhelming response to why people make energy improvements is to save money and energy. This result was consistent in all six geographic focus group locations; other reasons cited included comfort, reduced noise, improved value, environmental and sustainability concerns, appearance, and health and safety (DOE 2013b).

Another study surveyed 615 people in Vermont not known to have previously participated in statewide home performance or home retrofit programs. The study sought to discover the barriers to participation in these programs. When asked about reasons for completing home energy projects over the past five years, 62% cited lowering electric or heating bills as a reason. This compares to only 18% for improving comfort, 16% for reducing carbon impacts or helping the environment, and 11% for replacing broken or failing equipment (GDS 2013a).

A national survey conducted by the Acadia Consulting Group produced a similar response. In this study, the 1,278 respondents included contractors, energy auditors, weatherization agencies, and other trade groups. The survey's primary objective was to collect information related to challenges facing the home performance industry and how outside organizations can support this industry in the future. When asked what motivates homeowners to make energy efficiency or clean energy improvements in homes, 84% cited saving money and 68% said improving comfort (Acadia 2017).

As these studies clearly show, reducing bills and saving money is the primary driver for customers to engage in energy efficiency. Rate design can alter the payback periods of energy efficiency investments. A payback period analysis determines how many years it will take a customer to break even on their investment. Bill savings repay the customer. The higher the electricity rate avoided, the quicker the payback will occur.

METHODOLOGY

To better understand rate design's effect on payback periods, we reviewed payback periods for 14 energy efficiency measures or programs under 20 rate design scenarios. To conduct this analysis, we used energy efficiency savings and incremental cost data from the Arizona Public Service's *Technical Resource Manual* (APS TRM). This resource is updated annually and approved by the Arizona Corporate Commission. Table 10 shows the 14 programs, including data on annual energy savings, coincident peak demand reduction, and incremental cost (the cost of a measure or program above the baseline investment). Appendix D provides detailed descriptions of each program and measure.

Table 10. Measures and programs used in the analysis

Measure or program	Annual energy savings (kWh)	Coincident peak demand savings (kW)	Incremental cost ($)
LED 40-watt replacement	27.17	0.00139	$4.04
LED 60-watt replacement	36.87	0.00189	$6.02
LED 75-watt replacement	42.69	0.00219	$9.91
Variable-speed pool pump	1,725	0.19600	$437
Duct test and repair	865	0.81282	$907
Prescriptive duct repair	421	0.39572	$300
Advanced diagnostic tune-up	492	0.27232	$157
Equipment replacement with quality installation	576	0.62160	$330
New construction ESTAR Homes v. 3.0	2,156	0.86000	$2,132
New construction ESTAR Homes v. 3.0—Tier 2	3,247	1.31000	$2,830
New construction total program	2,593	1.04000	$2,411
Attic insulation	787	0.28000	$922
Air sealing and attic insulation	1,235	0.36000	$1,610
Smart strip	96	0.02532	$22.49

We calculated payback periods for these measures using the hourly load shape data in table 11 for 20 iterations of rate design. All 20 iterations are *revenue neutral*, that is, they produce the same revenue outcomes for the utility. The first three scenarios are simple two-part rates with different levels of customer charge and corresponding flat volumetric charges. The second set of scenarios involves a tiered rate structure under two different potential customer charges: $5 and $25. The next six scenarios are iterations of TOU rates based on different combinations of customer charges ($5 and $25) and corresponding volumetric rates based on different on- to off-peak ratios. The final nine scenarios are iterations of three-part rates consisting of customer, demand, and volumetric charges at various levels. Appendix E shows the specific rates for each scenario.

We relied on hourly load profile data from the Open Energy Information (Open EI) database.[12] Our analysis focuses on residential measures only, although the APS TRM and Open EI database contain relevant data on commercial and industrial measures as well. The hourly load data is for the Phoenix region. We normalized these data and created bins based on a four-hour peak time period from 3–8 pm on weekdays.[13] To do this, we summed the

[12] This dataset contains hourly load profile data for residential buildings based on the Building America House Simulation Protocols (Hendron and Engebrecht 2010). This dataset also uses the Residential Energy Consumption Survey (RECS) for statistical references of building types by location (Open EI 2016).

[13] We did not remove holidays for this analysis.

load in each hour and then divided each bin by the number of hours in each bin. Table 11 shows the load shape bins used for this analysis.

Table 11. Load shapes used for payback analysis (percentage of hours in each time period)

Load shape	Summer off-peak	Summer on-peak	Winter off-peak	Winter on-peak
Whole facility	52%	13%	28%	6%
HVAC	72%	23%	3%	1%
Interior lights	36%	5%	49%	10%
Interior equipment	41%	9%	41%	9%

LIMITATIONS OF ANALYSIS

This analysis has several limitations. First, it is limited to one utility service territory. Each utility service territory is different in terms of weather, geographic scope, and demographics. Weather differences will alter payback periods for different measures. Second, the analysis focuses on a five-hour peak window. Using a longer or shorter peak period will alter the payback periods. Finally, this analysis did not assume any customer response (changes in usage patterns and consumption) to the changes in rate design, which would likely occur for most customers.

FLAT AND TIERED RATE RESULTS

The first five scenarios are based on iterations of flat rates. Table 12 shows the assumptions for each scenario. The tiered rates were constructed using three tiers. We assumed energy savings from each measure occurred in the highest tier, shown as the energy rate in table 12. All rate scenarios are revenue-neutral based on the same test year sales levels.

Table 12. Assumptions for flat-rate scenarios

Scenario	Customer charge ($/month)	Energy rate type	Effective energy rate ($/kWh)
1	$5	3 tiers	0.1504
2	$25	3 tiers	0.1101
3	$5	Flat	0.1076
4	$25	Flat	0.0824
5	$50	Flat	0.0510

Table 13 shows the assumptions for the two scenarios with tiered rates.

Table 13. Tiered rate structure price assumptions

Scenario	Customer charge	Tier 1		Tier 2		Tier 3	
		$/kWh	Usage	$/kWh	Usage	$/kWh	Usage
1	$5	$0.0800	0–500	$0.1204	501–1,000	$0.1504	>1,000
2	$25	$0.0702	0–500	$0.0803	501–1,000	$0.1101	>1,000

Table 14 shows the differences in payback periods in years under the five scenarios shown in table 12.

Table 14. Payback periods for measures and programs under Scenarios 1–5

Measure/program	Tiered $5 CC	Tiered $25 CC	Flat $5 CC	Flat $25 CC	Flat $50 CC
LED 40-watt replacement	0.99	1.35	1.38	1.80	2.92
LED 60-watt replacement	1.09	1.48	1.52	1.98	3.20
LED 75-watt replacement	1.54	2.11	2.16	2.82	4.55
Smart strip	1.56	2.14	2.18	2.85	4.61
Variable-speed pool pump	1.69	2.30	2.36	3.08	4.97
Advanced diagnostic tune-up	2.12	2.90	2.97	3.87	6.26
Equipment replacement with quality installation	3.81	5.20	5.32	6.95	11.23
Prescriptive duct repair	4.74	6.47	6.62	8.65	13.97
New construction ESTAR Homes v3.0—Tier 2	5.80	7.92	8.10	10.58	17.09
New construction total program	6.18	8.45	8.64	11.28	18.23
New construction ESTAR Homes v3.0	6.57	8.98	9.19	12.00	19.39
Duct test and repair	6.97	9.52	9.74	12.72	20.56
Attic insulation	7.79	10.64	10.89	14.22	22.97
Air sealing and attic insulation	8.67	11.84	12.12	15.82	25.56

CC = Customer charge

As table 14 shows, the changes in rate design significantly alter payback periods, especially for measures with higher incremental costs. Of the five scenarios, the low customer charge ($5 per month) and three-tiered rate structure (with either level of customer charge) offer the shortest payback periods. Payback periods more than doubled when customer charges moved from $5 to $50. Moving from a $5 to $25 monthly customer charge produced payback periods that were 31% longer; going from a $25 to $50 customer charge increases payback periods by 62%.

TIME-OF-USE RATE RESULTS

The next six scenarios are based on iterations of TOU rates using various levels of customer charges and differing ratios of on-to-off peak rates. Our TOU rate analysis used a five-hour on-peak time period of 3–8 pm on weekdays. Table 15 outlines the details of each scenario.

Table 15. TOU rate scenarios

Scenario	Customer charge ($/month)	On- to off-peak ratio	Summer off-peak ($/kWh)	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)
6	$5	2	$0.090	$0.181	$0.091	$0.181
7	$25	2	$0.073	$0.145	$0.065	$0.129
8	$5	3	$0.077	$0.232	$0.079	$0.238
9	$25	3	$0.062	$0.186	$0.057	$0.170
10	$5	4	$0.068	$0.270	$0.071	$0.283
11	$25	4	$0.054	$0.217	$0.050	$0.201

Table 16 shows the differences in payback periods under the six scenarios in table 15.

