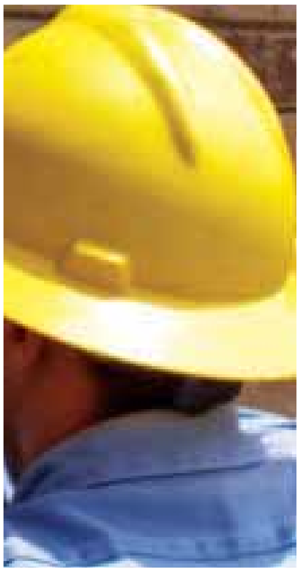
DECIDING ON SMART METERS

The lengthy Energy Policy Act (EPAct) is concise in how it deals with peak- and time-sensitive pricing, demand reduction techniques, and "smart metering." The Act, per se, does not require that utilities do anything. It requires that the regulators and the boards of directors of unregulated utilities shall "consider and determine" what, if anything, their companies must do to comply with the Act's objectives. It sets timelines for the determination and when any requirements, if established, will begin.



On one level, this treatment of alternative rates, demand response (DR), and "smart metering" may seem straightforward. But there are some potentially burdensome deliberations and financially intimidating requirements for many utilities. The devil is in the details. Many utilities already have time-of-use (TOU) rates, have offered them in accordance with the Public Utility Regulatory Policies Act of 1978 or even before, and still offer them. Many have already made large investments in advanced metering systems, some of which are "smart" and others of which are not.

Developing a business case for an advanced metering infrastructure is the key to its success.

By Ralph E. Abbott, Stephen C. Hadden, and Walter R. Levesque

The primary driver is only partly economic. It is policy, developed in a consensus process with legislators, utilities, regulators, businesses, and consumer advocates.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Many have offered TOU rates and found that a large majority of customers are simply not interested unless they are "free riders" who will pay less without altering their consumption patterns. And other utilities may enthusiastically embrace new metering and price-sensitive rates as important relief from the persistent growth in peak demand.

EPAct allows individual consideration before a determination is made. That consideration will address the significant differences among utilities in their needs, past practices, installed metering, rate design factors, customer preferences, and dozens of other factors that come into play. This is a complex matter having major long-term impacts on the utility and its customers.

Given that complexity, one must assume that careful planning and implementation are the keys to regulatory support for cost recovery. This requires a solid business case, encompassing all costs, pointing out benefits, and outlining how the system would work. Identifying the full range of operating benefits that advanced metering infrastructure (AMI) systems provide is a demanding and time-consuming task, because these systems typically produce benefits that reach into almost every department of the utility.

So, how do states consider AMI and decide what makes sense? They examine the likely balance of costs and quantifiable benefits for a given utility system. These fall into two possible buckets: those associated with utility operations, and those associated with potential customer responses to time-differentiated price signals. In many cases, AMI makes sense based solely on net benefits estimated in the first bucket.

But in all cases, as utilities "consider and determine" their future use of AMI, a business case weighing the costs and benefits is the order of the day.

The authors are with Plexus Research, Inc. in Boxborough, MA, a consulting firm specializing in advanced metering applications. This article is adapted from their report, "Deciding on 'Smart' Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005," published by Edison Electric Institute. For more information, contact expert@plexusresearch.com or visit www.eei.org.

The Imperatives to Action

While most businesses typically invest in something as substantial as AMI only if it is economically attractive in the near term, regulated utilities have a broader charter and will consider other motives.

Regulatory decisions may directly drive deployment of advanced metering independent of economic calculations. Regulators have many good reasons for directing utility actions, including fairness, value to the society as a whole, quality of service, and others.

For example, regulated electric utilities in California are now responding to regulatory direction to submit plans for large-scale AMI, with full delineation of costs and benefits. This regulatory initiative is an aggressive step, seeking to promote customer awareness of peak load periods and response to peak-sensitive pricing. The deployments will proceed in light of economic implications, but the primary driver is only partly economic. It is policy, developed in a consensus process with legislators, utilities, regulators, businesses, and consumer advocates.

Some regulatory bodies and utilities will decide to pursue peak-sensitive pricing and DR aggressively, depending on their perceptions and circumstances. Others will find that the policy objectives already are met or are otherwise not applicable. Local conditions will drive the decisions deemed best for customers. Many utilities, without any regulatory imperative, will continue deploying AMI systems simply because they reduce costs and improve the quality of service to consumers.

