

Chapter 7: Engaging Electricity Demand

In this chapter, we discuss the opportunities for grid operation associated with more actively engaging electricity demand. The past several years have seen significant and growing interest in encouraging greater customer involvement in managing their electricity use. Technologies that facilitate increased demand response and enhance energy efficiency are likely to become more affordable as they mature and costs continue to fall.

Sections 7.1 through 7.4 provide background. Section 7.1 introduces the motivation for increasing demand engagement, while Section 7.2 describes demand response programs as they exist today. Section 7.3 then assesses the potential benefits of more active demand management by electricity customers, and assesses the substantial uncertainty that continues to surround estimates of potential demand response benefits, particularly at the residential level. Section 7.4 describes energy conservation and energy-efficiency programs and their relationship to demand response programs.

Section 7.5 provides our main findings related to demand engagement. Carefully designed customer engagement programs and transition policies to dynamic pricing tariffs will be critical to creating responsive demand and realizing the full potential of advanced metering infrastructure (AMI) investments. Complementary technologies that promise to automate customer responses are likely to be important in these objectives. Their relative immaturity in 2011 signals the importance of ensuring upward compatibility and interoperability, to avoid stranding customer investments. Finally, we note that results of ongoing pilots and system deployments could dramatically narrow uncertainty surrounding the costs and benefits of AMI, associated technologies, and dynamic pricing—if data are shared.

Section 7.6 details our recommendations. We first recommend that utilities that have already committed to AMI deployment prioritize transition paths to broad-based dynamic pricing. We highlight the importance of publicly sharing information on their customer engagement programs, investment costs, and results of demand response initiatives. Such data can improve program design for adopters and decision quality for utilities that must evaluate whether to accelerate replacement of their customers' meters. We recommend that decision makers for utilities confronting uncertain investment cases recognize the option value of deferring decisions pending that early deployment data: adoption decisions are not "now or never" but "now or re-evaluate with new data."

INTRODUCTION

Policy makers, regulators, grid system operators, utilities, and customer groups have expressed increasing interest in electricity load becoming more responsive to system conditions, particularly to variations in the cost of supplying energy. More responsive demand can improve system efficiency and reduce costs. Reduced consumption at or near system peaks can

reduce the need for expensive investment in additional generating capacity, and shifting consumption to off-peak periods can flatten load curves,

improve capacity utilization on *More responsive demand can improve system efficiency and reduce costs.*

the system, and

reduce the total cost of delivering a given quantity of energy. Real-time adjustments to demand could reduce the cost of managing

supply volatility brought on by increased penetration of variable energy resources (VERs) and, by promoting off-peak charging, could reduce the need for new generation and network capacity to accommodate electric vehicles and plug-in hybrid vehicles. More price-responsive demand may help to mitigate market power concerns in restructured wholesale generation markets by reducing the profitability of price increases. In addition, making their own real-time electricity usage more visible to consumers may complement energy conservation goals.

The growing interest in engaging electricity demand has been accompanied by significant advances in the development and diffusion of technologies capable of facilitating this change. As described in Chapter 6, the U.S. has seen dramatic growth in the deployment of advanced metering infrastructure (AMI), which records a customer's electricity consumption at least hourly and provides two-way communication with the distribution utility. In addition to providing more granular data on customer usage, AMI complements a range of "smart" energy response and management technologies—such as programmable controllable thermostats and "smart charging" of electric vehicles—that can, in principle, involve even smaller commercial and residential customers in more active management of their electricity consumption and facilitate their responses to price or other supply-side signals.

Historically, only the demands of those large customers who had agreed to take "interruptible" power in exchange for lower rates were responsive to system conditions, and then only in emergencies or when demand nears system capacity. New technologies make it easier to reduce the demands of even smaller customers in emergency conditions. But the potential benefits of demand response go well beyond dealing with emergencies, as suggested above. To capture these potential benefits, however, communication to customers

must convey more than simple signals of emergency conditions, and customers must respond appropriately to those communications.

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AMI permits fine-grained communication of system conditions to customers and fine-grained measurement of customer responses. As we look to 2030 and beyond, it is difficult to envision a scenario without broad deployment of some form of advanced metering across U.S. utilities. Most currently installed meters will have reached the end of their useful lives by 2030, and some form of AMI is almost certain to be the replacement technology of choice. But utility systems may choose to invest in "early" AMI deployment, even before their current meters have fully depreciated. Some operate in states that have made universal AMI deployment a key policy objective. For others, as described in Chapter 6, system-wide deployment of AMI may reduce operating costs and, as part of a broader distribution system modernization and automation program, enhance service quality. However, as noted in Chapter 6, these operational benefits of AMI frequently constitute only a fraction—for some utilities, particularly those that have installed automated meter reading systems, a relatively small fraction—of the estimated capital costs of its universal deployment. For potential early adopters, the economic case for AMI may, therefore, rest heavily on the magnitude of benefits it creates through greater demand-side participation in electricity markets. AMI's ability to facilitate demand response through dynamic pricing—tariffs that go beyond simple time-of-use prices by allowing prices to change in response to contemporaneous system conditions—holds particular promise.

The cost-effectiveness of dynamic pricing already has been demonstrated for large-scale industrial and commercial customers.

The cost-effectiveness of dynamic pricing already has been demonstrated for large-scale industrial and commercial customers, even with their greater metering cost.¹ The focus of recent research therefore has been on residential and smaller commercial customers. Pilot projects demonstrate that experimental populations of residential customers reduce consumption when electricity prices are high.² Yet regulatory commitments to tap the capabilities of these meters for dynamic pricing by smaller commercial and residential customers often lag their installation. This appears to be due in part to continuing debate over how responsive the *typical* smaller consumer is likely to be to signals of electricity costs, particularly

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since electricity on average accounts for only 2% to 3% of household expenditures.³ It also reflects concerns about customer reactions to AMI technology, volatile electric bills (particularly unexpectedly high bills), and the differential impact of dynamic pricing on low-income customers. This chapter discusses the nature and impact of current demand response programs and assesses the evidence on the potential for expanded demand engagement, particularly by residential customers.

The discussion highlights an important question for regulators and utilities: what are the trade-offs between rapid universal rollout of AMI technology and a staged deployment that

evaluates the experience of early adopters before embarking on later waves of installations? The diffusion of AMI meters has been growing rapidly, assisted by legislative directives in some states, including California, Pennsylvania, and Texas, and smart grid stimulus grants under the American Recovery and Reinvestment Act of 2009 that have committed utilities to system-wide installation of AMI infrastructure. An estimated 27 million AMI meters have been deployed nationwide as of September 2011, and some projections suggest installations could reach more than 60 million (40% of utility customers) by 2015.⁴ Information from these projects, if broadly shared, can help refine the wide range of estimated potential benefits of AMI-facilitated demand engagement, inform “all-in” cost estimates for system-wide adoption, and highlight both technical and human-factor challenges in rolling out these technologies. Utilities and public utility commissions that have not yet committed to near-term AMI deployment can use this information to decide when and how to make cost-effective use of advanced meters.

7.1 WHY ENGAGE DEMAND?

As we have discussed in earlier chapters, electricity systems must precisely balance supply and demand at each moment in time. System operators historically have ensured the equality of supply and demand largely through supply-side tools: operators adjust the dispatch schedule for generators to meet forecast demand, adjust dispatch as forecasts are updated, and use ancillary services to adjust to real-time deviations in demand from forecast. Predictable variation in demand over time, day, and season is associated with changes in the marginal cost of supplying electricity that regularly vary by a factor of two or three.

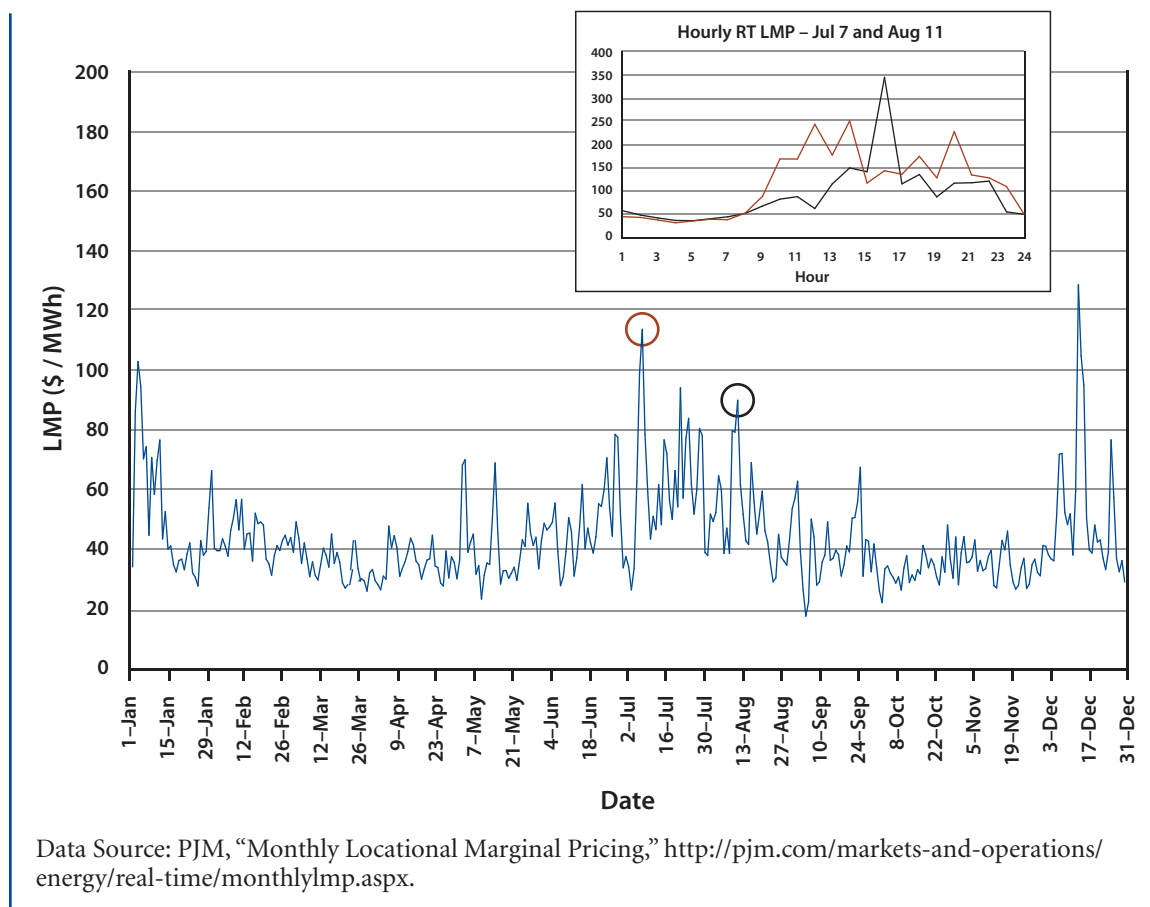
¹ The 2015 projections may be aggressive given that AMI deployments frequently have been delayed or deferred.⁴