Table 16. Payback periods (years) for TOU rate design scenarios for various measures

Program/measure	$5 CC 2:1 ratio	$25 CC 2:1 ratio	$5 CC 3:1 ratio	$25 CC 3:1 ratio	$5 CC 4:1 ratio	$25 CC 4:1 ratio
LED 40-watt replacement	1.43	1.91	1.45	1.94	1.47	1.97
LED 60-watt replacement	1.57	2.09	1.59	2.13	1.62	2.17
LED 75-watt replacement	2.23	2.97	2.27	3.03	2.30	3.08
Smart strip	2.20	2.91	2.21	2.91	2.21	2.92
Variable-speed pool pump	2.26	2.83	2.21	2.76	2.17	2.72
Advanced diagnostic tune-up	2.84	3.56	2.78	3.48	2.73	3.42
Equipment replacement with quality installation	5.10	6.38	4.99	6.24	4.90	6.14
Prescriptive duct repair	6.34	7.94	6.20	7.76	6.10	7.64
New construction ESTAR Homes v3.0—Tier 2	8.08	10.46	8.08	10.44	8.08	10.46
New construction total program	8.62	11.16	8.62	11.14	8.62	11.16
New construction ESTAR Homes v3.0	9.17	11.87	9.17	11.85	9.17	11.87
Duct test and repair	9.34	11.68	9.13	11.42	8.98	11.24
Attic insulation	10.43	13.05	10.20	12.76	10.03	12.56
Air sealing and attic insulation	11.61	14.53	11.35	14.20	11.16	13.98

CC = Customer charge

Payback periods for TOU rate scenarios varied by measure. For some measures, such as LED lighting, payback periods increased when moving to higher on- to off-peak ratio rates. For other measures, such as attic insulation and duct test and repair, the payback periods declined when moving from 2:1 to 4:1 on- to off-peak ratio rates because large amounts of usage occurred outside the peak window. However the changes in payback periods were small when changing the on- to off-peak ratios. The largest shifts in payback periods were caused by higher customer monthly charges. Moving from a $5 to $25 customer charge increased payback periods by 25–34%, depending on the measure.

DEMAND CHARGE RATE RESULTS

The final set of scenarios we considered include a customer charge, demand charge, and volumetric energy rate. We constructed rates using three different customer charges ($5, $15, and $25) and three demand rates ($5, $7.50, and $10 per kW). Determining payback periods for demand charge rates is complicated by the way in which demand charges are billed. These charges are typically based on the customer peak demand in a 15- to 60-minute period of the month. The peak demand period typically must fall within a specified time window—such as noon to 7 pm on weekdays. The demand savings in the APS TRM are coincident peak savings, meaning that the demand reduction is what you could expect during the utility's system peak. Therefore it is very difficult to know whether or not the specific measure's demand savings will occur at that time and produce bill savings. For the purpose of this analysis, we assumed coincident peak demand reductions would amount to customer bill savings 50% of the time. We based this assumption on discussions with internal staff and other industry experts and believe it to be conservative.

Table 17 outlines the demand charge rate scenarios.

Table 17.Demand charge rate scenarios

Scenario	Customer charge ($/month)	Demand charge ($/kW)	Energy rate ($/kWh)
12	$5	$5	$0.0815
13	$15	$5	$0.0690
14	$25	$5	$0.0564
15	$5	$7.50	$0.0685
16	$15	$7.50	$0.0559
17	$25	$7.50	$0.0434
18	$5	$10	$0.0555
19	$15	$10	$0.0429
20	$25	$10	$0.0303

Table 18 shows the differences in payback periods under the nine scenarios in table 17.

Table 18. Payback periods (years) for demand charge rate design scenarios for various measures

Program/measure	$5 CC $5/kW	$15 CC $5/kW	$25 CC $5/kW	$5 CC $7.50/kW	$15 CC $7.50/kW	$25 CC $7.50/kW	$5 CC $10/kW	$15 CC $10/kW	$25 CC $10/kW
LED 40-watt replacement	1.79	2.11	2.57	2.10	2.55	3.26	2.54	3.23	4.45
LED 60-watt replacement	1.97	2.32	2.82	2.31	2.80	3.58	2.79	3.55	4.89
LED 75-watt replacement	2.79	3.29	4.01	3.28	3.99	5.08	3.96	5.05	6.95
Smart strip	2.63	3.06	3.65	2.92	3.46	4.25	3.29	4.00	5.09
Variable-speed pool pump	2.99	3.50	4.24	3.44	4.15	5.23	4.07	5.10	6.83
Advanced diagnostic tune-up	3.25	3.73	4.37	3.42	3.95	4.68	3.60	4.19	5.02
Equipment replacement with quality installation	5.03	5.65	6.45	4.89	5.48	6.23	4.76	5.32	6.02
Prescriptive duct repair	6.49	7.33	8.42	6.43	7.25	8.32	6.37	7.17	8.21
New construction ESTAR Homes v3.0—Tier 2	9.31	10.75	12.73	10.06	11.76	14.17	10.94	12.98	15.98
New construction total program	9.94	11.48	13.59	10.74	12.57	15.14	11.69	13.88	17.09
New construction ESTAR Homes v3.0	10.58	12.22	14.47	11.44	13.38	16.13	12.45	14.79	18.22
Duct test and repair	9.56	10.79	12.40	9.46	10.68	12.24	9.37	10.56	12.09
Attic insulation	12.70	14.71	17.47	13.86	16.28	19.73	15.25	18.23	22.67
Air sealing and attic insulation	14.44	16.78	20.02	15.97	18.88	23.08	17.86	21.58	27.26

Energy charges for these scenarios are shown in table 17.

Payback periods increase under demand rates for all measures when compared to flat, tiered, or TOU rates, especially when combined with a high monthly customer charge of $25. Even under a low customer charge, payback periods increase by 42% on average moving from a $5 to $10 per kW demand charge. Shifting cost recovery from volumetric to demand rates increased the payback period for all measures we reviewed. For measures with higher incremental costs, the increase in payback periods was substantial. For example, in a scenario with a $5 per kW demand charge, moving from a $5 to $25 customer charge increased payback periods for air sealing and attic insulation from 14.5 to 20 years. For a higher demand charge ($10 per kW), the result increased a 17-year payback to more than 27 years.

PAYBACK ANALYSIS CONCLUSIONS

Our analysis shows that changes in residential rate design alter payback periods for the measures we reviewed. As an example, figure 8 shows the payback periods for the residential new construction total program.

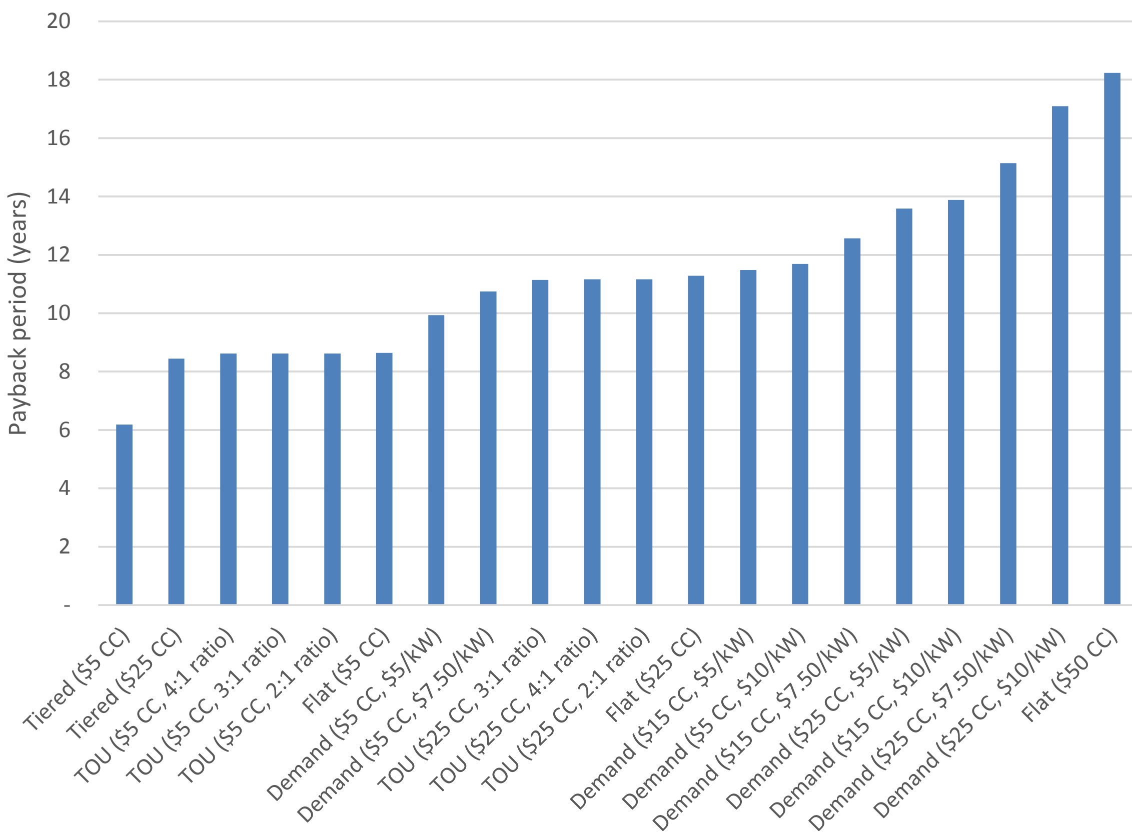

Figure 8. Residential new construction total program payback periods for various rate design scenarios

As the figure shows, the scenarios with the longest payback periods are those with higher customer charges (more than $25 per month) and demand charges. The scenarios with the lowest payback periods tended to be those with lower customer charges, tiered or flat rates, and TOU rates. Moving from a TOU or flat rate with a $5 customer charge to a demand rate with a $25 customer charge and a demand charge of $7.50 or $10 per kW doubled the payback period for this program. Moving from an inclining tiered rate with three tiers and a $5 customer charge to a flat rate with a $50 customer charge tripled the payback period.

Figure 9 shows the payback periods for replacing a 60-watt lamp with an LED.

