



Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets

IEE Whitepaper
June 2009



INSTITUTE FOR
Electric Efficiency

*Advancing energy-efficiency practices and
demand response among electric utilities.*

MOVING TOWARD UTILITY-SCALE DEPLOYMENT OF DYNAMIC PRICING IN MASS MARKETS

IEE Whitepaper

June 2009

Prepared by

Ahmad Faruqui, Ph.D.
Sanem Sergici, Ph.D.
The Brattle Group

Lisa Wood, Ph. D.
Institute for Electric Efficiency

TABLE OF CONTENTS

INTRODUCTION..... 1

DYNAMIC PRICING 2

COSTS AND BENEFITS OF DYNAMIC PRICING 7

EVIDENCE SHOWS THAT CUSTOMERS RESPOND TO DYNAMIC PRICES..... 12

 CALIFORNIA STATEWIDE PRICING PILOT (SPP) PILOT PROGRAM 13

CPP-F Impacts..... 13

CPP-V Impacts..... 14

TOU Impacts..... 14

 BALTIMORE GAS AND ELECTRIC (BGE) COMPANY- SMART ENERGY PRICING (SEP) PILOT 15

 COMMUNITY ENERGY COOPERATIVE – ENERGY SMART PRICING PLAN (ESPP) 16

 PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G) - MYPOWER PRICING PILOT PROGRAM 17

 PACIFIC GAS AND ELECTRIC COMPANY (PG&E) - SMARTRATE PROGRAM 18

 CONSENSUS SUMMARY 19

BUSINESS CASE FOR AMI DEPLOYMENT 21

 PG&E SMARTMETER PROGRAM 23

 SCE AMI BUSINESS CASE..... 24

 CURRENT STATUS OF AMI DEPLOYMENT..... 25

MAKING THE TRANSITION TO DYNAMIC PRICING 29

BIBLIOGRAPHY 31

INTRODUCTION

Prior studies have shown that dynamic pricing can provide numerous benefits to utilities and customers alike by lowering the need for expensive peaking capacity, improving system reliability, and reducing power costs. The purpose of this whitepaper is to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).

This whitepaper highlights five dynamic pricing programs that have been implemented in the U.S. and surveys the progress toward deploying AMI. In Section 2, we define and discuss the rationale for dynamic pricing. In Section 3, we assess the costs and benefits of dynamic pricing for customers, for utilities, and for independent system operators and regional transmission organizations. In Section 4, we explore whether customers respond to dynamic prices in a predictable way and rely on evidence from five dynamic pricing programs. We carefully review the design of these programs, three of which are pilots and two of which are full scale deployments, and summarize the empirical demand response results.

In Section 5, we examine the link between AMI and dynamic pricing. To inform this assessment, we first review the benefits of AMI that are typically used to support business cases for deployment. We then focus on the relationship between dynamic pricing and AMI and discuss why AMI is necessary for dynamic pricing and for realizing the potential of demand response. We conclude this section by reviewing the current state of AMI deployment in the U.S. We close, in Section 6, by discussing ways to make the transition to dynamic pricing.

DYNAMIC PRICING

Electricity is the resource that drives the modern economy. Electricity is used to illuminate and condition our homes, to power our businesses and factories, and to operate the appliances and devices that enhance our quality of life. Over the course of the last century, growth in electricity use has closely matched growth of the U.S. economy. But electricity itself is a commodity, the output of a process that involves the construction and operation of power generation units, transmission lines, and distribution systems.

As a commodity, the price of electricity is subject to the market forces of supply and demand. But, because electricity cannot be stored in large quantities, it has to be generated on demand. To serve demand that varies over time, different generation units with varying efficiencies and fuel sources are used to provide electricity at different times of the day as well as the year. But, at all times, adequate generation capacity must be maintained to serve periods of peak demand. For instance, certain generation units, typically gas combustion turbines, only operate during the one percent of the hours in a year when the demand for electricity is highest; due to their high fuel costs it makes economic sense to dispatch these expensive units only during peak demand hours. These units are kept idle for the rest of the hours of the year at a cost of billions of dollars nationwide. This implies that the real cost of serving customers is highly variable and is much higher during peak demand hours than in other hours of the year.

Despite these characteristics, today's retail tariffs typically do not account for the time-varying nature of demand and therefore the real cost to serve customers. Retail tariffs mask the real cost to serve a customer; by doing so, one of the main attributes of prices, which is to signal the true scarcity value of electricity, is lost. Customers have no incentive to reduce usage during hours when it is most expensive to serve that usage because they are not directly charged for the high cost of electricity during these hours.

Dynamic pricing overcomes this problem and by providing price signals that give customers incentives to lower their bills by curtailing peak usage and shifting it to less expensive off-peak periods. The purest form of dynamic pricing is "real-time pricing" (RTP) where customers pay electricity prices that are linked to the wholesale cost of electricity on an hourly (or sub-hourly) basis. Prices are provided on a day-ahead or hour-ahead basis and may apply to a customer's

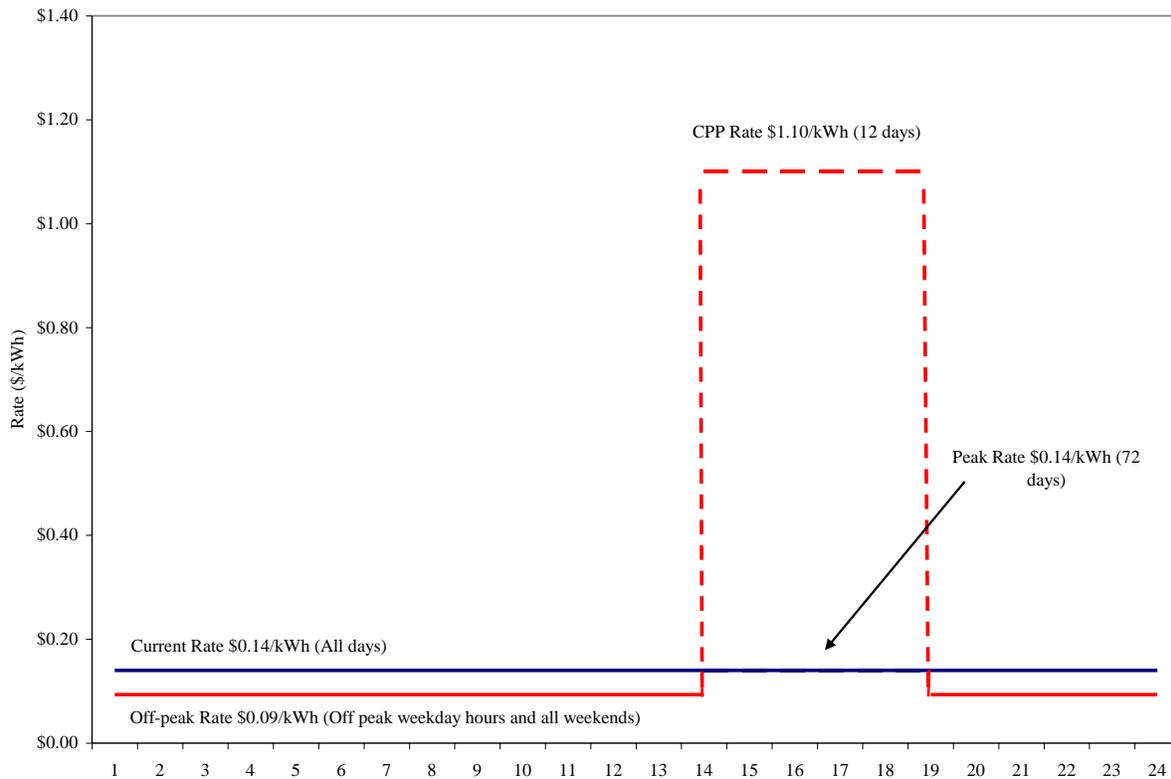
entire load or a portion. Typically, RTP is offered only to the largest customers — usually above one MW of demand. RTP programs post prices that reflect the cost of producing electricity during each hour of the day, and thus provide accurate price signals to customers, giving them the incentive to reduce consumption during the most expensive hours. Georgia Power has operated a successful RTP program for about 20 years with their largest customers. Over the past several years, over 70 utilities have offered RTP in either pilot or permanent programs.¹