Another driver is benefit to the customer, and AMI systems provide dozens of benefits to customers that are real but not readily quantifiable.

Whatever the principal motives, AMI's economic value is critical. Even if the motive is noneconomic, the utility needs to project the financial consequences of such a large capital expenditure. The conventional approach to showing economic value is to assemble a "business case." For a utility, some AMI capabilities will be highly valuable, others won't. The business case focuses on the high value, and those capabilities then become the requirements that then guide the technology selection process.

What Is a Business Case?

A business case calculation quantifies the costs and benefits of an investment over time, supports the decision of whether and how to make the investment, and measures its value.

A complete and capable AMI business case includes a "model" of the expected deployment—this allows the utility to experiment with and compare alternatives. (See the sidebar, "Process, Process, Process.") Experts involved in each potential application or source of value should help develop that application. For example, if you are assessing a system's outage detection and recovery capabilities, you must involve the personnel responsible for outage management. And so it goes with every other element of the business case. In the end, management rolls up the benefits that would accrue to each type of AMI system and then can see just how the benefits compare.

The business case also supports essential management processes after the AMI decision. By documenting the expected benefits and costs, it becomes a reference by which to measure actual project performance. It allows detailed planning for rate purposes and the basis for detailed regulatory dialogue. As the AMI deployment proceeds (generally over several years), updates to the business case support project reviews, refunding decisions, expansion, or redirection as budgets, management teams, and other circumstances change.

Key Business Case Attributes

The business case model must be transparent. It's true that a business case for a major technology investment like AMI can be complex, but the AMI team must have a way to show the results that allow the audience to see the assumptions, the relationships, the benefit elements, the cost elements—all the structural and numerical parts of the business case.

After all, since AMI is a large investment with sweeping operational consequences for the utility, a decision to invest must be defensible in every way, for management and regulators will scrutinize it repeatedly at every level.

The business case is the central tool for responding to that scrutiny. An audience of senior management, board of directors, regulators, or operating management should be able to test the case's assumptions and satisfy themselves that it is valid from their own viewpoint. And any of these parties should be able to veto the investment: A complex business

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Process, Process, Process

Here's a short description of the process of building an AMI business plan. (For more information, see the larger report, "Deciding on 'Smart' Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005," prepared by Plexus Research, Inc., and published by Edison Electric Institute. The report contains detailed "AMI benefit descriptions" and more.)

Kickoff. The utility assembles a team of representatives from all affected operating activities in the utility. This normally includes metering, meter reading, customer service, distribution engineering, distribution operations, telecommunications, information technology (IT), system planning, electric procurement and marketing, supply operations, settlement, rates, and regulatory relations.

Executive sponsorship. It is helpful (arguably, necessary) for the AMI team to have executive charter and sponsorship. Direct executive involvement in the working sessions will motivate everyone to keep the utility's and its customers' best interests in view. Teams without executive leadership tend to focus on shorter-term strategies and to find a lower total value of AMI benefits. In addition, without executive leadership, the team has more difficulty conducting the meetings with senior management. This hampers the decision process.


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Initial estimates. The team brainstorms to identify new ways the utility can take advantage of the AMI system and then does the detail work to estimate the financial impacts of the change. Each estimate must identify and quantify the benefit, of course, and the costs of achieving it. The cost of the AMI system itself is part of that cost and will be separately estimated. But the team must recognize and cite nonrecurring labor, capital, and operating/maintenance (O&M) costs of creating and sustaining the benefit.

Every benefit estimate must identify and quantify the costs the utility must incur to obtain that benefit that are not paid to the AMI vendor—the labor by the IT staff to create an interface for the call center, for example.

Review and edit. The process of identifying and estimating takes several weeks or months. Rushing the process limits the team's ability to see the best paths to obtaining the benefits. Indeed, as the team reviews its estimates, it almost always identifies other opportunities. Also, with the costs so large, management review during the process is essential for success.

Documenting estimates. A typical utility AMI business case may include 30-50 estimates (one for the impact on the call center, one for energy procurement, etc.). Clearly documenting the estimates supports the subsequent steps—review by utility senior management and board of directors, review with regulators (sometimes including public examination), detailed planning for achieving the benefits, and tracking that process as it occurs.