More important, unanticipated changes in generator or transmission availability, or unusually high demand—for example, air conditioning loads on an exceptionally hot August afternoon—may cause the marginal cost of providing an additional megawatt hour (MWh) of electricity to consumers to increase fivefold or tenfold or more. Compare, for instance, the PJM Interconnection region 2010 average daily real-time wholesale prices shown in Figure 7.1 with the hourly prices (inset) for two summer 2010 days.

Despite these cost fluctuations, the majority of electricity customers in the U.S., including almost all smaller commercial and residential customers, face retail prices that do not change over the course of a day or a week. Some face

prices that may not vary even seasonally. As a result, these customers have no incentive to shift their electricity use away from high system demand hours, and consumption can be highly “peaked.” It is estimated that fewer than 1% of annual hours (60–100 of 8,760 hours) account for 10%–18% of the capacity needs in North America.⁵ And, as Chapter 1 has shown, the “peakedness” of demand—measured, say, by the ratio of peak demand to average demand over a year—generally has been increasing over time. This problem affects generating capacity as well as electricity transmission and distribution networks because all must be sized to meet predicted maximum demand (plus a safety margin) at all times and across all geographical locations.

Figure 7.1 2010 Average Daily versus Selected Hourly Average Real-Time Locational Marginal Price (RT LMP) in the PJM Interconnection



Demand response programs may reduce the total cost of maintaining system balance by inducing changes in consumption, particularly when system capacity utilization, and thus the opportunity cost of energy, is high. The Federal Energy Regulatory Commission (FERC) uses this definition of demand response: “Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.”⁶

As the FERC definition suggests, these programs generally rely on one of two very different mechanisms. “Load management or control” programs offer customers incentives to reduce their consumption below a baseline or expected level in response to an instruction or signal from the system operator, or to install a switch that gives the operator or a third-party aggregator direct control of a customer’s load. Alternatively, “price-responsive demand” results when customers face prices that vary with system supply conditions and decide to reduce or to shift consumption when they value electricity at less than the observed current-period price (or to increase consumption during low-price periods, or to do both).

In practice, customer load response may differ substantially within and across these mechanisms. It may be useful going forward to distinguish between dispatchable programs, in which system operators, utilities, or third-party aggregators directly control load responses, versus reactive programs, based on customers’ voluntary reactions to price or other signals. These need not be mutually exclusive at the level of the utility or competitive retail supplier of energy: dynamic pricing may both enhance the attractiveness of dispatchable load programs

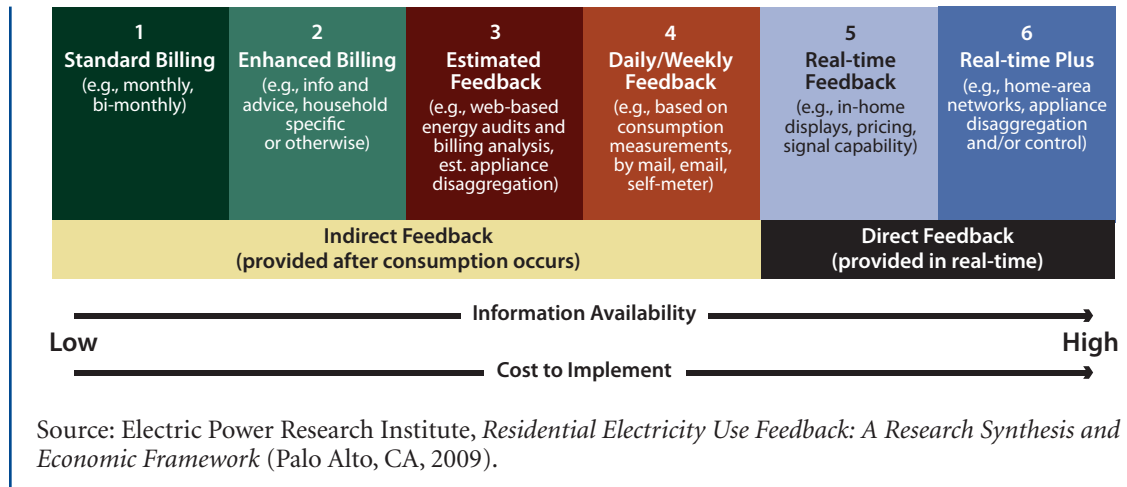
and encourage consumers to respond (either manually or automatically) to price or other signals they receive.

A second reason often given to engage energy demand is to reduce energy consumption. Demand responsiveness is distinct from energy efficiency or conservation, however, and though they may be related, one does not imply the other.⁷ Demand response programs generally focus on reducing consumption at particular times, often shifting it to other times, while efficiency and conservation programs target reductions in overall electricity consumption. Some conservation may occur through demand response, as when usage at peak periods is eliminated rather than shifted: consider the effect of turning up an air conditioner thermostat or turning off lights during a summer weekday afternoon.⁸ But some peak use, such as clothes drying, may simply be rescheduled, and lower off-peak prices associated with many dynamic pricing structures may further increase off-peak usage. Whether the direct net effect of demand response is to reduce or increase overall consumption is ultimately an empirical question, and there is considerable uncertainty in estimates of the likely net impact.

The detail and immediacy of energy consumption data from AMI meters, however, may provide additional support to conservation goals. For example, granular consumption data may offer insight into opportunities to tune building energy use and reduce consumption. A variety of third-party providers currently offer services to optimize building energy use based on detailed energy usage data, and this market seems likely to see substantial growth

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Figure 7.2 Informational Feedback Continuum



as AMI deployment expands.ⁱⁱ In residential applications, research increasingly focuses on the use of behavioral interventions through feedback mechanisms to reduce electricity consumption. These mechanisms provide information

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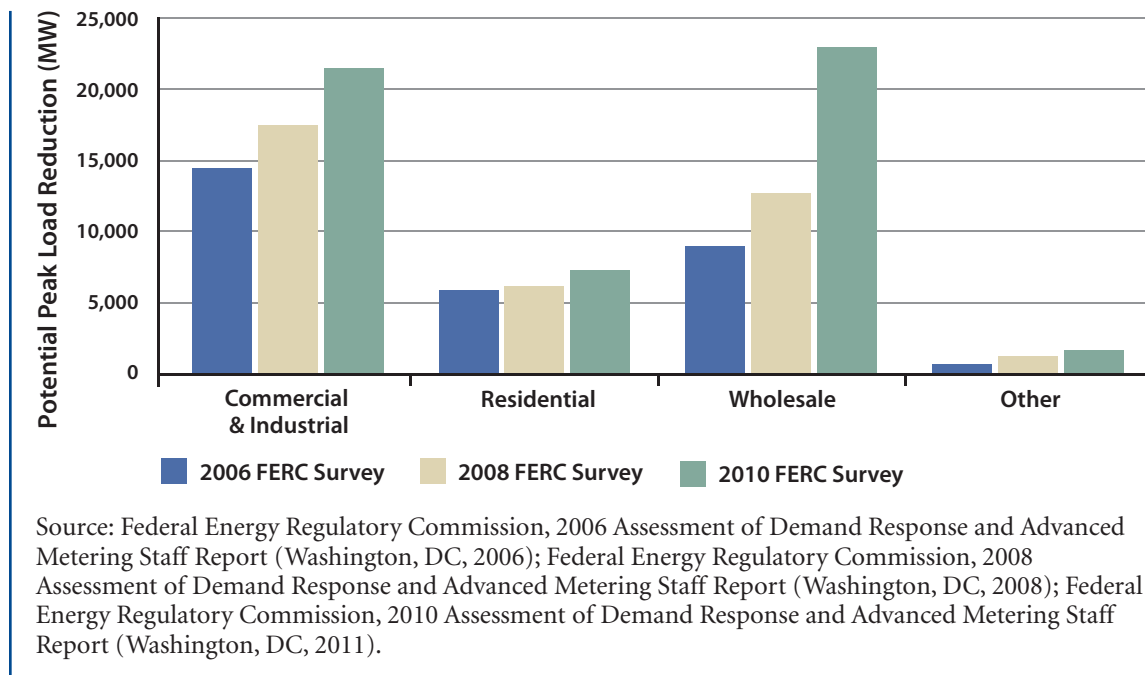
and assessment of behavior, often in the context of positive social norms, such as energy conservation. They might, for example, analyze the impact of reporting a consumer’s electricity usage in comparison to that of neighbors.⁹ In the residential electricity sector, this may involve either direct real-time information on consumption or indirect feedback provided at some later time, forming a continuum, as illustrated in Figure 7.2. AMI would be an integral part of the systems of direct real-time feedback at the upper end of the continuum, but could also contribute more granular information to indirect feedback mechanisms.¹⁰

7.2 DEMAND RESPONSE PROGRAMS TODAY

U.S. demand response programs have grown substantially in recent years. FERC reports enrollment in demand response programs collected in its 2006, 2008, and 2010 biennial surveys (released in 2007, 2009, and 2011, and reporting data for the full year prior to the survey date). By the 2010 survey, FERC recorded 53 gigawatts of potential peak load enrolled across a wide range of demand response programs, reflecting an 80% increase since the 2006 survey.¹¹ Commercial and industrial customers, who account for roughly 60% of U.S. electricity consumption, have historically accounted for the bulk of load enrolled in demand response programs, primarily through various load management programs. More recently, programs that allow customers or third-party aggregators to bid demand response into wholesale markets have increased dramatically and now comprise the largest category of demand response by enrolled load, as shown in Figure 7.3.

