Unlocking the Potential for Efficiency and Demand Response through Advanced Metering

Roger Levy, Levy Associates
Karen Herter, Lawrence Berkeley National Laboratory
John Wilson, California Energy Commission

ABSTRACT

Reliance on the standard cumulative kilowatt-hour meter substantially compromises energy efficiency and demand response programs. Without advanced metering, utilities cannot support time-differentiated rates or collect the detailed customer usage information necessary to (1) educate the customer to the economic value of efficiency and demand response options, or (2) distribute load management incentives proportional to customer contribution. These deficiencies prevent the customer feedback mechanisms that would otherwise encourage economically sound demand-side investments and behaviors. Thus, the inability to collect or properly price electricity usage handicaps the success of almost all efficiency and demand response options.

Historically, implementation of the advanced metering infrastructure (AMI) necessary for the successful efficiency and demand response programs has been prevented by inadequate cost-benefit analyses. A recent California effort has produced an expanded cost-effectiveness methodology for AMI that introduces previously excluded benefits. In addition to utility-centric costs and benefits, the new model includes qualitative and quantitative costs and benefits that accrue to both customers and society.

Introduction

A foundational premise of efficiency and demand response programs is that they provide lower-cost alternatives to conventional generation and distribution options. According to basic economic theory, customers will adopt efficiency and demand response technologies and behaviors if they cost less than peak electricity. In practice, however, customers are not exposed to peak electricity prices because standard-issue meters are unable to record electricity usage information in the intervals needed to charge customers time-varying prices. As a result, customers are charged rates that average the high-cost hours with the low, reducing the incentive to conserve electricity when the system needs it most.

To offset the absence of the natural load-flattening incentives of time-varying prices, energy efficiency and demand response programs were created. Under these programs, customers are paid to reduce load, either directly as payments for load control program participation, or indirectly through rebates for efficient appliances. These practices completely disconnect the *incentive* to flatten loads from the *reason* for flattening loads; i.e. to the participant, the check from the utility is not connected in any way to their electricity bill.

Despite billions of dollars spent to regulate, promote or otherwise encourage customers to better manage their electricity use, customers as a whole are not much savvier about electricity use today than they were 25 years ago. Until steps are made to re-connect incentives with bills, the development, marketing and overall effectiveness of these efficiency and demand response programs will not reach their full potential.