Costs. The largest and most obvious cost is the amount paid to the AMI system provider(s). But other costs will affect the business case, as well:

- AMI system hardware and software;
- new meters and meter-related utility equipment and labor for both new and redeployed meters;
- project management;
- meter data management system;
- IT integration; and more.

Costs for meters and meter communication systems have been declining slowly for many years, reflecting the general decline in electronic product costs. Right now, costs for automated remote meter reading (that is, a meter that does not include DR functions such as customer signaling) are about $100 to $175 per meter, including meters, all installation, and integration only with the monthly billing process.

Installed costs for DR components vary widely and may be from $100 to $350 per site for signaling and control of a first load, plus about $100 per additional load managed. (Note that traditional direct load control is less expensive but does not give the customer a controlling role and is not considered "demand response" in the context of the EPAct.)

Other input data. Other examples of utility-specific data in the business case include:

- labor rates;
- overhead and markup rates for all affected departments;
- hours and quantities drawn from activity analyses (number of off-cycle reads per month, customer outage minutes per year, etc.);
- details about the customers served;
- financial metrics (cost of capital, revenue); and
- physical asset data (number and age of meters of each type, etc.).

Done well, the complete process, including solicitation and evaluation of vendor costs, takes six to twelve months.

case that leaves the audience unsure whether it's had "the wool pulled over its eyes" will make it easier for those with veto power to exercise it. You need transparency to overcome the legitimate hesitancy to approve the AMI case.

The business case also needs to be revisable. Because the project involves large multiyear budgets, it will likely be reexamined each year as other budget priorities arise. The AMI team will need to explain the investment consequences of, for example, increasing next year's project budget by 10 percent and reducing the project schedule by a few months.

Moreover, it won't be enough to say, "This increase will improve the investment performance." It will be necessary to show how much because others will be advocating competitive opportunities in which to invest that money to genuine good advantage for the utility and its customers. Every year, AMI will vie for budget dollars with distribution automation, call center automation, improved billing systems, and myriad other investments.

And since producing a good business case is a significant effort, the AMI team won't have time to redo it each time the budget is called into question. The better approach is to "do it right the first time" by creating an updatable case.

The Unquantifiable Benefits First

AMI systems typically produce operating benefits across the utility. For example, these systems aid in outage detection and restoration, provide load data on distribution equipment, improve customer satisfaction through better accuracy and timeliness of meter readings, aid in detecting energy theft and current diversion, reduce the number and duration of call center inquiries, and provide detailed consumption data to those customers who are interested.

These benefits accrue not only to the utility, but also to its customers as improved service and moderated rates. AMI benefits to customers are difficult to value and therefore often do not appear in the business case. But they deserve consideration by utility and regulatory decision makers.

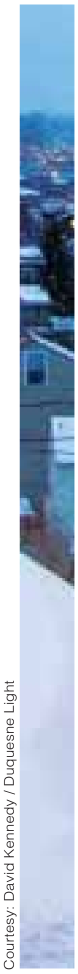
For instance, AMI boosts customer service. The first and most pervasive improvement is accurate and timely bills, with few estimated readings. Also, if the AMI system allows the utility to save daily meter readings, a customer service representative can (for example) help a customer questioning a high bill to pinpoint times of high usage in the preceding month. (And that customer appreciates the insight the utility has given him into his home operations.)

In addition, if the utility can know when and where outages occur, it can notify customers who wish to be notified. For example, if the power fails at my elderly mother's house in another town, she won't be able to cook on her electric stove. My utility can let me know. This is good customer service. If my business has an unstaffed warehouse in another town and the refrigeration unit stops because the power goes out, the utility can let me know, and I can arrange to protect key inventory. This, too, is good customer service.

Other examples are too numerous to recount. But the data provided by AMI are a substantial resource the utility can use

Courtesy: Georgia Power

AMI boosts customer service. The first and most pervasive improvement is accurate and timely bills, with few estimated readings.



to better understand customer behavior and provide data and services to customers.

Privacy and Fairness

AMI can help the utility get to the meter with no disruption to the customer. For example, some utilities have arranged with builders to install meters near the front of the property, easily reached by the meter reader. But that is not the norm. Meter readers commonly must go to the back of the house—into the dog's fenced area, behind the foundation planting bushes, and to other inconvenient places—to read the meter. It's inconvenient for the customer, too. The requirement to keep the dog in on a particular day or let the meter reader into the basement is a nuisance that working customers find increasingly annoying.