ⁱⁱ Southern California Edison recently entered a contract with the energy management company EnerNOC, for example, to support AMI-enabled commercial and institutional customer access to “EfficiencySMART Commissioning” software. The utility promises participating sites “10% or more savings on their total addressable energy expenditures.”¹²

Figure 7.3 Reported U.S. Potential Peak Load Reduction by Customer Class in 2006, 2008, and 2010 Federal Energy Regulatory Commission (FERC) Surveys (megawatts)



Measuring demand response potential is challenging. FERC’s “potential peak load reduction” is a better indicator of aggregate load enrolled in a demand response program than of expected reductions in system demand at peak periods. Nevertheless, it currently provides the greatest comparability over time and across systems.ⁱⁱⁱ There is some promise of progress on this front. The North American Electric Reliability Council (NERC) is developing a Demand Response Availability Data System to codify reporting of demand response enrollment and collect information on their actual responses to system “events” in an effort to improve data accuracy and

predictability of demand response resources.¹³ At present, NERC is focused in Phases I and II only on dispatchable, controllable resources that system operators can direct to respond to reliability-driven events. In Phases III and IV, this will be extended to nondispatchable, reactive (defined to include price-mediated) demand response resources. NERC’s goal is to develop performance-based data that will enhance industry confidence in the measurement and use of demand response resources to meet one or more core objectives.

Measuring demand response potential is challenging.

ⁱⁱⁱ Enrolled “potential peak load reduction” as measured by the FERC survey does not necessarily translate to actual, expected, or available load reduction at any given time for a number of reasons. For example, customers may not be drawing their full enrolled load at the time of a demand response event; local transmission congestion may render demand response from customers in uncongested areas irrelevant; or restrictions in the program may explicitly or implicitly limit the frequency or duration of system operator calls on a given customer to reduce their load. Finally, voluntary demand response programs typically provide less predictable and lower overall responses per MW of enrolled load than do direct load control or mandatory response programs.¹⁴ FERC reports that aggregate actual demand response averages less than one-third of potential peak reduction, with substantial variation in that figure across regions and years.¹⁵

Demand response programs may be targeted at various objectives. The earliest and most common focus has been reliability. Programs with this aim elicit customer reductions, usually through load management, in response to system emergencies or periods when electricity demand threatens to exceed the available supply of generation or network capacity.

More recent programs have begun to focus on reducing consumption in non-crisis peak periods and smoothing demand over time.

More recent programs have begun to focus on reducing consumption in non-crisis peak periods and smoothing demand over time. As noted in Chapter 1, in the capital-intensive electricity industry with no inventory and limited storage capability, generation, transmission, and distribution capacity that is sized to meet the maximum expected demand may go underutilized or unused in most periods, raising the long-run average cost of supplying a given amount of energy. Solutions to this “peak load” problem focus on economic incentives, price policies, and regulations that allow for an efficient investment in and use of capacity. While these may complement reliability objectives, their focus tends to be on long-run efficiencies rather than short-run operational exigencies. The greatest growth in programs targeted at peak load management has been in regions that allow demand-side resources to participate in long-term wholesale capacity markets.

Finally, there may be opportunities going forward to use demand-side resources to help balance energy supply and demand in real time, especially for regions with significant variable energy resources, such as wind or solar generators. As noted in Chapter 3, if loads could be quickly and reliably adjusted, demand response might substitute for flexible supply-side regulation services or storage. The value of this responsiveness is likely to increase with penetration of

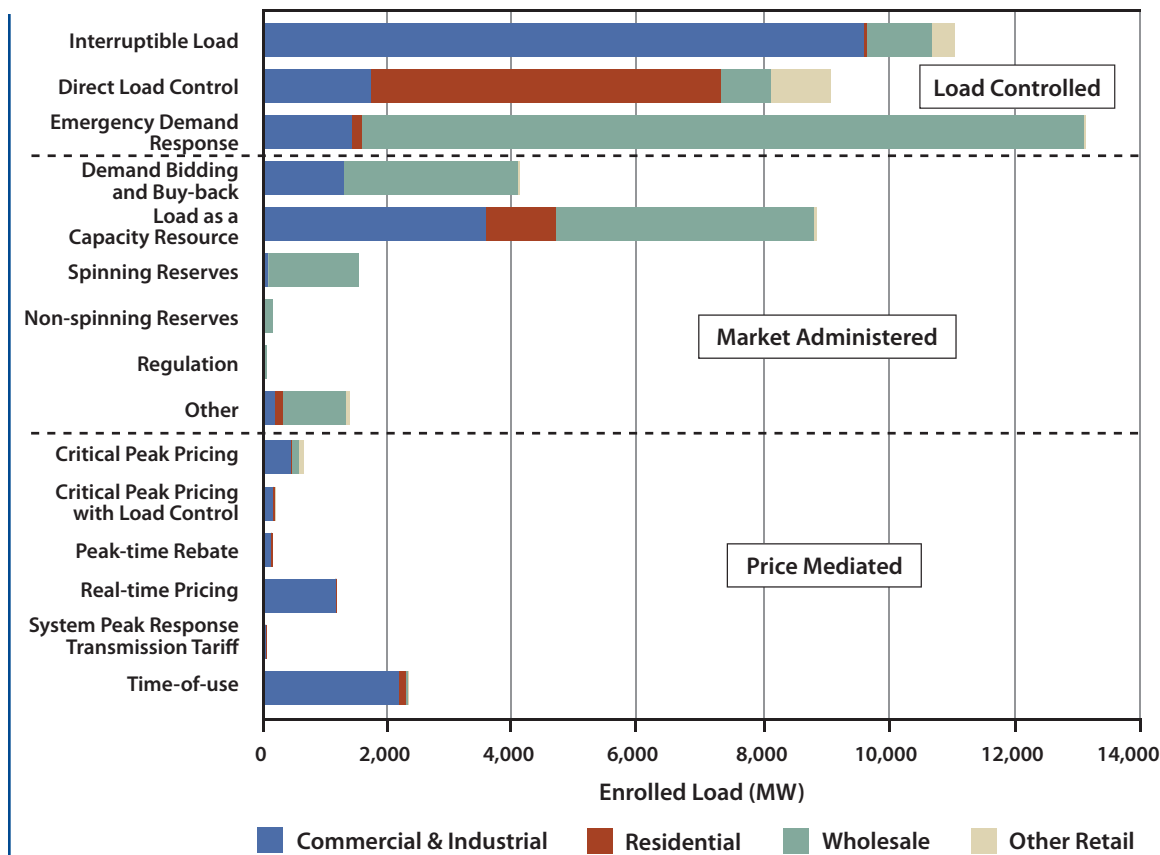
VERs and the importance of loads that may be especially amenable to predictable, quick responses through automated controls, such as air conditioning and charging of electric vehicles. The feasibility of using demand response at scale for this purpose may vary widely across types of programs, and operational feasibility, particularly for purely price-mediated demand response, remains to be demonstrated. In addition, changes to market rules and reliability standards are required in some regions to allow demand-side resources to participate fully in the provision of balancing services.¹⁶

The designs of demand response programs used to accomplish these objectives are varied. They can be broadly categorized into load control, wholesale market-administered programs, and customer price-mediated programs, as shown in Figure 7.4.

Load Control Programs

Load management or control programs comprise the largest segment of demand response programs in place today. Used since the late 1960s by load-serving entities, vertically integrated utilities, and system operators to maintain reliability, they have more recently begun to incorporate broader peak-shaving objectives. The immediate and often predictable load reductions many of these programs provide are especially valuable in responding to system emergencies. They can also reduce costs by shaving the increasingly sharp peak loads described in Chapter 1 that are associated with increased penetration of air conditioning, falling industrial load shares, and retail prices that do not vary with system conditions.¹⁷ While programs differ in operational details from entity to entity, they generally fall into three categories: emergency payment, interruptible tariffs, and direct load control. Enrolled customers typically receive a payment or rate credit as an incentive for participation. Load management programs contributed

Figure 7.4 Enrolled Load by Type of Demand Response Program and Customer Class



Source: Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering Staff Report* (Washington, DC, 2011).

approximately 62% of the nation’s potential peak load reduction in FERC’s most recent survey and continue to grow.¹⁸ The aggregate load (MW) enrolled in different categories of load control programs is summarized in Figure 7.4.

“Emergency programs” are now the largest category of demand response program by enrolled capacity, propelled to this position by a dramatic increase in wholesale demand response enrollment. These programs provide

incentive payments—ranging from \$150/MWh to \$1,000/MWh of curtailed energy use—to customers who curtail demand during reliability events.^{iv} However, curtailment in emergency programs is generally voluntary and does not provide the grid operator or load-serving entity with the same degree of certainty of load reduction as direct load control or interruptible tariff programs. Emergency programs accounted for 25% of national peak reduction potential reported in 2010.¹⁹

^{iv} These are in the range of maximum wholesale prices for generation in most U.S. markets. For example, 2010 maximum wholesale prices were \$396/MWh, \$343/MWh, and \$1,102/MWh in the Southwest Power Pool, Midwest, and Electric Reliability Council of Texas regions, respectively.²⁰ Wholesale prices provide an appropriate benchmark for incentive payments because they reflect the cost of energy inclusive of grid conditions.