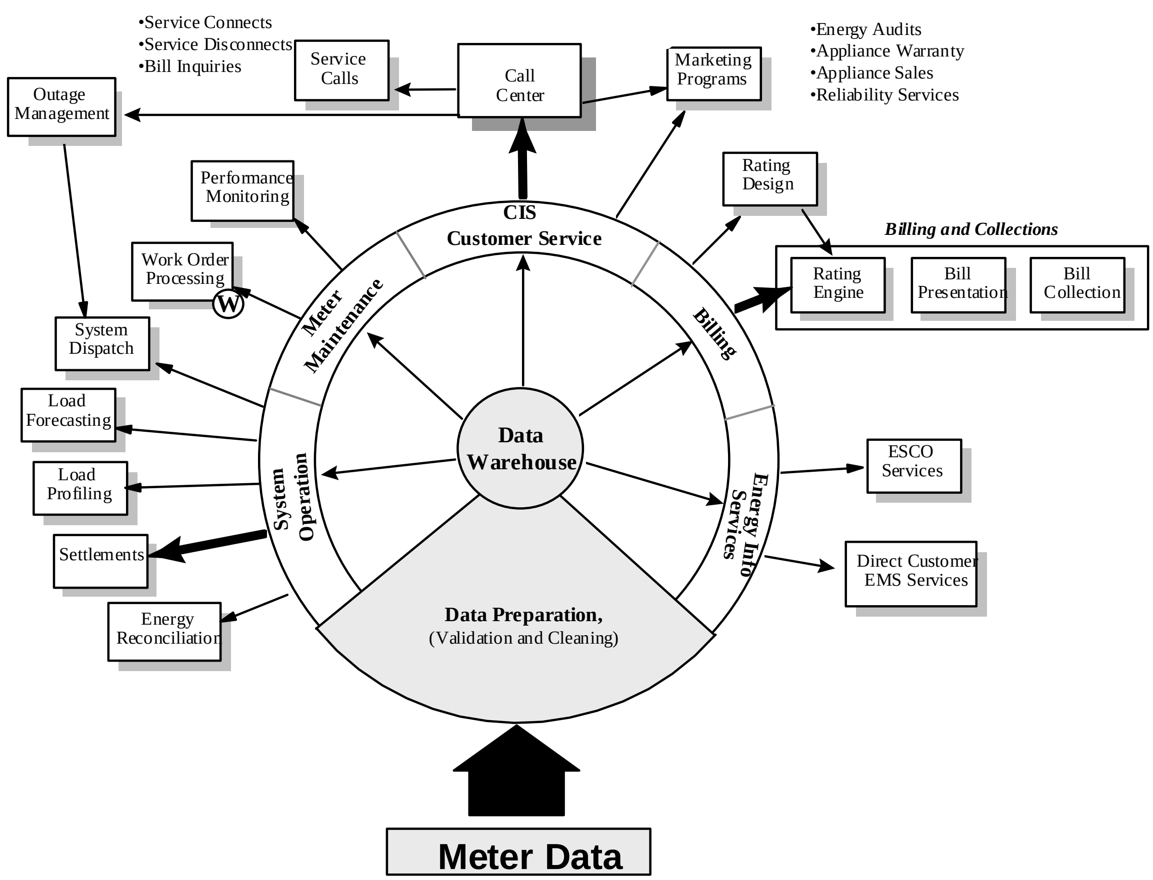
The key ingredient in the reunion of incentives and bills is advanced metering infrastructure (AMI) that allows for the collection of hourly or sub-hourly electricity usage. Among other things, this detailed information can be used to (1) educate customers about electricity usage and end-use purchase decisions and (2) price power correctly, such that load management incentives are distributed in proportion to individual customer contribution. Together, these features provide the customer feedback mechanisms that encourage economically sound investments and behaviors.

Metering Systems

Metering systems are traditionally viewed as the vehicle for collecting energy usage data to support the monthly billing function. The perspective of the meter as the "utility cash register" creates a focus on meter reading to support revenue requirements. That focus, in turn, ignores the impact that metered data has on every other aspect of utility operations. Treating metering and billing as isolated from other utility operations creates duplication of data, multiple systems with overlapping functionality, delayed access to information, and unnecessary costs.

To be most effective, metering systems must be designed from the outset to support system operations, meter maintenance, customer service, and energy information in addition to billing. Figure 1 shows just some of the utility applications that can be enhanced through proper metering system design.

Figure 1. Meter Data Applications within a Traditional Utility



Two attributes of the metering system determine whether and how metered data is used to support the applications identified in Figure 1: (1) the time interval over which electricity usage is measured and recorded, and (2) how long it takes to retrieve the data. For example, traditional watt-hour meters record only cumulative usage values, which are typically collected by meter readers on foot once a month. These monthly measurement and retrieval intervals limit the traditional system to monthly billing applications.

Automated meter reading (AMR) systems differ from traditional systems in that they allow data download to handheld devices, saving meter readers from manually entering values to a sheet of paper or a handheld recorder. Meters used with AMR systems may measure usage information as frequently as once every 15 minutes; however, the recorded values are aggregated into single monthly values or into a few defined billing buckets to support a particular rate. Since AMR cannot communicate data back to the utility, meter readers must walk or drive by, usually monthly, to download data into a handheld device. In the case of AMR then, shorter measurement intervals may allow a time-varying rate option, but monthly retrieval intervals preclude customer and utility applications that require real-time usage information, such as outage detection and building energy analysis.

Both the interval data and retrieval cycles of AMI systems are measured in minutes, and unlike AMR systems, AMI systems retain and make detailed interval data available for other uses. As a result, AMI is capable of supporting all of the utility functions shown in Figure 1. In addition, AMI systems provide remote communication to support daily or on-demand access to metered data; thus, AMI systems can support customer access to usage data independent of the billing process.