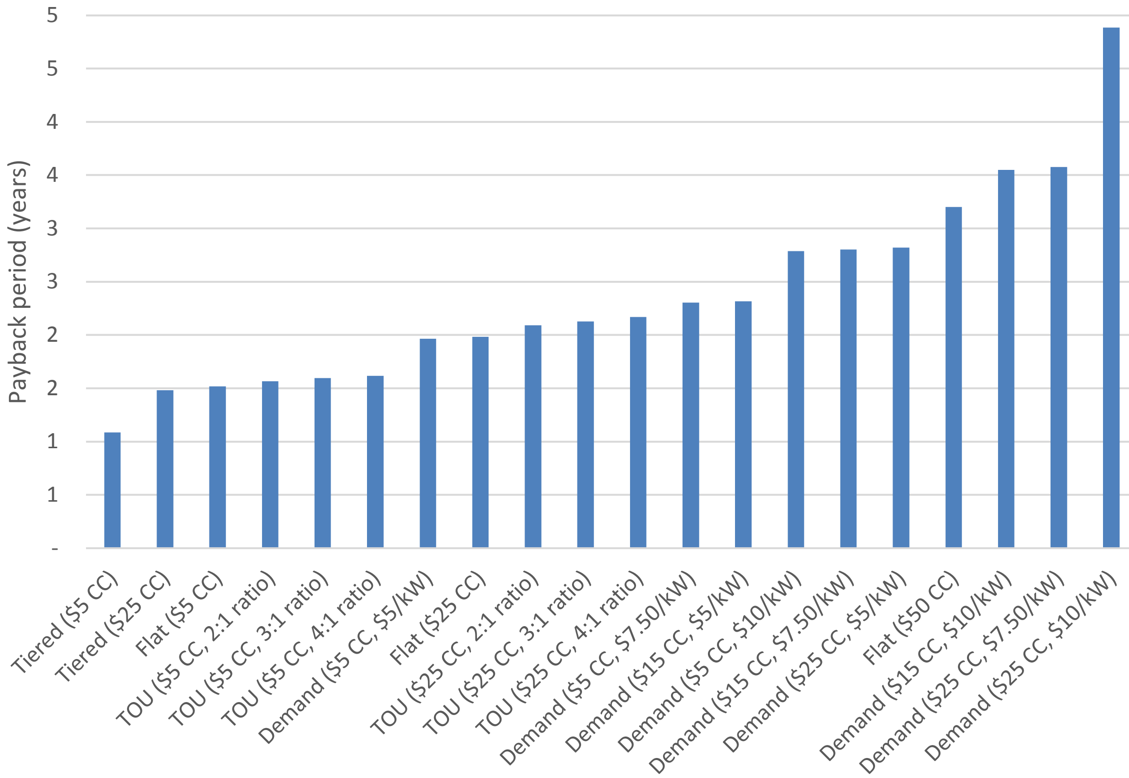

Figure 9. LED 60-watt replacement measure payback periods under various rate design scenarios

As figure 9 shows, the results here are similar: the rate designs with low monthly customer charges and tiered rates produce the shortest payback periods. TOU rates coupled with any level of customer charges performed well, with payback periods of approximately two years or less. Scenarios with demand charges performed poorly in payback periods; only the demand rate with a $5 monthly customer charge and $5 per kW demand charge fell under a two-year payback.

In all, rate design scenarios utilizing demand charges showed large increases in payback periods—often more than 30%—compared to flat or TOU rates. Scenarios focused on tiered rates showed the shortest payback periods, even when combined with a higher monthly customer charge. Scenarios with higher customer charges often increased payback periods, especially when combined with demand charges.

Rate Design Implications for Low-Income Customers

One policy consideration of ratemaking is the impact of proposed rates on low-income customers. Low-income customers have less ability to invest in energy efficiency and to respond to large rate swings. However low-income customers use relatively less energy during the peak hours, and their load profiles are often flatter than those of the average residential customer (Faruqui, Sergici, and Palmer 2010; Cappers et al. 2016b). Low-income customers may also use less electricity on average when compared with higher-income customers, although this may not be the case for all utilities.[14] In an analysis of 2009 data from the EIA's Residential Energy Consumption Survey, the National Consumer Law Center showed that electric consumption was lower for households under 150% of federal poverty guidelines in 26 of 27 regions nationally (Howat 2016).

If low-income customers tend to have lower usage, rate designs that recover more costs from lower usage customers could disproportionally affect them. In particular, utility proposals that significantly increase the customer charge are one form of rate design that disproportionately affects low-usage customers. Figure 10 shows the distributional impacts of a revenue neutral shift from a $5 monthly customer charge to $25. As the figure illustrates, low-usage customers are adversely affected. Customers using more than 800 kWh per month would see reductions in bills, while customers using less would experience bill increases.

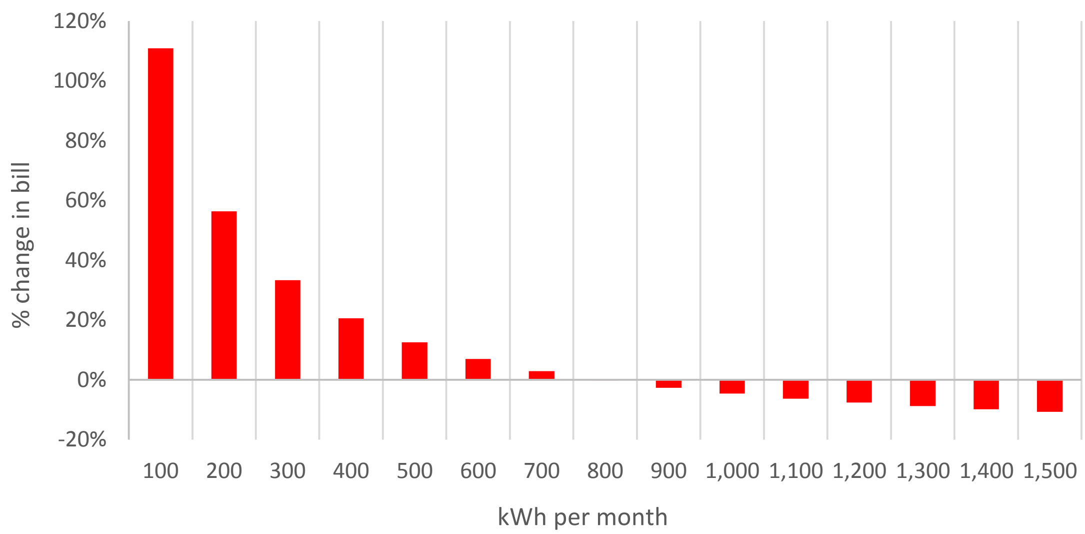

Figure 10. Distributional impacts for usage levels when shifting from a $5 customer charge per month to a $25 charge, based on data from table 8. Both rate options are revenue neutral.

EVIDENCE FROM PRICING PILOTS

Low-income customers often have a flatter usage profile, implying that any rate design structure with higher rates during peak hours could benefit them, even in the absence of behavioral or technological changes. Although most of the rate design pilots we reviewed did not specifically evaluate impacts on low- or limited-income customers, several did consider this issue.

[14] For example, residential customers on the low-income CARE for Pacific Gas and Electric rate use more electricity on average than customers not on CARE rates. Several factors explain this including: low-income customers live in hotter climate zones and have less energy-efficient homes. It is also important to consider that not all low-income customers are enrolled in low-income rates.

A recent Lawrence Berkeley National Laboratory report reviewed the experience of low-income customers with CPP rates using the results of two large pricing pilots in the Green Mountain Power (GMP) and Sacramento Municipal Utility District (SMUD) service territories. The study found that low-income customers in SMUD's service territory who had volunteered for the rate had lower average use levels during CPP events and were less responsive than other customers. However low-income customers under the default enrollment approach demonstrated a similar response to other customers. The study did not present changes on overall consumption, but it found bill impacts to be similar for low-income and higher-income populations. Finally, the study found that low-income customers did not report greater levels of discomfort or hardship while responding to the CPP events (Cappers et al. 2016b).

Under the SMUD SmartPricing Options study, low-income customers (those enrolled in the Energy Assistance Program rate) opted in and dropped out at a lower rate than other customers. Under the default TOU pricing plans, low-income customers showed very similar absolute and percentage load reductions. For default CPP and all opt-in plans, average load reductions for lower-income customers were less than other customers. The evaluation of the SmartPricing Options study also estimated price elasticities for low-income customers.[15] The analysis demonstrated that low-income customers were about 50% less responsive to changes in price than other customers (Jimenez, Potter, and George 2014).

Other studies in California show low-income customers are less responsive to changes in price. The California Statewide Pricing Pilot showed that CARE customers (those qualifying for bill assistance based on income criteria) showed very low price responsiveness (CRA 2005). Another evaluation of Pacific Gas & Electric's 2015 SmartRate CPP program shows that CARE customers demonstrated smaller demand reductions than other customers (Braithwait et al. 2016).

In phase 1 of the Oklahoma Gas & Electric Smart Study Together pilot, low-income participants demonstrated a higher percentage savings and higher demand savings than other income segments in some cases (GEP 2011). During the PECO Smart Time Pricing Pilot, low-income customers on TOU rates responded at a much higher rate than average accounts. Low-income customers—those with a household income under $34,000—had an average peak-load reduction of 7.3%, compared to 5.7% for all accounts (Bade 2015).

CONCLUSIONS ON LOW-INCOME CUSTOMERS AND RATE DESIGN

If low-income customers do have flatter load profiles than other customer groups, they could be favorably affected by TOU rates. Although some of these customers may still see increased bills, they could see lower bills than other customers with higher peak demand. Our review of a few studies documents this possibility, but this may not be the case for all utilities. Low-income customers have limited financial resources and lower levels of discretionary energy usage than other customers, which limits their ability to respond to

[15] *Price elasticities* measure how much a customer will change consumption in response to a change in price, generally representing the percentage change in consumption based on a 1% change in price.

rate changes. They should be carefully targeted in any transition to new rates and offered programs, tools, and information to help them respond.

Summary of Findings

Large-scale technological shifts are stimulating changes in the electric utility industry. These changes are also driving a wide range of new rate structures for residential customers. Some aspects of recently proposed rate design, such as higher customer charges, diminish the price signal to customers to be energy efficient. This could adversely affect the achievement of energy efficiency goals, including by reducing customer motivation to participate in utility energy efficiency programs or make energy efficiency investments. As we outlined in our rate design principles, a primary objective should be to promote conservation and energy efficiency. Incentivizing energy efficiency offers benefits, and sending customers proper price signals to efficiently use electricity will reduce system costs in the long run by avoiding costly infrastructure investments.