The second-largest category by enrolled capacity involves “interruptible or curtailable tariffs.” These programs focus primarily on large commercial and industrial customers, who receive a rate discount or credit for reducing consumption during declared emergencies. In some cases, third-party aggregators may be able to combine smaller users to provide interruptible demand. Customers may face significant penalties if they fail to comply with a curtailment signal, which ensures that these programs achieve predictable load reductions when called. Interruptible tariffs comprised approximately 20% of national peak reduction potential reported in the 2010 FERC survey, and respondents indicated plans to substantially increase load enrolled in these programs.²¹

“Direct load control” programs, in which customer equipment or appliances are directly controlled by the load-serving entity or grid operator through switches or meter controls, constitute the largest category of demand response program by number of customers enrolled, and the third largest by total enrolled potential peak load reduction. Direct load control accounts for approximately 17% of the national peak reduction potential reported in 2010. Although these programs may be offered to all customer classes, participation has been particularly strong among residential customers, with more than 5 million enrolled residential customers. Central air conditioning cycling and electric hot water heaters, which comprise 70% of residential peak load nationwide, are the two most common targets of residential direct load control programs.²² With loads under the direction of the system operator, these programs provide dispatchable load with high predictability of response. Respondents to FERC’s 2010 survey report the greatest expected growth in direct load control programs over the near term, with enrolled load in these programs predicted to increase by 6,300 MW by 2015.²³

As electric vehicle penetration increases, direct load control programs for charging stations may provide additional targets for enhancing demand response potential; see the discussion in Chapter 5.

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Most load management programs are used relatively infrequently because they are designed to provide reliability under emergency conditions or, particularly for direct load control programs, peak shaving on a small number of hours during the year. The amount of curtailment needed for reliability appears to be consistently much lower than available peak reduction potential. For instance, 14 out of 30 load management programs surveyed in 2001 were reported to have operated just once or not at all during that year, even though record-setting peaks were experienced in some parts of the country in that year.²⁴ In the 2010 FERC survey, respondents report actual reductions equivalent to 30% of the potential peak reduction. But when needed, these programs create considerable value. For example, New York Independent System Operator’s estimated reliability benefits for each of four curtailment events during the summer of 2001 range from \$800,000–\$3.4 million, and aggregate reliability benefits over the entire summer totaled over \$20 million.²⁵ It is difficult, however, to measure the dollar value of reliability-related peak reduction on a nationwide basis, particularly as its use, system conditions, and costs vary widely across the country.

While nothing intrinsic in incentive-based programs limits the frequency of their use, most operational experience has been with programs explicitly or implicitly designed to call for load reductions over a low number of days or hours of the year. One motivation for this has been concern about “demand fatigue,” decreased customer responsiveness or exit from the program if called too frequently. This makes it difficult to extrapolate participation and response rates should the programs be broadened to pursue objectives other than reliability, such as peak load management. This may be a fruitful area to explore further in well-designed pilot experiments.

Wholesale Market-administered Demand Response Programs

A variety of new wholesale market programs for demand response has emerged over the past decade and is gathering momentum, as illustrated in the bottom panel of Figure 7.4.²⁶ Programs administered by independent system operators (ISO) or regional transmission organizations (RTO) contributed approximately 27% of national peak reduction potential reported in 2010. They can be categorized as capacity, energy price or demand bidding, and ancillary service programs. “Capacity market programs” are designed to incentivize market participants to commit to load reductions as a substitute for increased generating capacity. Enrollment in these programs has expanded as large customers bid into forward capacity markets, committing to future load reductions when called as a substitute for (unbuilt) new generating capacity. In contrast, “energy price programs” typically are day-ahead or hour-ahead programs for near-term commitment to consumption reductions. In many wholesale markets, customers are increasingly allowed to provide “ancillary services,” such as spinning reserves, non-spinning reserves, and regulation, which are used to ensure the balance of supply

and demand in real time. Ancillary service programs represent a very small but growing share of wholesale demand response, particularly in the Electric Reliability Council of Texas region.²⁷ Some ISOs and RTOs also compensate voluntary load reductions during emergencies on an energy price basis.²⁸

Commercial and industrial customers along with wholesale purchasers comprise most of the load enrolled in wholesale programs. Large commercial and industrial customers can enroll and participate directly in these programs. Their volume of electricity consumption enables them to realize net savings even after bearing the costs of advanced meters and control equipment, and they frequently are better able to commit to transactions required for participation in wholesale programs, either directly or through aggregators. These factors enhance their attractiveness for increasing demand responsiveness in aggregate. Smaller customers can subscribe to services offered by third-party aggregators or “curtailment service providers,” who, in turn, participate in wholesale programs on behalf of their customers.²⁹ The aggregator is responsible for finding the demand reduction should the utility or system operator call for load to be shed. For example, Comverge aggregated almost 8,000 MW of residential load through a variety of programs in 2010, either through long-term capacity contracts or programs it managed on behalf of utilities or other clients.³⁰

Uneconomic behavior can be encouraged when some of these programs are layered on top of dynamic pricing tariffs. FERC Order No. 745 recommends paying the wholesale market price for reductions from baseline,³¹ but when customers are not committed to purchase their baseline quantities of electricity, doing so generally will provide excessive compensation for reductions.³² Customers facing high electricity prices generally will react by reducing usage; paying them in addition for those

reductions amounts to double compensation. They will, in effect, be selling something they have not bought; they will both reduce their electric bills and be paid for doing so.

If customers have not committed in advance to purchasing a quantity of electricity or a particular load profile, determining the amount of demand response eligible for payment also requires a difficult counterfactual analysis. What would have been purchased but for participation in the program is inherently unknowable. Wholesale programs that compensate demand for reductions in load relative to a historic or administratively determined baseline provide incentives for customers to manipulate the baseline or act on their private information to profit from differences between the predetermined baseline and their true consumption patterns.³³ Demand participation in long-term capacity markets also raises questions of the verifiability and credibility of contracted demand reductions that may be promised several years in the future.

FINDING

Demand response programs that pay customers for reducing consumption from a baseline generally provide excessive compensation and give customers incentives for strategic behavior.

Price-Mediated Demand Response Programs

Price-mediated demand response programs face customers with retail prices that change over time to reflect variations in the market or opportunity cost of providing electricity. The principle underlying these programs is that customers will adjust their usage to consume electricity only when the value they ascribe to its consumption is higher than their cost of purchasing that electricity. The four most

common time-varying pricing structures are time-of-use prices, real-time pricing, critical peak pricing, and peak-time rebates. These programs are much smaller than those in the previous categories. Aggregate enrolled load across all customer price-mediated programs contributed only about 8% of the national enrolled peak load potential reported in FERC's 2010 survey, with very little of that in the residential sector. But these programs may hold the greatest promise for future demand response.

As noted in Figure 7.4, the most common form of time-varying prices is “time-of-use tariffs.” These enrolled roughly 1.1 million residential customers and 250,000 commercial and industrial customers, accounting for approximately 4% of the enrolled potential peak load across all demand response programs.³⁴ Time-of-use rates set a time profile of prices far in advance, usually held constant over a season. For example, summer time-of-use rates might set a low off-peak rate that applies to weekday nights, early mornings, and weekend hours, and a higher peak rate for use during weekday afternoons and early evenings. This predictable and stable time profile of prices can encourage customers to make long-term changes in their consumption patterns—for example, by avoiding dishwasher use during early evening. However, while the price schedule reflects the fact that costs are on average higher during periods in which demand is on average higher, time-of-use prices are not truly dynamic. They do not, for example, distinguish normal July weekday afternoon conditions from those on an unusually hot day with a spike in air conditioning loads or an unexpected outage at a large generating unit.

Dynamic prices can respond to those conditions, but dynamic pricing plans vary widely in the frequency of price changes. At one end of the spectrum is “real-time pricing,” in which

retail prices change hourly (or more often) to reflect actual variations in the system's marginal energy cost. At the other end of the spectrum are plans that layer time-of-use tariffs with an infrequently invoked price change for so-called critical peak periods. "Critical peak pricing" programs enable utilities to designate, a day ahead, a small number of days on which demand is expected to be exceptionally high relative to available supply. On those days, they charge a price for electricity consumed during peak hours that is several times higher than the usual time-of-use peak rate. "Peak-time rebates" operate similarly to critical peak pricing programs, except that customers are given a credit for reducing consumption below their administratively determined baseline during designated critical peak hours, rather than being charged a premium for consumption during those hours. Peak-time rebate programs suffer from the same baseline calculation challenges described above for wholesale market-administered demand response programs.

None of these dynamic pricing plans yet accounts for significant peak load reduction participation. Enrollment is comprised almost entirely of commercial and industrial customers, primarily larger customers within those sectors. Yet these programs can be quite cost effective. For example, several utilities in the Southeast—including Georgia Power, Duke Power, and the Tennessee Valley Authority—have long offered variants of critical peak, hourly day-ahead, or real-time pricing tariffs to their large customers, and they report considerable success in both customer satisfaction and peak demand management. Georgia Power estimated that its real-time pricing customers reduced peak demand by 17%, roughly 800 MW, during the early 2000s, roughly equivalent to eliminating one large baseload power plant from the necessary dispatch.³⁵

Many utilities with limited penetration of dynamic pricing plans among their larger commercial and industrial customers are forgoing opportunities for significant cost-effective peak load management. Because interruptible load and emergency demand response programs are designed with different objectives and constraints, they are poor substitutes for dynamic pricing programs in this regard. Our report follows recent policy discussions in focusing on extension of demand response, particularly dynamic pricing, to the residential sector. But, there may be considerable gains to be realized from further penetration, particularly of real-time pricing, among large commercial and industrial customers.