Table 1 identifies the ability of standard, automated (AMR) and advanced (AMI) metering systems to provide some of the high-value utility, customer and societal applications and services. Note that AMI systems can be designed to support all of these functions, while standard watt-hour meters and AMR systems cannot.

Table 1. Comparing the Functional Capability of Various Metering Options

	Standard Meter	**AMR (Drive-by)**	**AMI (with Communications)**
Utility Applications			
Automated meter reading	NO	LIMITED	YES
Outage detection	NO	NO	YES
Theft detection	NO	LIMITED	YES
Load survey	NO	LIMITED	YES
Customer load shape	NO	LIMITED	YES
Customer Applications			
Customer rate choice	NO	LIMITED	YES
Customized billing date	NO	NO	YES
Real-time energy information	NO	NO	YES
Dynamic tariffs	NO	NO	YES
Enhanced billing information	NO	LIMITED	YES
Societal Applications			
Rates tailored to market conditions	NO	NO	YES
Performance based efficiency	NO	LIMITED	YES
Performance based DR	NO	NO	YES

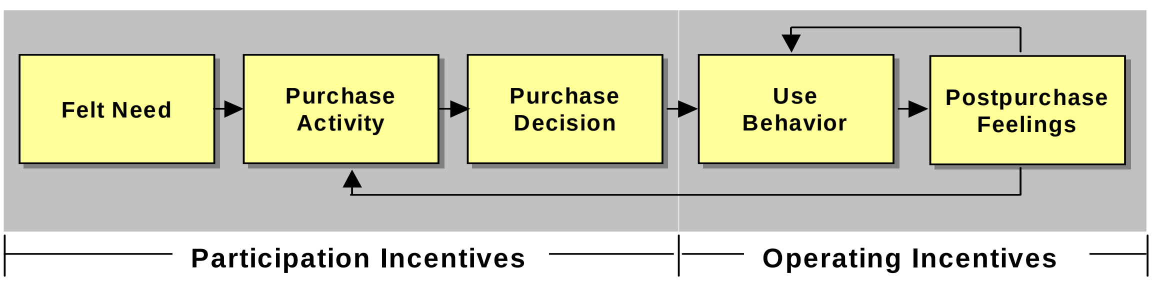
How AMI Can Benefit Efficiency and Demand Response

When customers are not provided the information necessary to understand the real economic value of load-flattening options, they are unable to internalize any useful heuristic for future efficiency and demand response purchases and behaviors. AMI can ameliorate this problem by providing (1) customer feedback on appliance purchasing and usage decisions, and (2) equitable distribution of load management incentives. The following sections will address these two issues in further detail.

Customer Feedback through Better Information and Rates

Most products and services abide by a common "purchase process" as shown in Figure 2. Most voluntary efficiency options abide by this same basic market model, in which one-time participation incentives are used to overcome initial investment barriers to accelerate adoption. Thereafter, operating incentives are supposed to provide feedback to encourage effective usage behavior and support repeat purchase activities.

Figure 2. Stages in the Customer Purchase Process (Kotler 1967)



In the context of energy efficiency, the purchase of an efficient appliance alone does not guarantee energy savings. In fact, anecdotal evidence shows that expectations of cost savings often encourage customers to increase their usage of efficient appliances. This implies that operating incentives, which provide information about behavioral effects on energy use, are essential to ensure that savings are actually achieved. This, in turn, may encourage customers to continue seeking efficient options in future purchase decisions.