Trends in rate design include increased utility proposals for higher customer charges; implementation of default TOU rates; increased attention to other dynamic rates, such as CPP, PTR, and VPP; and increased prevalence of residential three-part rates with demand charges. We also found strong customer opposition to higher customer charges and residential demand charges for the cases we reviewed.

A review of customer motivations shows that, while customers reduce consumption and participate in energy efficiency program for a variety of reasons, bill savings are the primary motivator. Changes in rate design can dramatically affect the potential bill savings and payback periods for many energy efficiency measures. Our analysis of 14 measures under 20 different rate design scenarios shows that demand charges increase payback periods—often more than 30%—compared with flat or TOU rates. Scenarios focused on tiered rates showed the shortest payback periods, even when combined with a higher monthly customer charge. TOU rates also demonstrated lower payback periods than demand charges or rates with higher customer charges.

Studies have long demonstrated the peak-load reduction effects of dynamic prices (Faruqui, Hledik, and Palmer 2012; Faruqui et al. 2016). While reducing peak demand is a valuable objective, changes in overall consumption are also very important. Our review of eight recent pricing pilots found that customers generally reduce overall consumption under time-varying rates.

A final important consideration of changes to rate design is the potential impact on low-income customers. Although low-income customers may lack the financial resources to invest in energy efficiency measures to avoid potential bill increases from rate changes, these customers have shown some ability to respond to dynamic rates. These customers also often have a flatter load profile, meaning that many could benefit financially from a TOU rate without any behavior change. The vulnerability of low-income customers makes it especially important for utilities to consider adverse impacts for those customers unable to reduce or shift their electricity usage.

Recommendations

ACEEE offers the following recommendations on energy efficiency and residential rate design options.

CUSTOMER CHARGES AND VOLUMETRIC RATES

ACEEE recommends limiting customer charges to include only costs associated with billing, customer service, meters, and service drops (also known as the *basic customer method*). This approach simplifies calculation of the customer charge, ensures equity, and provides a stronger price signal to conserve.

Our analysis demonstrates that, other things being equal, higher customer charges necessitate reduced volumetric rates. Lower volumetric rates can cause increases to overall consumption in the long term, thereby increasing the need for utility infrastructure to meet new demand. Higher customer charges also discourage the price signal for customers to engage in energy efficiency programs or make other energy efficiency investments. Finally, our payback period analysis showed that increased customer charges often adversely impacted payback periods for energy efficiency measures.

TIME-OF-USE RATES

ACEEE supports the implementation of TOU rates for residential customers as an alternative to higher customer charges and demand charges. TOU rates offer many advantages and send more accurate price signals to customers about the cost of electricity at specific times.

TOU rates provide many benefits, including reducing peak demand and more accurately collecting utility costs at the time they are incurred than most other rate options. TOU rates are also well understood by residential customers. Our review of recent pricing pilots shows that customers on TOU rates do not increase their overall consumption. The SMUD pricing pilot also indicated that customers who were defaulted into TOU rates were satisfied with the rates, did not opt out at high levels, and reduced peak demand at statistically significant levels. Low-income customers also seem to respond to TOU rates and, if these customers have a flatter load profile, they could benefit through lower bills. Finally, several states—including California, Massachusetts, and Arizona—are implementing default TOU rates for new customers.[16]

[16] For California, see California Public Utilities Commission Final Decision in Rulemaking 12-06-013 issued July 13, 2015 at docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF. For Massachusetts, see Massachusetts Department of Public Utilities Anticipated Framework for Time Varying Rates in D.P.U. 14-04-B on June 12, 2014 at 170.63.40.34/DPU/FileroomAPI//api/Attachments/Get/?path=14-04%2fOrder_1404B.pdf. For Arizona, see Arizona Corporate Commission Decision Number 75697 (Docket no. E-04204A-15-0142) Opinion and Order in UNS Electric General Rate Case, August 18, 2016 at docket.images.azcc.gov/0000172763.pdf.

DEMAND CHARGES

ACEEE strongly urges further analysis of residential customer response to and understanding of demand charges, potentially in the form of pilot studies.

The use of default or mandatory demand charges for residential customers should be approached with caution. As our review shows, little evidence exists on the implications of demand charges for overall customer consumption. Demand charges also seem to offer the smallest peak demand reductions among the rate designs we reviewed. Our research further demonstrates that demand charges produce the longest payback periods among all the energy efficiency measures we reviewed.[17] Finally, noncoincident demand charges are not cost based and do not align with customer cost of service, while coincident peak demand charges are virtually impossible to implement equitably. Unlike other dynamic price approaches, demand charges have yet to undergo rigorous pilots or pricing studies.

REVENUE DECOUPLING

ACEEE recommends the use of revenue decoupling as a policy to reduce the utility disincentive to promote efficiency and promote reduced sales, and also as a way to stabilize revenue.

While it is not a focus of this report, ACEEE has strongly supported revenue decoupling in the past and continues to recommend it. Many utility proposals for alterative rate design (especially higher customer charges) are responses to concerns about fixed cost recovery and revenue stability. Decoupling guarantees that utilities will recover commission-authorized revenues, thereby ensuring fixed cost recovery and stabilizing revenues. With this assurance, utilities can pursue rate design options that are more beneficial to customer interests.

[17] See the direct testimony of William Perea Marcus, filed on December 11, 2015 in PUC Docket No. 44941, Application of El Paso Electric Company to Change Rates. Also see Chernick et al. 2016 and Borenstein 2016 for a more detailed discussion of why demand charges are not cost based.

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Appendix A. Residential Customer Charge Results from Selected Rate Cases

Table A1 shows residential customer charge results for 87 selected rate cases from 2013 to the present, sorted by decision date. This list is not exhaustive.

Table A1. Residential customer charge results

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
NJ	Jersey Central Power and Light	$1.92	$2.99	$2.98	56%	55%	Dec-16
MD	Delmarva Power & Light	$7.94	$12.00	$9.43	51%	19%	Feb-17
KS	Empire District Electric	$14.00	$19.60	$14.00	40%	0%	Jan-17
MI	DTE Electric Company	$6.00	$9.00	$7.50	50%	25%	Jan-17
PA	Pennsylvania Power	$10.85	$13.41	$11.00	24%	1%	Jan-17
PA	West Penn Power	$5.81	$13.98	$7.44	141%	28%	Jan-17
PA	Metropolitan Edison	$10.25	$17.42	$11.25	70%	10%	Jan-17
PA	Pennsylvania Electric	$9.99	$17.10	$11.25	71%	13%	Jan-17
TX	Southwestern Public Service	$9.50	$10.50	$10.00	11%	5%	Jan-17
CA	Liberty Utilities	$7.10	$7.67	$6.56	8%	–8%	Dec-16
CT	United Illuminating Company	$17.25	$17.25	$9.67	0%	–44%	Dec-16
FL	Florida Light and Power	$7.87	$10.00	$7.87	27%	0%	Dec-16
ID	Avista Utilities	$5.25	$6.25	$5.75	19%	10%	Dec-16
ME	Emera Maine	$5.82	$6.31	$6.75	8%	16%	Dec-16
NC	Dominion North Carolina Power	$10.96	$13.48	$10.96	23%	0%	Dec-16
NV	Sierra Pacific Power Company	$15.25	$20.75	$15.25	36%	0%	Dec-16
SC	Duke Energy Progress	$6.50	$9.25	$9.06	42%	39%	Dec-16
WA	Avista Utilities	$8.50	$9.50	$8.50	12%	0%	Dec-16
CO	Xcel Energy CO	$7.71	$5.78	$5.39	–25%	–30%	Nov-16
CO	Black Hills Energy	$16.50	$18.62	$16.50	13%	0%	Nov-16
MD	PEPCO	$7.39	$12.00	$7.60	62%	3%	Nov-16
WI	Wisconsin Power and Light	$7.67	$18.00	$15.00	135%	96%	Nov-16
TN	Kingsport Power Company	$7.30	$11.00	$12.63	51%	73%	Oct-16
MA	Massachusetts Electric Co	$4.00	$20.00	$5.50	400%	38%	Sep-16
MI	Upper Peninsula Power	$12.00	$15.00	$15.00	25%	25%	Sep-16
MO	KCP&L MO	$9.54	$14.50	$10.43	52%	9%	Sep-16
NM	Public Service Co. of New Mexico	$5.00	$13.00	$7.00	160%	40%	Sep-16
AZ	UNS Electric	$10.00	$20.00	$15.00	100%	50%	Aug-16