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Why the focus on residential customers in policy discussions? Until recently, the high cost of required metering precluded extension of price-mediated demand response programs to most residential and smaller commercial customers. While metering costs to support dynamic pricing for commercial and industrial customers, estimated at 2010 US\$750–\$5,000 per customer connection, are higher than for residential users, they tend to be a smaller fraction of potential savings for large electricity purchasers.³⁶ The deployment of AMI technology across many systems now enables those utilities to offer residential customers at least one dynamic pricing option, perhaps in addition to existing non-dynamic rate structures, at little or no incremental cost. Whether and when utilities will do so is an open question. FERC's 2010 survey recorded some retrenchment from existing time-of-use and dynamic pricing programs, though that may in large part reflect changes in the survey methodology; there was some expected growth in dynamic pricing

programs reported in plans for establishing future demand response programs.³⁷ The experiences of utilities that do implement dynamic pricing can provide insights on a host of important questions about customer education and service requirements, expected uptake of optional plans, and predictability of expected load response. We turn next to existing evidence on those questions.

Deployment of AMI and complementary technologies enhances potential demand response to supply conditions and may enable improved energy efficiency and conservation.

7.3 PREDICTING THE BENEFITS OF INCREASED DEMAND ENGAGEMENT

Deployment of AMI and complementary technologies enhances potential demand response to supply conditions and may enable improved energy efficiency and conservation. Estimating the expected magnitude of these benefits may be critical to determining the economic value of AMI-related investments—but the task poses considerable challenges.

Enhancing Demand Response

The aggregate benefits of introducing a new demand response program depend on the value of a given MW change in demand in response to a set of system conditions, the anticipated magnitude in MW of the response generated by the program, and the certainty of that response. Each factor is likely to vary substantially across service areas and among program designs.

The expected economic value of a MW of demand response is probably the most straightforward element to compute. It reflects the avoided cost of supply or shadow cost of supply constraints at a given moment, which system operators and utilities already calculate. This

value is likely to vary across systems as well as over time. For example, many regions now operate with substantial reserve margins above expected peak demand as a result of past capacity investments, economic contraction, or population decline.³⁸ Increased enrollment in programs designed to reduce consumption at peak times is likely to generate minimal near-term benefits for systems that expect this situation to persist, even though the benefits could be substantial for systems anticipating inadequate peak reserve margins.

Measuring the expected impact of demand response involves predicting customer participation rates as well as customer response conditional on participation in a given program. Both may be difficult to assess. Analyses of demand response typically have focused on mean load changes across enrolled participants, paying little attention to modeling the determinants of participation or the certainty or distribution of load response. Some Recovery Act–funded pilot programs are now investigating these questions. Altering program design can compound the challenges. For example, changing a direct load control program’s objectives from infrequent emergency or peak-shaving calls to a more frequent balancing role may make customer participation and response results from historical program data uninformative about future

Demand response mediated through dynamic pricing can be particularly challenging to value.

participation and response. Expanding the target population to add residential customers to a program populated by large commercial and industrial customers, or changing the tools—say, from direct load control to dynamic pricing—may require new experimentation and data to predict responses. Demand

response mediated through dynamic pricing can be particularly challenging to value if system operators lack accurate prediction models for when, where, and how much load will respond.^v

In light of these challenges, at least three sources of information may help to narrow the uncertainty in the benefits calculus:

- Simulation methods, which are useful to assess the general plausibility of a stylized economic case and determine which parameters or assumptions are most critical.
- Pilot programs and demonstration projects, which can provide feedback on parameters of customer response and impacts of variants in program design.
- Experience from large-scale deployments, which can help refine estimates of customer response over larger populations, longer time periods, and in the context of actual deployment. They also provide data on the actual costs of implementation and how those deviate from forecasts.

Simulation Analysis

Theoretical analyses of dynamic pricing can provide some insights on the source and likely

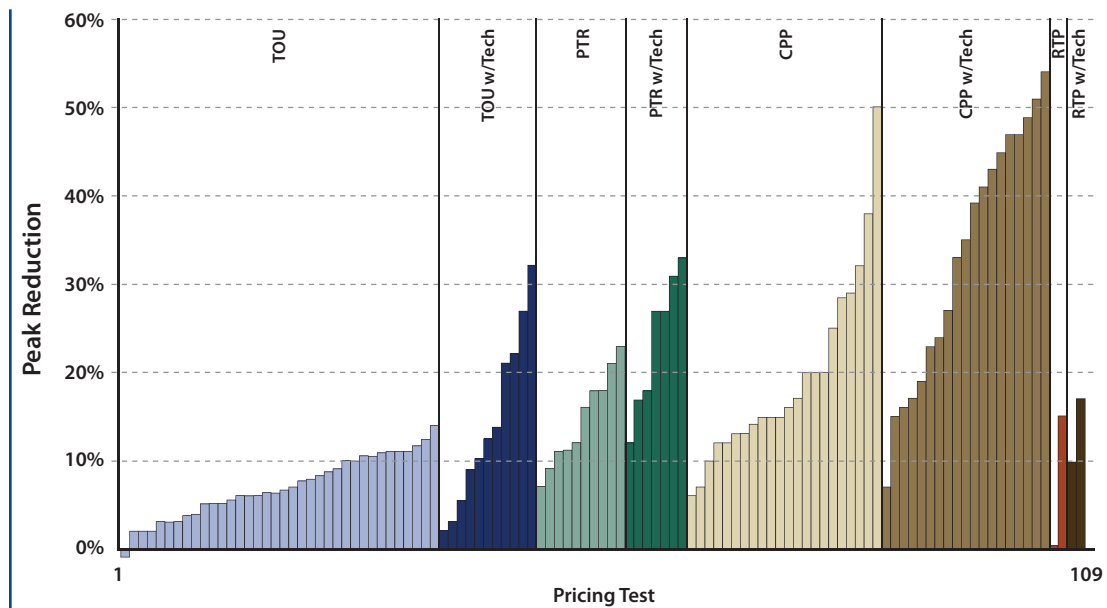
magnitude of potential gains from broad deployment of dynamic pricing. Simulation analyses that have focused on system-wide deployment of real-time pricing yield some broadly consistent results:^{vi}

- Real-time pricing schemes with prices that vary hourly or more frequently could reduce peak-period electricity consumption substantially under plausible demand elasticity assumptions. In the long run, this reduces necessary investment in peaking generating plants, leading to lower average electricity costs than would otherwise occur.³⁹
- A substantial fraction of the potential economic benefits of universal real-time pricing may be secured without universal penetration across customers: in simulations, putting less than a third of load on real-time pricing can yield roughly half the potential total benefits. Customers remaining on average cost-based flat rates will realize much of the cost savings that real-time pricing creates without adjusting their consumption patterns, indicating an issue of “free riding” in voluntary dynamic pricing schemes.⁴⁰
- Dynamic pricing schemes do not necessarily reduce overall electricity consumption. While peak prices increase relative to flat rates, off-peak prices fall, which tends to encourage

^v Some have expressed concern that this challenge may be so great as to threaten power system stability. For example, recent work illustrates the potentially destabilizing effect of price-responsive demand in a model of an ISO that uses only data on loads in past periods to forecast future load and sets price so that generation equals forecast load, ignoring past prices, the impact of price changes, and its own past forecast errors.⁴¹ This analysis is closely related to the classic cobweb model in economics, which has little explanatory power in most settings because actors are more sophisticated forecasters than assumed in the model.⁴² Forecasting load with reactive demand is difficult but soluble, as suggested by considerable experience internationally as well as in the U.S. with dispatch under customer-directed responses to emergency load-management, as well as wholesale price-mediated, customer time-of-use rates, and dynamic pricing programs.

^{vi} A recent Institute for Electric Efficiency white paper simulates lifetime costs and benefits of AMI-facilitated demand response for four “prototype” utilities.⁴³ This paper probably is best viewed as providing a framework for analysis rather than simulation results for net returns to AMI investment, as a number of parameters are varied in ways that do not nest across prototypes, and the focus is on high-level aggregate returns rather than analysis of sensitivity to parameter values or modeling assumptions.

Figure 7.5 Peak Load Reduction from Dynamic Pricing Pilot Programs by Rate Design and Technology



Note: TOU=time-of-use pricing; Tech=technology; PTR=peak-time rebate; CPP=critical peak pricing; RTP=real-time pricing.

Source: A. Faruqi, “The Tao of the Smart Grid,” presentation to the Michigan Smart Grid Collaborative, Lansing, MI, August 24, 2011, http://www.brattle.com/_documents/UploadLibrary/Upload973.pdf.

greater off-peak consumption as well as load-shifting. If off-peak consumption increases exceed peak-period declines, aggregate energy use will rise.⁴⁴

- Real-time pricing exacerbates bill volatility. A substantial fraction of the annual electricity charges accrue during a very few, but very high-price peak hours, suggesting substantial swings in monthly bills—especially for customers whose demand is correlated with system loads (e.g., those who use more air conditioning at system peaks). Making available hedging strategies that can manage or reduce bill volatility is likely to play a significant role in encouraging the adoption of real-time pricing policies.⁴⁵

In general, these simulation results are useful for assessing the qualitative impacts of dynamic

pricing on electricity consumption. With their many simplifying assumptions and dependence on knowing realistic parameter values, however, theoretical studies cannot replace empirical evidence obtained from pilot projects, or better still, programs implemented at large scale.