For the business with security issues, admitting the meter reader every month is a costly distraction. Alternatively, allowing the meter reader to carry a key is a security risk many businesses would prefer not to take. Many utility meter reading departments keep thousands of keys to customer premises, and key management is a significant problem and risk for the utility, too.

A saturation AMI deployment produces a fairness benefit that can be notable, too. Traditional induction meters (that is, electro-mechanical meters, with a spinning disk) can slow down very gradually as they age. Most regulated utilities must audit a portion of in-service meters annually to measure accuracy, and when a set of meters proves excessively inaccurate, the utility removes them. However, some sets may be within permitted accuracy tolerances and still under-register consumption. Indeed, while it varies among utilities, overall meter plant accuracy of about 99.7 percent is typical—that is, the meters under-register consumption by about 0.3 percent. This comes to less than $10 per year for most residential customers—it's an amount small enough to make fixing the problem not cost-effective. But the AMI deployment changes every meter anyway and brings aggregate meter plant accuracy much closer to 100 percent. If the meters used for AMI are electronic (rather than induction), then this fairness benefit will be enduring—electronic meters have no mechanical wear and do not slow down over time.

Reducing other kinds of meter losses is another benefit—energy theft, meter installation problems, and meter failures. This benefit is larger and easier to value than meter accuracy, but it has some uncertainty. Few utilities know how much energy is lost to theft and meter problems. Various studies have indicated losses as high as 3 percent of revenue in North America. A 2001 EPRI study found that losses are more likely lower than that, around 1 percent or less. Of this amount, perhaps half is due to meter problems and failures; the other half is due to theft of service. A competent AMI deployment that re-installs all meters will remedy nearly

Courtesy: David Kennedy / Duquesne Light

Traditional induction meters can slow down very gradually as they age. Most regulated utilities must audit a portion of in-service meters annually to measure accuracy.

Many AMI systems notify the utility when a meter experiences a service outage. This function supports more rapid and efficient restoration efforts by utility crews.

Courtesy: Hunt Technologies

all meter failures and a significant amount of the loss due to other meter problems. If the deployment includes inspection of each meter installation for evidence of tampering and diversion, then this, too, will produce a benefit to customers. Finally, for the life of the system, the AMI-equipped meters will detect and report some kinds of energy diversion and meter tampering. (See the sidebar, "Who Will Report From the Field?")

In jurisdictions where the utility is operating with essentially fixed rates, these reductions in meter losses benefit the utility financially until the next rate case readjusts rates to account for these (and other) consequences of AMI. But the enduring benefit goes to ratepayers as the elimination of the $5 to $50 per year that honest businesses and consumers pay to cover meter problems and energy theft by others.

Enhancing Electric Service Quality

Electric load data are a mainstay of distribution engineering, defining the base level of service the distribution system must support. Utilities traditionally rely on instrumentation in substations (such as supervisory control and data acquisition systems), engineering studies, and statistical data samples to quantify electric load in different segments of the distribution system. Substation instrumentation often keeps an exact hourly load profile for each feeder, but the utility ends up estimating much of the data for smaller distribution segments.

AMI data, on the other hand, allow engineers to more accurately size equipment and protection devices and understand distribution behavior. Some utilities report they have improved quality of service and reliability as a result.

Many AMI systems notify the utility when a meter experiences a service outage and when power returns. This function supports more rapid and efficient restoration efforts by utility crews, further improving service quality.

In addition, the DR capacity of AMI systems offers further service quality improvements through reduced congestion in power lines and more balanced transmission and distribution load management.

Reliability

In the summer of 2000, California's independent system operator (ISO) implemented rolling blackouts to avoid system collapse as electric demand approached available supply. The direct power costs have been estimated at tens of millions of dollars; estimates of indirect costs (such as business and consumer losses) range in the tens of billions. Many have argued that a modest DR capability would have avoided the need for the ISO's action. Indeed, avoiding the societal dislocation associated with interruptions of electricity is part of EPAct's purpose.

DR has come to mean actions by energy users in response

Who Will Report From the Field?