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
MO	Empire District Electric	$12.52	$14.47	$13.00	16%	4%	Aug-16
NJ	Atlantic City Electric Company	$4.00	$6.00	$4.44	50%	11%	Aug-16
NM	Southwestern Public Service	$7.90	$9.95	$8.50	26%	8%	Aug-16
TX	El Paso Electric	$5.00	$10.00	$6.90	100%	38%	Aug-16
IN	NIPSCO	$11.00	$20.00	$14.00	82%	27%	Jul-16
TN	Entergy Arkansas	$6.96	$8.40	$8.40	21%	21%	Jul-16
MD	Baltimore Gas & Electric	$7.50	$12.00	$7.90	60%	5%	Jun-16
NM	El Paso Electric	$7.00	$10.00	$7.00	43%	0%	Jun-16
NY	New York State Electric and Gas	$15.11	$18.89	$15.11	25%	0%	Jun-16
NY	Rochester Gas & Electric	$21.38	$26.73	$21.38	25%	0%	Jun-16
IN	Indianapolis Power & Light	$11.00	$17.00	$17.00	55%	55%	Mar-16
MT	Montana-Dakota Utilities	$5.40	$7.50	$5.40	39%	0%	Mar-16
AR	Entergy Arkansas	$6.95	$9.00	$8.43	29%	21%	Feb-16
WA	Avista Utilities	$8.50	$14.00	$8.50	65%	0%	Jan-16
ID	Avista Utilities	$5.25	$8.50	$5.25	62%	0%	Dec-15
MI	DTE Electric Company	$6.00	$10.00	$6.00	67%	0%	Dec-15
PA	PECO	$7.09	$12.00	$8.45	69%	19%	Dec-15
TX	Southwestern Public Service	$7.50	$9.50	$9.50	27%	27%	Dec-15
WI	Xcel Energy	$8.00	$18.00	$14.00	113%	87%	Dec-15
MI	Consumers Energy	$7.00	$7.50	$7.00	7%	0%	Nov-15
OR	Portland General Electric	$10.00	$11.00	$10.50	10%	5%	Nov-15
PA	PPL	$14.09	$20.00	$14.09	42%	0%	Nov-15
SD	NorthWestern Energy	$5.00	$9.00	$6.00	80%	20%	Nov-15
WI	Wisconsin Public Service	$19.00	$25.00	$21.00	140%	83%	Nov-15
NY	Orange & Rockland	$20.00	$25.00	$20.00	25%	0%	Oct-15
KS	KCP&L	$10.71	$19.00	$14.00	77%	31%	Sep-15
KS	Westar	$12.00	$27.00	$14.50	125%	21%	Sep-15
MO	KCP&L	$9.00	$25.00	$11.88	178%	32%	Sep-15
MI	Indiana Michigan Power	$7.25	$9.10	$7.25	26%	0%	Aug-15
CA	Pacific Gas & Electric Company	$-	$10.00	$-	0%	0%	Jul-15
CA	San Diego Gas & Electric	$-	$10.00	$-	0%	0%	Jul-15
CA	Southern California Edison	$0.95	$10.00	$0.95	953%	0%	Jul-15
SD	MidAmerican	$7.00	$8.50	$8.00	21%	14%	Jul-15

State	Utility	Existing customer charge	Proposed customer charge	Approved customer charge	Existing to proposed	Existing to approved	Decision date
KY	Kentucky Utilities Company	$10.75	$18.00	$10.75	67%	0%	Jun-15
KY	Louisville Gas-Electric	$10.75	$18.00	$10.75	67%	0%	Jun-15
KY	Kentucky Power	$8.00	$16.00	$11.00	100%	38%	Jun-15
MO	Empire District Electric	$12.52	$18.75	$12.52	50%	0%	Jun-15
NY	Central Hudson Gas & Electric	$24.00	$30.00	$24.00	25%	0%	Jun-15
NY	Consolidated Edison	$15.76	$18.00	$15.76	14%	0%	Jun-15
MN	Xcel Energy	$8.00	$9.25	$8.00	16%	0%	May-15
WV	Appalachian Power/Wheeling	$5.00	$10.00	$8.00	100%	60%	May-15
MI	Xcel Energy	$8.65	$8.75	$8.75	1%	1%	Apr-15
MI	Wisconsin Public Service	$9.00	$12.00	$12.00	33%	33%	Apr-15
MO	Ameren	$8.00	$8.77	$8.00	10%	0%	Apr-15
OK	Public Service Co. of Oklahoma	$16.16	$20.00	$20.00	24%	24%	Apr-15
PA	Pennsylvania Power	$8.89	$12.71	$10.85	43%	22%	Apr-15
PA	West Penn Power	$5.00	$7.35	$5.81	47%	16%	Apr-15
PA	Metropolitan Edison	$8.11	$13.29	$10.25	64%	26%	Apr-15
PA	Pennsylvania Electric	$7.98	$11.92	$9.99	49%	25%	Apr-15
WA	PacifiCorp	$7.75	$14.00	$7.75	81%	0%	Mar-15
CT	Connecticut Light & Power	$16.00	$25.50	$19.25	59%	20%	Dec-14
MD	Baltimore Gas & Electric	$7.50	$10.50	$7.50	40%	0%	Dec-14
WI	Madison Gas and Electric	$10.29	$68.00	$19.00	113%	87%	Dec-14
VA	Appalachian Power Co	$8.35	$16.00	$8.35	92%	0%	Nov-14
WI	We Energies	$9.13	$16.00	$16.00	75%	75%	Nov-14
WI	Wisconsin Public Service	$10.40	$25.00	$19.00	140%	83%	Nov-14
NV	Nevada Power	$10.00	$15.25	$12.75	53%	28%	Oct-14
ME	Central Maine Power Company	$5.71	$20.00	$10.00	250%	75%	Aug-14
UT	Rocky Mountain Power	$5.00	$8.00	$6.00	60%	20%	Aug-14
	Average	**$9.09**	**$14.64**	**$10.48**	**61%**	**15%**	
	Median	**$8.00**	**$13.00**	**$9.67**	**63%**	**21%**	

Appendix B. Pricing Study Details

This appendix describes the pricing pilot studies we reviewed. Table B1 gives a brief overview of each pilot or pricing program.

Table B1. Pricing studies reviewed

Pricing study	Years	Utility	State / province	Rates
myPower Pricing Pilot	2006–2007	PSEG	NJ	TOU, CPP
SmartGridCity™	2010–2013	Xcel	CO	TOU, CPP, PTR
SmartPricing Options	2011–2103	SMUD	CA	TOU, CPP
Ontario Smart Price Pilot	2006–2007	OEB	ON	TOU, CPP, PTR
Consumer Behavior Study	2012–2013	GMP	VT	CPP, PTR
EnergySense CPP Pilot	2011–2012	MMLD	MA	CPP
Smart Energy Pricing Pilot	2008	BGE	MD	CPP, PTR
Consumer Behavior Study	2010–2012	OG&E	OK	VPP, TOU+CPP
Energy Smart Pricing Plan	2003–2005	CEC	IL	RTP
Power Smart Pricing	2007–current	Ameren	IL	RTP
Res Real-time Pricing	2007–current	ComEd	IL	RTP
PowerCents DC	2007	PEPCO	DC	CPP, PTR, RTP

PSEG myPower Pricing Pilot Program, 2006–2007

This pricing pilot targeted residential customers with a TOU rate combined with CPP. One group received educational materials (education group), while the other received education and a programmable thermostat (technology group). Within the education group, the treatment groups were split between those with and without central air-conditioning. The study also relied on hourly data from a control group to estimate energy and peak demand savings. Several CPP events were called during the pilot timeframe including: two in summer 2006, five in summer 2007, and three in non-summer months of 2007. The impact analysis for this pilot estimated peak demand and energy savings impacts from both the TOU and CPP. Table B2 shows the pilot's demand savings results. Peak demand reductions did occur in the winter months, but at a much smaller rate than in the summer.

Table B2. myPower Pricing Pilot demand reduction results by rate type

	TOU only		CPP only		Total	
Customer group	kW	%	kW	%	kW	%
Technology	0.59	21%	0.74	26%	1.33	47%
Education w/central AC	0.07	3%	0.36	14%	0.43	17%
Education w/o central AC	0.09	6%	0.23	14%	0.32	20%

The program evaluation also demonstrated energy savings from the TOU rate. The most significant savings occurred in the summer months, but minimal savings were also shown in the winter months. Table B3 shows the savings from the summer months.

Table B3. myPower Pricing Pilot summer energy savings

Customer group	Summer energy savings from TOU	
	kWh per customer	%
Technology	139	3.3%
Education w/central AC	144	3.7%
Education w/o central AC	127	4.3%

The study also evaluated winter and shoulder period changes in consumption. The evaluation demonstrated very little kWh shifting or energy savings for any customer groups during winter months and shoulder periods. The only significant change was a 1.65% decrease in energy use during winter months by the myPower Sense group with central air-conditioning (statistically significant at the 90% confidence level).

Xcel SmartGridCity™ Pricing Pilot (Boulder), 2010–2013

Xcel Energy conducted this pricing pilot in Boulder, Colorado, from October 2010 to September 2013 to better understand how customers responded to various rate structures. Customers were able to opt in to three different rate options: PTR, CPP, or TOU. The program was targeted to customers with AMI meters installed in the City of Boulder in two phases during the three-year period. Each phase represented a different group of customers. A small subset of program participants was given in-home smart devices, but not enough customers received the devices to generalize results to a broader population. Evaluation of the pilot showed that customers did respond to rates by reducing overall usage and reducing demand during peak hours and events (Enernoc 2013).

Each year, pilot participants enrolled in two phases. Phase 1 participants opted in to the rate. Phase 2 participants were selected at random and then given a choice between three time-varying rates and the standard rate. Although customers were given a choice, if they did not choose, they were ultimately placed on the standard rate, making this option not a true opt-out rate.

Table B4 shows the estimated demand savings from each rate type; results are presented by season or type of customer. Some customers on TOU rates were also enrolled in the Saver's Switch program, an air-conditioning load management program. These customers are noted by "SS" for Saver's Switch or "NSS" for non-Saver's Switch.

Table B4. SmartGridCity peak demand reduction results by rate type

Rate type	Description	2011		2012		2013	
		Ph. 1	Ph. 2	Ph. 1	Ph. 2	Ph. 1	Ph. 2
CPP	Average summer event day	29%	26%	26%	23%	22%	13%
CPP	Average non-summer event day			24%	14%	16%	8%
PTR	Average summer event day	14%	12%	8%	8%	8%	8%
PTR	Average non-summer event day			5%	3%	5%	2%
TOU	Average summer weekday (SS)	8%	9%	6%	7%	7%	5%
TOU	Average non-summer weekday (SS)	2%		–1%	1%	1%	1%
TOU	Average summer weekday (NSS)	9%	6%	7%	5%	5%	3%
TOU	Average non-summer weekday (NSS)	1%		4%	3%	4%	3%

The table demonstrates the significant peak demand reductions from each rate. Demand reductions decline year to year, indicating a drop off in persistence. Table B5 shows the overall energy savings for each rate type.