Although RTP may be “ideal” from a price signal perspective, for smaller mass market customers (e.g., residential and small commercial) it may not be the best option. For the majority of mass market customers, approximations of RTP make more sense. One good approximation is to price the peak and off-peak periods differently, since the cost of electricity is more expensive during the peak hours than the off-peak hours, and link the price of only a small number of “critical” hours to the system conditions.² This pricing scheme, “critical peak pricing” (CPP), attempts to convey the true cost of power generation to electricity customers by providing a price signal that more accurately reflects energy costs during a small percentage of all hours, but during the most “critical” hours. This provides an opportunity for customers to reduce their electricity bills. This rate form is particularly effective when high wholesale prices are limited to about 100 hours of the year, and their onset is somewhat predictable. Under critical peak pricing, the period of time when the rate would be in effect (such as from 2 p.m. to 7 p.m.) and the number of days per year (e.g., 12 days in the summer months) are determined in advance. However, there is uncertainty surrounding the exact days when these critical prices go into effect since this depends on actual wholesale market prices. CPP is a dynamic rate in that it is dispatchable by the utility based on wholesale market conditions. Figure 1 shows an example of a CPP rate where the critical peak rate is \$1.10 per kWh for a 5-hour period on 12 days a year in June, July, August, or September. On the 72 non-critical weekdays in these months, the peak rate is \$0.14 per kWh for the same 5-hour period from 2 p.m. to 7 p.m. The off peak rate is \$0.09 per kWh in all other weekday hours and on weekends and holidays.

¹ See Goldman, Barbose, and Neenan (2006).

² Peak hours are more expensive to serve compared to the off-peak hours as the higher demand during peak hours requires going further up along a dispatch curve, which ranks the generation units in an ascending order in terms of their marginal costs, to meet the level of demand.

Figure 1: Illustration of a CPP Rate Design



Source: Faruqui and Wood (2008)

Another alternative is a “peak time rebate” (PTR) program which is a mirror image of the CPP rate. Under the PTR program, instead of paying higher rates during the critical event hours, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This, of course, requires the establishment of a baseline load from which the reductions can be computed. However, one advantage of PTR is that if customers don’t respond to the PTR rates, their bills remain exactly the same as they would be under their existing tariff. In other words, PTR offers bill protection in that customers will not pay more than what they pay under their current rates. Such a concept may provide a politically feasible way to transition from the current flat rates and for an eventual transition to other flexible rate options such as CPP or RTP. PTR poses some problems, primarily the computation of a baseline profile and educating customers that they are on the rate. Other problems that need to be addressed include estimation of free-ridership, finding a source for payment of the rebates, and dealing with the problems of transitioning from a rebate mechanism to a price-based mechanism.

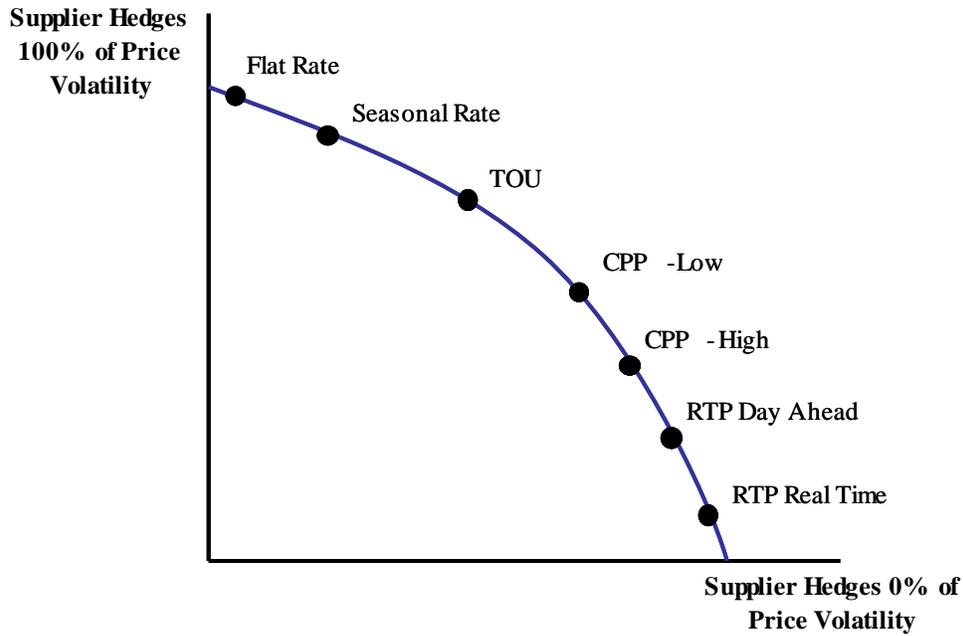
The more traditional “time-of-use: (TOU) rate structures, which have been in existence for over 30 years, reflect the higher cost of supply during peak periods and lower cost during off-peak periods. But, TOU rates are not dynamic in that they are not dispatched based on actual wholesale market hourly prices. For example, a peak period might be defined as the period from 12 p.m. to 6 p.m. on weekdays, with the remaining hours defined as off-peak. There is no uncertainty as to what the rates would be and when they would occur. In other words, these rates are independent of the system conditions and are dispatch-able by the utility as are the RTP, CPP, and PTR rates. But even then, TOU rates do help lower peak loads, reduce the need for peaking capacity, and encourage the installation of devices such as thermal energy storage which would yield permanent changes in load shapes.

As we move from traditional flat rates to more flexible rate options such as TOU, CPP, and RTP, wholesale price signals are passed on to customers. Each one of the rates shown in Figure 2 carries a different hedging premium depending on how much the utility pays to minimize price volatility. Utilities purchase hedging contracts or make other arrangements to limit their exposure to wholesale price swings. The hedging premium is inversely related to customer exposure to wholesale market prices. The premium is highest for customers on flat rates where the utility suppresses all price volatility to customers (by maximizing its hedging obligations). As rates become more dynamic, the premium decreases. Under a “real time” RTP, the hedging premium is equal to zero.³ This implies that there is a clear trade-off between price volatility and price level.

A prerequisite for the implementation of dynamic pricing programs is automated metering infrastructure (AMI) which allows for two-way communication between the utility and the customer and a link to a smart thermostat and/or a home area network (HAN). The whole premise of dynamic pricing is based on pricing the usage of customers differently at different times of the day determined by electric power system conditions. This is only feasible if the customer usage can be metered by the increments of time required by the specified pricing mechanism and communicated from the customer to the utility. AMI is not required to notify the customers of the event days and hours because this can be achieved through conventional

³ See Faruqui and Wood (2008).

Figure 2: Alternative Rate Designs and Associated Risk Premiums



Source: Faruqi and Wood (2008)

communication methods such as telephone calls, text messages, and/or emails. However, AMI enables more effective communication from utility to customer through Energy Orbs and programmable communicating thermostats, thereby making it easier for customers to respond or, in some cases, allowing the customer (or the utility) to automate the customer response.