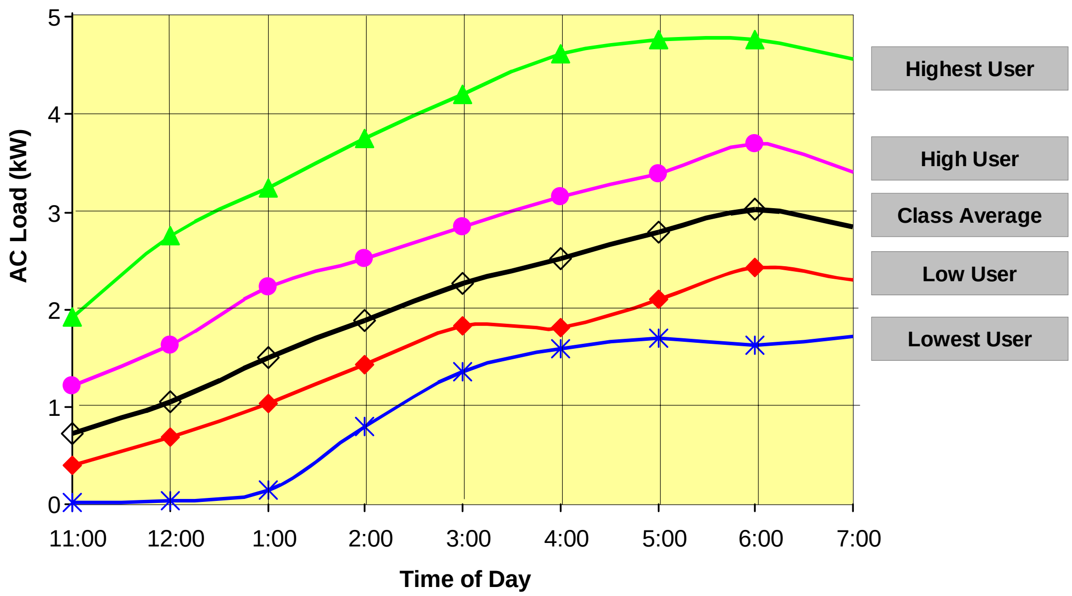
When customers purchase more efficient appliances, their expectation is that they will use less energy and save money on their electricity bill. Unfortunately, this expectation is never confirmed or refuted because efficiency programs do not provide customers with information on actual energy savings after the purchase is made. Instead, efficiency programs implicitly rely on customer bills to provide operating feedback. Unfortunately, the myriad factors contributing to a single monthly usage value makes teasing out any efficiency gains nearly impossible.

With AMI, efficiency programs could estimate the real savings for customers based on before and after usage patterns. Utilities could provide customers with information that would allow them to actually see the difference in usage. In the absence of such feedback, customers cannot determine whether new appliance purchases and/or operating strategies are cost-effective, so operating behaviors and future purchasing decisions will be unaffected.

In addition to pure information benefits, AMI provides utilities the ability to offer time-varying rates. Under rates with higher peak and lower off-peak pricing, the savings from peak-intensive appliances like air-conditioning would be more eye-catching than would savings under conventional rates, further encouraging efficient appliance investments. Below we provide an example to illustrate how better rates can create incentives that not only encourage energy efficient purchases but also reinforce operating behavior.

Figure 3 depicts peak period air conditioner loads for residential customers in an air-conditioner load control program in California (Levy Associates 1983). The data is stratified into five average usage groups.

Figure 3. Stratified Peak Period Air Conditioner Loads



Using the air-conditioning load data from Figure 3, we calculated peak day costs for the highest and lowest usage groups under inclining block, time-of-use (TOU) and critical peak pricing (CPP) rates.[1] Results are shown in Table 2.

Table 2. Peak Day Air-Conditioning Costs, 11 a.m. to 7 p.m.

Usage Group	Inclining Block	TOU[1]	CPP[2]
Lowest Usage	$0.92	$1.72	$3.94
Highest Usage	$5.28	$5.93	$12.14

1. TOU peak period: 2:00 pm to 7:00 pm weekdays only
2. CPP critical peak: 4:00 pm to 7:00 pm up to ~15 times per year

[1] Rates taken from the California Statewide Pricing Pilot (CPUC 2003). Note that TOU and CPP rates assume revenue neutrality for the utility; i.e. higher prices in peak periods are offset by lower costs in another, so annual bills across rate types would be the same (assuming no change in energy use).