Table B5. SmartGridCity annual energy savings results by rate type

Rate Type	2011		2012		2013	
	Ph. 1	Ph. 2	Ph. 1	Ph. 2	Ph. 1	Ph. 2
CPP	5%		8%	2%	10%	1%
PTR	3%		6%	3%	6%	4%
TOU SS	0%		–1%	0%	0%	0%
TOU NSS	–2%		0%	2%	0%	2%

Negative values show increases in consumption.

Overall decline in energy consumption was present in all three rate types, but it was much smaller in TOU than in CPP and PTR. In two instances, energy consumption increased for customers on TOU rates. TOU SS customers did decrease consumption during peak periods, but increased consumption at off-peak times. Overall, CPP customers demonstrated the strongest price response for demand and energy consumption. PTR customers reduced overall consumption, even during non-event times.

Baltimore Gas & Electric Smart Energy Pricing Pilot, 2008

Baltimore Gas & Electric (BGE) implemented this pilot in summer 2008 to test customer response to TOU+CPP and PTR. The pilot included one TOU+CPP rate and two PTR variations—one awarding a rebate of $1.16/kWh and the other awarding $1.75/kWh. Two technologies were also included in this pilot: the Energy Orb (a device that emits various colors to signal different prices) and an air conditioner switch that allows BGE to cycle the customer's air conditioner during a peak event. These variations produced eight different treatments. All treatment groups were voluntary participants. Evaluation of this pilot estimated hour-specific substitution and daily price elasticities to determine load reductions by period.[18] Table B6 shows the impact evaluation results from all eight treatment groups for critical days peak reduction and total consumption change for the entire month (Faruqui and Sergici 2009).

Table B6. BGE Smart Energy Pricing Pilot impact estimates

Rate design	Enabling technology	Critical days peak reduction	Overall energy savings
TOU+CPP	None	20.11%	–0.94%
TOU+CPP	Energy Orb and AC switch	32.54%	–1.16%
PTRL	None	17.82%	0.50%
PTRL	Energy Orb only	23.03%	0.50%
PTRL	Energy Orb and A/C switch	28.48%	0.50%
PTRH	None	20.94%	0.63%
PTRH	Energy Orb only	26.83%	0.63%
PTRH	Energy Orb and A/C switch	32.95%	0.63%

PTRL = Peak-time rebate low. PTRH = peak-time rebate high.

The evaluation demonstrated substantial reductions in use during peak events, but also increased usage during off-peak hours. It is unclear in the evaluation how much of the increased consumption in off-peak hours was "snapback"—that is, a spike in usage following an event. Total consumption changes were positive for CPP+TOU rates, meaning that customers increased usage overall. Finally, the evaluation demonstrated that the rates produced a stronger response to price when combined with technology.

Sacramento Municipal Utility District Smart Pricing Options Study, 2011–2013

The SMUD Smart Pricing Options consumer behavior pilot is one of the most well-known recent pricing experiments. SMUD implemented this pilot as part of the Department of Energy's Smart Grid Investment Grant program to test both customer response to dynamic pricing and the use of information to induce behavior change (Jimenez, Potter, and George 2013).[19] The SMUD study included seven treatment groups using: three rate design variations (a two-period TOU rate with a 4–7 pm peak period, a CPP combined with an inclining tiered rate, and a CPP price combined with a TOU rate); default or opt-in enrollment; and the offer of an IHD device. The pilot began in October 2011 and was in effect June–September in 2012 and 2013. Attrition from the pilot was higher than expected

[18] The evaluation also determined load reductions for three weather scenarios (mild, average, and extreme). For this report, we show only impacts based on average weather.

[19] A total of 11 utilities participated in consumer behavior studies focused on the integration of smart grid technologies and price response. More details of this initiative can be found at smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html.

due to more people moving than expected; the actual dropout rates were low at 4–9% over the two-year pilot (Jimenez, Potter, and George 2014).

Table B7 shows the load impacts and energy savings changes for the seven treatments. Each estimate is for all evaluation periods.

Table B7. SMUD Smart Pricing Options load reductions and energy savings estimates

Treatment group	CPP day impact	Average weekday impacts	Energy savings
Opt-in TOU/IHD offer	13.1%	11.9%	0.9%
Opt-in TOU/no IHD offer	10.1%	9.4%	1.1%
Opt-in CPP/IHD offer	25.1%	n/a	3.5%
Opt-in CPP/no IHD offer	20.9%	n/a	–1.0%
Default TOU/IHD offer	5.9%	5.8%	1.3%
Default CPP/IHD offer	14.0%	n/a	2.6%
Default TOU+CPP/IHD offer	12.3%	8.7%	1.3%

Evaluation of the pilot showed measurable load impacts from all seven treatment groups. The results also show energy savings from all seven treatments. The TOU treatment group energy savings were not statistically significant at the 95% confidence level. However the insignificant energy savings values in table B7 are evidence of savings because of a demonstrated lack of load shifting from peak to off-peak hours. These values also show no increase in consumption in off-peak hours during lower prices. For the CPP treatment group, both the opt-in CPP IHD offer and default CPP IHD offer groups demonstrated large reductions during peak periods but also statistically significant reductions in the pre-event period (Jimenez, Potter, and George 2014).

The study also focused on persistence of usage reductions. For most pricing options, the change in demand reduction from one summer to another was not statistically significant. Two pricing plans showed statistically significant changes in persistence from year to year: the opt-in TOU with IHD showed a decline in demand reduction, while the default CPP pricing plan showed an increase. This may suggest an initial learning curve, and that customers come to better understand the pricing and develop strategies to respond over time. More education and recommended strategies up front might shorten the learning curve.

The SMUD Smart Pricing Options produced several key findings. According to an LBNL study, enrollment rates were five times higher under the default enrollment, and once customers were enrolled, dropout rates were very low. Also, when considering the demand reductions for the default treatment groups, 20% of the entire consumer population was highly unengaged and inattentive (these customers did not provide any measurable energy savings in response to the TOU rate). These are the customers who need the most attention to not be worse off with this rate. Utilities should target these customers in a default TOU rollout. Finally, LBNL found no evidence of dramatic dissatisfaction between default and opt-in customers (Cappers et al. 2016a).

Ontario Energy Board Smart Price Pilot (Ontario, Canada), 2006–2007

The Ontario Energy Board, the electricity regulator of the Ontario province, conducted a pilot between August 2006 and March 2007 to better understand how residential customers responded to three different pricing structures: an existing TOU rate, a TOU with a CPP, and a TOU with a PTR. This pilot utilized AMI meters, but did not use any other technological interventions. Customers under all three rate structures responded by shifting load and reducing overall consumption (IBM 2007). Table B8 displays the peak demand and conservation results. These results are for the entire seven-month period.

Table B8. Ontario Energy Board Smart Price Pilot peak-shifting and conservation results

Program	Shift as % of critical-peak hours	Shift as % of all peak hours	% reduction in overall consumption
TOU	5.7%[1]	2.4%[2]	6.0%
TOU+CPP	25.4%	11.9%	4.7%[3]
TOU+PTR	17.5%	8.5%	7.4%

[1,2] Not statistically significant at the 90% level and cannot be generalized to larger population.
[3] Not statistically significant at the 90% level, but is significant at an 88% confidence level.

Green Mountain Power Pilot (Vermont), 2012–2013

Green Mountain Power conducted a pilot from fall of 2012 to summer of 2013 to assess how customers would respond to CPP and PTR. Four events were called in September 2012 and 10 in summer 2013. Each event occurred between 1 pm and 6 pm. Some customers in each treatment group were also given IHDs, which provide customers with real-time information on pricing and usage. Subsequent impact evaluation found that while no treatment group exhibited consistent responses over the 14 events, customers on average did reduce consumption during critical-peak events (5.3–15% for CPP and 3.8–8.1% for PTR) (Blumsack and Hines 2015).

Evaluation results also indicated that customers with IHDs showed a higher price response than other customers. These customers exhibited higher demand reductions during peak events and also reduced overall consumption at a higher rate than those without IHDs, by about 4%. Subsequent surveys of customers with IHDs showed that education in how to use the devices was critical. Finally, the study demonstrated a lack of persistence among customers, questioning the program's ability to serve as a capacity resource for the region (Blumsack and Hines 2015).

Oklahoma Gas & Electric Consumer Behavior Study, 2010–2012

Oklahoma Gas & Electric (OG&E) administered a two-year pricing pilot to evaluate the price response of customers on time-varying rates. The first phase of the pilot was conducted in 2010 and included 3,000 participants. The second phase began in 2011 and added an additional 3,000 customers. Participants were placed on either a VPP rate or a TOU rate with a critical-peak price component. The variable-peak price uses four defined price levels to replace the on-peak rate in the TOU. The variable price signal applies to the five-hour peak period on a weekday and is communicated to customers by 5 pm on the prior day. Participants were also given various technologies, including programmable communicating thermostats (PCTs), IHDs, access to a web portal, or all three (GEP 2011). Table B9 shows the rates used for both rate treatments.

Table B9. OG&E 2010 Phase 1 pricing pilot rates ($ per kWh)

Component	VPP+CPP	TOU+CPP
Off-peak/low	$0.045	$0.042
Standard	$0.113	$0.23
High	$0.23	$0.23
Critical	$0.46	$0.23
Critical price event	$0.46	$0.46

Source: GEP 2011

During Phase 1, both VPP and TOU+CPP rate groups demonstrated statistically significant load reductions under all technology scenarios. During non-event days, the most significant reductions were during peak times, but the TOU+CPP group also reduced usage in peak hours in most technology variations, except for the PCT group on the weekend. This is likely explained by the fact that the PCT group included those with only central air-conditioning. For the first year during off-peak hours, usage dropped for all TOU+CPP and all but PCT VPP+CPP groups on the weekends. Customers with IHD showed the largest decrease in usage. In the second year, off-peak consumption increased for all groups except those with web portal only. The net change in consumption was still negative though because the increase was less than the decrease in on-peak consumption (GEP 2012).