Certainly, traditional meter readers threading through the service territory have produced many positive benefits. Stories abound relating how a meter reader helped a fallen elderly person, discovered an incipient house fire, reported a serious electrical hazard in a service drop, and performed other socially valuable actions. Plus, there's the goodwill and corporate branding that builds up in a community that has consistent utility presence. If meter readers no longer follow their appointed rounds, who will be there to be the company's—and the community's—eyes in the field? And how will we discover meter tampering and other energy thefts?

Some of these items are hard to respond to with certainty. While someone else could discover the fire or fallen elderly person, it is unlikely that others will be as quick to notice a meter hazard or report meter tampering. Some also argue that, notwithstanding tamper-detection mechanisms, AMI may actually increase energy theft when meter readers no longer visit every meter every month. On the other hand, while it's true AMI will not specifically detect and report some kinds of theft, such as electricity taps before the meter, it will allow the utility to detect some distribution problems that would otherwise degrade to failure before the utility can know about them. Also, since AMI often involves retrieval of daily or hourly consumption readings, this added information (compared with prior once-a-month readings) can provide useful insight in identifying locations where theft is occurring.

And it isn't clear that meter readers are the most effective at discovering meter tampering. Two shareholder-owned utilities that checked for meter tampering when deploying AMI found that 0.3-0.5 percent of meters showed evidence of tampering that had gone unreported by meter readers.

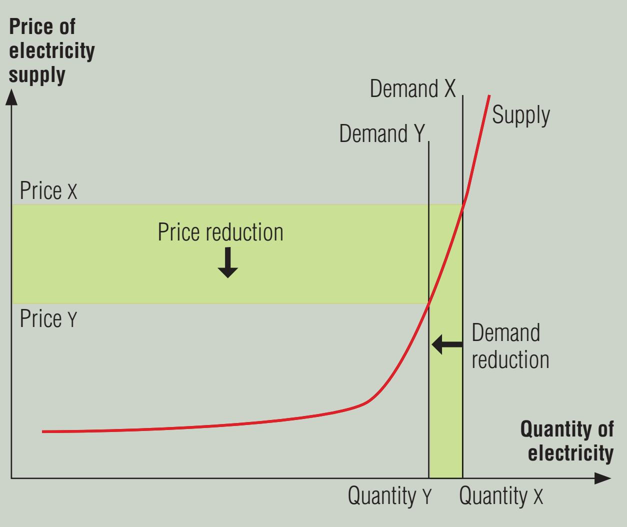
One way around this is to institute a meter site sampling program to annually examine enough meters to monitor whether energy theft is rising. Some utilities do so on a roughly five-year cycle. Such a program can be integral to other field activities that occur for other reasons, such as collections, new meter sets, distribution work, etc.

It's true—the other benefits of manual reading may be lost. But the positive benefits of AMI will far outweigh the lost ones, which often rely on chance.

to electric market dynamics. Its principal benefit is that, during periods of high energy demand and price, a small reduction in demand produces a relatively large reduction in market price. (See Figure 1.) Advanced metering is a prerequisite for fair and effective DR. It enables the utility to measure how much a customer uses during DR events, so that the utility can bill or pay out benefits to the customer according to consumption.

Other reliability benefits of AMI and DR are more certain and more practical to estimate than customer service and strategic benefits:

FIGURE 1
PRIMARY DEMAND RESPONSE BENEFIT



- improved efficiency of energy use;
- favorable environmental impact; and
- lower user costs, which may produce an overall benefit to consumers and the economy, particularly in a time of rapidly rising energy costs.

Still, evaluating those things is a significant challenge—and utility business cases generally do not include such benefits because they do not improve utility operations or otherwise result in lower electric rates. However, it may be practical and constructive for regulatory policy to assign some value to them. Moreover, DR produces a clear benefit in reduced supply cost that is readily estimated if the analyst can predict consumer and business behavior during DR events.

Now to the Quantifiable

The original and clearest motive for automating meter reading is to reduce or eliminate the labor expense of manual meter reading while improving the accuracy and completeness of monthly billing. When you include manual reading's vehicle, training, health insurance, and other overhead expenses, reducing or eliminating manual reading is often the largest single AMI benefit—typically one- to two-thirds of the total benefit in traditional utility operations. (A traditional utility can make a "quick and dirty" estimate of AMI benefits by multiplying by 2.5 the total cost of its manual meter reading activity. Other benefits, such as DR, are additional.)