COSTS AND BENEFITS OF DYNAMIC PRICING

Dynamic pricing can provide substantial benefits for utilities, customers, and organized markets. These benefits come with costs and there are well-established tests to gauge the net benefits and cost effectiveness of dynamic pricing.⁴ In this whitepaper our goal is to introduce these benefits and costs without delving into a discussion of the net benefits.

Dynamic pricing programs are mostly implemented for peak clipping or load shifting purposes. They may yield some conservation but that is rarely the goal of such programs. As a result, the major benefit for a utility from a dynamic pricing program is the reduced peak capacity requirement (i.e., capacity savings). By lowering system peak demand, the utility can avoid the cost of building new peaking generation.⁵ Lower peak demand also implies reduced power generation costs because the need to purchase fuel to generate power or to procure expensive peak energy declines (i.e., energy costs). Moreover, additional investments in transmission and distribution infrastructure can be avoided if energy and capacity requirements can be lowered. Figure 3 shows the distribution of utility benefits for a prototypical east coast utility from the CPP rate design shown in Figure 1, as quantified by Faruqui and Wood (2008), under the assumption that eighty percent of the residential customers will participate in the program. The share of the benefits will vary for different program designs and for different utilities, but the capacity cost savings will remain the largest share of the total benefits.

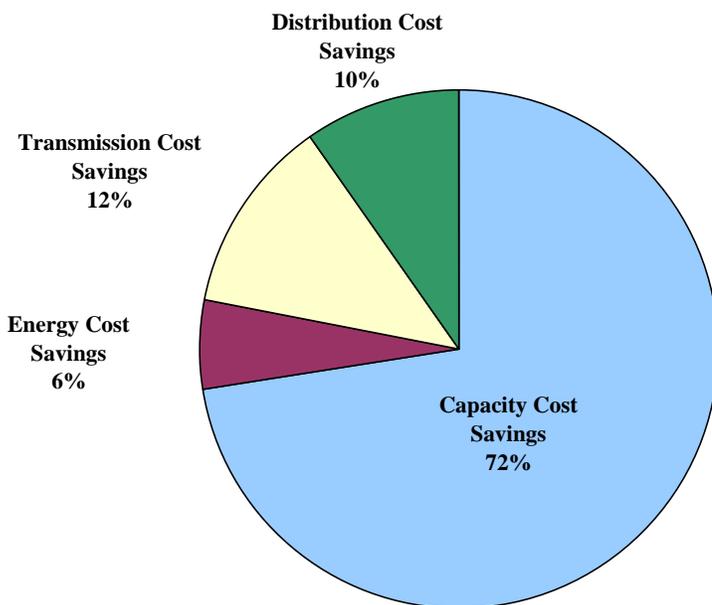
In addition to the utility benefits discussed above, dynamic prices also can help to relieve congestion by incenting demand response from customers and reducing the likelihood that the utility will interrupt service to relieve congestion when the electric grid is under stress. This feature of dynamic prices is related to improved system reliability. With the implementation of dynamic prices, the system operator obtains another tool or resource to maintain the stable and uninterrupted working of the grid. These benefits are not quantified in Figure 3.

Customers also derive benefits from dynamic pricing. It is important to note that every benefit that accrues to the utility ultimately accrues to the customers in the long-run since dynamic

⁴ See Faruqui and Wood (2008).

⁵ For example, Georgia Power estimates that it has saved 3000 MW from its RTP program; this is equivalent to 30 100 MW peaking units.

Figure 3: Distribution of Utility Benefits under CPP Rate Design for a Prototypical Utility – Capacity Savings Dominate the Benefits of a Dynamic Price



Source: Faruqui and Wood (2008)

prices will result in lower rates compared to what they would otherwise be without the demand response. The reason is straightforward: demand response as a resource is cheaper than the alternative, which is building peaking power plants. This in turn implies that the cost to serve a customer on a dynamic price is lower than the cost to serve a customer on a fixed rate.

In the short-run, the major potential benefit for customers on dynamic prices is a reduction in their monthly electricity bill. If customers respond to dynamic prices by shifting their load from high-priced to low-priced hours of the day, their monthly bills will decrease. Also, for customers with flatter than average load shapes, even if they do not shift their load from the more expensive hours to the less expensive hours, their monthly bills will decrease. Customers also benefit from increased reliability introduced by the buffering role of dynamic prices on the grid's stress level. In the long run, additional benefits accrue to customers in the form of lower system costs.

Independent system operators (ISOs) benefit from dynamic prices because they can utilize dynamic prices to manage the system's constraints. As the system peak decreases, the average

variable cost of the unit that sets the marginal price of power is likely to be lower, which in turn implies that the wholesale market clears at a lower price. The value of demand response was validated in PJM during a heat wave in August 2006. On the day PJM reached a new all time peak in August 2006, demand reductions produced price reductions that yielded a \$230 million reduction in payments for energy.⁶

There are costs associated with implementing dynamic pricing. As mentioned earlier, an AMI infrastructure that can provide two-way data communication between the utility and the customer is required. The total cost of AMI includes hardware and software costs, equipment and installation costs of new meters, project management, and information technology integration costs. According to Faruqui and Wood (2008), the cost of automated meter reading ranges from \$100 to \$175 per meter and reaches \$200 to \$525 with the addition of demand response components such as customer signaling and demand control functions. Although these costs are falling as technology improves, utilities can expect to incur substantial costs when AMI is deployed on a large scale for mass market customers. This is happening today across much of the U.S. (and discussed in Section 5).

Many utilities are now filing AMI business cases with their regulatory commissions because such expenditures must typically pass a benefit-cost test and be approved. In over 30 states across the country, utility-wide AMI deployment to mass market customers is either underway, planned, or proposed. Over the next five years, a large percentage of mass market customers in the U.S. will have AMI or some type of smart meter on their home or small business. A large portion of the costs of AMI are justified through operational benefits such as remote meter reading, faster outage detection, fewer truck rolls, and remote on/off service switching. However, there are also significant demand response benefits from dynamic pricing. In some cases, utilities rely on the demand response benefits of dynamic pricing to justify the AMI investment and achieve overall positive net benefits. In other cases, although the operational benefits alone of AMI may suffice to pass the benefit-cost tests, the benefits of dynamic pricing should not be ignored or overlooked. The share of benefits that can be attributed to dynamic prices in AMI business cases is discussed in Section 5.

⁶ McNamara (2009)

As mentioned earlier, dynamic pricing programs offer a wide range of benefits to customers, utilities, and system operators. However, such programs are still in their infancy, largely because of concerns that customers won't effectively respond to dynamic rates or, related to this, because policy makers think that mass market customers may be better off under existing rates structures which largely do not provide price signals to customers, or that some group of customers—such as low income—may be harmed. These are all fair concerns.

Another argument against dynamic pricing is that we can achieve all of the demand response (DR) that we need via direct load control (DLC). DLC does provide significant DR benefits, can reduce the need for peaking plants, and is often used for reliability purposes. To date, DLC has been used primarily as a reliability resource (rather than an economic resource) by utilities and more recently, in the forward capacity markets in the northeast. However, DLC is being increasingly repurposed as an economic resource which is operated in conjunction with price responsive demand. Price responsive demand has two important attributes – it provides both an opportunity for the customer to determine their own price threshold (rather than having the utility control the response) and an opportunity to get rid of the risk premium (or hedge premium) embedded in average cost-based fully hedged rates. In other words, if all customers on a dynamic price were in their own power purchasing pool, the average cost to supply their power would be lower compared to all customers on direct load control. DLC customers still pay the risk or hedge premium that is embedded in average cost-based rates; this is a major disadvantage. In addition, rather than responding to a price signal, DLC customers also receive a rebate or a credit (such as \$5 to \$25 per month) that is typically unrelated to the value of the actual load that is shifted when an event occurs. However, the use of DLC programs is starting to change as utilities consider using DLC as a hedge against price volatility in conjunction with price responsive demand. As indicated in the recent EPRI potential study, price-responsive demand, direct load control, and interruptible programs are all needed to realize the demand response potential in the U.S.⁷

The deployment of AMI is costly, and although it is relatively straightforward to understand the related operational benefits, the potential benefits of dynamic pricing-induced demand response

⁷ See EPRI 2009.

and why we need those benefits “in addition to” direct load control for mass market customers may be less obvious. The next section attempts to clarify these issues.