The results are fairly clear. Customers on CPP rates have more incentive to purchase efficient air-conditioners and choose behaviors that reduce peak use. While the CPP peak day charges provide substantial immediate incentives to change operating behavior, revenue neutrality ensures that the annual bill for the average load shape would be the same under all three rate scenarios. It has long been believed that rising block rates provide strong support for efficiency options; however, Table 1 indicates that alternatives like CPP rates warrant closer examination.

More Equitable Distribution of Incentives through Rates

In a typical utility environment, efficiency and demand response participation incentives are established using cost-benefit calculations based on average load impacts. Efficiency incentives provide each participant with the same fixed dollar rebate for purchasing a specific efficient appliance, regardless of differences in customer usage. Similarly, demand response programs provide fixed incentives to load control participants that are unrelated to individual demand impacts. Depending on your point of reference, pegging incentives to the average customer creates equity problems in one of two ways.

From the point of view of most in the industry, fixed efficiency rebates and load control payments will always over-compensate the low users and under-compensate the high users of the targeted end-use. For example, looking back again at the Figure 3 air-conditioning loads, let's assume that one of the lowest users and one of the highest users each make similar unit replacements and receive the same efficiency rebate. Since the highest user uses about four times as much energy air-conditioning his home as the lowest user, his per-kWh rebate will be about one-fourth that of the lowest user.

This issue is even more extreme in the context of air-conditioning load control programs, as illustrated in Table 3. Average peak load reduction values given are actual measured results from a Midwestern utility (Levy Associates 1982). In this hypothetical example, effective incentive values were calculated by dividing an annual participation payment of $50 by the load impacts based on 40 hours of operation. Here the equity problem is obvious: low users are paid significantly more per kWh reduction than the high users. This outcome is the same regardless of the values used for participation payment and hours of operation.

Table 3. Distribution of Incentives in Load Control Programs and CPP Rates

	Average Peak Load Reduction (kW)	Peak Reduction Incentive ($/kW)
Lowest User	<0.01	>$1000.00
Low User	0.04	$31.25
Average User	0.37	$3.38
High User	0.74	$1.69
Highest User	1.97	$0.63

In the literature, the three lowest contributing strata in load control programs are often referred to as “free riders” because they are financially compensated without contributing equivalent load reduction. While free riders are considered a drain on program resources, no equivalent concern is usually expressed for the highest users, who are *under-compensated* for their contribution. In actuality, the problem is not who participates, but how they are compensated.

An alternate but related point of view is that paying a customer to reduce electricity use is comparable to paying a kidnapper ransom; i.e. those who are causing the problem are given money to stop causing the problem, and those not causing the problem have no opportunity to benefit. Thus paying participants to reduce load is considered by some to be an unfair practice. The obvious examples can be found once again in air-conditioning efficiency rebates and load control programs. In both cases, customers with central air-conditioning are offered cash benefits to reduce their energy use, either permanently or intermittently. Customers without central air-conditioning are completely forgotten in this scene. Despite being the equivalent of an efficiency program participant with an infinitely efficient unit, or a load control participant cycled at 0%, customers without central AC do not receive any monetary benefit for their “contribution.”

The problems seen from both of these viewpoints can be resolved with retail electricity rates enabled through AMI. With AMI, rates can be designed to charge more when demand is high and less when demand is low. Such rates give customers the opportunity to “earn” money by reducing energy use, but do so in a way that distributes bill savings in proportion to energy savings, thereby overcoming the free-rider issue. At the same time, such rates overcome the ransom issue by more correctly apportioning peak hour costs. Thus customers with low peak usage would automatically benefit, while those with high peak usage would be charged more and so provided with stronger incentives to reduce load.

Why AMI is not Widespread

Business cases in support of system-wide AMI implementation have almost always proven unsuccessful for two main reasons. The first is that the scope of issues relevant to cost-justification of AMI is often too narrow. The second common reason for failure of the AMI business case is that the methodology focuses on minimizing cost rather than maximizing value. These two issues are discussed in further detail below.

Narrow Cost-Justification Scope

In deciding whether to implement a particular program that requires AMI, regulators and utilities often attempt to justify AMI costs solely through the single set of benefits that accrue to that particular program, with the result that infrastructure costs outweigh potential benefits. Technology improvements and declining costs have failed to change this conclusion.