Pilot Programs

In the last decade, a large number of small-scale and a few large-scale pilot programs have experimented with various forms of dynamic pricing at the residential level. Additional data will be collected over the near term as system-wide AMI deployments supported by the Recovery Act come on line. Unfortunately, data from most pilots typically have been inaccessible to outside researchers, making it difficult to draw general conclusions. Figure 7.5 is a summary presented by researchers at the

Brattle Group based on their proprietary data on 24 pilot projects implementing 109 variants of price and technology interventions.⁴⁶ In this figure, each bar represents a different price and technology variant and the height of the bars represent the peak load reduction observed. The results are grouped by rate design and whether the program provided customers with enabling technology, such as programmable controllable thermostats, energy lights or “orbs” that indicate high-price periods, or home-area energy management systems. The results are arranged in ascending order within each category of rate design and technology. The results suggest consistent evidence that consumers respond to dynamic prices by reducing their electricity consumption during high-price periods, in some cases, quite substantially.

Average peak load reductions by participating customers vary more than tenfold across the pilots.

As evidence that consumers will respond to price signals, these results are powerful. Extrapolating these results to make specific quantitative predictions is more problematic. The estimated average peak load reductions by participating customers vary more than tenfold across the pilots reported in Figure 7.5. Enormous response variation remains even when the results are grouped by rate design. This variation is in part explained by the magnitude of each pilot’s price differential between peak and off-peak periods, the penetration of central air conditioning among the customer base, weather during the experiment, and the availability of automated technologies, all of which involve utility-specific adjustments.⁴⁷ Nonetheless, it appears that considerable heterogeneity persists even after many cross-study controls are employed.⁴⁸ For situations in which the quantitative magnitude of potential demand response is an important determinant

of the business or policy case for AMI investment, additional data or econometric modeling may be necessary to improve the precision of expected mean reductions.⁴⁹

Moreover, pilot project outcomes must be interpreted cautiously with attention given to the strength of individual pilot design and implementation quality.

Moreover, pilot project outcomes must be interpreted cautiously with attention given to the strength of individual pilot design and implementation quality. Several caveats should be highlighted:

- Most significantly, despite efforts to implement an experimental protocol with treatment and control groups, virtually all studies suffer in varying degrees from some form of selection bias in participation. In most cases, “treatment” (dynamic pricing) and “control” (standard tariff) groups were selected from customers who voluntarily participated in the pilot. In many experiments, customers assigned to the the dynamic pricing tariff (the “treatment group”) were permitted to drop from the study and revert to standard rates. Discretionary participation implies that participants may be among the customers most willing to respond to price signals, and, as a result, may not be representative of the broader overall customer group.
- Pilot program participants may be representative of consumers enrolling under a similar optional dynamic pricing tariff in a given service territory, but extrapolating participation rates from one program type or area to another may be difficult. Determinants of participation rates appear to be one of the most significant unknowns in determining overall program benefits. Participation varies widely across pilots—for example, from 3% in Connecticut Light & Power’s pilot to 20%, at least initially, in the California Statewide Pricing Pilot—and has not been carefully

studied. Even if the selection at work in the pilots is related to the behavior of customers likely to participate in voluntary dynamic pricing programs, it will be difficult to predict responses to system-wide programs without information on the pilot protocol selection rule, the fraction of customers selecting into the pilot, and correlates of customer participation rates. This may make it difficult to match predicted participation from pilots to those for the tariff under consideration. Future pilots and system deployments should provide greater information and focus on participation determinants under optional programs.

- The quality of information provided by pilots varies widely. Many pilots enrolled relatively few customers, limiting the strength of statistical inferences and making it dangerous to generalize the results to the broader population. Others do not have adequate control groups or baseline data that allow analysts to measure treatment group responses against an untreated control group.
- Most pilot studies report relatively simple measures of responses, usually mean reduction in peak-period consumption relative to a baseline or control group's behavior, that mask a wide variance in the number of hours for which data are collected. In addition, there has been little analysis of the predictability of the mean response or the temporal distribution of responses by the group facing dynamic prices, though this information may be important to operate the system and assess the value of demand response. For example, a 5% peak reduction on every critical peak day may have dramatically different implications for system operation than a 10% reduction on half the critical peak days and no reduction on the remaining (perhaps hotter) days, though both scenarios imply a 5% mean reduction.

- Consumer responses to permanent dynamic pricing plans may differ from those in short-term pilot projects. Long-term responses may be greater, as when consumers invest in complementary technology or adopt new behaviors. They could be smaller if pilots attract greater consumer attention that wears off over time. Few pilots have measured residential responses for more than a few months or a year, although two studies that followed customers across two summer seasons report similar or increased responsiveness among those who participated in both years, suggesting the first effect dominated any short-term novelty or attention effects.⁵⁰

- Few pilots have analyzed the distribution of responses or bill impacts across customers, though this may be an important input to regulators considering dynamic pricing plans (discussed in greater detail in this chapter). There is some evidence to show that most reduction in demand comes from a relatively small number of customers, but we do not know whether those could be identified in advance and targeted or how persistent their identity is over time.⁵¹

System-wide deployments of AMI combined with optional dynamic pricing tariffs may provide the data needed to fill in at least some of these gaps.

System-wide Deployments

System-wide deployments of AMI combined with optional dynamic pricing tariffs may provide the data needed to fill in at least some of these gaps. A number of utility systems have recently completed or will soon complete rollouts of AMI technology to all or most of their customer base as a result of utility initiatives, statewide legislative or regulatory mandates, or Smart Grid Investment Grant

projects. Many of these utilities have proposed or committed to some form of dynamic pricing to follow the AMI deployment; some plan to offer customers a menu of pricing options. There is considerable heterogeneity in program design, including the dynamic pricing options that are offered, customer defaults and opt-in or opt-out rules, and availability of hedging or commitments that guarantee bills will be no higher under dynamic pricing than under historic tariffs during some specified transition period (a year is common). If data on responses to these programs are collected in a systematic and thoughtful way, this variety could help to refine or validate predictions for dynamic pricing impacts that come out of the pilot studies.

Deployments made with Smart Grid Investment Grant funding were expected to collect data on consumer responses under a structured experimental protocol, and deployments in systems not subject to these requirements also should collect and make available comparable data to facilitate learning and comparisons across installations. The scale of these programs, the diversity of the pricing schemes, and the ongoing, permanent nature of the installations are all likely to make information on consumer response of enormous value in improving our ability to assess the potential benefits of AMI-facilitated demand response programs. Efforts led by the U.S. Department of Energy to create mechanisms for utilities to share data from smart grid projects, including SmartGrid.gov (www.smartgrid.gov) and the Smart Grid Information Clearinghouse (www.sgiclearinghouse.org/), could yield significant social benefits, provided these data are made available to researchers and utilities that are not grant recipients. Unfortunately, such access remains uncertain as of this report's writing. Facilitating data collection and ensuring data accessibility could improve the design of dynamic pricing plans for utilities that have deployed AMI technologies and the quality of adoption decisions for utilities that have not yet committed to AMI.

7.4 REDUCING RESIDENTIAL ENERGY CONSUMPTION

Since the 1970s, many electric utilities have been tasked with improving energy efficiency, particularly for residential customers, and reducing energy use through programs that include a broad mix of targets that may range from energy-efficient lightbulbs and appliances to insulation and weather stripping. Energy-efficiency budget expenditures in 2010 exceeded \$5.4 billion, an increase of 24% over 2009, of which 88% was in utility-administered programs.⁵² Ratepayers typically fund utility-run programs in which all consumers pay a small surcharge on monthly bills to support the program budget, which may provide appliance rebates, energy audits, and subsidies for a variety of energy-enhancing home improvements to participating customers. These programs are associated with modestly reduced consumption, which recent estimates suggest cost an average of four cents per imputed kilowatt hour (kWh) saved,⁵³ comparable to the average wholesale electricity price or avoided generation cost in many regions of the country. This calculation does not include, however, many private costs of efficiency programs: the additional expenses in devices, equipment, or home improvements that consumers must incur to achieve the reduction in energy use. At these levels, costs largely offset the savings from reduced consumption, apart from any social externality associated with electricity use. This, combined with an objective of greater consumption impacts, has prompted industry and policy makers to search for new types of programs, focusing attention on potentially lower-cost behavioral interventions or potentially higher-impact programs based on informational feedback.

As noted earlier, a number of companies already offer commercial or industrial customers services that can use granular consumption data, such as that provided by AMI technologies,

to suggest cost-effective modifications to reduce energy consumption. Much of the untapped potential for reducing electricity use may lie in residential behavioral changes and modifications to traditional consumption patterns.

The untapped potential for reducing electricity use may lie in residential behavioral changes.

Many experimental programs over the last several decades have assessed the impact of informational feedback on household electricity consumption. Average energy reductions in kWh ranged from 4% to 14% across a variety of programs on different continents between 1974 and 2010.⁵⁴ A recent comparison of direct feedback pilots using in-home displays reported reductions averaging 7%.⁵⁵

However, energy-efficiency and conservation field experiments, perhaps even more than demand response pilots, frequently suffer from measurement, assessment, and design flaws that sharply limit the generalizability of their findings, may lead to unrepresentative or non-random samples of participants, and generally do not resolve whether the responses are long term or transitory. One of the more substantial recent projects tracked roughly 60,000 customers across treatment and control groups in the U.K. for a broad range of interventions (see Box 7.1). Despite considerable attention to program design and implementation, however, even these experiments confronted significant participant selection and dropout challenges.⁵⁶

Feedback-based behavioral programs that provide a “social nudge” to consumers based on a positive norm of reducing electricity consumption have been the subject of increased experimentation in recent years. These appear to reduce consumption, although the magnitude of the effect tends to be consistently modest.

For example, a recent analysis of a large set of data collected across 11 utility pilots (750,000 households) that includes pre-treatment observations, randomized treatment, and control groups reports average consumption reductions of roughly 2% across programs, with a range of 0.9%–2.9%.⁵⁷ Profiling and targeting programs to high-consumption households may increase the impact to around 6%, relative to pretreatment consumption levels. One of the very few experiments to report program costs and quantify the net economic impact suggests that behavioral interventions may be cost-effective, with program costs running roughly 2.5 cents for each kWh saved.⁵⁸ This estimate is based on a vendor-run indirect feedback campaign that makes use of mailings to customers and does not rely on technologies. Profiling, which targets behavioral intervention programs at those individuals most likely to respond, may further improve a program’s cost-effectiveness.