EVIDENCE SHOWS THAT CUSTOMERS RESPOND TO DYNAMIC PRICES

Dynamic pricing has two important attributes. First, providing price signals to customers will motivate them to shift their usage from high-priced to low-priced hours of the day. Second, dynamic prices are dispatched based on the real cost of electricity on a given day, so they have the potential to (1) lower the market clearing price, and (2) reduce the need for new peaking plants. Just as customers respond to prices in other markets, there is sufficient evidence that customers do respond in a predictable and quantifiable way to dynamic electricity prices.

This section reviews five programs from the past five years which have measured how customers respond to dynamic prices in pilot programs and in full-scale roll-out settings. We summarize the design and customer response results of each program and conclude with a general account of customer response to dynamic pricing programs.

1. California's Statewide Pricing Pilot (SPP) Pilot Program – 2003-2004
2. Baltimore Gas and Electric Company Smart Energy Pricing (SEP) Pilot – 2008
3. Commonwealth Edison's Community Energy Cooperative's Energy Smart Pricing Plan (ESPP) – *Full-scale roll-out*
4. Public Service Electric and Gas Company MyPower Pricing Pilot Program – 2007
5. Pacific Gas and Electric Company's SmartRate Program – *Full-scale roll-out*

We focus on these five programs because of their strong adherence to sound experimental design and statistical analysis principles. Hence, we believe that the results of these programs can be generalized to the larger population of customers in the U.S.

- First, the programs measure the load impacts from dynamic prices using the data on a large number of participants. This implies that the results from the programs are not subject to small sample biases, and if that is the case for certain treatments, they are clearly acknowledged in the studies.
- Second, these programs establish a true cause-effect relationship between the prices and the load impacts within the program, using a control group of customers, before and after comparisons, and control variables to eliminate the effect of confounding factors. By following this practice, these studies avoid reaching spurious conclusions about program impacts.
- Third, all of these programs fully informed participants about program features by holding informational workshops and providing welcome kits. However, control group customers

were not provided any such information and therefore represented a proxy for how the treatment group customers would have behaved if they had not been placed on dynamic pricing rates.

CALIFORNIA STATEWIDE PRICING PILOT (SPP) PILOT PROGRAM

California's three investor-owned utilities, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), and the two regulatory commissions, the California Public Utilities Commission and the California Energy Commission, conducted the Statewide Pricing Pilot (SPP)⁸ from July 2003 to December 2004. The purpose was to test the impact of several time-varying rates. The SPP included about 2,500 residential and small-to-medium commercial and industrial (C&I) customers and tested several rate structures: a TOU-only rate where the peak price was twice the value of the off-peak price and a CPP rate where the peak price during the critical days was roughly five times greater than the off-peak price with a TOU rate that was in effect on non-critical days. The SPP also tested two variations of the CPP rates. The CPP-F rate had a fixed critical peak period and day-ahead notification. The CPP-F customers did not have an enabling technology. The CPP-V rate had a variable critical peak period and day-of notification. The CPP-V customers had the choice of adopting an enabling technology. The average price for customers on the standard rate was about \$0.13 per kWh.

Below we discuss the rates and impacts for residential customers for the CPP-F, CPP-V, and TOU programs in the CA SPP.

CPP-F Impacts

Under the CPP-F rate, the average peak-period price on critical days was roughly \$0.59 per kWh, the peak price on non-critical days was \$0.22 per kWh, and the average off-peak price was \$0.09 per kWh. On critical days, the statewide average reduction in peak-period energy use was estimated to be 13.1 percent. Impacts varied across climate zones from a low of 7.6 percent in moderate climate zones to a high of 15.8 percent in hot climate zones. These customers did not have enabling technologies. On normal (i.e., non-critical) weekdays, the average impact was 4.7 percent, with a range across climate zones from 2.2 percent to 6.5 percent. No change in total

⁸ See CRA International (2005).

energy use across the entire year was found based on the average SPP prices. The impact of customer characteristics on energy use by rate period was also examined. Central AC (CAC) ownership and college education were associated with the largest reduction in energy use on critical days.

CPP-V Impacts

Under the CPP-V rate, the average peak-period price on critical days was roughly \$0.65 per kWh and the average off-peak price was \$0.10 per kWh. This rate schedule was tested on two different treatment groups. Track A customers were selected from a population with energy use greater than 600 kWh per month. In this group, average income and CAC saturation were much higher than the general population. Track A customers were given a choice of installing smart thermostats and/or load controllers for water heaters and pool pumps and about two thirds of them opted for the enabling technologies. The Track C group was formed from customers who previously volunteered for a smart thermostat pilot. All Track C customers had CAC and smart thermostats. Hence, two-thirds of Track A customers and all Track C customers had enabling technologies. Track A customers reduced their peak-period energy use on critical days by about 16 percent (about 25 percent higher than the CPP-F rate impact). Track C customers reduced their peak-period use on critical days by about 27 percent. Comparing the CPP-F and the CPP-V results suggest that usage impacts are significantly larger with an enabling technology than without it.

TOU Impacts

Under the TOU rate, the average peak-period price was roughly \$0.22 per kWh and the average off-peak price was \$ 0.09 per kWh. The reduction in peak period energy use during the summer months of June, July, and August in 2003 was estimated to be 5.9 percent. However, this impact completely disappeared in 2004, perhaps due to the small size of the TOU samples. In order to derive TOU impacts, the CPP samples contain the necessary information since customers on the CPP rate were on a standard TOU rate on non-critical days.

BALTIMORE GAS AND ELECTRIC (BGE) COMPANY- SMART ENERGY PRICING (SEP) PILOT

Baltimore Gas and Electric Company conducted a smart energy pricing (SEP)⁹ pilot from June 1, 2008 through September 30, 2008. BGE tested three dynamic pricing programs: a dynamic peak pricing (DPP) program which combined a CPP rate with a TOU rate; and two peak time rebate (PTR) programs. One PTR program tested a low rebate level (PTRL) and the other tested a high rebate level (PTRH).

Under the DPP, peak period hours were defined as 2 p.m. through 7 p.m. on weekdays; all remaining hours were off-peak. Twelve critical peak event days were called during the summer. Under the DPP program, the critical peak price was \$1.30 per kWh, the peak period price was \$0.14 per kWh, and the off-peak price was \$0.09 per kWh.

In the PTR programs, participants' rates remained unchanged (on average \$0.15 per kWh during the pilot period). However, on the critical event days, between the hours of 2 p.m. and 7 p.m., participants received a rebate if they reduced their consumption below their "typical" or baseline usage during these hours. Participants received \$1.16 and \$1.75 per kWh reduction below their baseline, respectively, under the PTRL and the PTRH options.

BGE also tested the implications of enabling technologies in the SEP program. Some participants were provided with the "Energy Orb" (ORB), a sphere that emits different colors to signal off-peak, peak, and critical peak hours while others had both the Energy Orb and an air conditioning switch (ET+ORB). In total, the SEP tested eight different programs: DPP, DPP with ET+ORB, PTRL, PTRL with ORB, PTRL with ET+ORB, PTRH, PTRH with ORB, and PTRH with ET+ORB. The final pilot sample included 1,375 customers; 1,021 of which were subject to the SEP programs and the remaining 354 constituted a control group. BGE called a total of 12 critical peak event days throughout the pilot. Results from the pilot are as follows:

- Customers showed the same price responsiveness under the DPP and PTR programs. Substitution and daily price elasticities estimated for DPP, PTRL, and PTRH were not significantly different in statistical terms.