The VPP+CPP group exhibited demand reductions that corresponded with changes in the variable rate. Many technology variations within the VPP+CPP group showed an increase in off-peak consumption, but this was offset by higher on-peak reductions. The average change in off-peak consumption was negative for both rate treatments during non-event days and the decrease in energy usage was strongest for those with IHDs. Weather during event days was mild and savings were smaller, but still statistically significant for most groups (GEP 2011). Table B10 shows the changes in on- and off-peak consumption during year 1 for non-event days.

Table B10. Non-event day residential changes in consumption

Rate design	On-peak reduction in consumption	Off-peak reduction in consumption
TOU+CPP weekend		0.51% to 6.93%
TOU+CPP weekday	10.03% to 25.73%	5% to −3.42%
VPP+CPP weekend		1.32% to −1.31%
VPP+CPP low weekday	12.94% to 14.85%	11.75% to −2.01%
VPP+CPP standard weekday	6.37% to 23.97%	0.16% to −5.43%
VPP+CPP medium weekday	7.92% to 31.41%	−1.41% to −8.85%
VPP+CPP high weekday	10.99% to 34.95%	−0.97% to −8.39%

Range represents the four technology treatments. Negative numbers show an increase in consumption.

During Phase II, OG&E added an additional 3,000 residential participants and included small commercial customers. The TOU+CPP customers recruited in the second year showed statistically significant load reductions only for the PCT and three-technologies groups; in Phase I, load reductions were present for all technology groups. The VPP+CPP group exhibited similar behavior in year two, showing a strong positive relationship between price and load reduction. Finally, the evaluation found that the three-technologies group demonstrated load reductions throughout the day and during peak periods, showing potential behavior changes from the web portal and IHD in addition to automated savings from PCT (GEP 2012).

This pilot was so successful that, in 2016, OG&E rolled out time-varying rates to more than 120,000 customers (20% of its total customers) to defer investment in 170 MW of new generating capacity (DOE 2013a).

Marblehead ENERGYSENSE CPP Pilot, 2011–2012

Marblehead Municipal Light Department conducted a two-year CPP pilot in 2011 and 2012. This pilot, called EnergySense, relied on a pricing structure of a flat rate of $0.09/kWh and a CPP rate of $1.05/kWh. The control group in this study was charged a flat rate of $0.14/kWh. All CPP events were six hours in duration and called only during the summer months of June, July, and August. All participants were given access to a web portal containing information related to real-time consumption, historical usage, and current monthly bill estimates. In the second year, customers with central air-conditioning were given Wi-Fi-enabled programmable thermostats, customers with electric water heaters were given load switches, and customers with both were given both (GDS 2013b). Table B11 shows the evaluated estimates of the pilot's effect.

Table B11. EnergySense CPP Pilot results 2011–2012

Year	Average reduction in consumption over all summer months	Average hourly reduction in consumption during events	Program reduction in consumption on system coincident peak demand
2011	0.3%	36.7%	0.8%
2012	0.3%	21.3%	0.9%

The table shows a strong response from customers during peak events. The evaluation also demonstrated a reduction in overall usage during summer months and a decline in the system coincident peak demand. The program evaluation also documented a statistically significant difference between the response in year one and year two, but did not infer the participants suffered from program fatigue.[20] Finally, while technologies were offered as part of the program, difficulty with customer installations prevented a sample size large enough for worthwhile analysis (GDS 2013b).

Community Energy Cooperative Energy-Smart Pricing Plan (Illinois), 2003–2005

The Energy-Smart Pricing Plan (ESPP) began in 2003 with 750 customers, growing to 1,400 participants at the end of three years. The real-time price offered is based on the day-ahead wholesale market price. Customers are notified via email or phone if the price exceeds 10 cents/kWh. In the first two years of the program, customers responded to prices but weather was mild. The most significant response was when prices exceeded 10 cents/kWh, with consumption sometimes decreasing by more than 25% in the first hour. Multifamily customers also exhibited the largest response among residential customers. Lower-income households also exhibited high levels of response (Tholin et al. 2004, Isaacson et al. 2006).[21] The trend of lower-income households responding at greater levels than high-income households was consistent throughout the first three years. At the end of year three, independent evaluation also demonstrated that participants reduced overall usage in the summer months by 3% (Summit Blue 2006). Table B12 shows price elasticities for the program annually. Negative elasticities represent a reduction in usage in response to the program.

[20] Program fatigue is a reduced response from year to year or event to event.

[21] The details of high price response by low-income customers in this study were unclear because it is not certain whether low-income customers were curtailing use of essential energy services in response to price signals.

Table B12. ESPP annual elasticities 2003–2006

Year	Overall elasticity	Other key elasticities
2003	–0.042	
2004	–0.080	
2005	–0.047	–0.067 for air-conditioning cycling
2006	–0.047 when prices below $0.13/kWh –0.082 when prices above $0.13/kWh	–0.098 for air-conditioning cycling –0.067 for PriceLight

PriceLight is an IHD device that changes colors as energy prices change to alert customers to modify behavior. *Source:* Summit Blue 2006, p. 10.

Ameren Illinois Power Smart Pricing (Illinois), 2007–current

Ameren Illinois has offered an RTP program since 2007. This program, administered by Elevate Energy, sends participants high-price alerts the evening before a day where hourly electricity prices are at or above 9 cents/kWh. These alerts are sent through email, phone call, or text message. Prices are based on the day-ahead hourly Midcontinent Independent System Operator (MISO) market prices. At the end of 2015, this program had more than 10,500 participants (Elevate Energy 2016).

The 2015 Annual Report presented several key findings for program year 2014. When asked what actions were taken to reduce or shift energy usage, 12% of customers responded that they invested in whole home energy efficiency. A large percentage (27–32%) also reported behavioral changes, such as turning off the lights or adjusting the temperature setting. Program participants were able to save money on bills in nearly every year of this program. The evidence of changes to overall consumption are mixed. There were no average annual energy savings from 2008–2010. Instead, customers showed an average increase in annual consumption of 0.2%, with the largest increase during the winter months (9.2%) and a decrease in the other three seasons. For the period 2011–2014, annual usage was reduced 0.7% for regular customers and 0.6% for electric space heating customers (Elevate Energy 2015).[22]

PEPCO PowerCents DC (District of Columbia), 2007

The PowerCents DC program was initiated in 2007 as part of a smart meter pilot program intended to test customer response to dynamic pricing, smart meters, and smart thermostats. The program included nearly 900 resident participants taking service under CPP, critical-peak rebate, or hourly pricing. The program ran from summer 2008 through summer 2009. Changes in overall consumption were not measured as part of this experiment, but peak demand reductions were present in all three pricing structures. The response from hourly pricing was the lowest among the three pricing options, primarily because the prices were much higher under CPP and critical-peak rebates. Market

[22] From the annual report, it is unclear if this result is statistically significant.

conditions reduced the hourly prices, thereby reducing the response. Hourly pricing customers showed the highest bill savings from the program, with an average bill savings of 39%, primarily due to lower wholesale prices resulting from the Great Recession.

Commonwealth Edison Residential Real-Time Pricing Program (Illinois), 2007–present

Commonwealth Edison (ComEd) has offered an hourly RTP program to residential customers since 2007. The program relies on sending customers a day-ahead price alert if energy prices exceed a certain threshold (currently, 14 cents per kWh) through a variety of channels including email, phone, and text. Ten thousand residential customers are currently enrolled in the program.

Since inception, customers have saved money on energy costs, with the exception of 2014. The program has no price caps on the cost of electricity, and extreme weather in the first three months of 2014 caused much higher prices than average. The eight-year supply cost savings average is 19.4%, but in 2014 the annual supply savings was –4.7% (Becker 2015). The program has also undergone regular evaluations. A 2013 evaluation demonstrated price response, showing that, in response to an hourly 10% average price increase, consumption decreased by 0.5–1.5% (Becker 2015). The evaluation also showed a reduction in annual overall usage of 4% from 2007–2010. The reduction in overall usage was higher in the summer and lower in the winter, which was expected because prices were higher in the summer. During the extreme weather events of 2014, the reduction in overall consumption was more than 14% from January 8 through March 31. During this period, there was no significant load shifting, just reductions in overall use (Becker 2015).

Appendix C. Pricing Pilot Observations

Table C1 lists pricing pilot details for the 50-treatment observation used in figure 4, showing the distribution of reduction in overall consumption statistics for the pricing studies reviewed.