The experience with feedback programs more broadly raises the question of whether it is the content of the feedback that leads to conservation, or simply the incidence of messaging. That is, do recipients of feedback find the information provided useful, or does the act of providing feedback serve as a reminder of conservation goals?⁵⁹ While this causal difference has not generally been tested systematically, some results are consistent with messaging being more important than content. For example, the combination of AMI and real-time display treatment was associated with reduced consumption for all the previously mentioned U.K. trials except Scottish Power’s trial, which the final report speculated “may be related to the fact that the meter replacement [for Scottish Power] was presented as a routine replacement rather than as a smart meter or part of a research trial.”⁶⁰

BOX 7.1 THE OFGEM ENERGY DEMAND RESEARCH PROJECT

Of the many electricity systems that have undertaken pilot projects to evaluate the effects of informational feedback to customers, the Office of the Gas and Electricity Markets (Ofgem) Energy Demand Research Project in the U.K. is noteworthy because of its large scale, long time frame, and breadth of technologies and interventions.⁶¹ Since 2007, more than 60,000 residential customers of four different energy suppliers participated in a variety of trials (roughly one quarter as controls), including tests of in-home display units, detailed billing, incentive programs designed to reduce or shift consumption, and advanced metering. University research centers assisted with independent statistical analysis and program design; the final project report was prepared by consulting firm AECOM.⁶²

Highlights of the findings include the following:

- Programs focused on engaging and motivating consumers to reduce energy consumption with a combination of in-home displays and advanced metering generally were more effective than those without one or both of these technologies.
- The nature and quality of engagement with AMI installers appears to have influenced consumer responses, raising the possibility that behavioral interventions may be as significant as technology.
- While many of the interventions record consumption declines generally in the range of previous studies, there was limited consistency in energy savings across energy suppliers testing similar interventions.
- Consumers found price and cost data more useful than quantity or carbon emissions data.

Technical and management lessons from the project are informing the planned nationwide deployment of electricity and gas meters to enable the provision of informational feedback to consumers.

Given the current state of knowledge, the design of behavioral interventions to reduce electricity consumption seems a promising area for continued experimentation and research. This seems especially true of interventions that draw on fairly simple and inexpensive informational feedback. Initial experiments suggest that such programs can be designed and implemented at relatively low costs. Moreover, they could be a suitable near-term alternative to AMI-mediated technologies for systems that have not yet committed to broad AMI deployment. This is also an option for consumers who have access to AMI meters but for whom the cost-effectiveness of investment in additional energy management technologies is unclear.

FINDING

While a variety of programs suggest that energy savings are possible through informational feedback, the design of cost-effective behavioral interventions merits further experimentation.

7.5 EXPANDING DEMAND ENGAGEMENT: FINDINGS

As noted earlier, we believe that by 2030, AMI will be widely deployed across the U.S. and that dynamic pricing will be widely available, at least as an option. How individual systems will or should move toward that situation over time is much less clear. Although no one-size-fits-all recommendation can be formulated, some generalizations arise. We focus on these first in the context of systems that have already committed to universal deployment of AMI.

For utilities that are deploying AMI throughout their systems, dynamic pricing programs promise potentially substantial benefits.

For utilities that are deploying AMI throughout their systems, dynamic pricing programs promise potentially substantial benefits.⁶³ To realize this potential, utilities must carefully plan, stage, and support transitions to dynamic pricing that include extensive customer education, outreach, and service. Dynamic pricing plans are likely to be embedded in a menu of tariff offerings available to customers. Inducing general acceptance of dynamic pricing will require a different approach toward customer engagement than the one most utilities have taken in the past. This is highlighted in a recent report released by the Smart Grid Consumer Collaborative, which identifies key themes and best practices that emerged from its in-depth study of 21 organizations with successful customer-facing AMI, dynamic pricing, or efficiency programs.⁶⁴ Moreover, some pilots and early system deployment experiences suggest that customer service demands may actually rise, not fall, in the months following the installation of new meters, though most business cases assume call center and customer service expenses ultimately decrease with AMI installation. Regulators must be prepared to approve investments necessary to develop

effective programs to engage customers and fund periods of higher customer service costs through the transition.

Implementing rate hikes or new price structures at the same time new meters are installed may exacerbate consumer resistance not only to the tariffs, but also to the technology itself.⁶⁵ Addressing this after the fact can be costly, as ongoing consumer protests over Pacific Gas & Electric's smart meter installations demonstrate. Strategies utilities have adopted to mitigate potential adverse reactions include running AMI side-by-side with existing meters for some time, offering bill comparisons of charges under current and future tariffs based on actual consumption data for the period, and providing maximum bill guarantees for a specified term following take-up of a dynamic pricing plan. Utilities and their customers are likely to gain if best practices for transitions are analyzed and widely shared.

Competition in electricity retailing may complement AMI deployment in hastening the development and penetration of dynamic pricing options and their associated benefits, provided that appropriate default service tariffs are established or the monopolies that provide distribution services (so-called wires firms) are excluded entirely from the business of selling energy.⁶⁶ Retailers that can successfully reduce their customers' usage during periods with high wholesale prices—through dynamic pricing tariffs, energy management technologies, or direct load control programs, for example—will reduce their average energy acquisition costs and consequently can offer their customers lower average bills. A monopoly utility has the same opportunities but may have weaker incentives to innovate (see Chapter 8). It needs to obtain approval for new rate structures from its regulator (or equivalent, if publicly owned) in an inherently political environment. Given customer resistance to change, utilities and regulators may have strong incentives to be

cautious and find relatively little to be gained by confronting that resistance. Competitive retailers, in contrast, have strong incentives to find ways to use the benefits of dynamic pricing to win customers. Retail competition consequently may encourage greater experimentation than most regulated monopolies will undertake.

FINDING

Well-designed and well-executed customer engagement programs and tariff transition policies are needed to avoid customer backlash to AMI technology and dynamic pricing plans. Retail competition, where implemented appropriately, may facilitate dynamic pricing.

Concern about distributional impacts of dynamic pricing, particularly for lower-income households, may impede transitions to dynamic pricing under monopoly retailing. This should not be seen as insurmountable. Many low income consumers may have flatter than average consumption profiles, suggesting a benefit from dynamic pricing without any demand response. Moreover, while few pilots have focused specifically on low-income consumers, one recent analysis of data from several pilots suggests that low-income customers respond to higher prices, though in most cases, their demand responsiveness in terms of peak load reduction was below the mean for all customers in the program.⁶⁷

Dynamic pricing plans may eventually come to be viewed as more equitable than flat-rate tariffs because they allocate more of the cost of consumption to those who are responsible for imposing those costs on the system. The constant rate structure applied to most retail electricity customers—and virtually all residential and smaller commercial customers—subsidizes customers who impose higher costs on the system, such as those with peak demands

that are coincident with system peaks.⁶⁸ Customers with less peaked demand profiles may be inherently less costly to serve and may benefit from dynamic pricing.⁶⁹

Moreover, ways to limit distributional impacts exist. For example, the peak rebate tariff tested in the PowerCents program coupled a basic time-of-use rate with rebates for peak-hour consumption reductions relative to baseline on preannounced critical peak days. This provides a form of insurance: customers gain from reducing peak electricity use but do not pay higher rates if consumption is unchanged. To be clear, providing this insurance on a system-wide basis is not free. Peak-time rebates may provide incentives for customers to raise baseline consumption to increase their potential rebate and tend to be associated with lower mean responses than critical peak pricing plans, as shown in Figure 7.5.⁷⁰ The level of base rates also must be high enough to cover the revenue needed to pay for rebates to customers who adjust peak consumption, suggesting that consumers who do not participate in peak-period reductions eventually may experience higher average bills, all else equal. But all else may not be equal: demand response by even a fraction of consumers may reduce system-wide energy costs, offsetting part or all of this effect on base rates.⁷¹

Dynamic pricing plans may eventually come to be viewed as more equitable than flat-rate tariffs because they allocate more of the cost of consumption to those who are responsible for imposing those costs on the system.

While regulators in some jurisdictions have agreed to make time-of-use or dynamic pricing plans a required or default contract for large commercial or industrial customers, there is widespread reluctance to require smaller customers—especially residential customers—to enroll in time-varying tariffs. If participation is voluntary, as we expect it will generally be at least initially, the available evidence

suggests that opt-in plans generally lead to much lower participation rates than default, or opt-out, plans.⁷² Experimentation may be needed to determine how best to design customer choice into dynamic pricing plans. As argued here, retail competition may provide stronger encouragement to such experimentation than regulated monopoly.

FINDING

Concern about the impact of higher or more volatile bills, particularly for low-income consumers, may limit the perceived political viability of dynamic pricing but this can be addressed by well-designed menus of rate options.

Consumers may be able to respond manually in limited ways and at relatively low cost to some forms of dynamic pricing. For example, in critical peak pricing programs, consumers are told the day before about price spikes and can decide to adjust consumption accordingly. But it seems unlikely that many consumers will want to spend a lot of time and effort managing their electricity usage, particularly when the overall bill impact may be small.⁷³ One of the most consistent findings across pricing pilots is the much greater responsiveness of demand in the presence of enabling technologies. This could be something as simple as a programmable controllable thermostat, which can receive price or other signals from the distribution system and adjust air conditioner load automatically based on preassigned instructions, or an energy “orb” that signals high price periods by changing colors. Or consumers could opt for more complex and expensive home energy management systems that integrate “smart” automated appliances, HVAC systems, and other major loads and optimize use based on granular consumption data from solid-state meters, customers’ price and comfort preferences, and utilities’ price

signals.⁷⁴ Implementing complex dynamic pricing schemes before low-cost enabling technologies are available may limit realized benefits and cost-effectiveness, and doing so may also lead to consumer frustration as bills increase because consumers cannot easily avoid high-cost consumption.