For example, cost-justification for dynamic rates, which require AMI, is often attempted solely on the basis of energy and capacity savings. In this context, high metering costs have tended to exceed potential savings. At best, results might support metering and demand response programs targeted only to the largest customers. Targeting not only reduces or eliminates many potential operating benefits, but also reduces economy-of-scale benefits. In some cases, targeting actually raises costs by requiring utilities to maintain duplicate metering and support systems.

Utility business case evaluations that examine the potential system operating benefits of AMI have also proven unsuccessful when they exclude potential demand-side benefits like efficiency and demand response. While AMI can simultaneously support both demand-side and utility operating benefits, the separation of these two complimentary benefit categories until now has ensured the failure of many AMI business case evaluations. For an AMI business case evaluation to be complete, it must span the variety of utility, customer and system operating benefits discussed earlier in this paper.

Emphasis on Cost-Minimization Rather than Value-Maximization

The California Standard Practice Methodology and other conventional business case approaches emphasize cost minimization rather than value maximization. In doing so, these approaches implicitly establish the functionality of existing metering and information management processes as the de facto standard against which all other alternatives are judged. With this approach, new investment is judged not by the *value* of the future capabilities and customer needs supported, but by how well the ‘new system’ can satisfy the ‘existing system’ business practices.

Regulatory approaches rarely start from or assign value to the functional capabilities and systems necessary to support anticipated future customer or market needs. Consequently, AMI options that might provide additional and more valuable functionality at a higher initial cost immediately become less attractive investments: there is no attempt to value the increase in functionality relative to the level of service provided in the existing metering system. For example, most would agree that comparing the cost-effectiveness of a desktop computer to a pocket calculator by looking only at purchase cost and ability to add and subtract is an unfair comparison. Any objective comparison would require that each device be assessed based on the full value of its entire capabilities relative to its total cost.

Designing an Improved AMI Business Case Analysis

As part of a joint effort that began in the summer of 2002, the California Energy Commission, Public Utilities Commission, and Power Authority joined together in a cooperative proceeding to reexamine metering, pricing and demand response practices (CPUC 2002). In September 2003 the joint agencies concluded that a more comprehensive and integrated business case evaluation of advanced metering was warranted. The evaluation methodology proposed by the joint agencies attempts to take a comprehensive look at how AMI can affect both utility system operations and customer service.

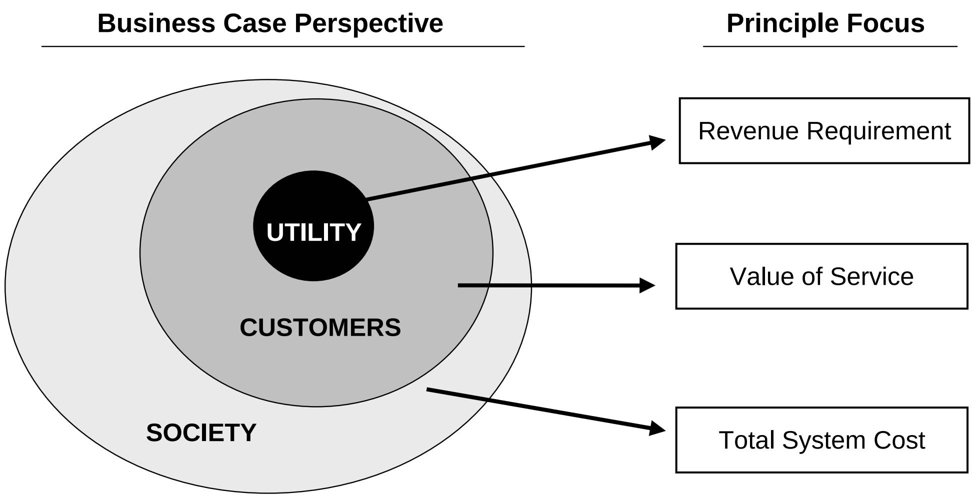
Investments in advanced metering are usually evaluated using a form of capital investment model, which computes the net present value of a stream of costs and benefits over a defined time period. The prospective investment is considered feasible only if the net present value is positive. Utilities that operate in a regulated environment may also have to consider other Pareto Optimal least cost criteria, where guidelines may mandate that: (1) the aggregate dollar value of the benefits must exceed the investment cost, and (2) the investment must also produce an outcome where no one will be worse off.