Table C1. Pricing pilot details for the 50-treatment observation used in figure 4

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
myPower Pricing Pilot	Technology	TOU CPP	Smart thermostat	Opt in	2007	Summer	47%	3%
myPower Pricing Pilot	Education w/ central AC	TOU CPP	None	Opt in	2007	Summer	17%	4%
myPower Pricing Pilot	Education w/o central AC	TOU CPP	None	Opt in	2007	Summer	20%	4%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2011	Annual	29%	5%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2011	Annual	14%	3%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2011	Annual	8%	0%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2011	Annual	9%	2%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2012	Annual	26%	8%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2012	Annual	8%	6%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2012	Annual	6%	1%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2012	Annual	−1%	0%
SmartGridCity	CPP Phase I	CPP	None	Opt in	2013	Annual	22%	10%
SmartGridCity	PTR Phase I	PTR	None	Opt in	2013	Annual	8%	6%
SmartGridCity	TOU w/ SS Phase I	TOU	None	Opt in	2013	Annual	7%	0%
SmartGridCity	TOU w/o SS Phase I	TOU	None	Opt in	2013	Annual	5%	0%
SmartGridCity	CPP Phase II	CPP	None	Opt in	2012	Annual	23%	2%
SmartGridCity	PTR Phase II	PTR	None	Opt in	2012	Annual	8%	3%
SmartGridCity	TOU w/ SS Phase II	TOU	None	Opt in	2012	Annual	7%	0%
SmartGridCity	TOU w/o SS Phase II	TOU	None	Opt in	2012	Annual	5%	2%
SmartGridCity	CPP Phase II	CPP	None	Opt in	2013	Annual	13%	1%
SmartGridCity	PTR Phase II	PTR	None	Opt in	2013	Annual	8%	4%
SmartGridCity	TOU w/ SS Phase II	TOU	None	Opt in	2013	Annual	5%	0%
SmartGridCity	TOU w/o SS Phase II	TOU	None	Opt in	2013	Annual	3%	2%
Smart Energy Pricing Pilot	TOU+CPP	TOU CPP	None	Opt in	2008	Summer	20%	−1%

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
Smart Energy Pricing Pilot	TOU+CPP w/tech	TOU CPP	EnergyOrb, AC switch	Opt in	2008	Summer	33%	−1%
Smart Energy Pricing Pilot	PTR low	PTR	None	Opt in	2008	Summer	18%	1%
Smart Energy Pricing Pilot	PTR low	PTR	EnergyOrb only	Opt in	2008	Summer	23%	1%
Smart Energy Pricing Pilot	PTR low	PTR	EnergyOrb, AC switch	Opt in	2008	Summer	28%	1%
Smart Energy Pricing Pilot	PTR high	PTR	None	Opt in	2008	Summer	21%	1%
Smart Energy Pricing Pilot	PTR high	PTR	EnergyOrb only	Opt in	2008	Summer	27%	1%
Smart Energy Pricing Pilot	PTR high	PTR	EnergyOrb, AC switch	Opt in	2008	Summer	33%	1%
SmartPricing Options	Opt-in TOU, IHD offer	TOU	IHD	Opt in	2012	Summer	13%	1%
SmartPricing Options	Opt-in TOU, no IHD offer	TOU	None	Opt in	2012	Summer	10%	1%
SmartPricing Options	Opt-in CPP, IHD offer	CPP	IHD	Opt in	2012	Summer	26%	4%
SmartPricing Options	Opt-in CPP, no IHD offer	CPP	None	Opt in	2012	Summer	22%	−1%
SmartPricing Options	Default TOU, IHD offer	TOU	IHD	Default	2012	Summer	6%	1%
SmartPricing Options	Default CPP, IHD offer	CPP	IHD	Default	2012	Summer	12%	3%
SmartPricing Options	Default TOU-CPP, IHD offer	TOU CPP	None	Default	2012	Summer	8%	1%
SmartPricing Options	Opt-in TOU, IHD offer	TOU	IHD	Opt in	2013	Summer	11%	1%
SmartPricing Options	Opt-in TOU, no IHD offer	TOU	None	Opt in	2013	Summer	9%	1%
SmartPricing Options	Opt-in CPP, IHD offer	CPP	IHD	Opt in	2013	Summer	24%	4%
SmartPricing Options	Opt-in CPP, no IHD offer	CPP	None	Opt in	2013	Summer	21%	−1%
SmartPricing Options	Default TOU, IHD offer	TOU	IHD	Default	2013	Summer	6%	1%
SmartPricing Options	Default CPP, IHD offer	CPP	IHD	Default	2013	Summer	17%	3%
SmartPricing Options	Default TOU-CPP, IHD offer	TOU CPP	None	Default	2013	Summer	10%	1%
Ontario Smart Price Pilot	TOU	TOU	None	Opt in	2006	Fall/winter	6%	6%
Ontario Smart Price Pilot	TOU+CPP	TOU CPP	None	Opt in	2006	Fall/winter	25%	5%
Ontario Smart Price Pilot	TOU+PTR	TOU PTR	None	Opt in	2006	Fall/winter	18%	7%
EnergySense CPP Pilot	CPP	CPP	Web portal	Opt in	2011	Summer	37%	0%

Pricing study	Treatment description	Rate	Technology	Recruitment	Year	Time period of study	Reduction in peak demand	Reduction in overall consumption
EnergySense CPP Pilot	CPP	CPP	Web portal	Opt in	2012	Summer	23%	0%

Appendix D. Measure and Program Description

Table D1. Measure and program descriptions

Measure or program	Applicability	Description
LED 40-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
LED 60-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
LED 75-watt replacement	Replace on burnout	This lighting end-use measure promotes the replacement of existing incandescent or halogen lamps with LED lamps.
Variable-speed pool pump	Replace on burnout and new construction	Variable-speed pumps enable pool technicians to set a pool pump exactly to the lowest motor speed requirements for both the daily cleaning and daily filtration settings, thus saving wasted energy.
Duct test and repair	Retrofit	The Duct Test and Repair measure consists of testing the ducts for leakage and repairing them as needed. Duct testing includes determining the amount of air leakage, identifying leakage locations, making sure the duct connections are securely fastened, and providing test results to the homeowner. Duct repair includes repairing ductwork, sealing duct connections with long lasting sealant, and repairing any unsealed or poorly fitting grills. The ducts are then retested after the repairs and sealing are completed to verify leakage reduction.
Prescriptive duct repair	Retrofit	Duct repair includes repairing ductwork, sealing duct connections with long lasting sealant, and repairing any unsealed or poorly fitting grills. The ducts are then retested after the repairs and sealing are completed to verify leakage reduction.
Advanced diagnostic tune-up	Retrofit	The Advanced Diagnostic Tune-Up measure is a refrigerant charge and airflow correction for residential air conditioners and heat pumps that are at least three years old and between two and five tons.
Equipment replacement with quality installation	Replace on burnout	The Equipment Replacement with Quality Installation measure gives an incentive for customers to use a participating contractor to replace an air conditioner or heat pump that is at least 10 years old with a new system that is installed in accordance with Arizona Public Service Quality Installation Standards.

Measure or program	Applicability	Description
Res new construction ESTAR Homes v3.0	New construction	This whole house option promotes ENERGY STAR certified new homes designed and built to standards well above most other new homes. An ENERGY STAR certified home has undergone a process of inspections, testing, and verification to meet strict EPA requirements, delivering better quality, better comfort, and better durability.
Res new construction ESTAR Homes v3.0 - Tier 2	New construction	This is the same as 3.0, but with improved efficiency for building envelope, windows, and HVAC, and a better Home Energy Rating System (HERS) rating.
Res new construction total program	New construction	This whole house option promotes ENERGY STAR certified new homes designed and built to standards well above most other new homes. An ENERGY STAR certified home has undergone a process of inspections, testing, and verification to meet strict EPA requirements, delivering better quality, better comfort, and better durability.
Attic insulation	This measure is applicable only to the Home Performance with ENERGY STAR program.	Attic insulation involves repairing and/or adding insulation to existing attics. Insulation must be installed in the right location and without gaps, voids, or compressions. Homes must be properly air sealed prior to increasing attic insulation to achieve maximum performance. Insulation values are based on the measure of a material's thermal resistance, or *R-value*.
Air sealing and attic insulation	This measure is applicable only to the Home Performance with ENERGY STAR program.	This measure includes installation of a combination of air sealing and attic insulation for a single participant home. Air sealing is performed prior to attic insulation for maximum performance.
Smart strip	Retrofit	This measure is for load-based smart strips. The measure should be installed only in the primary entertainment center and primary home office.

Source: APS 2016

Appendix E. Payback Analysis Scenario Detail

Table E1. Payback analysis scenario details

Scenario	Customer charge	Energy tiers	Description	Demand charge ($/kW)	Summer off-peak ($/kWh	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)	No. of times coincident peak hit
1	$5	Yes	Low customer charge, three-tiered rate (0–500, 501–1,000, >1,000)	$-	$0.1504				
2	$25	Yes	High customer charge, three-tiered rate (0–500, 501–1,000, >1,000)	$-	$0.1101				
3	$5	No	Low customer charge, flat energy rate	$-	$0.1076				
4	$25	No	High customer charge, flat energy rate	$-	$0.0824				
5	$50	No	Very high customer charge, flat energy rate	$-	$0.0510				
6	$5	No	Low customer charge, 4:1 ratio TOU	$-	$0.0904	$0.1809	$0.0907	$0.1815	
7	$25	No	High customer charge, 4:1 ratio TOU	$-	$0.0727	$0.1454	$0.0645	$0.1291	
8	$5	No	Low customer charge, 3:1 ratio TOU	$-	$0.0773	$0.2320	$0.0795	$0.2384	
9	$25	No	High customer charge, 3:1 ratio TOU	$-	$0.0622	$0.1865	$0.0570	$0.1696	
10	$5	No	Low customer charge, 2:1 ratio TOU	$-	$0.0676	$0.2702	$0.0707	$0.2828	
11	$25	No	High customer charge, 2:1 ratio TOU	$-	$0.0543	$0.2171	$0.0503	$0.2011	
12	$5	No	Low customer charge, flat mid-demand charge	$5.00	$0.0815				6

Scenario	Customer charge	Energy tiers	Description	Demand charge ($/kW)	Summer off-peak ($/kWh	Summer on-peak ($/kWh)	Winter off-peak ($/kWh)	Winter on-peak ($/kWh)	No. of times coincident peak hit
13	$15	No	Mid customer charge, flat mid-demand charge	$5.00	$0.0690				6
14	$25	No	High customer charge, flat mid-demand charge	$5.00	$0.0564				6
15	$5	No	Low customer charge, flat high-demand charge	$7.50	$0.0685				6
16	$15	No	Mid customer charge, flat high-demand charge	$7.50	$0.0559				6
17	$25	No	High customer charge, flat high-demand charge	$7.50	$0.0434				6
18	$5	No	Low customer charge, tiered demand charge	$10.00	$0.0555				6
19	$15	No	Mid customer charge, tiered demand charge	$10.00	$0.0429				6
20	$25	No	High customer charge, tiered demand charge	$10.00	$0.0303				6