⁹ See *The Brattle Group* (2009).

- The overall reduction in critical peak period usage ranged from 18 to 33 percent depending of the presence of enabling technologies.
- Without enabling technologies, the DPP, PTRL, and PTRH programs yielded customer response impacts from 18 to 21 percent.
- With the Energy Orb, the DPP, PTRL, and PTRH programs yielded customer response impacts from 23 to 27 percent.
- With both the A/C switch and the Energy Orb, customer response impacts ranged from 28 to 33 percent; almost twice as high as for customers with no enabling technology.
- As a result of the programs, total monthly consumption increased by about one percent for DPP and decreased by about ½ percent for PTRL and PTRH.

COMMUNITY ENERGY COOPERATIVE – ENERGY SMART PRICING PLAN (ESPP)

The Community Energy Cooperative’s (CEC) Energy-Smart Pricing Plan (ESPP)^{10 11} is the first large-scale deployment of residential real-time pricing (RTP) in the U.S. It was conducted as a pilot in Commonwealth Edison’s service territory in northern Illinois between 2003 and 2006 (and became a Commonwealth Edison program in 2007). ESPP initially included 750 participants and expanded to nearly 1,500 customers in 2005 and 2006. ESPP tested the hypothesis that major benefits could result from RTP without the adoption of expensive technology. The ESPP design included:

- Day-ahead announcement of the hourly electricity prices for the next day. On the day of the event, customers were charged the hourly prices that had been posted the day before.
- High-price day notification via phone or email when the price of electricity climbed over \$0.10 per kWh (in 2006, the notification threshold was set to above \$0.13 per kWh).
- A price cap of \$0.50 per kWh for participants, meaning that the maximum hourly price could not exceed \$0.50 per kWh during their participation in the program.
- In 2005 (continued in 2006), cycling switches for CACs were installed at 57 of the 1500 participant homes, which effectively reduced energy consumption by CAC units during high price periods.
- Energy usage education for participants.

¹⁰ See Summit Blue Consulting, LLC (2006).

¹¹ See Summit Blue Consulting, LLC (2007).

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy conservation.

In 2005, the overall price elasticity during the summer was -0.047, meaning that a 100 percent increase in the electricity price resulted in a five percent decrease in usage. With automatic cycling of the central-air conditioners during high-priced periods, the overall price elasticity increased to -0.069, meaning that a 100 percent increase in the electricity price resulted in a seven percent decrease in usage. The largest responses occurred on high-price notification days (i.e., over \$0.10 per kWh in 2005). On the highest priced day during the summer of 2005, participants reduced their peak hour consumption by 15 percent compared to what they would have consumed under the flat ComEd residential rate. ESPP participants also reduced their summer electricity usage by roughly three to four percent.

Analysis of the ESPP in 2006 supported the findings of the program's 2005 results. For hours when the price of electricity was less than or equal to \$0.13 per kWh, the summer price elasticity was -0.047. For hours when the price of electricity was above \$0.13 per kWh, the price elasticity was -0.082. For customers with CAC cycling, the price elasticity for high-price periods was estimated at -0.098. Similar to the 2005 results, participants reduced their summer electricity usage by three percent, on average.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G) - MYPOWER PRICING PILOT PROGRAM

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two programs.¹²

- Under the first program, *myPower Sense*, participants were educated about the TOU/CPP tariff and were notified of a CPP event on a day-ahead basis.
- Under the second program, *myPower Connection*, participants received a free programmable communicating thermostat (PCT) that received price signals from PSE&G and adjusted their air conditioning settings based on previously programmed set points on critical days.

¹² See PSE&G and Summit Blue Consulting (2007).

A total of 1,148 customers participated in the pilot program; 450 in the control group, 379 in *myPower Sense*, and 319 in *myPower Connection*. PSE&G recruited the participants for each group through direct mail with follow-up telemarketing: *myPower Sense* customers received a \$25 incentive upon enrollment and \$75 was paid upon the conclusion of the program; *myPower Connection* participants received free PCTs and received \$75 at the end of the program.

The TOU/ CPP tariff included a night discount, a base rate, an on-peak adder, and a critical peak adder for the summer months. The base rate was \$0.09 per kWh; the night discount was \$0.05 per kWh in both summers. The on peak adders were \$0.08 per kWh and \$0.15 per kWh respectively in the summers of 2006 and 2007, making the prices \$0.17 per kWh and \$0.24 per kWh, respectively. The critical peak prices were \$0.78 per kWh and \$1.46 per kWh, respectively, in the summers of 2006 and 2007. PSE&G called two CPP events in Summer 2006 and five CPP events in Summer 2007. The pilot results show that:

- *myPower Sense* customers with CAC reduced their peak demand by three percent on TOU-only days. On CPP days, these customers reduced their peak load by a total of 17 percent. *myPower Sense* customers without CAC reduced peak load by six percent on TOU-only days and by a total of 20 percent on CPP days.
- *myPower Connection* customers (i.e., those with the PCT) reduced their peak demand by 21 percent due to TOU-only pricing. On CPP days, these customers reduced their peak load by a total of 47 percent.

Hence, the technology-enabled segment (i.e., the *myPower Connection* customers) reduced their peak-demand consistently more than the *myPower Sense* customers who received education only. The *myPower Sense* customers were able to reduce their demand on critical days even if they did not have a CAC.

PACIFIC GAS AND ELECTRIC COMPANY (PG&E) - SMARTRATE PROGRAM

PG&E deployed the first large scale critical peak pricing program in North America in the summer of 2008 for the six months May through October. The SmartRate¹³ tariff was initially offered to residential (E-1 and E-8) and non-residential customers (A-1) in the Bakersfield and

¹³ See Freeman, Sullivan & Co. (2009).

greater Kern County region¹⁴. Direct mail was sent to approximately 135,000 accounts, and 10,000 customers enrolled in the program (194 non-residential customers). SmartRate pricing is structured as an overlay on the existing tariffs which consisted of a five-tiered inclining block rate structure. Peak period (from 2 p.m. to 7 p.m.) prices on SmartDays were substantially higher than the prices under the existing tariff, and for all other hours from June to September customers received a per-kWh credit. Peak period incremental charges are 60 cents per kWh and 75 cents per kWh for residential and non-residential customers, respectively. The credit has two components, both of which are applicable from June to September. The first part, roughly \$0.03 per kWh, applies to all usage except the peak period usage on SmartDays. The second part, roughly \$0.01 per kWh, applies to tier 3 and high usage customers regardless of the time period. No enabling technologies were used.

PG&E called nine SmartDays during the summer of 2008. The results are as follows:

- Standard residential tariff customers reduced their peak load by 16.6 percent on average across the nine SmartDays.
- Customers who qualified for CARE (California Alternate Rates for Energy), a program in which low income customers receive lower rates, reduced their peak load by 11 percent on average across the nine SmartDays.
- Non-CARE customers reduced their peak load by 22.6 percent on average across the nine SmartDays.
- Standard small commercial tariff customers reduced their peak load by 16 percent on average, across the nine SmartDays (note that this result is based on a small number of participants).

CONSENSUS SUMMARY

The single most important conclusion from our review of the five dynamic pricing programs is that customers do respond to dynamic prices; customer response is real. The extent of demand response varies from one program to the other, mainly due to the differences in prices. This conclusion is also supported by several other pilot programs that have been conducted in North

¹⁴ PG&E's standard tariff is E-1. E-8 has the same five-tier structure as E-1 except that the prices in E-8 are lower in tiers 3, 4, and 5 and include a higher monthly charge.