A capital investment model using net present value of costs and benefits provides a reasonable approach for evaluating the metering investment decision, provided the analytical framework adequately addresses the following issues.

Customer and Societal Benefits

The AMI business case must include factors beyond those that directly impact the utility revenue requirement, in particular: (1) customer benefits associated with improved information, and (2) the societal benefits associated with improved system reliability. The California business case model will integrate utility, customer and societal perspectives, as shown in Figure 4.

Figure 4. Scope of the California AMI Business Case Analysis



Qualitative Impacts

Uncertainty or difficulty in quantifying benefits should not preclude them from being considered. To address this issue, the California business case analysis will consider impacts out of scope only if they are not relevant to the final decision process (CPUC 2004). Table 4 gives some examples of qualitative and quantitative benefits in each of the three benefit areas.

Table 4. Types of Benefits to Include in the AMI Business Case Analysis

	Qualitative Benefits	**Quantitative Benefits**
Utility	Opportunity for improved load research and customer relations	Lower meter-reading costs
Customer	Opportunity for improved understanding of the consequences of purchases and behavior	Improved bill management
Societal	Opportunity for more equitable distribution of system costs and benefits	Fewer blackouts

Implementation and Financing Scenarios

The AMI business case analysis should contrast utility ownership with outsourced options, and at the same time contrast the base case with targeted and full implementation. Table 5 depicts the recommended scenario approach, which includes three levels of implementation (base, partial, and full) and two financing alternatives (utility and outsourcing).

Table 5. Recommended Scenarios for the AMI Business Case Analysis

Implementation Options	Financing Options	
	Utility Ownership	Outsourcing
1. Base Case	A_1	B_1
2. Partial Implementation	A_2	B_2
3. Full Implementation	A_3	B_3

Integrated Utility System Scope

Each of the scenarios must assume that metering is just one component of an integrated set of utility operating and information systems (Figure 1). Changes in one system, metering in particular, will create beneficial and non-beneficial impacts in other systems.

Opportunity Costs and Risks

Not having the capability to quickly respond to short-term weather related outages; normal market price spikes or longer-term outage/price situations incur a cost to both the utility and customer. For example, the inability of California's utilities and regulatory agencies to quickly implement supplemental interruptible, curtailable and demand response rates in response to the 2000-2001 shortages resulted in rotating outages and significant rate increases for all customers. Like traditional loss of load probabilities, some of these situations can be anticipated and estimated using risk-based adjustments. The potential opportunity costs and risks of not investing in AMI and related systems must be identified as part of the business case assessment.

Establishing the Base Case

Utility business case evaluations compare the costs of AMI implementation to a base case that is usually defined as the existing embedded system costs. However, the defined base case generally excludes any additional utility investment in billing, customer information, load survey, outage management and other related operating systems that may be anticipated in future years. Excluding future investment costs that either maintain or add functionality to the existing systems understates the costs of the base case. As a new system, the full implementation or AMI scenario often includes the costs to modify these same systems, without also accounting for the benefits that might accrue from these modifications. Under the recommended approach, modifications to the base case to keep the existing system up-to-date and to provide special functionality that might otherwise have been provided with AMI will be identified.

Conclusions

The effectiveness of efficiency and demand response programs could be greatly enhanced through advanced metering, which would allow customers access to energy usage information and financial feedback on their actions. In addition, new rates enabled by AMI would allow more equitable distribution of incentives to encourage efficiency and demand response. Changes in how advanced metering infrastructure is evaluated could have a significant impact in the conclusions drawn from cost-benefit analyses. In particular, taking a broad perspective that includes the qualitative and quantitative costs and benefits would likely show that AMI has net benefits to the utility, to customers, and to society.

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