Implementing complex dynamic pricing schemes before low-cost enabling technologies are available may limit realized benefits and cost-effectiveness

Of course, there is a chicken–egg issue here: without dynamic pricing, enabling technologies offer few benefits, and accordingly, there will be little incentive to develop or deploy them. Attempting to install enabling technology across a utility’s entire customer base is likely to be unnecessarily expensive even with dynamic pricing tariffs, especially if enrollment in dynamic pricing plans is not mandatory. While consumer participation rates in demand response programs have not been well-studied, most analysts agree that enrollment will be far less than universal.⁷⁵ The most cost-effective solution is likely to involve assignment of the responsibility for technology installation decisions, ownership, and payment to participating customers. We would expect third-party service providers or, if present, competitive retailers to be active in this market if policies do not restrict their activity or embed enabling technology investment in utility ratebases.

FINDING

Capturing significant benefits from dynamic pricing is likely to require investments in complementary technologies, particularly those that permit customers to automate their responses to price changes.

Finally, we turn to those utilities that have not yet committed to a system deployment of AMI. As noted in Chapter 6, for some utilities, the pure operational benefits of AMI may fall far short of the cost of deployment. This may be especially likely for systems that have recently installed automated meter reading (non-AMI) systems throughout their customer base. Where operational benefits are low relative to deployment costs, systems may be reliant on demand response and conservation benefits to make a business case for investment. For these systems, AMI investments are not yet sunk. Their net benefit of expanding residential price-responsive demand may not be clear, particularly because, at present, there is considerable uncertainty about both the cost of AMI and its required associated technologies, and the precise magnitude of demand response benefits that investment would produce.

Using AMI to enable real-time pricing or other demand response programs requires significant expenditures by the distribution utility in meter data management systems, information technology, and customer education and service, in addition to meter acquisition and installation costs. Many customers may choose not to participate in demand response programs, at least for some time. For these customers, the full metering cost is incurred with no prospect of demand response benefits as offsets. Utility rate filings, such as those surveyed in Chapter 6, suggest that the expected all-in cost of AMI deployments averaged perhaps \$300 per installed meter over the past five years, though more recent industry estimates suggest a possible decline to \$150–\$250 per meter.⁷⁶ Moreover, customers choosing to participate in voluntary demand response programs are likely to incur additional investment costs for enabling technology—which may be as complex and expensive as a separate home-area network or as simple as a programmable controllable thermostat. Whether those costs are paid directly by the customer, a third-party

aggregator, a competitive energy retailer, or, in some cases, the distribution utility itself, they belong in the economic cost–benefit calculation.

Actual costs of deployment may differ from the prospective estimates submitted in utility proposals because of the lag between submission, approval, and subsequent staged deployment over a few years. Predictions may be especially uncertain for the costs of information technology, customer education, and customer service. Fortunately, information on many of these is likely to improve considerably over the near term. Similarly, as systems implement price-mediated demand response programs, estimates of demand response participation rates and system benefits are likely to improve.

FINDING

For systems with limited operational savings from AMI, the economic value of early replacement of existing meters with new AMI meters is uncertain due to limited information on both the “all-in” costs of deployment at scale and the expected demand response benefits. Current deployments are likely to improve the quality of information on costs and benefits and thus enable better decision-making.

7.6 CONCLUSIONS AND RECOMMENDATIONS

We confidently expect the demand for electricity to become increasingly responsive to system conditions, to an important extent because of increased adoption of dynamic pricing over time. The value of making demand more responsive will increase as VERs, pure electric vehicles, and plug-in hybrid vehicles become more important and concerns for system efficiency persist or intensify.

Complementing this, new technologies, particularly AMI, are reducing the cost of transmitting fine-grained, real-time price signals to customers and of both automating and measuring their responses. But, the path from today's flat-rate pricing system for all but the largest commercial and industrial customers, to a system in which some form of time-varying prices becomes the default for many if not all customers, is likely to differ across utilities. Because AMI deployment is both a major investment and essential for truly dynamic pricing, our recommendation for how to proceed depends on whether a utility is presently committed to widespread AMI deployment.

Early AMI Adopters

Many utilities have already made commitments to universal AMI deployment throughout their systems; in fact, some have already accomplished that objective. For other utilities, AMI investments may pass cost-benefit tests without requiring any significant demand-side benefit, and we would expect those commitments to be made. For example, systems that operate manually read, traditional electromechanical meters and those with low customer density, high customer turnover or high billing losses may find that the operational cost savings from reduced meter-reading labor, outage detection, remote connection and disconnection, and theft reduction largely offset the capital costs of universal AMI deployment across their service area over an estimated 20-year useful meter life.⁷⁷ These systems may find the economics of near-term AMI investments attractive and join the utilities that have already committed to AMI.

Early adopters confront a number of challenges and responsibilities. Home energy management systems, automated residential appliances, and other complementary technologies are relatively

immature and costly. Capabilities and costs are improving rapidly, and the direction of innovation is difficult to predict. In addition, consumers are concerned about the privacy and security implications of AMI. The system standards for cybersecurity are in the early stages of evolution, as discussed in greater detail in Chapter 9. Stranding consumer or utility investment in meter or control technologies that are not compatible with later generations could be quite costly. Ensuring that new meters and any associated equipment installed by the utility offer interoperability with current and potential new communications and "behind-the-meter" technologies is essential to preserving the value of these investments.

For the many utilities that have already installed AMI technology across their systems or are committed to doing so, the largest cost of enabling greater demand engagement via dynamic pricing has been sunk, particularly if their information technology systems have simultaneously been upgraded to accommodate the data flow from AMI systems. If dynamic pricing tariffs are offered but not mandated, as seems likely at least initially, default service tariffs should be designed to reduce subsidies to flat-rate customers and encourage efficient evolution toward universal dynamic pricing defaults over time.

Structuring demand response program implementation using best-practice pilot design will enhance the ability of researchers to measure programmatic impact. For example, utilities should collect baseline consumption data before exposing consumers to new rate designs and may stagger the rollout of new rate options across service areas to provide a synthetic control group. This structure also can improve a utility's ability to allocate customer service resources and respond effectively to any unforeseen problems that develop in implementation.

These requirements should be viewed not as impediments but as requisites to effective implementation. As in many other areas, sharing information gained from innovative programs and investments is critical to efficient evolution at the national level. Smart Grid Investment Grants were designed to have a crucial information-sharing component, and the Department of Energy has led efforts to create mechanisms for sharing data via www.smartgrid.gov and the Smart Grid Information Clearinghouse (www.sgiclearinghouse.org/). Ensuring timely reporting to these repositories, using them to collect similar information for deployments that were not supported by stimulus funding, and making data accessible to both industry participants and researchers outside the utility sector are critical to realizing the greatest value from early AMI adoption.

RECOMMENDATION

Where a commitment to AMI technology is already in place, investment decisions should focus on interoperability and compatibility with later generations in meters and associated technologies. Utilities should design and follow a transition path that includes appropriate investments in customer education and engagement programs to encourage migration to universal dynamic pricing, with an ultimate goal of substantial real-time pricing penetration. Early adoptions have an important research and demonstration component: information on investment costs and the results of demand response programs should accordingly be collected and shared widely.

Systems without Present AMI Commitments

For many other U.S. utilities, operational benefits of universal AMI deployment may offset only 50%–60% of the system installation costs. This is likely to be the case for many of the utilities operating the roughly 50 million non-AMI meters now deployed in the U.S. that can be read remotely. These meters capture a significant fraction of the reduced meter-reading costs promised by AMI technologies, and they may have many years of useful life remaining. In this case, investments in AMI might range from significantly uneconomic to substantially positive in net present value, depending on uncertain implementation costs and demand-side benefits. Utilities in this situation may rationally decide not to commit investment dollars to AMI until some uncertainty is resolved.⁷⁸ Crucially, AMI investment decisions are not “now or never,” but rather “now or reconsider next year.”

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Waiting until lessons are learned from the first wave of AMI installations may yield myriad benefits. The capability-adjusted costs of AMI and complementary technologies seem likely to decline as innovation advances and manufacturers gain greater experience and scale in production. Given the volume of existing AMI installations and those committed to completion over the next few years, the quality of information on deployment costs and the range of demand-side benefits also is likely to improve considerably in the near term. Utilities that have not yet committed to AMI rollout have the option to wait while this information is collected and then revisit the decision. Deferring deployment decisions also reduces the chance that a utility will be locked into an early but inferior technology.

This does not imply that utilities in this evaluation mode must forego residential demand response. For example, as noted earlier, direct load control programs targeting air conditioning and electric hot water heating have substantial current enrollments in some utility service areas. Direct load control programs could be expanded on both the intensive margin—increasing the frequency or set of circumstances under which utilities can invoke load control—and the extensive margin—expanding the set of utilities and customers using direct load control. Electric vehicle charging may offer additional opportunities for direct load control in regions with significant electric vehicle penetration. These programs do not require universal AMI for implementation and may be a highly cost-effective alternative or complement to dynamic pricing for many customers, even where AMI is installed and especially where it is not.⁷⁹

RECOMMENDATION

The decision whether to adopt AMI need not be made immediately. Decision makers should recognize the option value of waiting to learn from early deployment data on costs, technologies, customer responses, and demand response program design and benefits.

To be clear, we are advocating care, not indefinite delay. We expect by the end of our study horizon in 2030, most, if not all, U.S. utilities will have rationally deployed AMI technologies, and we hope that policy makers will have facilitated movement far along the path to universal dynamic pricing.

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