America, Europe and Australia over the last 15 years.¹⁵ Repeated demonstrations of customer response in different geographies across North America and elsewhere indicate that, regardless of the utility or the region, customers respond to price signals.

The second most important conclusion from our review is that enabling technologies such as Energy Orbs, programmable communicating thermostats (PCTs), and central air conditioning switches significantly increase the customer response to the price signal.

- When customers have a visual aid such as an Energy Orb, which reminds them when high priced periods are in effect (thereby giving them a visual clue to respond), evidence shows that they respond more.
- When customers have enabling technologies, they respond more than with no technology. For example, PCTs can be programmed to respond when the utility relays a high price signal by raising the thermostat setting a pre-determined 2-3 degrees, thereby reducing the air conditioning load.

There is no “one size fits all” dynamic pricing structure. Each utility has to determine the dynamic pricing regime that would best fit the characteristics of their system, their customers, and their demand response goals. For instance, two of the California utilities, SDG&E and SCE, are rolling out PTR rates to get customers accustomed to responding to dynamic rates and to raise awareness of dynamic rates. Other utilities are considering a PTR rate in the short term as a transition to a CPP rate.¹⁶ Another California utility, PG&E, is deploying voluntary CPP rates (and is considering deploying PTR rates at a later date).

¹⁵ These pilot programs are reviewed in Faruqui and Sergici (2009).

¹⁶ See Faruqui and Wood (2008).

BUSINESS CASE FOR AMI DEPLOYMENT

The Federal Energy Regulatory Commission (FERC) (2006) defines AMI “as a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.” In plain language, AMI enables two-way communications between the utility and its customers.

Utilities deploy AMI for different reasons. AMI could be driven by regulatory initiatives as in the case of the investor-owned utilities in California. California’s Energy Action Plan makes energy efficiency and demand response the first resources in energy resource procurement.¹⁷ Many other utilities carry out AMI pilots and/or have plans to fully deploy AMI without any regulatory imperatives because they recognize the potential economic benefits as well as the benefits to their customers and the power system.¹⁸

Utilities that are engaged in AMI deployments must project both the costs and benefits of the AMI investment. The major cost components of AMI are the system hardware (primarily meter) and software costs which are swiftly decreasing with improvements in technology. In addition, there are labor costs associated with the deployment and installation of new meters, customer education, and IT system integration costs. We categorize the benefits of AMI or “smart meters” in three categories below– customer benefits, operational benefits, and price responsive demand benefits.

The first group of benefits is related to *better electricity service quality and customer support* made possible by AMI. These benefits include:

- More accurate and prompt billing,
- Faster resolution of the disputed bills,
- Better electricity service due to faster detection of and response to power outages because the detection of outages and restoration of power can be automated,
- Reduction in power theft,

¹⁷ See Southern California Edison (2008).

¹⁸ See Plexus Research (2006).

- Improved convenience, security and privacy due to automated meter reading,
- More rate options and bill savings opportunities for customers because AMI enables dynamic pricing,
- Facilitation of smart grid by acting as a basic building block to smart price signals and home area networks.

The second group of AMI benefits includes improvements in the *utility operations*. The major operational benefit of AMI is the elimination of manual meter reading. When automated reading replaces the traditional manual reading, all the variable costs of manual reading are avoided. This benefit typically represents one third to two thirds of the total utility operational benefits of AMI.¹⁹ AMI also leads to other indirect operational benefits such as reduced number of customer support inquiries, and therefore potential reduction in customer support expenses. AMI related improvements in utility operations usually represent the largest fraction of the total quantifiable AMI benefits in utility business cases.

The third group of AMI benefits is *price-responsive demand benefits*. Implementation of dynamic pricing programs requires some type of AMI system that allows for two-way communication between the utility and its customers so that the utility can send the price signal to the customer and when the customer responds, the utility can record the fluctuation in usage. When customers respond to price signals by shifting load, the utility's system peak demand is reduced. But, it is not enough to simply have a system with the ability to send a price signal and record the response, the utility must also be able to send a signal that can control an "enabling" technology or an in-home device such as a PCT, an Energy Orb, or a switch (at minimum) that can automate or enhance the customer response.

The reduction in the system peak demand that occurs in response to the price signal has several implications for the utility and the grid. Such price responsive demand:

- reduces peaking capacity requirements which translate into reduced need for additional generation capacity (either through new investments or procurement in capacity markets),
- avoids additional investment in transmission and distribution infrastructure,

¹⁹ Id.

- reduces congestion resulting in lower wholesale market prices and a lower likelihood of blackouts,
- eliminates dispatch of the highest cost generation units during system peaks.

Depending on the utility and the specific dynamic pricing program, the benefits of price-responsive demand can be a significant component of the total benefits associated with AMI, especially if the avoided cost of a blackout is included as a benefit.²⁰

AMI has many benefits, but the costs are significant and, as with any investment, both the costs and benefits must be factored into business cases. The decision to “go ahead” with AMI depends on the relative magnitudes of the benefits and the costs and whether the net benefits are positive. Below, we present two examples of AMI business cases.

PG&E SMARTMETER PROGRAM

PG&E was the first utility in the United States to begin to deploy AMI for all of its customers. Starting in the summer of 2008, PG&E began deploying AMI through its SmartMeter program.²¹ This involves the deployment of over 10 million electric and gas meters over the next five years; a communication network; and IT systems to manage, store and communicate the meter reads.

PG&E identified three drivers for SmartMeter program deployment:

- First, better and more cost-effective customer service is enabled by AMI. PG&E expects to improve customer service through more convenient and less intrusive meter reading, faster outage detection and power restoration, and more innovative billing practices.
- Second, the enhanced demand response potential of AMI. AMI is a prerequisite for the implementation of dynamic rate programs since these programs are made possible by two-way communication between the customer and the utility. With the deployment of AMI, PG&E can offer its customers a greater range of rate choices and more control over their own usage; in-turn, PG&E can expect load shifting benefits.
- Third, PG&E’s SmartMeter program enables future innovations by establishing a platform. PG&E’s SmartMeter program will facilitate the smart grid by leveraging home area networks (HAN), remote connect/disconnect capability, distributed generation and renewable resources, plug-in hybrid vehicles, and other smart systems and resources.

²⁰ Id.

²¹ See Pacific Gas and Electric Company (2008).

SCE AMI BUSINESS CASE

SCE identified four main drivers of its AMI initiative:²²

- First, California's Energy Action Plan places energy efficiency and demand response first in the "loading order" for energy resource procurement.²³
- Second, the California Global Warming Solutions Act requires global emissions be reduced to 1990 levels by 2020.
- Third, regulatory incentives in California make energy efficiency investment comparable to supply-side investments.
- Fourth, AMI helps to mitigate peak load growth and to improve the falling load factor in the SCE service territory.

SCE has plans to deploy AMI systems to five million residential and small commercial customers to provide better service, better communication, new bill payment options, saver programs, and dynamic rates. Starting in October 2009, SCE plans to implement PTR and CPP programs. PTR will be available to residential customers and will provide bill credits for usage reduction below baseline during peak hours on an unlimited number of event days. CPP will be available to residential, small commercial, and agricultural customers.