Other benefits enhance utility operations and can produce value exceeding the meter reading value. (See Table 1.) The table's categorization of benefits is just one of many ways to portray them. For example, rather than a new revenue benefit, "reduced read-to-pay time" can also be a capital reduction benefit. The shorter read-to-pay time advances the utility's cash flow by a day or so, creating a one-time revenue influx. This effectively reduces the utility's need for working capital. But some utilities choose to include it in the business case as "revenue" equal to the recurring annual interest on that capital. The overall point is that AMI impacts are broad and substantial throughout the utility and constitute significant enhancements to routine utility operations.

From the Supply Side

Price and demand reductions during high-demand periods benefit the utility in many ways, providing

- reduced peak capacity requirements;
- reduced congestion costs;
- reduced generation and delivery costs;
- reduced potential for market influence by any one supplier;
- improved electric system efficiency through lower operating costs;
- improved electric system reliability through lower maintenance costs; and
- greatly facilitated settlement data management.

Electric market settlement commonly is not completed until 30 days or more after energy delivery. AMI allows a utility to gather settlement data much more quickly and accurately. If the regional settlement process supports a faster resolution, AMI reduces the utility's capital costs by reducing the "float" time associated with the long settlement process.

In 2003, California conducted a statewide pricing pilot

TABLE 1

AMI BENEFITS FOR TRADITIONAL UTILITY OPERATIONS

QUANTIFIABLE

NEW REVENUE
- Reduced read-to-pay time
- Improvements for performance-based rates
  - Reduced outages
  - Fewer estimated reads
- Additional customer services
  - Energy information
  - Selectable bill date
  - Selectable bill frequency
  - Bill aggregation
  - On-demand billing
  - Customized bill
  - Meter reading for other utilities
  - Outage restoration notification
  - Energy saving analysis
  - Prepayment

ONE-TIME AND SHORT-TERM
- Improved meter accuracy
- Sale of used meters
- End of meter changeout
- Tamper detection and correction

CAPITAL REDUCTIONS
- Load research equipment
- Meter reader vehicles
- Optimized transformer sizing
- Meter inventory

REDUCED EXPENSES
- Customer service
  - Fewer bill inquiries
  - Faster inquiry resolution
  - Fewer customer site visits
- Billing
  - Reduced manual processing
  - Fewer estimated bills
  - Fewer pre-bill audits
- Metering and reading
  - More on-cycle reads
  - Fewer off-cycle reads
  - Increased meter reader safety; decreased liability
  - Less meter reader training
  - Reduced meter testing
  - Direct access settlement
  - Load research metering

AVOIDED LOSSES
- Reduced nonbillable consumption
  - Deterred tampering
  - Stopping power to unoccupied premises
- Electric system optimization
  - End-of-line voltage
  - Feeder load balancing
  - Power factor losses

INTANGIBLE

CUSTOMER SERVICE BENEFITS
- Diversified customer services
- New rates
- Increased utility responsiveness
- Less utility intrusion
- Power quality monitoring

STRATEGIC BENEFITS
- Distribution automation
- Managing distributed generation
- Greater approved return
- Improved costs and pricing basis
- Improved load forecasting and system planning
- Improved system reliability
- Market segmentation and targeting
- Improved public and regulatory relations
- Improved customer satisfaction