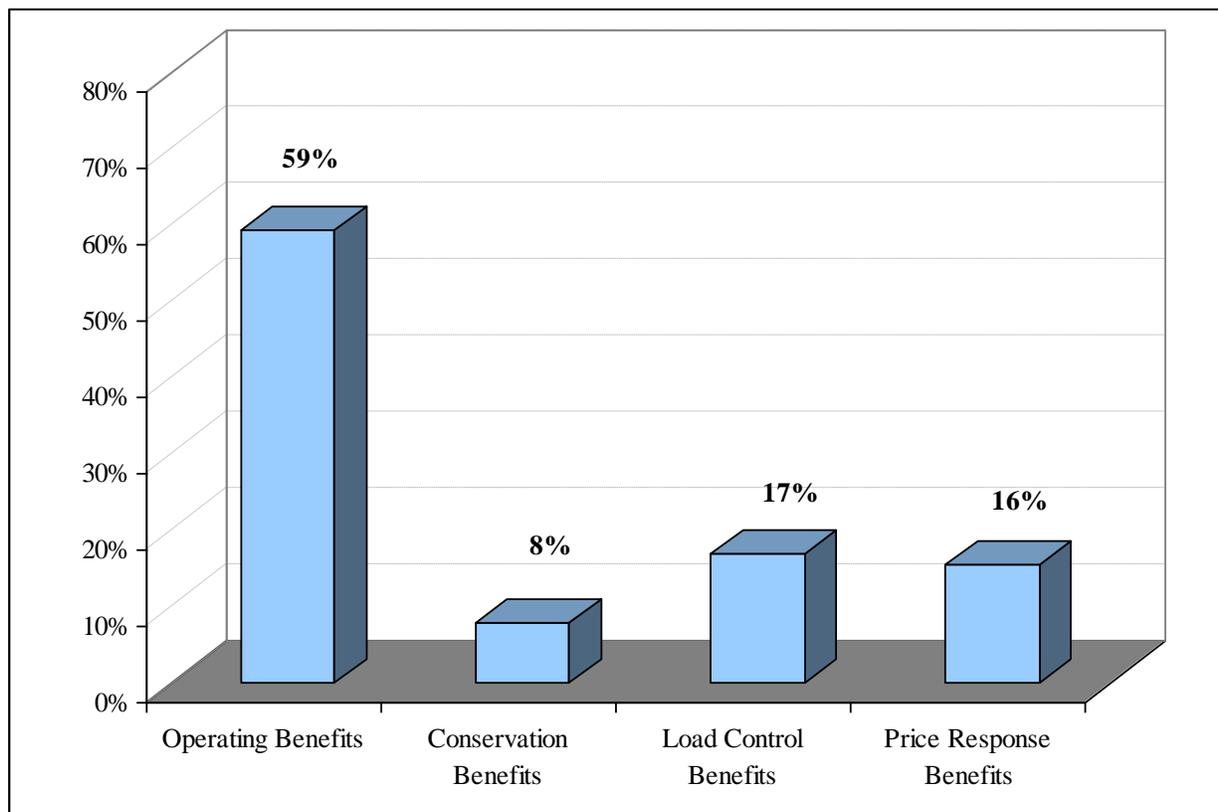
The SCE AMI business case incorporates the following quantifiable benefits of AMI: remote meter reading, remotely controlled demand response (auto DR), remote connect/disconnect, faster outage detection, prepayment services, demand response from dynamic rates, and energy conservation prompted by information. According to SCE's AMI business case, the present value of AMI benefits (as of 2007) is \$2,076 million and the total present value of the AMI costs is \$1,960 million. A breakdown of the quantifiable benefits is provided in Figure 4. Together, load control and price response benefits comprise one-third of the total benefits.

In utility AMI business cases, operational benefits are always substantial and usually justify more than half of the total AMI costs. The remainder is usually made up of load control and demand response benefits. In SCE's business case, load control and demand response benefits

²² See Southern California Edison (2008).

²³ In the California Energy Action Plan loading order, energy efficiency and demand response are followed by renewable resources, distributed generation, conventional generation and transmission infrastructure.

Figure 4: Breakdown of Quantifiable AMI Benefits from SCE’s AMI Business Case



cover a third of the total AMI costs. In SDG&E’s business case, demand response benefits justify 50 percent of the total costs.²⁴ For Southern Company and the four operating utilities, operational benefits alone were significant enough to justify the costs of AMI.²⁵

CURRENT STATUS OF AMI DEPLOYMENT

Comprehensive information about the status of AMI deployment in the U.S. is available from the FERC 2008 Staff Report on “Assessment of Demand Response and Advanced Metering.”²⁶ In this report, FERC surveyed utilities in all 50 states to identify the percentage of total meters being used for advanced metering.²⁷ The report also surveyed the participants on the use of AMI

²⁴ See FERC (2008).

²⁵ Id.

²⁶ Id.

²⁷ Survey response rate was 60 percent, but the total number of meters reported by the survey account for 91 percent of all currently installed meters in the U.S. Hence, it was possible to extrapolate the survey value to the entire population of meters.

meters beyond automated meter reading. The top five most cited uses of AMI (beyond automated meter reading) were enhanced customer service, outage detection, detection of theft and other line losses, outage restoration and remote connect/disconnect functions. Other cited uses of AMI were its use with home area networks and for prepay metering.

Based on the FERC 2008 report, advanced metering penetration in the U.S. has grown significantly from less than one percent to 4.7 percent between 2006 and 2008.²⁸ Driven by federal legislation such as the Energy Policy Act (2005) and the Energy Independence and Security Act (2007,) and by individual state policies, more utilities have announced plans to deploy AMI in the near future. The map in Figure 5 presents utility-scale smart meter deployments, planned deployments, and proposals by investor-owned utilities (and some public power) for mass market customers. As shown, as of May 2009, more than 30 states have started or announced plans or proposals for significant utility-wide AMI deployment. In the next five years, we will have significant penetration of AMI among mass market customers across the U.S; far beyond the 5% that we have today.

IEE research also lists the AMI projects by utility, detailing the number of meters being deployed as well as deployment schedules.²⁹ Figure 6 summarizes this information.

²⁸ As of 2008, the number of total customer meters was provided as 144,385,392 while the number of meters used for AMI was 6,733,151.

²⁹ See IEE (2009).

Figure 6: Utility Planned and Proposed AMI Deployment Projects

State	Utility	Number of Meters	Deployment Plan
AZ	AZ Public Service	0.8 million	Expected completion by 2012
AZ	Salt River Project	0.3 million	Completed in 2008
CA	SCE	5.3 million	Expected completion by 2012
CA	PG&E	5.1 million	Expected completion by 2012
CA	SDG&E	1.4 million	Expected completion by 2011
CT	Connecticut Light & Power	1.2 million	Deployment will start after the completion of a pilot program in 2009
DC (also in DE, MD,NJ,VA)	PEPCO Holdings	1.9 million	Target completion date is 2013. 258,000 deployed as of January 2009
FL	FPL	4.4 million	Completion date has not been released
GA (also in AL, FL, MS)	Southern Company	4.3 million	Expected completion by 2013
HI	HECO	0.43 million	Expected completion by 2015
IA (also in MN, WI)	Alliant Energy	1.0 million	Expected completion by 2011
ID	Idaho Power	0.475 million	Expected completion by 2011
IL	Ameren	1.1 million	Completion date unknown. 0.55 million meters installed as of June 2008
IL	Commonwealth Edison	0.2 million	Completion date has not been released
IN (also in KY, MI, OH, OK, TX, VA, WV)	AEP	5 million	Expected completion by 2015. One million of these meters are expected to be deployed by 2010.
IN (also in SC)	Duke Energy	1.6 million	Filed in 2008, approval pending
MA	Statewide program	Potentially 2.6 million	MA Green Communities Act mandates a smart meter pilot, potentially followed by a statewide deployment
MD (also in PA, WV)	Allegheny Power	Potentially 0.7 million	Expected filing August 2009
MD	Baltimore Gas & Electric	1.2 million	Completion date has not been released
ME	Bangor Hydro-Electric	0.12 million	Expected completion by 2010
MI	DTE	4.0 million	Expected completion by 2014
OR	Portland General	0.85 million	Expected completion by 2010
PA	Statewide program	6 million	Act 129 signed in 2008 mandates that all customers must have smart meters by 2018.
TX	Oncor	3 million	Expected completion by 2012
TX	CenterPoint	2 million	Expected completion by 2014
TX	Austin Energy	0.23 million	Approved in 2008
VA	Dominion	0.2 million	Deployment for the pilot to begin in 2009
VT	Central VT Public Service	0.15 million	Expected to begin between 2011-2013

MAKING THE TRANSITION TO DYNAMIC PRICING

The benefits of dynamic pricing will only be realized if customers are offered these rates and take advantage of them. However, moving from our current flat rates for the majority of mass market customers will be difficult. All customers on dynamic pricing will have the opportunity to shift their usage, especially on high priced days, and lower their energy bills, but they may be unwilling to try this out unless they are educated and their concerns are addressed.

Based on our experiences working with customers and with utilities designing dynamic pricing pilots and programs, customers are interested in trying new rate options, managing their energy use, and saving energy. In order to open up this market and allow customers to experience different types of rate options, we recommend undertaking one or more of the following:

- **Create customer buy in.** Customers need to be educated about why rates are changing. They have to be shown how dynamic prices can lower energy costs for society, help them lower their monthly utility bill and manage their energy use, prevent another energy crisis from occurring, improve system reliability, and lead to a cleaner environment.
- **Offer tools such as in home displays.** These tools should allow customers to get the most out of dynamic pricing. At the simplest level, they should be equipped with information on how much of their utility bill comes from various end-uses such as lighting, laundry and air conditioning and what actions will have the largest response on their bill. At the next level, customers could be given real-time in-home displays which disaggregate their power consumption and tell them how much they are paying by the hour. Finally, they could be provided enabling technologies such as programmable communicating thermostats and home area networks to manage their energy use.
- **Design two-part rates.** The first part of the rate would allow them to buy a predetermined amount of power at a known rate (analogous to how they buy all their electricity today) and the second part would give them access to dynamic pricing above a certain usage and allow them to manage their energy costs by modifying the timing of their consumption. This approach has been used by Georgia Power with its larger customers for almost two decades.
- **Provide bill protection and bill comparisons.** This would ensure that for the first year, the utility bill would be no higher than what it would have been on the existing rate but would not preclude the bill from decreasing as a result of the dynamic pricing rate. Customers would simply pay the lower of the two amounts. In later years, the bill protection could be phased out. For example, in year one, the customer bill could be fully protected and would be no higher than it would have been otherwise; in year two, it would be no higher than five percent; in year three, no higher than ten percent; in year four, no higher than fifteen percent and in year five, no higher than twenty percent. In the sixth year and beyond, bill protection would be provided for a fee.

- **Credit customers for the hedging premium.** Existing fixed price rates are very costly for suppliers to provide since they transfer all price and volume risk from the customers to the suppliers. The supplier has to hedge against the price and volume risk embodied in such as open-ended fixed price contract and pays a premium for this hedge which is passed on to the customer (like an insurance premium). The supplier risk depends on the volatility of wholesale prices, the volatility of customer loads, and the correlation between the two. Theoretical simulations and empirical work suggest that this risk premium ranges between five-to-thirty percent of the cost of a fixed rate; it is higher when the existing rate is fixed and time-invariant, and smaller when the existing rate is time-varying or partly dynamic. Customers who move to dynamic pricing rates could be credited with some portion of this risk premium.
- **Give customers choices.** Dynamic pricing rates, even with all the items mentioned above, may not be appropriate for some customers. Fixed rates may not be appropriate for other customers. Customers should have the option of migrating to different types of time-varying rates (perhaps with varying lengths of the peak period and with varying numbers of pricing periods) or between time varying and fixed rates. The bottom line is that customers need to be able to experience different rate options and we need to figure out a way to pave the way for them to do just that.

The benefits of dynamic pricing are well established and increasingly within reach as AMI, in-home displays, home area networks, and other smart grid technologies are deployed throughout the nation. What stands in the way of progress is inertia, misplaced concerns about price volatility, and a fear of dealing with the potential push back that might come from those who would lose the subsidies that they have enjoyed under existing rates.

This whitepaper discussed several ways to start to make the transition to dynamic pricing for mass market customers; this transition will not occur without the collaboration of regulatory commissions, consumer advocates, and electric utilities. Regulatory commissioners, consumer advocates, and utility executives can use these pricing methods and recommendations to get started. We also have new research results in behavioral economics that suggest ways to “nudge” customers toward new behaviors that will benefit them.³⁰ The transition to dynamic pricing in the electric power sector is important; without it our nation will continue to experience the well-known inefficiencies of uniform, static, “fixed” pricing for mass market customers and will continue to build peaking plants that run 100 hours of the year (i.e., one percent of the time). We simply can no longer afford to do that.

³⁰ See Thayer and Sunstein (2009).

BIBLIOGRAPHY

- CRA International. 2005. "Impact Evaluation of the California Statewide Pricing Pilot." Oakland, California. March 2005.
- EPRI. 2009. "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)." January 2009.
- Faruqui, Ahmad and Lisa Wood. 2008. "Quantifying the Benefits of Dynamic Pricing in the Mass Market." Edison Electric Institute, Washington, D.C., January 2008.
- Faruqui, Ahmad and Sanem Sergici 2009. "Household Response to Dynamic Pricing of Electricity – A Survey of The Experimental Evidence," can be downloaded from <http://www.hks.harvard.edu/hepg/>.
- Federal Energy Regulatory Commission. 2008. "Assessment of Demand Response and Advanced Metering." Staff Report.
- Freeman, Sullivan & Co. 2008. "2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate Tariff." Prepared for Pacific Gas and Electric Company, December 2008.
- Goldman, Charles, Galen Barbose, and Bernie Neenan. 2006. "RTP as an Optional Service: It's Alive But Is It Well," Lawrence Berkley National Laboratory, Paper LBNL 59740.
- Institute for Electric Efficiency (IEE). 2009. "Utility-Scale Deployment of Smart Meters," February 2009.
- McNamara, Sean. 2009. "Testimony of Sean McNamara- PJM Interconnection, New Jersey Clean Energy Council." April 2009.
- Pacific Gas and Electric Company. 2008. "SmartMeter Program Overview." December 2008.
- Plexus Research Inc. 2006. "Deciding on Smart Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005." Prepared for Edison Electric Institute, September 2006.
- PSE&G and Summit Blue Consulting. 2007. "Final Report for the myPower Pricing Segments Evaluation." December, 2007.
- Summit Blue Consulting, LLC. 2006. "Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report." Boulder, Colorado. August 2006.
- Summit Blue Consulting, LLC. 2007. "Evaluation of the 2006 Energy-Smart Pricing Plan-Final Report." November 2007.
- Southern California Edison. 2008. "Demand Response Enabled by Advanced Metering," Presented at Institute for Electric Efficiency Eforum, November, 2008.

Thaler, Richard and Cass Sunstein, 2009. "Nudge: Improving Decisions About Health, Wealth, and Happiness." Penguin.

The Brattle Group. 2009. "Baltimore Gas and Electric Company Smart Energy Pricing Pilot-Summer 2008 Impact Evaluation," Prepared for Baltimore Gas and Electric Company, January 2009.

For more information contact:

Institute for Electric Efficiency
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
1.202.508.5440
www.edisonfoundation.net/iee



INSTITUTE FOR
Electric Efficiency