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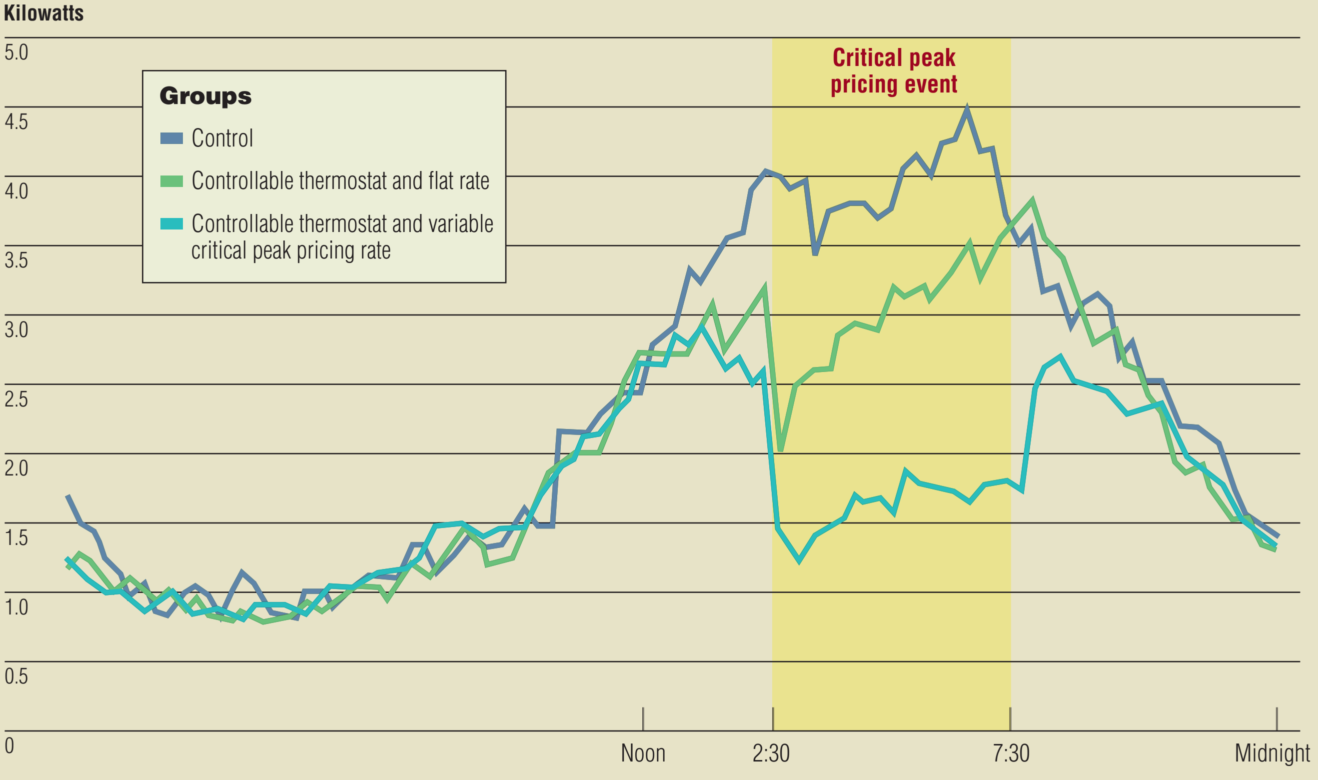
In some cases advanced metering systems can be a good investment purely for the benefits they provide to utility operations.

FIGURE 2

RESIDENTIAL CRITICAL PEAK IMPACTS



Source: Levy Associates

program to test the willingness of consumers to respond to market prices. The study involved about 2,500 randomly chosen participants in various climates, economic strata, and other pertinent categories. Participants received electric service under time-varying electric rates, including critical peak pricing (CPP) rates—the latter applied a high price when the electric market was under stress. The results convincingly demonstrated that, at least in the short term, consumers are willing to make substantial reductions in response to such rates. (See Figure 2.)

The impact (up and down) of the CPP rates on customer bills averaged about 5 percent for residential customers and about 10 percent for business customers. Some paid more, others less, but the dramatic benefit to the electric system came about with a relatively small overall impact on bills.

Converting the demand reduction benefits into dollar value in a business case requires many assumptions about future energy prices and market conditions. One relatively simple approach is to use past market data as a proxy for future market behavior. A complex approach—which may be no more accurate—involves risk valuation and probabilities of occurrence for various market event scenarios.

Depending on the utility operating scenario and assumptions, the aggregate benefits of DR can be greater or less than the AMI benefits in traditional utility operations. If one includes the avoided costs and consequences of rolling blackouts, then DR benefits may be many times the operating benefits and also many times the cost of the AMI system.

Grist for the Mill

In some cases, where the rate differentials are minimal, advanced metering systems can be a good investment purely for the benefits they provide to utility operations. Accordingly, many utilities have proceeded with an advanced metering system without the additional imperatives of advanced rate structures. They now have AMI in place that can support a wide variety of DR programs. In addition, it also is possible that DR alone will produce enough benefit to amply justify AMI.

The AMI process does not start with consideration of specific technologies. Instead, you must establish and attach value to the requirements before you move to technologies. And it begins with an examination of the many operational benefits of AMI systems, and which of these actually apply. That becomes the grist for the all-important business case, followed by the request for proposal, the vendor solicitations, evaluation, assessments, contracting, acceptance testing, and full-scale deployment. ♦

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